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ENHANCED OIL RECOVERY FOR NORNE FIELD (STATOIL) C-SEGMENT USING ALKALINE-SURFACTANT-POLYMER FLOODING

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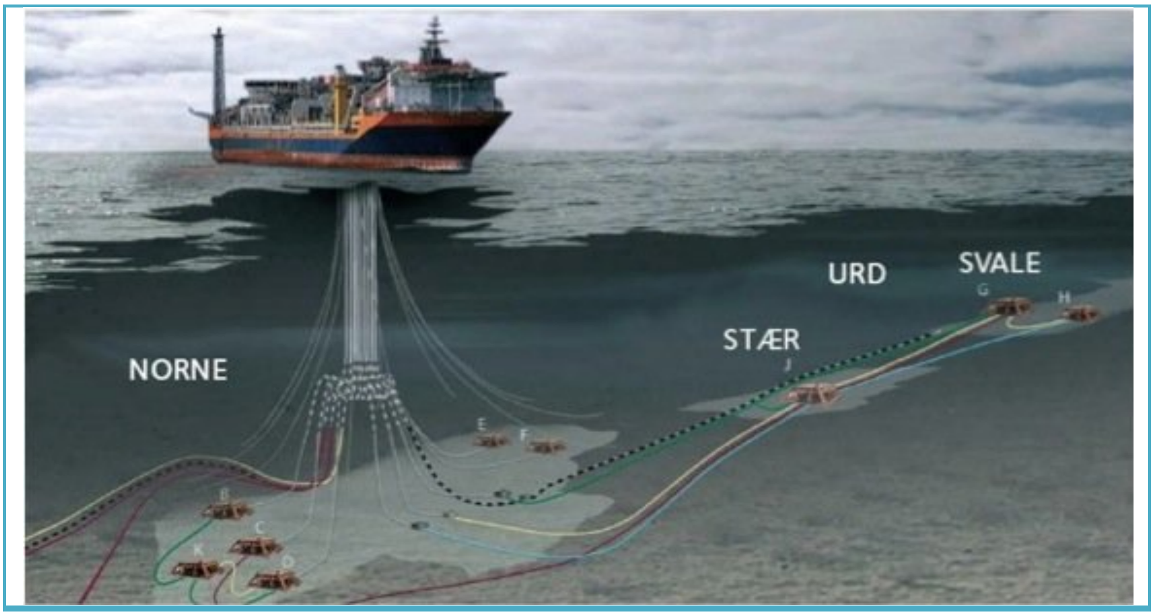

MASTER THESIS

BY

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DISCLAIMER

All ideas expressed in this thesis work are my opinions and do not necessarily reflect the views of Statoil and the Norne field operating partners.

ABSTRACT

A great percentage of oil is observed to be left in the reservoir after the traditional primary and secondary recovery methods. This oil is described as immobile oil. Alkaline-Surfactants are chemicals used to reduce the interfacial tension between the involved fluids, while polymer is used in making the immobile oil mobile.

Norne C-segment is in the decline stage and is facing considerable challenges regarding volume of oil bye-passed due to water flooding. There is need for developing cost efficient enhanced oil recovery (EOR) methods that would be suitable for Norne fluid and rock properties and therefore improve sweep efficiency significantly. Based on literature and screening criteria, alkaline-surfactant-polymer can be used as an enhancing agent to produce extra oil and reduce water-cut significantly in the C-segment.

The objective of this work is to evaluate the possibilities of using alkaline, surfactant and/or polymer to increase the oil recovery factor and prolong the production decline stage of Norne field. An initial study was conducted using heterogeneous synthetic models (with Norne C-segment fluids and rock properties) to assess the suitability of alkaline/surfactant/polymer (ASP) flooding. All the chemical cases simulated gave substantial incremental oil production and water-cut reduction.

However, history matched Norne C-segment reservoir model was used to simulate alkaline-surfactant-polymer flooding using Eclipse 100. Appropriate chemical quantity for injection was ascertained by simulating several cases with different concentration, injection length and time of injection. Different sensitivity analyses were made and simulations revealed that the most effective method was not the most profitable. Having established most profitable method which was injecting ASP slug with a concentration of 7Kg/m3, 2Kg/m3 and 0.3Kg/m3 into C-3H (injector) for 4-years in a cyclic manner, an incremental recovery factor of 2.61% was recorded and Net Present Value (NPV) was calculated to be 1660 x10^3MNOK.

ACKNOWLEDGEMENT

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NOMENCLATURE

Symbols

μ	Viscosity
Bbl	Barrel
B_o	Oil formation volume factor
Cr	Rock Compressibility
Dp	Pressure Gradient
K_a	Absolute Permeability
K_{eff}	Effective Permeability
Kg	Kilogram.
K_{rg}	Relative Permeability to Gas
K_{ro}	Relative Permeability to Oil
P_c	Capillary Pressure
Q	Volumetric Flow Rate
Sm^3	Standard cubic meter
S_{oi}	Initial Oil Saturation
S_{or}	Residual Oil Saturation
S_{wi}	Irreducible Water Saturation
T	Temperature
USD	United State Dollar
V	Velocity
V_b	Bulk Volume
V_p	Pore Volume
ϴ	Contact Angle
λ	Mobility
ρ_o	Oil Density
σ	Interfacial tension
Φ	Porosity
Ҡ	Permeability

Abbreviations

$(1+r)^t$	Discount Factor
2D	Two-Dimensional
3D	Three-Dimensional
AdC	Polymer Adsorptive Capacity on the Rock
AIME	American Institute of Mechanical Engineers
AS	Alkaline Surfactant
ASP	Alkaline Surfactant Polymer
BHP	Bottom Hole Pressure
BSm^3	Billion Standard Cubic-Meters
CA (C_{surf})	Adsorption Isotherm
CAo	Concentration of acid in Oil
CA_w	Concentration of acid in Water

CDC	Capillary Desaturation Curve
CMC	Critical Micelar Concentration
CON	Concentration
Cp	Polymer Adsorbed
DX	Grid thickness in x-direction
DY	Grid thickness in y-direction
DZ	Grid thickness in z-direction
E_A	Areal Displacement Efficiency
E_d	Displacement Efficiency
EIT	Expert in Team
EOR	Enhanced Oil Recovery
E_V	Vertical Displacement Efficiency
F_{kr}	Permeability Reduction Factor
Fo	Fractional flow of Oil
FOE	Field Oil Efficiency
FPSO	Floating Production Storage and Offloading
FVF	Formation Volume Factor
GOC	Gas Oil Contact
GOE	Group Oil Efficiency
GOR	Gas Oil Ratio
GTADSUR	Group Total Surfactant Adsorption
GTPTSUR	Group Total Surfactant Production
GTPTSUR	Group Total Surfactant Production
HEC	Hydroxyl Ethyl Cellulose
HPAM	
IFT	Interfacial Tension
IOC	Centre for Integrated Operations
IPT	Institute of Petroleum Technology
K_n	Partition Coefficient
K_p	Rock Permeability when Aqueous Polymer Solution Flows
Kw	Rock Permeability when Water Flows
LS	Low Salinity
LSW	Low Salinity Water
LSWF	Low Salinity Water Flooding
M	Mobility Ratio
MD	Rock Mass Density
MEOR	Microbial Enhanced Oil Recovery
MNOK	Million Norwegian Kroner
MSm3	Million Standard Cubic-Meters
MultPV	Multiply Pore Volume
Nc	Capillary Number
NCF	Net Cash Flow
NGL	Natural Gas Liquid
NOK	Norwegian Kroner
NPD	Norwegian Petroleum Directorate
NPV	Net Present Value
NTNU	Norwegian University of Science and Technology
OGIP	Original Gas in Place

OOIP	Original Oil in Place
OWC	Oil Water Contact
$P_{or}V$	Pore Volume
PV	Present Value
PVT	Pressure Volume Temperature
ROS	Remaining Oil Saturation
SAGD	Steam Assisted Gravity Drainage
SCM	Standard Cubic Metre
SP	Surfactant Polymer
SPE	Society of Petroleum Engineers
SUR	Surfactant
V	Pore Velocity
WAG	Water Alternating Gas
σ_{os}	Interfacial tension between Oil and Substrate
σ_{ow}	Interfacial Tension between Oil and Water
σ_{WS}	Interfacial Tension between Water and Substrate

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CHAPTER 1

INTRODUCTION

1.1 Background

Globally, annual oil consumption has increased from 30.7 billion barrels in 2005 to 34.6 billion barrels in 2010 and is expected to increase to more than 44.6 billion barrels in 2020 (BP report, 2011). Presently, there is no viable economical substitute for crude oil and this can be given as one of the reasons for continuous exploration and discovery of volume of oil around the world. This is mainly due to two reasons which are: access to some very prospective resources areas and advances in technology. Every oil reservoir, whether mature, recent or yet to be discovered, is a candidate for enhanced oil recovery (Steven L. B et al, 2000). This is because reservoirs still contain significant amount of oil after conventional primary and secondary recovery processes. Primary and secondary methods are typically used one after another in the development of an oilfield, and the transition between methods occurs when production method becomes uneconomical. In some fields, Tertiary methods follow primary depletion without necessarily using secondary strategy to improve recovery of the field.

In the Norwegian continental shelf, current average recovery factors are above 46%. The ministry of petroleum and energy of Norway established a task force in 2001 to face the challenge of targeting 50% average oil recovery factor. Among other strategies, EOR was one of the solutions to meet this objective (Kleppe et al, 2008).

The future of many world waters looks very different from what has been the case earlier. The first 40 years of Norwegian continental shelf's oil history have been the age of the giants (Statfjord, Ekofisk, Gullfaks, Oseberg and Troll). Three out of four discovered fields since 2007 are large or medium-sized. The future will be characterized with marginal fields and enhanced oil recovery techniques (Statoil, 2006). Many producers have promised the market a stable output despite the declining assets; this implies that they are faced with challenges and commitments of looking for optimum solutions to get the maximum out of the big fields.

Alkaline surfactant polymer (ASP) process is considered as a potential method for enhanced oil recovery (Nelson et al, (1984). Clark et al noted different recovery methods, water flooding (40% OOIP), polymer-augmented water flooding (40% OOIP), an alkaline/polymer (40% OOIP) and an alkaline/surfactant/polymer (ASP) flooding (56% OOIP). (Nelson et al ,1984) demonstrated that Alkaline/Surfactant/Polymer has a much better post-water-flood record and could extend field life and increase recovery.

Many academic researchers have simulated chemical EOR processes on Norne E-segment, recently (Kalnaes, 2010) and (Emegwalu, 2010) in their academic works concluded that surfactant flooding is a good candidate for Norne E-segment. (Awolola et al, 2011) concluded that surfactant flooding is a good choice for E-segment (Norne) provided the oil price is high. Also (Maheshwari, 2011) in his comparative simulation study of chemical EOR methodologies with a case study of Norne E-segment concluded that if chemical (alkaline, surfactant and/or polymer) is injected earlier, it can yield an incremental oil recovery of 1.4%. Alkaline/Surfactant/Polymer is not just a simple combination of three different chemicals.
All these researchers focused on producing extra oil. The mechanisms, operational strategies and optimization of ASP processes must be fully understood and tested before real field

application. Therefore, this thesis is aimed at increasing oil recovery in Norne C-segment by increasing capillary number (ultra-lowering interfacial tension IFT) and increasing sweep efficiency through chemical improved (Alkaline/Surfactant/Polymer) water flooding. Norne full field model is used for this investigation with emphasis on C-segment.

1.2 Objective of Study

The main objective of this thesis is to obtain an optimized condition where different concentration of alkaline, surfactant and polymer can produce desirable properties and interfacial tension for its use in enhancing oil production in the Norne C-segment. Alkaline-surfactant–polymer injection, although relatively new in Norwegian continental shelf has demonstrated huge influence in term of incremental oil production in many sandstone reservoirs around the world.

When Norne field started production in November, 1996 (with recoverable reserve of 93.4 million SCM oil, 11.7 billion SCM gas and 1.7 million tones NGL) the plan was to end production in 2016. But for a good reservoir like Norne having water injection as production drive mechanism and also with some new discoveries close to it, this PDO has been extended till 2021. Since this reservoir has been flooded for many years with water, there is bound to be pockets of oils unswept (immobile) especially in the Ile and Tofte formations that accommodate 80% of total oil and also gas condensate in the Not formation. As at 2011, the reservoir contains 8.8 million SCM of oil, 5.5 billion SCM of gas and 0.9 million tons of NGL) of recoverable reserve.

A synergetic chemical is needed to ultra-lower the high interfacial tension that exists between water and oil in these two formations. It is better to produce as much as possible from a brown field (old) by employing an appropriate EOR to extend reservoir pool life and extract incremental reserves that are inaccessible by mere water injection rather than incurring high expenses on green (new) fields that are full of uncertainties. This thesis therefore analyses the mechanism and economic benefits of alkaline, surfactant and polymer on Norne mixed wettability rock and crude properties.

1.3 Methodology

The numerical simulation of the effect of lowering IFT on Norne C-segment using Eclipse 100 simulator requires two types of synthetic models and C-segment coarsened model. These models include heterogeneous model (layered case), heterogeneous model (Inclusion case) and Norne C-segment coarsened model. Inclusion depicts part of reservoir with different permeability compared with surrounding matrix and coarsened model represents number of active cells in the amalgamated global grid.

Saturation dependent data, rock properties and fluid properties from Norne field are introduced in each model. The way the synthetic model works; chemical (AS and/or P) solution is injected into the model, chemical concentration solved by conservation equation in the water phase, interfacial tension is calculated as a function of chemical concentration, capillary number is calculated as a function of interfacial tension, oil and water phase relative permeability is interpolated as function of capillary number. Water-oil capillary pressure reduced as a function of chemical concentration, chemical adsorbs onto the reservoir rock and finally wettability of the rock changes as a function of amount of chemical adsorbed.

Firstly, 2-D heterogeneous stratified model of 10 x 1 x 5 in I, J and K direction representing vertical heterogeneity containing five layers with different permeability and porosity was used to capture Norne reservoir simulation conditions. This represents a vertical cross section of a reservoir and effect of vertical heterogeneity and gravity segregation on reduced IFT was simulated.

Secondly, heterogeneity was introduced through inclusion**.** 3-D model of 10 x 10 x 3 was used to demonstrate chemical flooding behavior in a low permeability inclusion model. This illustrates variation in permeability distribution in some part of the reservoir as compared to entire reservoir matrices. It is a representation of heterogeneity that mostly occurs in mixed-wet rocks including Norne. When fluids flow in a porous medium, rock heterogeneous property result into capillary trapping of one or more phases flowing through the porous medium. This effect is captured in this synthetic model.

Thirdly, the flooding potentials, in form of incremental oil production of surfactant, polymer, alkaline-surfactant, surfactant-polymer and alkaline-surfactant-polymer were evaluated on C-segment reservoir model using Eclipse 100. But before this, effort was made to improve this reservoir model by history matching based on 2004 geological model little improvement was achieved and a reservoir prediction file was created. The next step taken was to ascertain, in each injection system (that is, alkaline, surfactant, AS, SP and ASP) the quantity of chemical that would yield maximum recovery with minimum chemicals loss. Different screening tactics were adopted by simulating various cases within the system for different concentrations, injection period, cyclic or continuous and time of injection.

Having established the appropriate concentration for injection, the right time to inject, the efficient duration of injection, the suitable manner of flooding (continuous or cyclic) for each aforementioned chemical flooding system was the next focus. Economical viability of each project (case) was evaluated using net present value, NPV. Net present value (NPV) compares the monetary value today to the value of same money in the future, taking inflation and returns on investment into account. If the NPV of a prospective project is positive, it should be accepted. However, if NPV is negative, the project should probably be rejected because cash flows will also be negative.

Lastly, sensitivity analysis tool (tornado diagram) was brought into play to measure the impact of change in variable(s) on net present value, NPV. Sensitivity analysis show how the uncertainty in NPV of the flooding project could be apportioned to different sources in the input variables. The input variables used here are oil price, discount rate, surfactant price, inflation rate, polymer price and alkaline price.

CHAPTER 2

LITERATURE REVIEW

Some basic terms associated with this study are discussed below.

2.1 Enhanced Oil Recovery Methods

With increased demand for oil, more countries and companies are evaluating and applying enhanced oil recovery techniques to achieve the full potential of producing assets. EOR means oil recovery beyond the usual primary and secondary stages. EOR application depends on the oil properties and reservoir characteristics.

2.2 Classification of Enhanced Oil Recovery Methods

Enhanced oil Recovery methods can be broadly classified into two main groups; Thermal and non-thermal. The focus of this thesis is on non-thermal group and brief description of non-thermal processes are given below. Most of the light oils are produced globally with non-thermal methods as summarized in figure1.

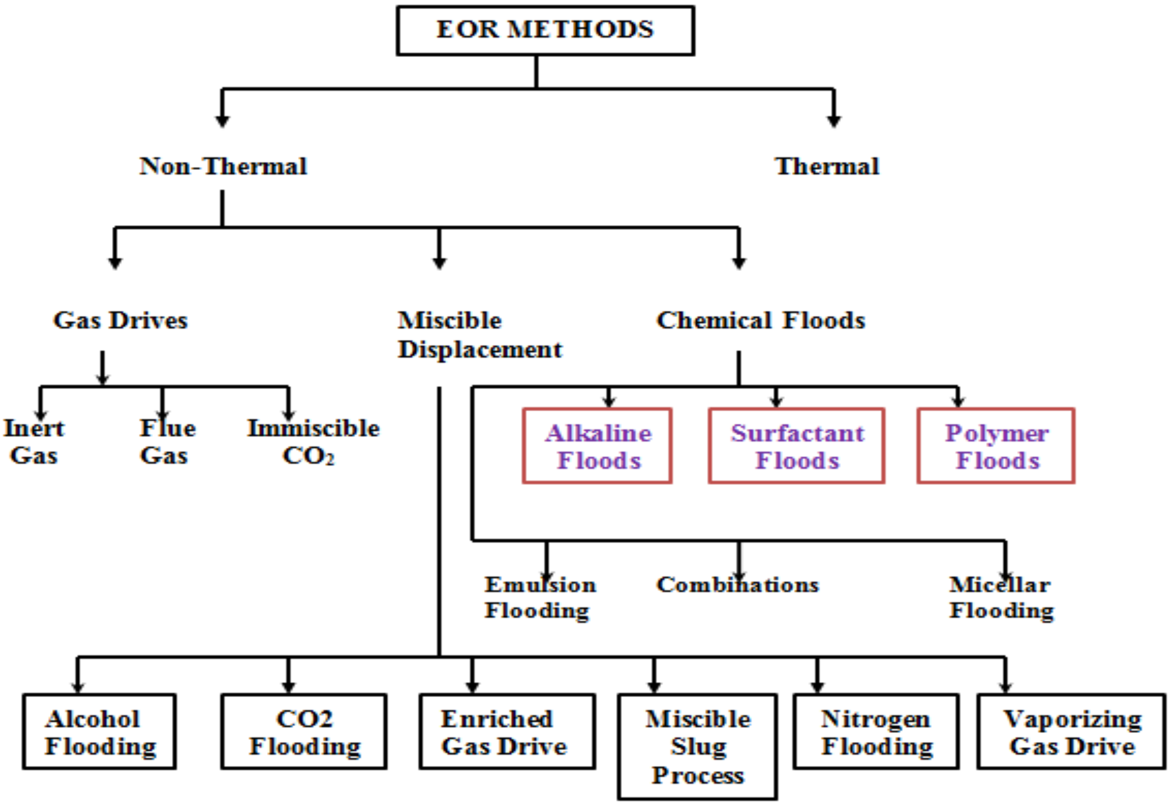


Figure 1: Classification of EOR Methods. Farouq Ali et al **(1996)**

2.2.1 Chemical Processes

Chemicals are injected to improve oil efficiency. Surfactants and alkaline when introduced into the reservoir tend to alter interfacial tension to increase oil production. In some reservoir, dilute solution of water soluble polymer increase the viscosity of the injected water and can increase oil production.

The main challenge associated with chemical flooding is the problem of adsorption and loss onto rock of the oil containing formation.

2.2.2 Mobility-Controlled Processes

The overall efficacy of the EOR process depends on both, macroscopic and microscopic efficiencies. The mobility ratio controls the aerial sweep in the reservoir, and the vertical sweep is controlled by the difference in the densities of the injected and displaced fluids. The low residual oil saturations in swept zones, and overall poor volumetric reservoir sweep are the main issue in a chemical flood. (Bataweel M. A et al, 2012)

2.2.3 Low-Salinity Water Flooding

This is an enhanced oil recovery method that uses water with a low concentration of dissolved salts as a flooding medium.

For so many years water flooding has been used as an oil recovery method after primary depletion of reservoir pressure. In the early years, the volume of water injected was considered as the most important factor in recovering oil. Later it was discovered that the composition and quality of the water are more important factors in optimizing oil recovery by water flooding.

Conditions identified with low salinity by (Tang and Morrow, 1999) in sandstone cores are as follows:

- Clay fraction present in sandstone
- Presence of connate water
- Exposure to crude oil to create mixed-wet conditions

Low-salinity brine injection is one of the most in expensive and environmentally friendly oil recovery methods. Other advantages of this injection method are: reduction in scaling and corrosion of equipment in the fields as well as potential for reservoir souring. These factors favor project economics (Gamage et al 2011).

2.2.4 Micelar Flooding

Micro emulsion or micelar flooding is a complex but very promising tertiary oil recovery method for light oils. This consists of the injection of micelar solution.

2.2.5 Microbial (MEOR)

Microbes are discovered and developed using gene mutation which functions either by generating bio-surfactants, digesting long hydrocarbon molecules or by emitting carbon dioxide which can function as gas injection.

2.2.6 Miscible Processes

A miscible process is one in which both displacing and displaced fluids mix in all proportions to form one phase. The interfacial tension is zero, capillary number becomes very large and the microscopic displacement efficiency is maximized. Types of miscible processes are: single-contact miscible process which involves injection fluids as liquefied petroleum gases and alcohols. The injected fluids are miscible with residual oil immediately on contact.

The second type is the multiple-contact, in which the injected fluids do not form miscibility on first contact. The injected fluid and oil are not miscible on first contact but rely on a process of chemical exchange of the intermediate hydrocarbons between phases to have miscibility. (Ghaderi S.M et al, 2012)

2.2.7 Miscible Slug Process

Propane or LPG slug is injected and is mostly driven by lean gas for example flue gas. Sometimes water is injected with the drive gas in small alternating slugs. A gas-slug inter phase will be formed to improve the mobility ratio.

2.2.8 Condensing Gas Drive

Here, a slug of gas enriched with ethane to hexane fractions is injected, driven by lean gas and water in the WAG mode. These crude fractions joined the oil around injector while lean gas moves ahead. A miscible zone is usually formed between injected gas and the reservoir oil and displaces the oil further.

2.2.9 Vaporizing Gas Drive

This is a multiple contact process, using lean gas (e.g. methane). In this case, ethane to hexane fractions are transferred from the oil to the gas until miscibility is obtained.

2.2.10 Gas Injection

Gas injection involves injecting natural gas, nitrogen or carbon dioxide into the reservoir. The gases can either push oil through the reservoir or, mix with the oil thereby decreasing the viscosity and increasing flow. (Mansour Soroush et al, 2012)

2.3 Previous Works on ASP Flooding

Study in the early 90’s by Dakuang H. showed that emphasis was placed on alkaline-surfactant-polymer combined flooding mechanisms. A pilot test of ASP flooding was implemented in Shengli oil field and pilot test of AP flooding was carried out in the Liaohe oil field. The ASP flooding yielded 13.4% OOIP incremental recovery and 30.4% remaining oil recovery. (Dakuang H., 1997) investigation revealed that ASP flooding not only could increase the swept volume by improving the mobility ratio, but also could significantly decrease the interfacial tension at oil-water interface. This was because the synergism of two kinds of surfactants which are the added surfactant and one generated by the interaction of alkaline agent with acid substance in the crude contributed to IFT reduction.

(Nelson et al, 1984) recognized that in most cases the soaps formed by injecting alkali would not be at the optimal conditions needed to achieve low tensions. They proposed that a relatively small amount of a suitable surfactant be injected with the alkali so that the surfactant/soap mixture would be optimal at reservoir conditions. With polymer added for mobility control the process would be an alkaline-surfactant-polymer (ASP) flood. The use of alkali also reduces adsorption of anionic surfactants on sandstones because the high pH reverses the charge of the positively charged particle sites where adsorption occurs.

Zhang et al (2006) developed a one dimensional simulator which has the capability to model the in-situ soap generation and track its movement. Other chemical reactions which may occur during the ASP flooding such as cation exchange and precipitation or dissolution reactions were not considered in their model. One of the main assumptions in their model was that all the naphthenic acid present in the crude oil will be converted to soap in the presence of alkali.

Stoll et al,2010) discussed a flow work for design of ASP from laboratory scale to pilot scale as a feasibility study of ASP in a field wide sandstone reservoir in Oman. They simulated the ASP floods by including limited set of reaction such as carbonate-bicarbonate and saponification of petroleum acid to soap and cation exchange between sodium and hydrogen on clay. A “mixing rule” is used to calculate the optimum salinity of mixture of soap and surfactant. The phase behavior is not modeled but instead they used a power law partitioning coefficient between oil and water in the presence of soap and surfactant.

2.4 Principles of Improved Recovery

Mobility ratio and capillary number improvement are the focal point of most recovery methods including chemical flooding. It is therefore imperative to discuss the underlying principles and to explain the important concepts associated with improved recovery using chemical flooding

2.4.1 Mobilization of Remaining Oil

At the early stages of a water flood in a water-wet reservoir system, the brine exists as a film around the sand grains and the oil fills the remaining pore space. At a time intermediate during the flood, the oil saturation would decrease and exists partly as a continuous phase in some pore spaces but as discontinuous droplets in other pores. At the end of the flood, when the oil has been reduced to residual oil saturation, the oil exists primarily as immobile oil that has been isolated and trapped by the displacing brine. The water flooding of oil in an oil-wet system yields a different fluid distribution (Ajay Mandal et al, 2008).

At the beginning during water injection, the brine forms continuous flow paths through the center portions of some of the pore spaces. The brine enters more and more of the pore spaces as the water flood progresses. At residual oil saturation, the brine must have entered a sufficient number of pore spaces to put-off the oil flow. The residual oil exists as a film around the sand grains. In the smaller flow channels, this film may occupy the entire void spaces. (Craig F. F et al, 1957)

In all wettability systems, mobilization of oil requires that the discontinuous globules be connected to form a continuous flow channel that leads to a producing well. But in mixed-wet porous medium, the film of oil around the sand grains must be displaced to large pore channels and be connected in a continuous phase before it can be mobilized. The mobilization of oil is governed by the viscous forces (pressure gradients) and the interfacial tension forces that exist in the sand grain oil-water system.

2.4.2 Reservoir Rhythmicity

The influence of water and chemical flooding on reservoir follow different rhythmicity. Permeability rhythmicity plays important influence in oil recovery. Different correlations can be made under different and same Kv/Kh. In most reservoirs we can have either positive rhythm, negative rhythm or combinative rhythm. When Kv/Kh=0, the results of positive, negative and combinative rhythm are very similar (Yuan, S. et al, 1998).

For positive rhythm, the increase of Kv/Kh is unfavorable for injection by water because of gravity. But for chemical flooding, increase in Kv/Kh influences vertical seepage and further extension of the sweeping volume of displacement solution, which is favorable for EOR.

2.4.3 Mobility Ratio

This is expressed as the ratio of mobility of displacing fluid to that of displaced fluid. In a water flooding system, if M>1, the displacing fluid moves faster than the displaced liquid that is, oil. This is not desirable because the displacing fluid will overflow displaced fluid. For M much larger than 1, the displacing fluid will channel past oil front. This is called ''viscous fingering''. For maximum displacement efficacy, M should be less than or equal to 1. Viscous fluid (polymer) is used in ASP project to achieve M being less than unity. This is possible by:

- Improving relative permeabilities (water and oil)
- Increasing the viscosity of displacing fluid, Water
- Decreasing the viscosity of displaced fluid, oil

Areal sweep efficiency, displacement and vertical sweep efficiency decrease as the mobility ratio increases (Larry W. Lake, 1989).

$$\lambda = {}^{K_i}/_{\mu_i} \qquad (2.1)$$

λ = Mobility

μ = Fluid Viscosity

K = Effective Permeability

i = Fluid (Oil, Water)

$$M = \frac{\mu_o K_{rw}}{\mu_w K_{ro}} \qquad (2.2)$$

M = Mobility Ratio

K_{rw} = Relative permeability to Water

K_{ro}= Relative permeability to Oil

2.4.4 Capillary Number

A dimensionless group estimating the ratio of viscous forces to capillary forces. Another aim of EOR project is to maximize the flowing ability of the fluid through the reservoir.

$$N_c = {}^{\mu V}/_{\sigma} \quad (2.3)$$

N_c = Capillary Pressure
V = Pore Velocity
μ = Fluid viscosity
σ = Interfacial Tension between Oil and Water

2.4.5 Dispersion of Chemicals

Chemical dispersion is normally unfavorable. It will lower the concentration of chemical slugs and efficiency. When the concentration of injected chemicals is relatively high and slug size is relatively big, the effect due to chemical dispersion will be small (Delshad M. et al, 1986).

2.4.6 Displacement Efficiency

This is the fraction of original oil saturation that has been displaced from the pores by water. Residual oil can be recovered by injecting a fluid that will be miscible with the reservoir oil so as to dislodge the oil droplet by dynamic or viscous force (Larry W. Lake, 1989)

2.4.7 Chemical Adsorption

Chemical adsorption affects directly the economic and technological efficiency. But chemical adsorption is sometimes useful for the decrease of permeability of water phase

2.4.8 Areal Sweep Efficiency

This is the fractional area of a path that is swept by water. Enhanced recovery program can improve sweep efficiency by lowering the mobility ratio and this can be achieved by raising the viscosity of injected water using polymer.

2.4.9 Contact Factor

Contact factor is the fraction of the swept volume that can be reached or contacted by the injection fluid.

CHAPTER 3

EVALUATION OF ALKALINE-SURFACTANT-POLYMER PROCESSES

3.1 Polymer Method

Polymer flooding may involve addition of polymer to the water of a water flood to decrease its mobility. The resulting increase in viscosity, as well as a decrease in the resulting aqueous phase permeability, causes a lower mobility ratio. This lowering usually increases efficiency of the water flood through greater volumetric sweep efficiency. In most cases, polymer is economical only if the water flood mobility is high, the reservoir heterogeneity is high or a combination of these two occurs (Larry W. Lake, 1989).

Polymers can be used in oil production in three modes**:**

- As agents to lower water-oil mobility ratio.
- As near-well treatment to improve injector performance by blocking high conductivity zones
- As in situ cross-linked agent used to plug high conductivity zone in the reservoir depth

3.1.1 Types of Polymers

There are two main types of polymers used for flooding; synthetic polymers and biopolymers. Other types of polymers are natural polymers and their derivatives. This includes hydroxyl ethyl cellulose (HEC), guar gum and sodium carboxymethyl cellulose.

3.1.2 Hydrolyzed Polyacrylamide

Structurally, polyacrylamide is similar to polyethylene with hydrogen atom on every other carbon replaced by an amide group.—$CONH_2$. The amide groups permit linkage between polymer strands. The structure –CONHCO- is formed when CONH2 group from one molecule reacts with the same group of another molecule. The linked amide groups form hydrogen bond with water molecules. Generally, the performance of a polyacrylamide in a flooding process will depend on its molecular weight and its degree of hydrolysis.

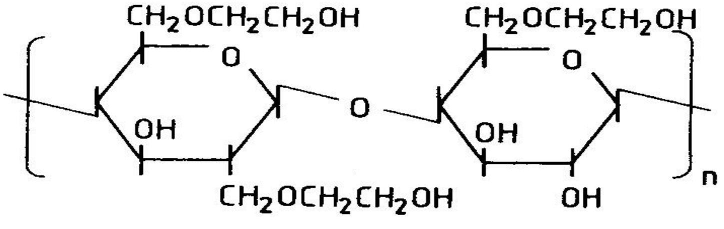


Figure 2: Molecular structure of hydroxyl ethyl cellulose

3.1.3 Xanthan Gum

Xanthan gum is a member of biopolymer which is produced by bacterium xanthomonas campestris. Biopolymers fall toward the low end of the range of polyacrylamides, in term of molecular weight. Their molecular structure is stiff making biopolymers excellent viscofying agents with high resistance to shear degradation.

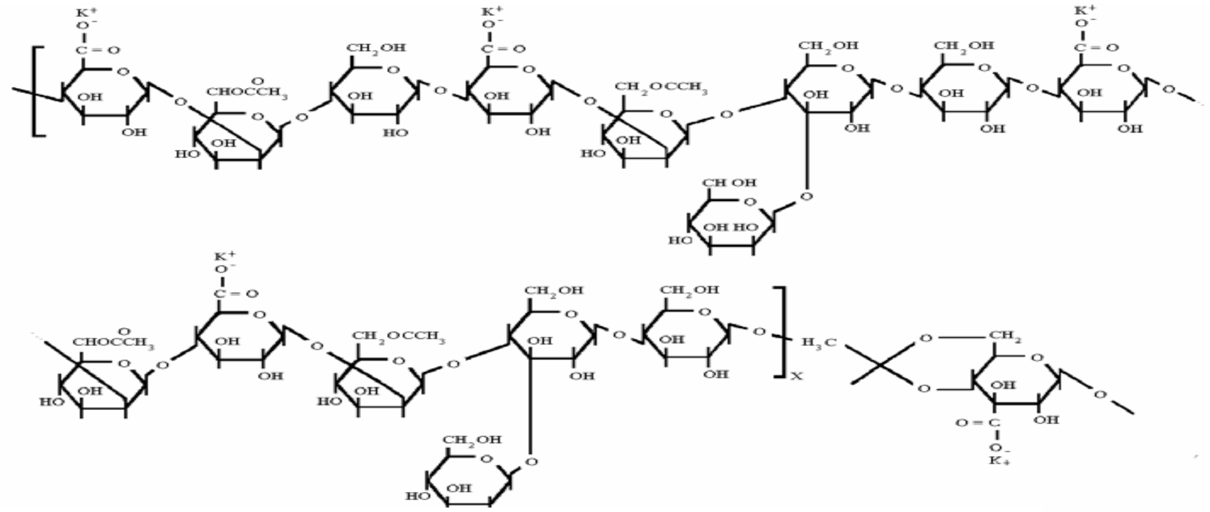


Figure 3: molecular structure of xanthan (Lake L.W **(1989)**

3.2 Polymer Flooding Mechanisms

The fluid-flow variation in the reservoir is one of the main mechanisms of EOR of polymer flooding, and the nonlinear coupling and interaction between pressure and saturation fields results in the fluid-flow variation in the reservoir. In the vertical heterogeneous reservoir, the polymer agents flow initially in the high-permeability layer. Later, the flow direction changes toward the low and middle-permeability layers because the resistance in the high-permeability layer increases on physical and chemical reactions such as adsorption, retention, and emulsion (Pingping et al, 2009).

3.2.1 Retention in Porous Media

Polymer retention includes adsorption, mechanical trapping and hydrodynamic retention. Mechanical entrapment and hydrodynamic retention are related.

3.2.2 Effect of Temperature

Adsorption of anionic and non-ionic polymers decrease with temperature because of combined electrostatic repulsion and molecular forces which include hydrophobicity, Van der Waals and hydrogen bond. For a non-ionic polymer such as HPAM, adsorption is more related to electrostatic repulsion. When the temperature is increased, it is easier for the hydrogen bond to break up, causing PAM adsorption to decrease. When the temperature is increased, the negative charge on the rock surface is increased, resulting in higher electrostatic repulsion. Thus, the ionic polymer HPAM adsorption is reduced.

3.2.3 Fractional Flow

The fractional flow analysis describes the way in which a section of reservoir approaches its ultimate residual oil saturation through relative permeability and fluids viscosities (oil and water). Darcy's law is applied to oil and water phases flowing through segment of a porous medium.

The fractional flow of oil, F_O can be written as;

$$F_o = 1/(1 + \mu_o\, K_w/\mu_w K_o) \tag{3.1}$$

Any change that reduces the ratio of $\frac{\mu_o K_w}{K_o \mu_w}$, will increase fractional flow of oil and in turn will improve rate of oil recovery.

F_o = fractional flow of oil

μ_o = Oil viscosity

μ_w = Water Viscosity

K_w = Water Permeability

K_o = Oil permeability

Fractional flow of water will be greater in reservoir where oil viscosity is high. Polymers reduce relative permeability to water. This applies to any part of the reservoir where relative permeability to oil is greater than zero. If K_o is small because the mobile oil saturation is low, then F_o will remain small at any achievable K_w or μ_w.

3.2.4 Fluid Diversion Effects

This is a phenomenon that occurs in many reservoirs which contain heterogeneous properties in both horizontal and vertical directions. This leads to preferential water entry to the more permeable zones and to more rapid sweep-out of these zones. Those areas of reservoir that are contacted by flood water do experience efficient oil recovery while other parts are left untouched.

3.2.5 Permeability Reduction and Resistance Factor

Pore blocking or permeability reduction is caused by polymer adsorption. Rock permeability is reduced when a polymer solution is flowing through a porous medium as compared with when water is made to flow through. This permeability reduction is described by permeability reduction factor (Fkr).

$$\text{Fkr} = K_w/K_P \tag{3.2}$$

K_w = Rock Perm. When Water Flows

Kp = Rock Perm. When Aqeous Polymer Solution Flows

Adsorption process is irreversible; this implies that the maximum permeability reduction corresponds to the polymer adsorptive capacity on the rock. The permeability reduction factor is linearly correlated based on the ratio of the amount of polymer adsorbed to the adsorptive capacity.

$$\text{Fkr} = 1 + (\text{Fkr}, \max - 1)\frac{C_p}{\text{AdC}} \qquad (3.3)$$

Where;

Fkr = Permeability reduction factor

C_p = Polymer Adsorbed

Adc= Polymer adsorptive capacity on the rock

3.3 Surfactant Methods

The word surfactant means a blend of surface active agent. Surfactants are amphipilic organic compounds, meaning they consist of hydrophobic group (tail) and hydrophilic group (head). They are soluble in both organic solvent and water.

3.3.1 Types of Surfactants

Surfactants are classified according to polar head group. A non-ionic surfactant has no charge groups in its head. The head of an ionic surfactant carries a net charge. If the charge is negative, the surfactant is more specifically called anionic; if the charge is positive, it is called cationic. If a surfactant contains a head with two oppositely charged groups, it is termed zwitterionic. Commonly encountered surfactants of each type include:

3.3.2 Anionic

Anionic surfactants contain anionic functional groups at their head, such as sulfate, sulfonate, phosphate, and carboxylates. Prominent alkyl sulfates include ammonium lauryl sulfate, sodium lauryl sulfate (Sodium dodecyl sulfate, SDS) and the related alkyl-ether sulfates sodium laureth sulfate, also known as sodium lauryl ether sulfate (SLES), and sodium myreth sulfate.

3.3.3 Cationic

Cationic surfactants are basically soaps or detergents, in which the hydrophilic, or water-loving, end contains a positively-charged ion, or cation. Typical examples are trimethylalkylammonium chlorides, and the chlorides or bromides of benzalkonium and alkylpyridinium ions.

3.3.4 Nonionic

Nonionic surfactants are surface active agents which do not dissociate into ions in aqueous solutions, unlike anionic surfactants which have a negative charge and cationic surfactants which have a positive charge in aqueous solution. Nonionic surfactants are more widely used as detergents than ionic surfactants because anionic surfactants are insoluble in many hard water and cationic surfactants are considered to be poor cleaners. An example is Cetyl alcohol

3.3.5 Zwitterionic

Zwitterionic (amphoteric) surfactants have both cationic and anionic centers attached to the same molecule. The cationic part is based on primary, secondary, or tertiary amines or quaternary ammonium cations. The anionic part can be more variable and include sulfonates, as in CHAPS (3-[(3-Cholamidopropyl) dimethylammonio]-1-propanesulfonate).

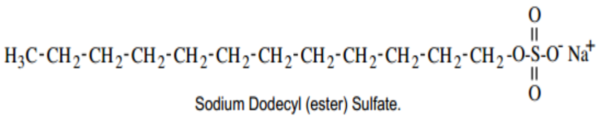
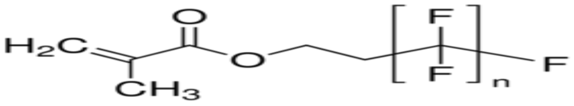
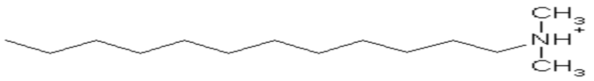
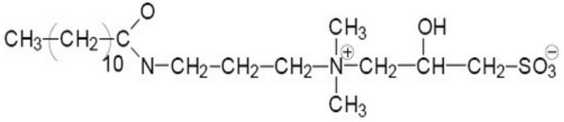
Anionic surfactant	Nonionic surfactant
 $H_3C\text{-}CH_2\text{-}CH_2\text{-}CH_2\text{-}CH_2\text{-}CH_2\text{-}CH_2\text{-}CH_2\text{-}CH_2\text{-}CH_2\text{-}CH_2\text{-}CH_2\text{-}O\text{-}\overset{O}{\underset{O}{S}}\text{-}O^-\,Na^+$	
Cationic: Benlkonium Chloride 	Zwitterionic: Cocamidopropylbetain  $CH_3\text{-}(CH_2)_{10}\text{-}\overset{O}{C}\text{-}N\text{-}CH_2\text{-}CH_2\text{-}CH_2\text{-}\overset{CH_3}{\underset{CH_3}{N^{\oplus}}}\text{-}CH_2\text{-}\overset{OH}{CH}\text{-}CH_2\text{-}SO_3^{\ominus}$

Figure4: Types of Surfactants

3.4 Concepts of Surfactant Injection

3.4.1 Darcy's Law

(Henry Darcy, 1858) describes the permeability of a medium through which the passage of viscous fluid under pressure differential in which the porous medium has a cross sectional area. Darcy is a macroscopic one-phase flow equation.

$$Q = \frac{-KA\,(dP)}{\mu L} \tag{3.4}$$

Where μ is fluid viscosity,

dP is pressure gradient

K is absolute permeability

Q = flow rate, and

A is cross-sectional area.

3.4.2 Surfactant Retention

Retention is the main limitation to the commercial application of surfactant flooding. This challenge can be traced to selectivity. Surfactants should have good selectivity for oil-water interfaces, but they should have poor selectivity for fluid-solid interfaces. This could be in a form of precipitation, phase trapping or adsorption.

3.4.3 Wettability

The preference of a solid to contact one fluid (liquid or gas), known as the wetting phase, rather than another. The wetting phase will tend to spread on the solid surface and a porous solid will tend to imbibe the wetting phase, in both cases displacing the non-wetting phase. Rocks can be water-wet, oil-wet or mixed-wet. The intermediate state between water-wet and oil-wet can be caused by a mixed-wet system, in which some surfaces or grains are water-wet and others are oil-wet, or a neutral-wet system, in which the surfaces are not strongly wet by either water or oil. (Denekas et al, 1959) described how reservoir rocks could change from strongly water-wet by adsorption of polar compounds and/or the deposition of organic matter originally present in the crude oil.

The wettability of a crude oil-rock system does pose important impact to oil flow and distribution of residual oil (Morrow, N. R, 1990). Rock minerals, connate water saturation, water and oil compositions and temperature are factors that determine level of wettability. Contact angle test is used widely to measure wettability.

$\emptyset = contact\ angle$

σ_{ow} = interfacial tension between oil and water

σ_{os} = interfacial tension between oil and substrate

σ_{ws} = interfacial tension between water and substrate

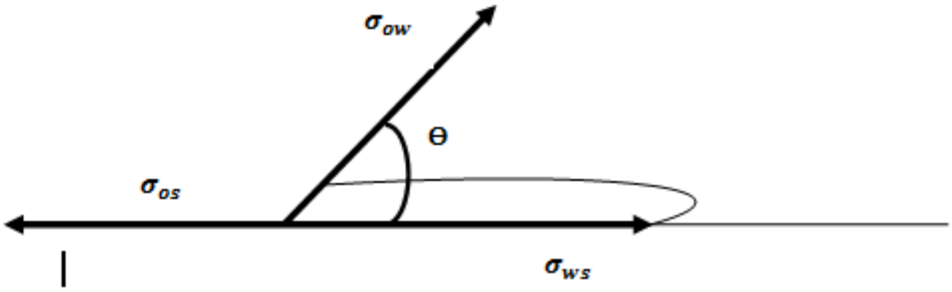


Figure 5: Contact angle measurement (Morrow N. R, 1990)

3.4.4 The displacement efficiency

The displacement efficiency is the volume of oil produced divided by the amount of oil initially present in the swept zone.

$$E_d = \frac{Soi-Sor}{Soi} \quad (3.5)$$

S_{oi}= initial oil saturation
S_{or}= residual oil saturation

Wettability, capillary pressure, viscosity, relative permeability, interfacial tension (IFT) and time are factors that determine displacement efficiency. No matter the displacement capability of the injected water, some oil would remain undisplaced due to capillary forces. The capillary force aids oil mobilization while capillary forces favor oil trapping (Delshad M. et al, 1986)

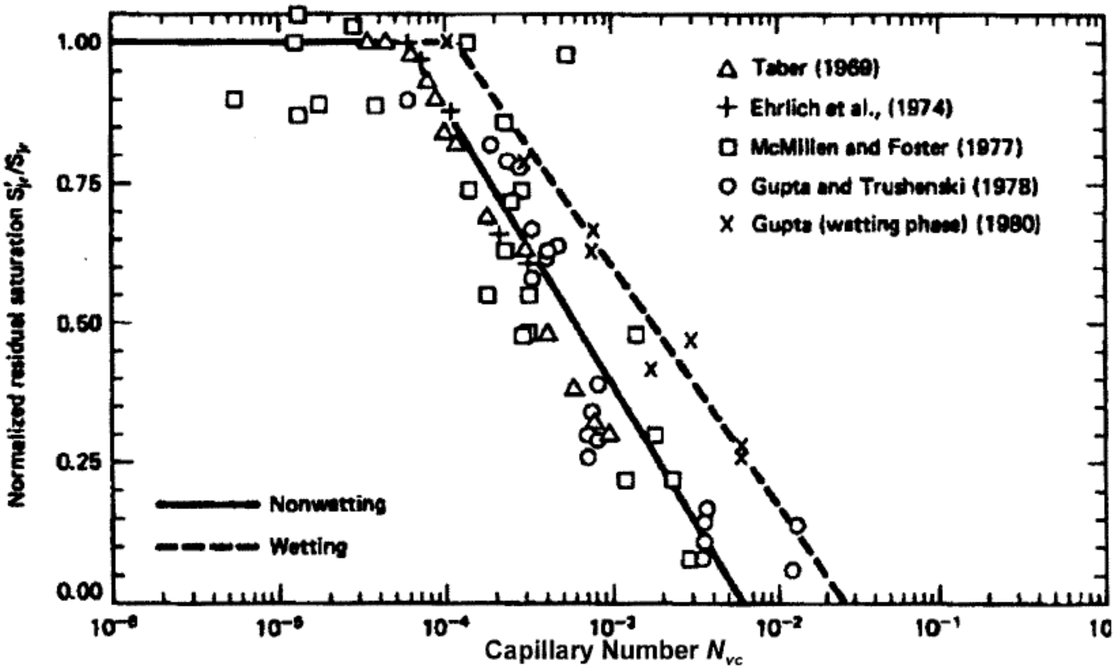


Figure 6: Capillary Desaturation Curve for sandstone cores (Delshad et al, 1986)

3.4.5 Imbibitions

This is a process whereby a porous rock absorb wetting phase into itself. Imbibition is important in water drive reservoir because it can advance or hinder water movement, affecting areal sweep. Spontaneous imbibitions refer to the process of absorption with no pressure driving the phase into the rock (Larry W. Lake, 1989). Oil and water can be imbibed into a given rock, with water imbibing at low water saturation displacing excess oil from the surface of the rock grains, and oil imbibing at low residual saturation displacing excess water.

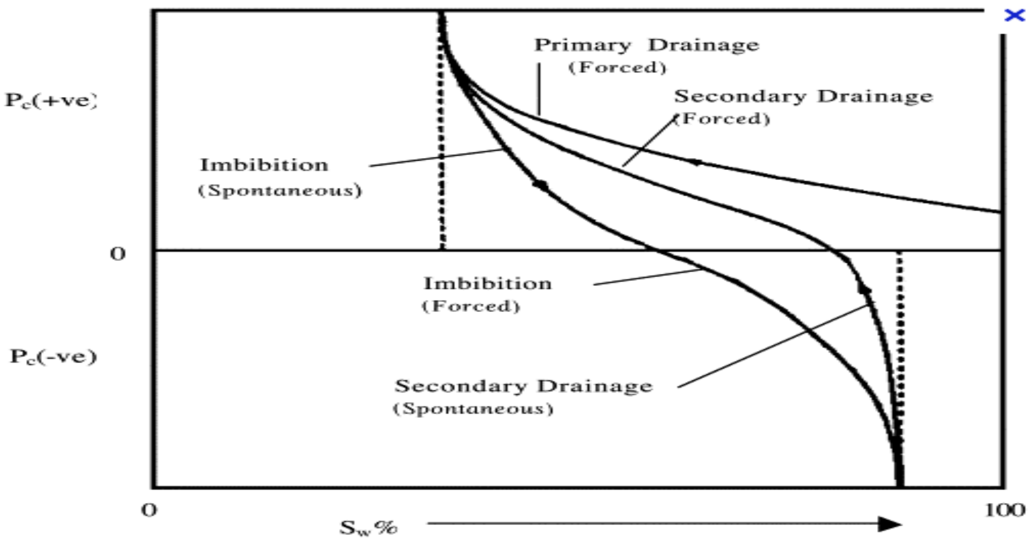


Figure 7: Drainage and imbibition process (Larry W. Lake, 1989)

3.4.6 Micellization

Micelles are formed when the surfactant concentration is more than critical micelle concentration (CMC). The micelles formation is driven by entropy because the entropy penalty of surfactants molecules gather to form a micelle is less than the entropy penalty of water molecules (or solvent) gathering together via hydrogen bonding to isolate the hydrophobic part in a cage like structures.

3.4.7 Surfactant Adsorption

Surfactant adsorption occurs instantaneously and the quantity of adsorbed surfactant depends on the concentration of the surfactant (Schwartz et al, 1977).

$$\text{Adsorbed surfactant (mass)} = \text{PorV}.\ \frac{1-\emptyset}{\emptyset}.\ \text{MD.CA}\ (C_{surf}) \qquad (3.6)$$

PorV= pore volume

$\emptyset = \text{porosity}$

MD = rock mass density

CA (C_{surf}) = adsorption isotherm

3.4.8 Relative Permeability

The relative permeability model is essentially a transition from immiscible relative permeability curves at low capillary number to miscible relative permeability curves at high capillary number. A transition between these curves is made and a table that describes the transition as a function of $\log_{10}$ of the capillary number must be included.

3.4.9 Capillary De-saturation

The capillary de-saturation function explains the transition between immiscible and miscible conditions as a function of capillary number.

3.4.10 Emulsification

Surfactants are emulsified to oil, forming oil in water emulsion and thereby improving mobility ratio and sweep efficiency. This attribute makes it easy for oil to flow easily to the production well.

3.5 Alkaline Methods

In alkaline flooding, formation of water –in-oil emulsion and wettability alteration are two very possible mechanisms for enhancement and, consequently, improving oil recovery. Alkaline floods are used because of the relatively low cost of the chemicals compared with surfactants and polymers which are hydrocarbon. Alkaline could also be used as pre-flush but most usage is in combination with surfactant and/or polymer.

Alkalis are basic ionic salt of metals or earth metals that dissolve in water. These compounds have P^H greater than 7.

Some examples are:

- Sodium hydroxide (caustic soda)
- Potassium hydroxide (caustic potash)

- Lye
- Calcium carbonates (free lime)
- Magnesium hydroxide.

According to Sydanisk (1982) experiment, it was noted that alkali solution at high temperature (85°C) might interact with sandstone, leading to sandstone weight loss and increased porosity. Alkali reactions depend on concentration, temperature, type of rock and contact time. For high reservoir brine, alkali such as Na_2CO_3 can be precipitated. For this effect, recent studies have mentioned the use of sodium metaborate as a substitute for sodium carbonate. (Hirasaki et al, 2004) suggested that sodium carbonate should be used because it gave a small surfactant adsorption compare with other alkali.

3.5.1 Alkalinity Loss

Disappearance of injected alkali into the reservoir rock surface is of great concern. The reaction of an alkali with oil, reservoir rock and brine often lead to large amount of alkali loss. Large chemical consumption could mean that the chemical requirements are very high for achieving a satisfactory rate of propagation. Hence, the loss of alkali owing to the interaction with rock minerals should not be ignored in the design of any high-pH chemical injection.

(Dezabala et al, 1982) studied the reactions responsible for alkali consumption. According to his studies, alkali loss during flooding can be grouped thus:

- Mineral dissolution
- Cation exchange
- Hydroxides precipitation

3.5.2 Cation exchange

Ca^+/H^+ exchange and associated OH^- loss is high in a reservoir of high Na^+ concentration.

$$CAo \overset{Kn}{\Leftrightarrow} CA_w$$

$$K_n = \frac{[CAw]}{[CAo]} \tag{3.7}$$

Where Kn is the partition coefficient,
CA_w is the concentration of acid in water
CA_o is concentration of acid in oil.

Dissociation of acid in water in aqueous phase to give anionic surfactant (soap)

$$CA_w \overset{Km}{\Leftrightarrow} C^+ + A^-$$

$K_m$is the reaction constant and is given by;

$$K_m = \frac{[C+][A-]}{[CAw]}. \tag{3.8}$$

3.5.3 Mineral dissolution

This involves alkali reaction with reservoir minerals during flooding. P^H increase, contact time with minerals and temperature increases alkali loss. Dissolution of reservoir minerals contributes to high alkali consumption. For instance, kaolinite, $AL_2Si_2O_5(OH)_4$ which is present in sandstone formation could dissolve at high pH

$$\text{Kaolinite} + 4OH^- + 3H_2O \rightleftarrows 2\,AL(OH)4^- + 2H3SiO4^-$$

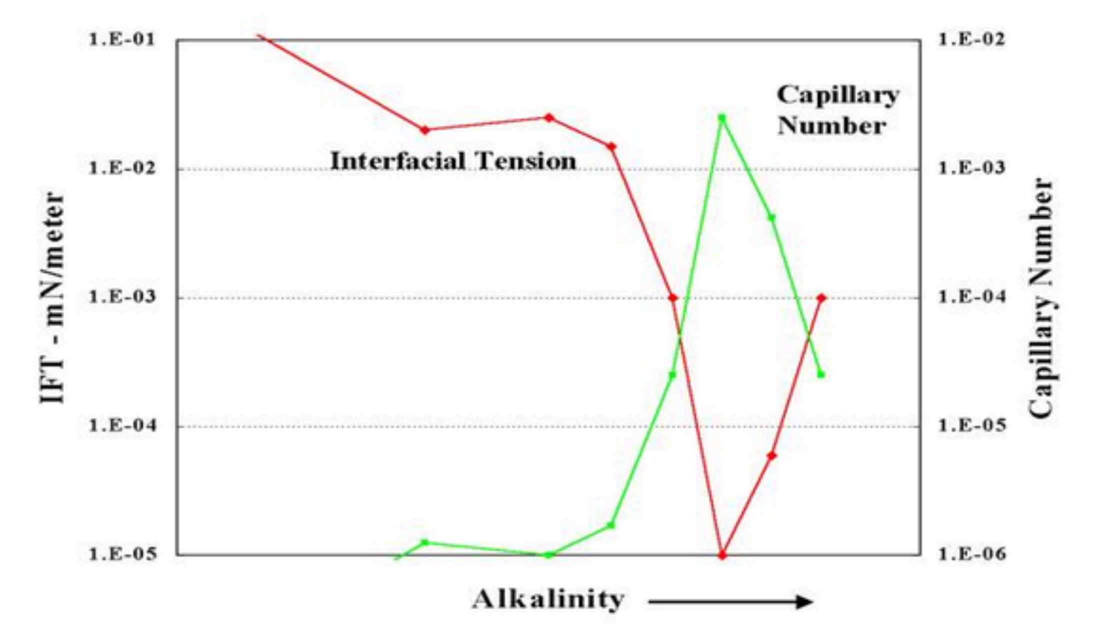


Figure 8:alkalinity against interfacial tension and capillary number (Denekas M.O et al, 1959)

The figure 8 illustrates how alkalinity reduces interfacial tension and raises the ratio of viscous to capillary forces known as capillary number. When capillary number is low for example $1x10^{-6}$, oil is trapped and when it increases to $1x10^{-3}$, oil is released.

3.5.4 Unfavorable Conditions for Chemical EOR

Among others, harsh reservoir condition is identified as the main threat to application of chemical EOR processes. These conditions are:

- Extremely high reservoir temperature
- High salinity brine
- Hard brine
- Heavy oil

CHAPTER 4

THE NORNE FIELD

4.1 General Field Overview

The Norne Field was discovered in December 1991. The Host block is approximately 9Km x 3km. It is an oil field located about 80 km north of the Heidrun field in the Norwegian Sea. The field is situated in the blocks 6608/10 and 6508/1 in the Southern part of the Nordland II area. Its location, relative to the nearby fields is shown in Figure 9**.** Development drilling began in August 1996 and oil production started November 6th, 1997. Sea depth in the area is about 380 m. The field has been developed with a production and storage vessel which is operated from Harstad in Norway by Statoil ASA and its partners EniNorge AS and Petoro (Statoil, 2006)

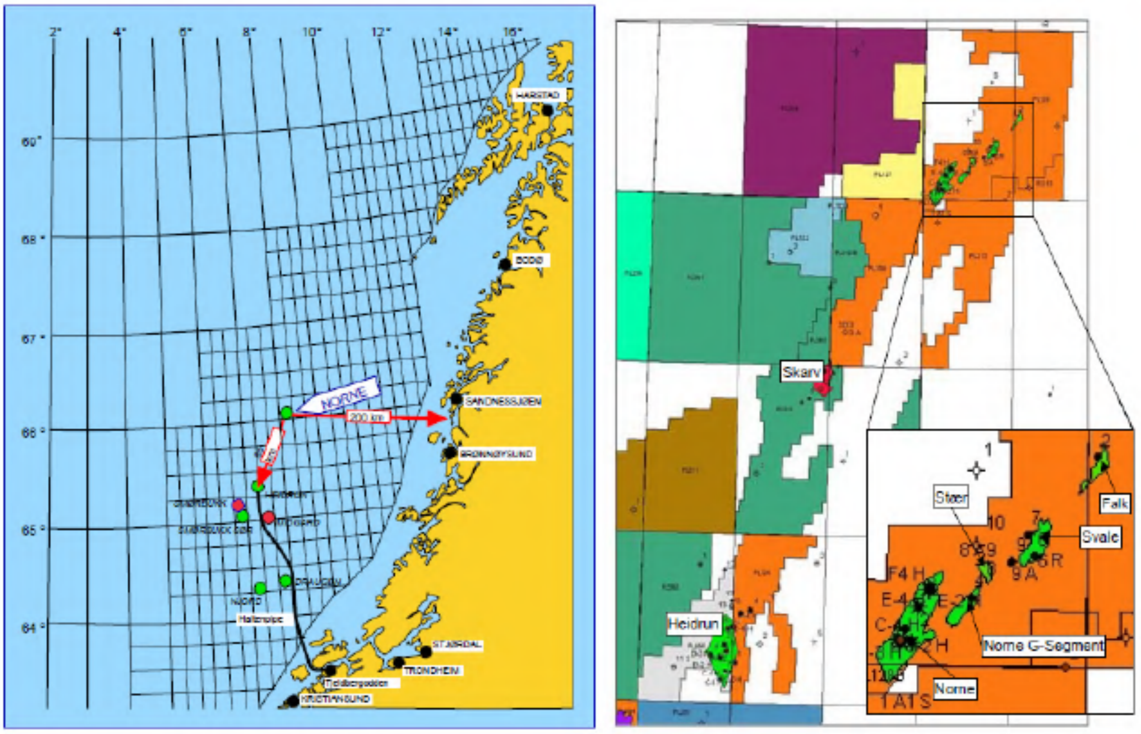


Figure 9: Norne Field Location **(Statoil, 2006)**

There are two main oil compartments in Norne field: main segments (C, D and E segments), housing 97% of OOIP, and Norne G-segment (located on the field North-Eastern part). The field was developed with a floating production and storage vessel (FPSO). The vessel is connected to six subsea templates namely B, C, D, E and K. The Field has produced 83.2 MSm^3 of oil in total as at March 2010 (Norwegian Petroleum Directorate, 2010).That is approximately 88% of initially estimated recoverable reserves.

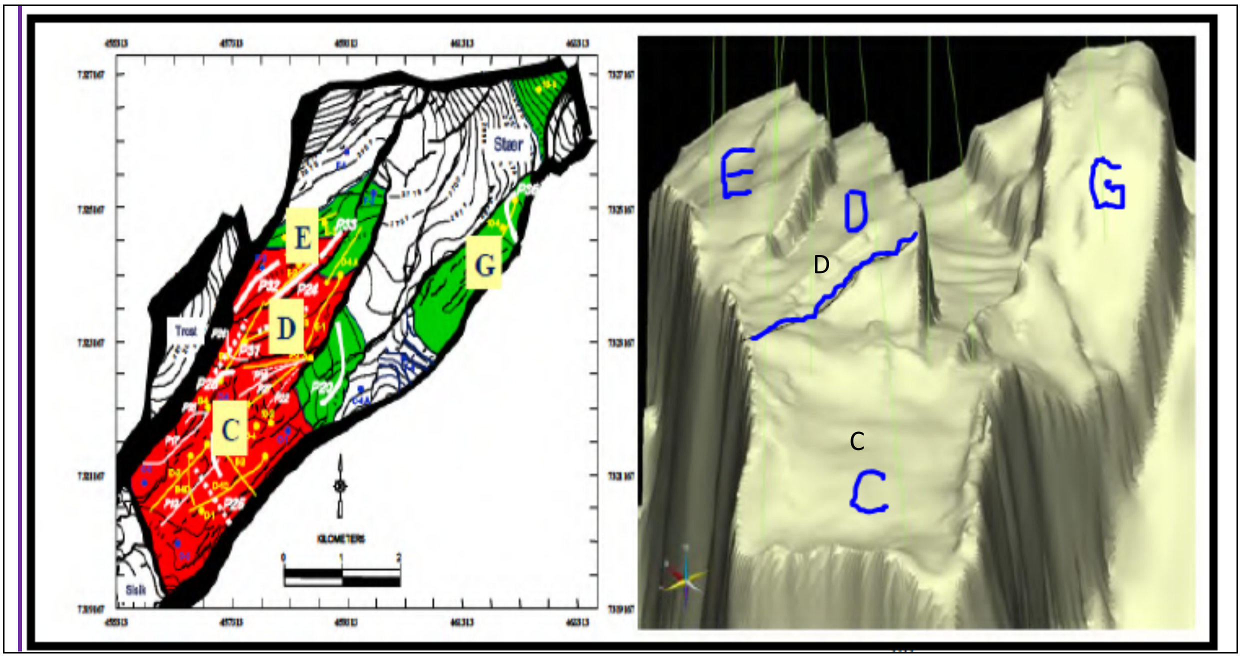


Figure 10: Norne cross-section and Top reservoir map **(Statoil, 2006)**

The main Hydrocarbon column (based on well 6608/10-2) is 135m which contains 110m oil and 25m gas. Almost 80% of oil in place is located at Ile and Tofte formations and gas in Garn formation. Reservoir rocks are of lower and middle Jurassic age.

The field structure is relatively flat with Garn being a gas filled formation and gas-oil contact in the vicinity of Not formation. GOC and OWC in different formations within C-segment are highlighted in table 1 below**.** Reservoir pressure data from development wells indicate that the Not formation is sealing and there is little or no communication with the adjacent formation during production.

Table 1: GOC and OWC in different formations of Norne C-Segment (IOC, 2010)

Formations	**C-Segment**	
	GOC (m)	OWC (m)
Garn	2582	2692
Ile	2585	2693
Tofte	2585	2693
Tilje	2585	2693

4.2 Field Reserves

As at 2007, estimated in-place for oil (OOIP) and gas (OGIP) were 157MSm^3 and 29.8BSm^3 respectively. A cumulative production of 86.3MSm^3 Oil and 6.4BSm^3 of gas have been made as at January 2012, leading to an oil recovery factor of 54.9% (Norwegian Petroleum Directorate, 2010).

Recoverable reserves estimated as at end of 2009 were 97.7 MSm^3 Oil and 10.5 BSm^3 Gas. As at February 2012 unproduced recoverable reserves were 11.4MSm^3 oil and 4.1BSm^3 gas respectively. The estimated ultimate oil recovery factor of approximately 62.2% making Norne one of the highest recovery subsea fields in the world. NPD (2010)

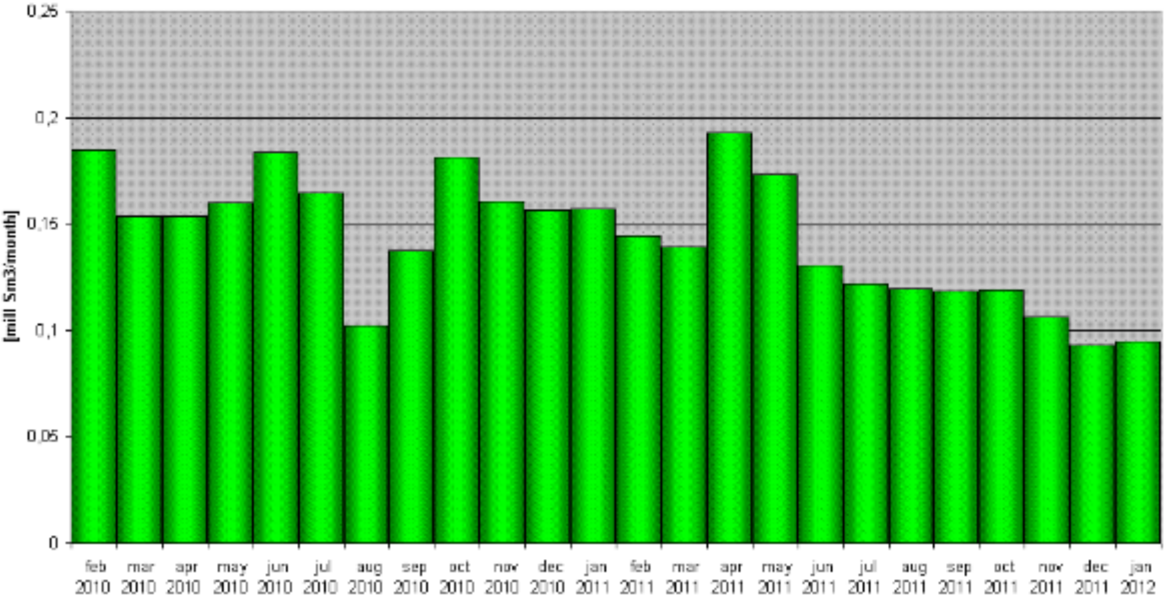


Figure 11: Norne Oil production 2010-2012 **(IOC , 2010)**

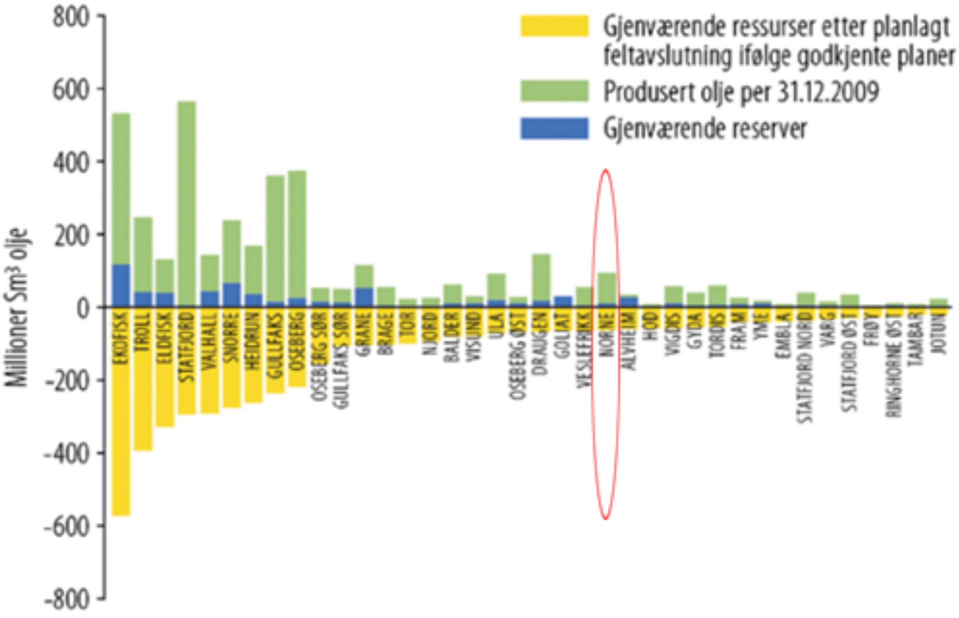


Figure 12: Remaining Norwegian Reserves (NPD, 2010)

4.3 Geological Information

4.3.1 Stratigraphy and Sedimentology

The reservoir is subdivided into four different formations from top to base: Garn, Ile, Tofte and Tilje. Hydrocarbons in this reservoir are deposited in the Lower to Middle Jurassic sandstones. The reservoir sandstones are dominated by fine-grained and well-to-very well stored sub-arkosic arenites. The sandstones are buried at a depth of 2500-2700m and are affected by digenetic processes. Mechanical compaction is the most important process which reduces reservoir quality yet, most of the sandstones are good reservoir rocks. The porosity is in the range of 25-30 percent while permeability varies from 20 to2500 mD.

The source rocks are believed to be the Spekk Formation from Late Jurassic and coal bedded Are Formation from Early Jurassic. The cap rock which seals the reservoir and keeps the oil and gas in place is the Melke formation. The Not Formation behaves as a sealing layer, preventing communication between the Garn and Ile Formations. The entire reservoir thickness, from Top Are to Top Garn Formations, varies over the Norne Field from 260 m in the southern parts to 120 m in the northern parts (Statoil, 1994). According to the seismic mapping, the reason for this difference is the increased erosion to the north, causing especially the Ile and Tilje Formations to decrease in thickness (Mari Hertland and Verlo B., 2008)

4.3.2 The Åre Formation

This is the lowest formation within the Norne Field. It is mainly comprised of channel sandstone which is 2-10 m thick and interbedded with mudstones, shale and coals. The total thickness of the formation varies from 200 m to 800 m.

4.3.3 The Tilje Formation

The formation is thinning to the north due to decreased subsidence rate during the deposition, along with increased erosion to the north/northeast at the base of the overlying Tofte Formation. This was deposited in a marginal marine, tidally affected environment. Sediments deposited are mostly sand with some clay and conglomerates.The source of the sediments was found west of the Norne area.

4.3.4 The Tofte Formation

The thickness of the Tofte Formation across the field is 50 m. The depositional environment was marine from foreshore to offshore. The Tofte Formation is divided into three reservoir zones. Tofte 1 consists of medium to coarse grained sandstones with steep dipping lamina. Tofte 1 has limited distribution in the east-west or northeast-southwest direction. Tofte 2 is an extensively bio-turbated, muddy and fine grained sandstone unit.

Floating clasts can be found in the lowermost part of the section, which is coarsening upward. Tofte 3 consists of very fine to fine grained sandstone where almost none of the depositional structures are visible because of bioturbation. Some low angle dipped layers occur in the upper part.

4.3.5 The Ror Formation

This is an extensively bioturbated sandstone deposit with very fine grain particles. The Ror Formation is only 8.5 m thick at the Norne Field. In addition to the sand content, glauconitic, phosphate nodules and calcareous shells can be found in this sandstone deposition. These depositions indicate that the depositional environment was in a lower shore face, with low sediment supply. The formation is assumed to have good reservoir quality.

4.3.6 The Ile Formation

The reservoir quality of the Ile formation is generally good, especially in the regressive depositions, whereas the reservoir properties are decreasing toward the top of the formation. Ile formation is 32-40m thick sandstone. This formation is divided into three reservoir zones: Ile 1, Ile 2 and Ile 3. The separation between Ile1 and Ile 2 is the same as the boundary between the Ror and Ile 1 formations, a cemented calcareous layer.

The layers are probably the result of minor flooding events in a generally. These layers are probably the result of minor flooding events in a generally regressive period.

4.3.7 The Not Formation

The Not formation was also deposited during Aalenian time. It is a 7.5m thick, dark grey-to-black claystone with siltstone lamina. The Not formation has a coarsening upward trend which continues into the Garn formation. Therefore, it can be seen as a layer of very fine grained, bioturbated sandstone in the upper part of the formation. The upward coarsening indicates deposition during a regression.

4.3.8 The Garn Formation

This formation is also divided into reservoir zones based on differing properties and deposits. For the Garn formation the number of reservoir zones is three. Garn 1 is a sandstone unit which is coarsening upward, from very fine to fine grained sand. The lower part is muddy and bioturbated, as it is the continuance of the Not formation, while the upper part has an increased sand content. This part of the formation has faster beddings, ripple lamination and thin layers of coarser grained sandstone. At the top of Garn 1, coarse to very coarse grained bed is found.

4.3.9 The Melke Formation

The thickness of the formation varies from 212 m to 160 m. The formation is dominated by claystones with thin siltstone lamina in between. The depositional environment was in offshore transitional to lower shore face. Within the Norne Field the offshore transitional environment is dominating, while the lower shore face environment is dominating to the north. This indicates that the land was located north of the Norne Field, which also is the sedimental source area.

4.4 Reservoir Communications

Vertical and lateral flow in the Norne Field is affected by both faults and stratigraphic barriers. Although these barriers are not expected to be important in a field-wide scale, it is important to consider the effect they have on the fluid flow to enhance the drainage strategy.

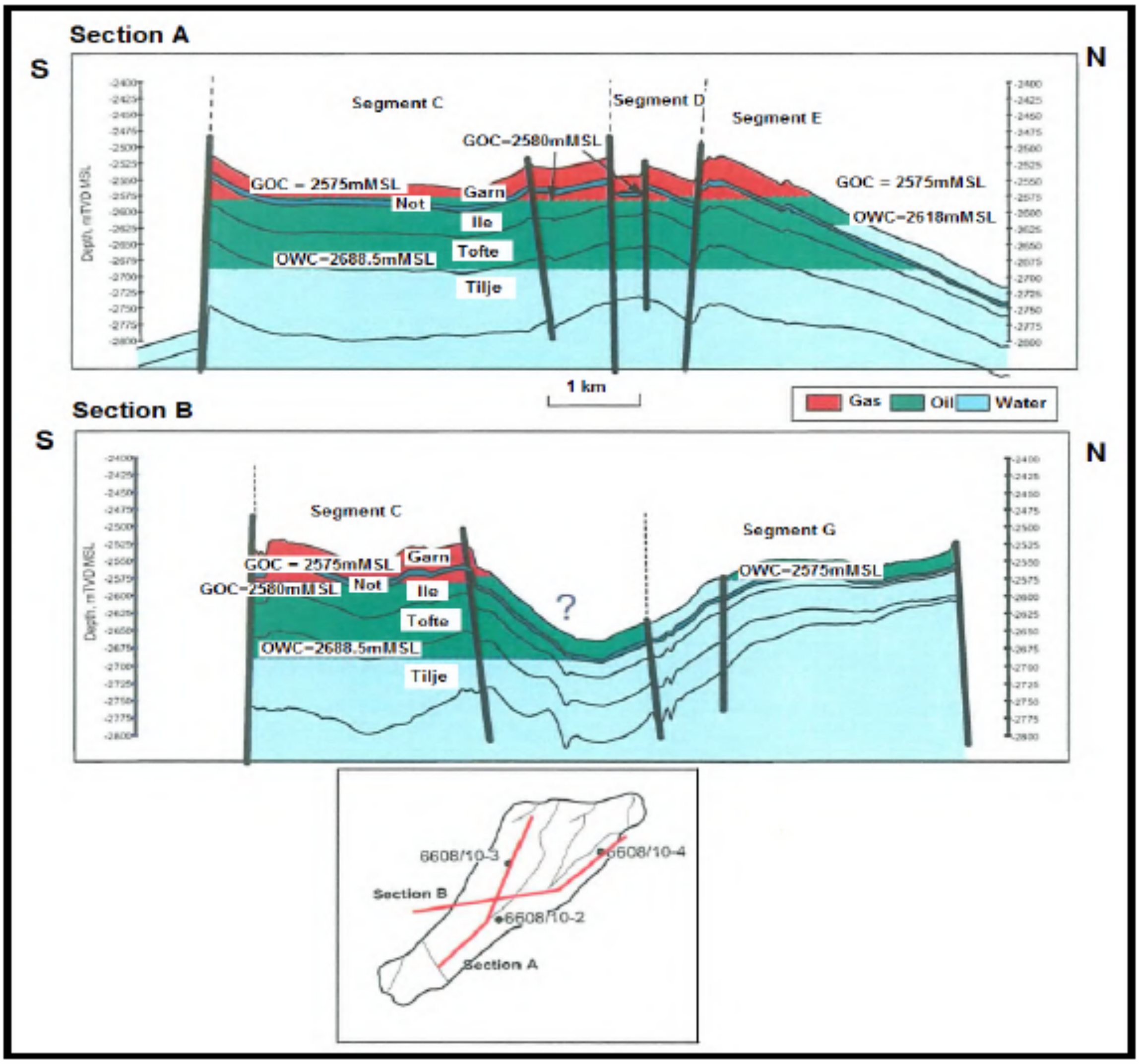


Figure 13: Structural cross-sections through the Norne Field with fluid contacts **(IOC , 2010)**

Several stratigraphic barriers are present in the field. Their lateral extent and thickness variation are assessed using cores and logs. Continuous intervals which restrict the vertical fluid flow within the Norne field are listed below:

- Garn 3/Garn 2- Carbonate cemented layer at top Garn 2
- Not Formation-Claystone formation
- Ile 3/Ile 2- Carbonate cementations and increased clay content at base Ile 3
- Ile 2/ Ile 1- Carbonate cemented layers at base Ile 2
- Ile 1/ Tofte 4-Carbonate cemented layers at top Tofte 4
- Tofte 2/ Tofte 1- Significant grain size contrast, and
- Tilje 3/ Tilje 2-Claystone formation

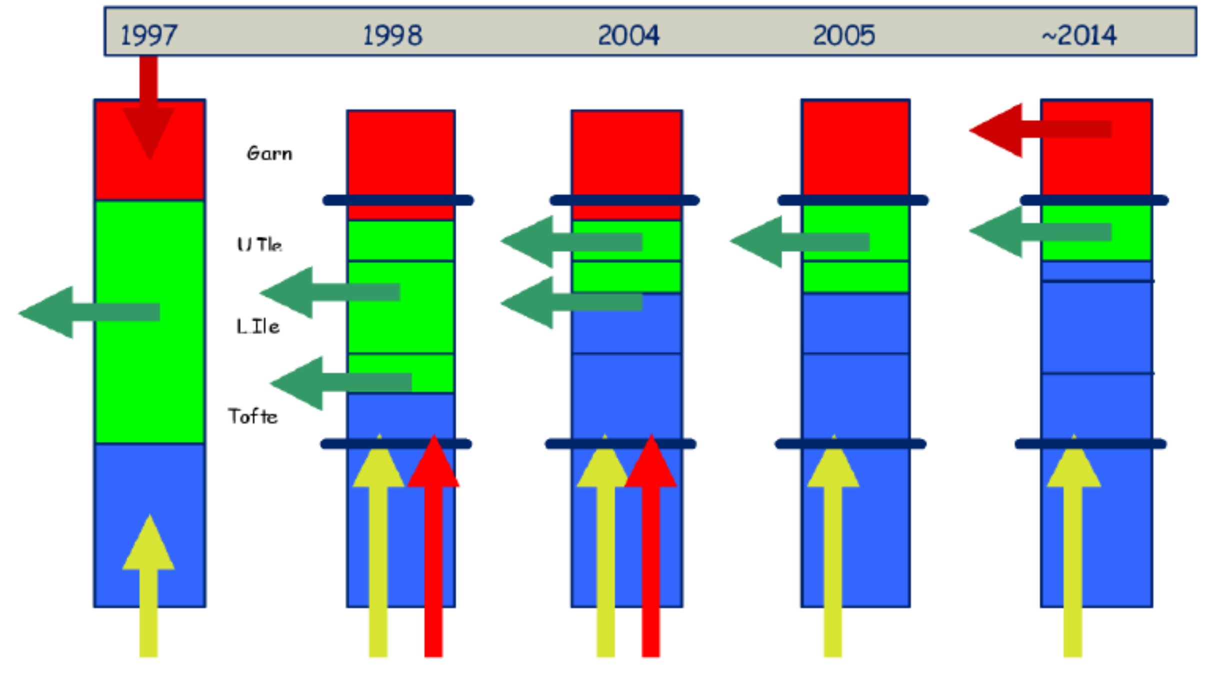


Figure 14: The drainage strategy for the Norne Field from pre-start until 2014 **(IOC , 2010)**

As shown above, gas injection was also introduced in 1998 and both water and gas were injected up to 2004. Gas injection stopped in 2005 and oil was produced by water injection only as a drive mechanism.

4.5 PVT Properties of Norne Fluids

Fluids exist in reservoirs as mixtures of gas, oil, and water. Some reservoirs may contain mixture of gas and water, oil and water, or mixtures of gas, oil, and water. Irrespective of the proportions of these fluids present in a reservoir, obtaining fluid samples and studying their phase behaviour in a laboratory are necessary for establishing reservoir type, devising strategies for reservoir management, and estimating expected hydrocarbon recovery. The importance of collecting representative reservoir fluid samples (preferably early in the life of the reservoir) and having the samples analyzed in a reputable laboratory cannot be over emphasized.

CHAPTER 5

NORNE C-SEGMENT

As at the end of 2006, Norne C-segment consists of 19911 active grids having about 13 wells; 9 producers and 4 injectors.

Table 2: List of Wells in C-Segment

Producers	**Start Date**	**Total Production**
B-2H	12.1997	1.14E+07
D-1H	11.1997	4.97E+06
D-2H	12.1997	7.99E+06
B-4H	04.1998	1.01E+06
D-4H	06.1998	3.08E+06
B-1H	04.1999	3.75E+06
D-1CH	11.2003	2.50E+06
B-4DH	07.2004	1.47E+06
K-3H	10.2006	1.96E+04
Injection Wells in C-segment		
Injectors	Total Injected gas (Sm^3)	Total Injected water (Sm^3)
C-1H	2.19E+09	1.47E+07
C-2H	0	2.17E+07
C-3H	3.51E+09	5.73E+06
C-4AH	2.93E+09	5.47E+06

5.1 The Norne C-Segment Coarsened Model

The current reservoir model of C-segment is based on a 2004 geological model. It is a 3-D three-phase full field black oil model consisting of 46 * 112 * 22 grids in x, y and z directions. Of these, only 19911 grids belong to the C-segment are active while other cells are coarsened. Reservoir formations are represented by layers, for instance, Garn is represented by layers 1-3, Ile formation is represented by 5 to 11, Tofte by 12 to 18 and Tilje formation is represented by layers 19 to 22.

5.2 Wells Grouping

Grouping of wells allows for analyzing, strategizing and managing wells trends in a particular field or segment. It is easy to display injection and production data for a set of wells; including summing, arranging or time-normalizing production and injection data.
The wells grouping method give two options for grouping the wells:

- Group Plot (sum wells); this method sums the selected wells production and injection streams. The data can be shown as either a cumulative or an average plot.

- Individual Well Plot; this method plots the individual production and injection streams for each selected well.

5.2.1 Display and Calculate Ratios

Ratios that can be calculated and displayed using the production group option include:

- Water-Oil ratio
- Gas-Oil ratio
- Oil-Gas ratio
- Gas-Liquid ratio
- Water cut
- Oil cut
- Any user defined ratio

5.3 Grouping Wells in C-Segment

Since the EOR study is focused on C-segment of Norne field, all the wells in this segment are grouped. Therefore the grouped production and injection data are used for analysis throughout this study except for reservoir pressure because it is assumed that C-segment gets and gives pressure support to other segments.

5.3.1 Modification of the C-segment Wells

- Well (B-1H) is producing from both C-segment (90%) and D-segment (10%). The perforation of this producer was changed in such that the well is only producing from C-segment.
- Well (B-3H) was removed from C-segment because only the wellhead is located at C-segment while the well produces from D-segment. This modification is updated on the reservoir model.

5.3.2 Keyword to Activate Wells Grouping Option in a Model

5.3.3 Grouptree

This keyword is required only if a grouping structure is needed with up to three levels in the hierarchy. That is: Field-Groups-Wells as illustrated in appendix C1.2

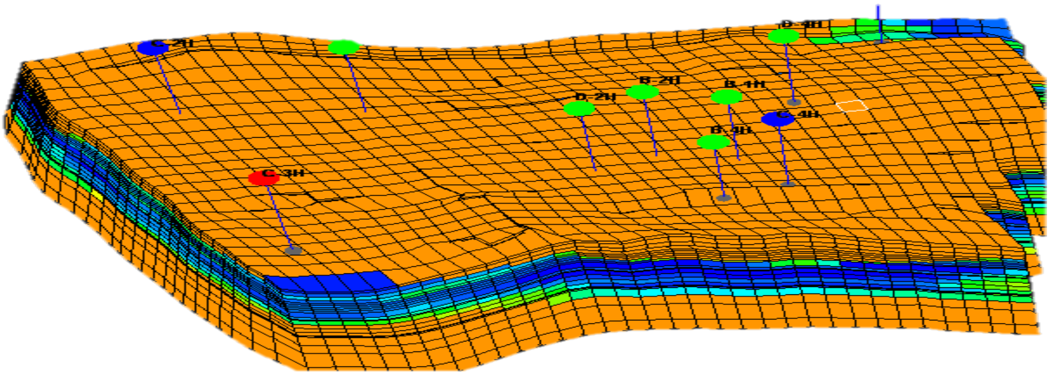


Figure 15: Norne C-Segment Model

5.4 Screening Guidelines for EOR Techniques

Screening guidelines are the most common, fast and easy tool use to evaluate if a reservoir is a good candidate for implementing an enhanced oil recovery process. Oil properties as well as reservoir characteristics must be queried in order to provide a concise representation of the EOR criteria. The screening criteria are proposed by different authors and at different stages of maturity of a recovery process; therefore, special care must be taken when choice of technique is to be made.

Table 3: Screening Guidelines for EOR Methods

Methods	No. of Projects	API Gravity	Depth Distribution (d)	Oil Sat. (So)	Perm. (K)	Visco. (μ)	Porosity Distr.(θ)	Temp. Distr.(T)
	#	API	(m)	-	(mD)	(cp)	(%)	(oC)
Chemical EOR	70	31-42	<4000	0.62-0.81	200-7000	0.4-90	20-35	70-160
Combustion	27	35-38	1000-11000	0.5-0.92	10-12000	10-80	18-35	180-230
Steam Flooding	271	16-35	<3000	0.5-0.9	1000-12000	20-8000	30-65	70-350
Immiscible Flooding	40	36-55	2000-18000	0.41-0.98	50-8000	10^{-4}-50	22-32	120-320
Miscible Flooding	212	44-55	4000-18000	0.3-0.97	0.1-8000	10^{-4}-1.0	08-45	90-320

Table 4: Reservoir and Oil Properties for Norne Field

Reservoir Properties		**Oil Properties**	
Temperature, ^{o}C	98.3	Gravity (API)	32.7
Oil Saturation, %	35-92	Viscosity	<1.2
Depth, m	2500-2700	Density, Kg/m^{3}	859.5
Thickness, m	110		
Porosity, %	25-30		
Permeability, mD	20-2500		
Formation Type	Sandstone		

5.4.1 Advances in EOR Technologies

EOR methods are known to be classified into four main categories: chemical, gas, thermal and other. But latest advance in technology has classified EOR methods into five principle groups: water-based, gas-based, thermal-based, combination and other methods. The detailed nomenclature is shown in appendix C1.1

5.5 Justification for Injector(s) Selection

About two-third of the remaining oil in Norne C-segment is contained in Ile and Tofte formations. Figure 17 and 18 show oil saturation distributions in Ile formation in 2006. Although, a known fraction of this oil has since been brought to the surface, but figure 19 shows expected oil saturation in Ile formation in 2013.

There are four injectors in C-segment namely; C-1H, C-2H, C-3H and C-4AH. To optimize chemical injection with less adsorption, five simulation runs were made using surfactant and polymer to determine which injector(s) will perform best and in return lead to highest oil production. Figures 25 and 26 show total oil production for different injector selection and injecting through combined wells C-2H and C-3H give higher recovery factor compare with other combined injectors. It is rather wasteful to inject through two wells if same effect could be achieved using a single injector. As shown in figures 21 and 25 flooding through C-3H is better and more efficient with little adsorption than using C-1H, C-2H and C-4AH. Therefore, subsequently all C-segment flooding cases will be done through C-3H.

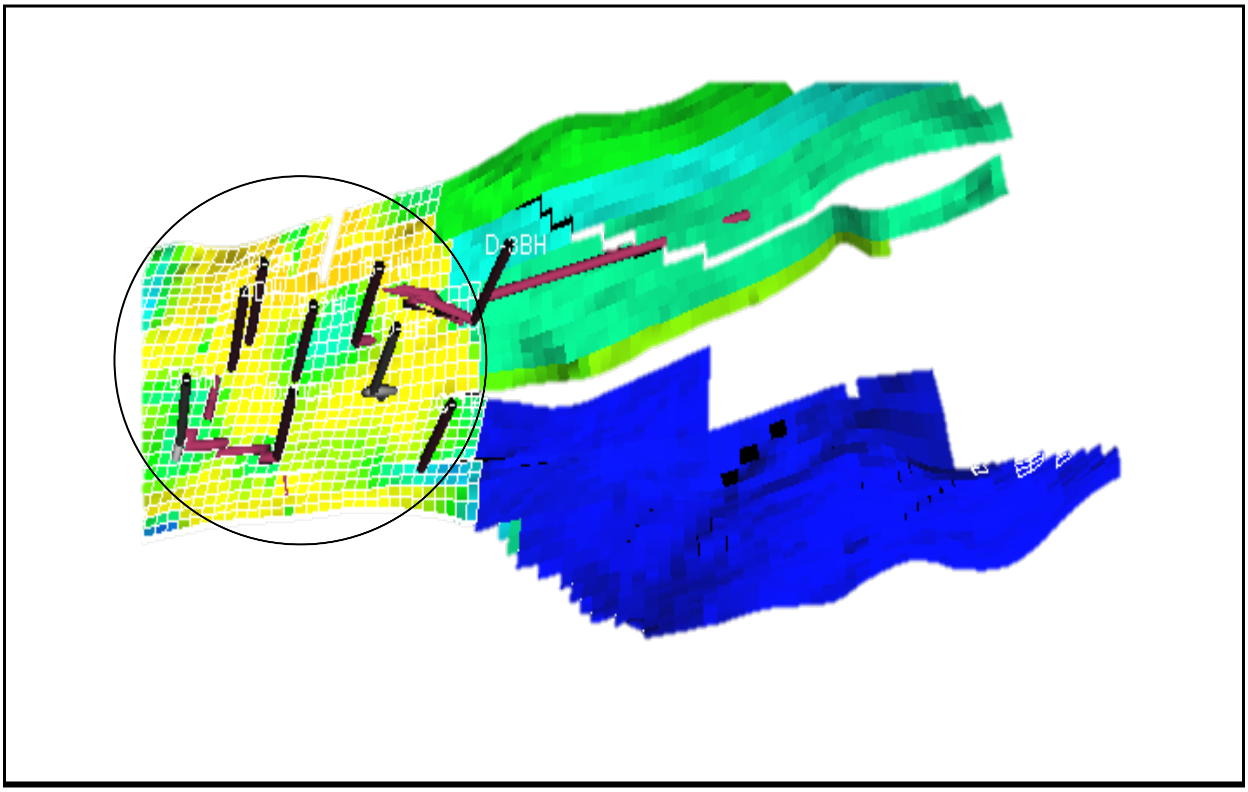
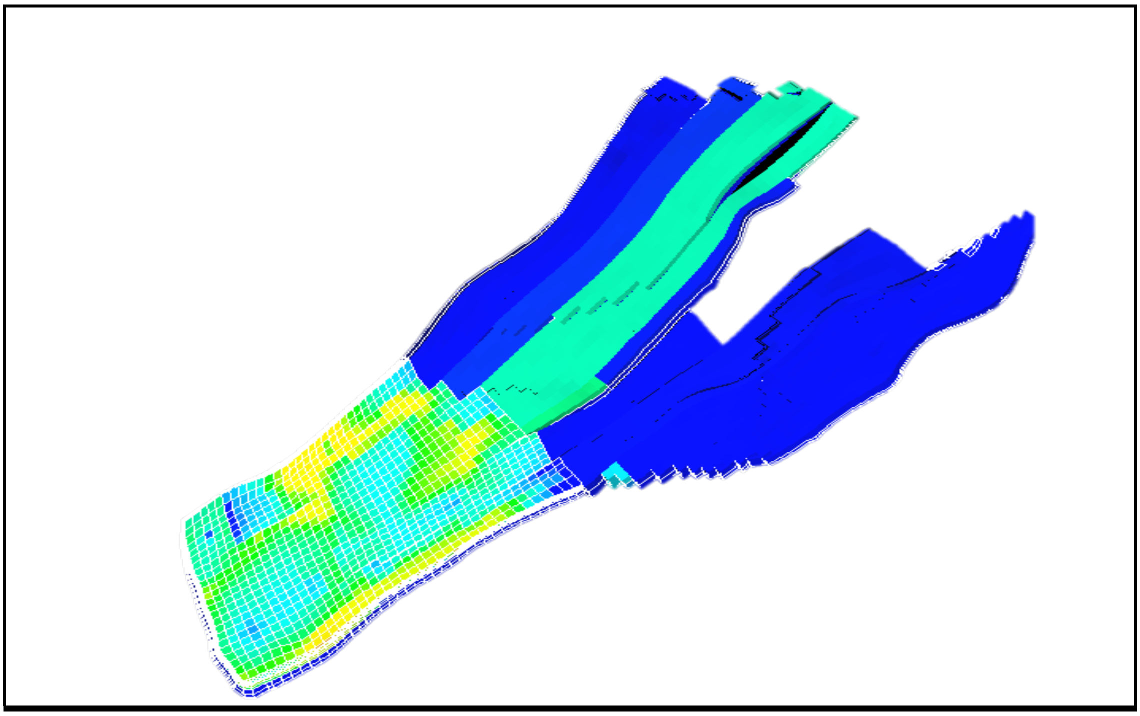


Figure 16: Wells in C-Segment

Figure 17: Tofte (layer 12) oil saturation in 2006



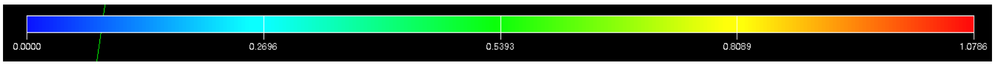
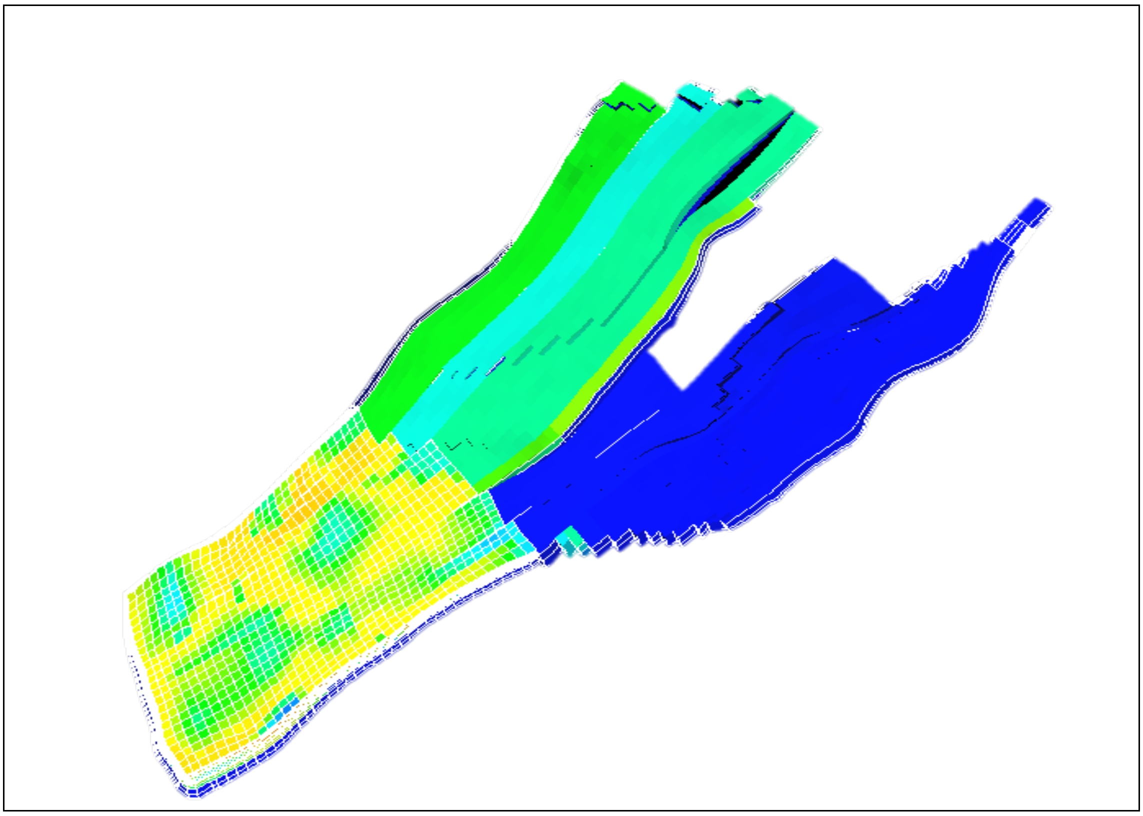


Figure 18: Ile (layer 8) oil saturation in 2006



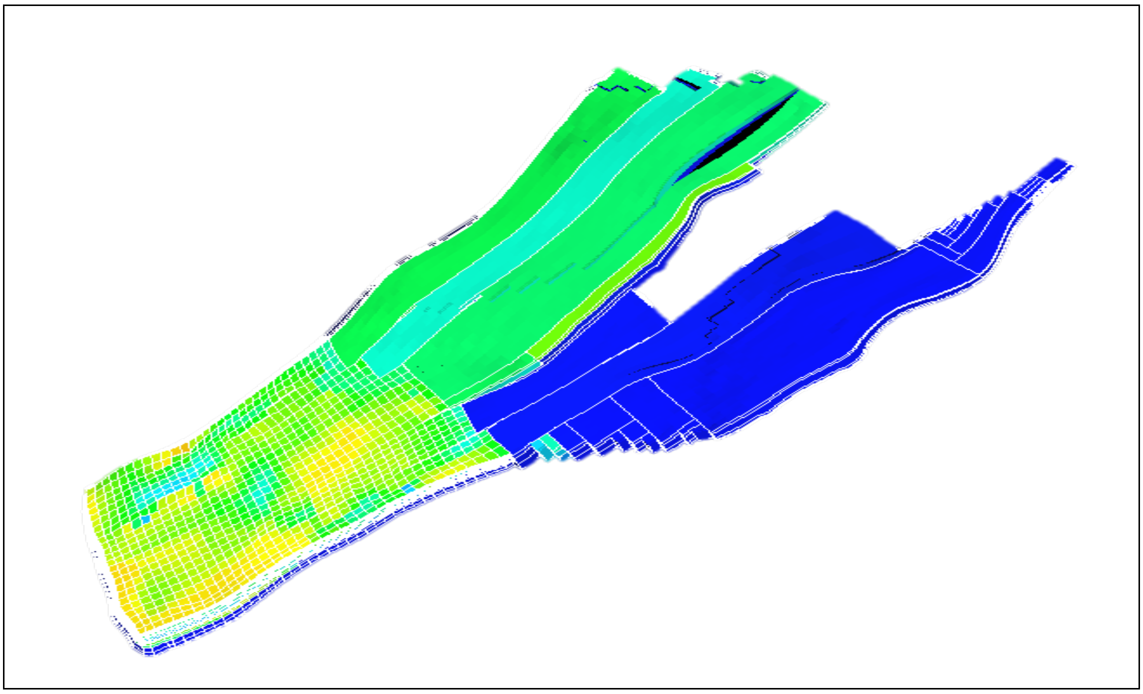


Figure 19: Ile (layer 5) oil saturation in 2013

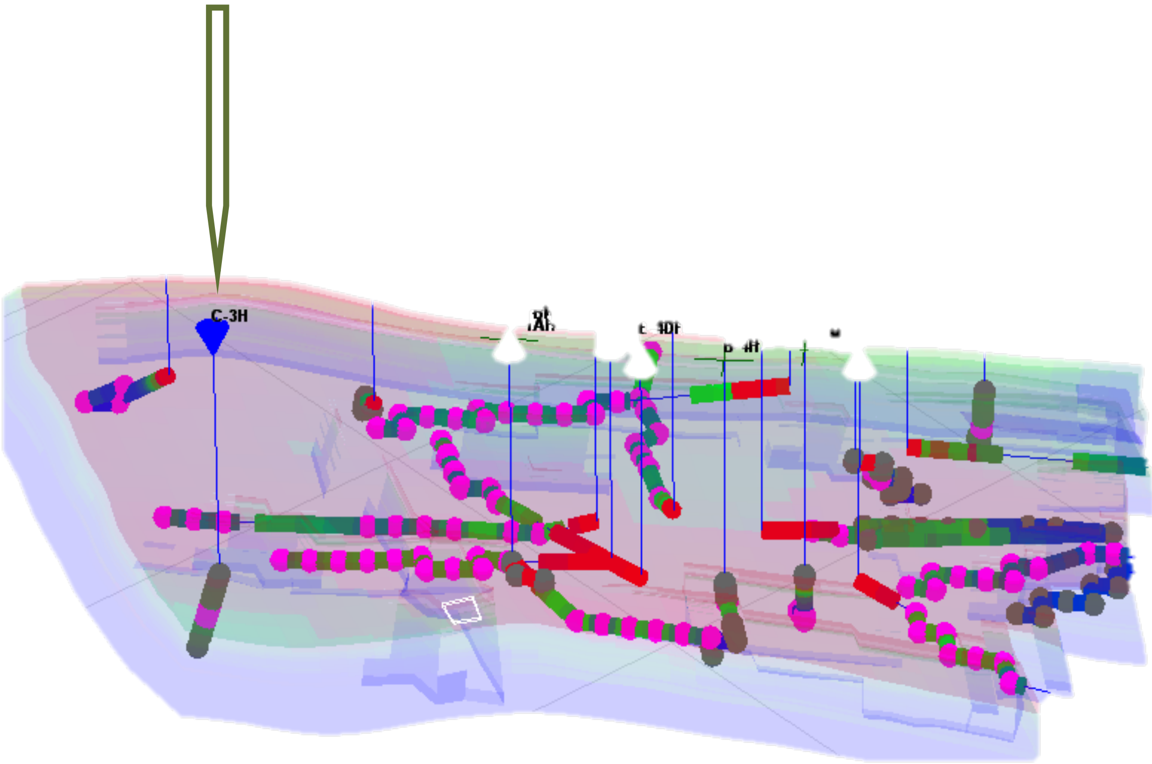


Figure 20: Injector (C-3H) Location on C-Segment

5.5.1 Surfactant Flooding for Injector Selection

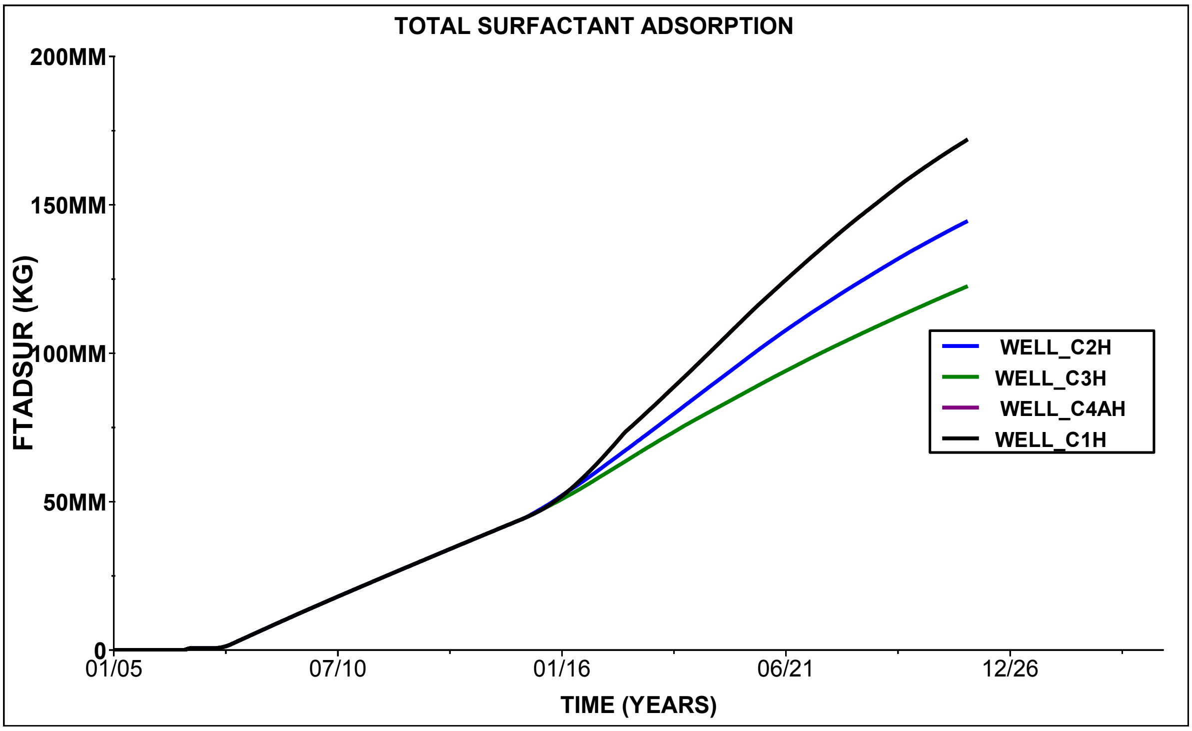


Figure 21: Injectors Total Surfactant Adsorption during Injector Selection

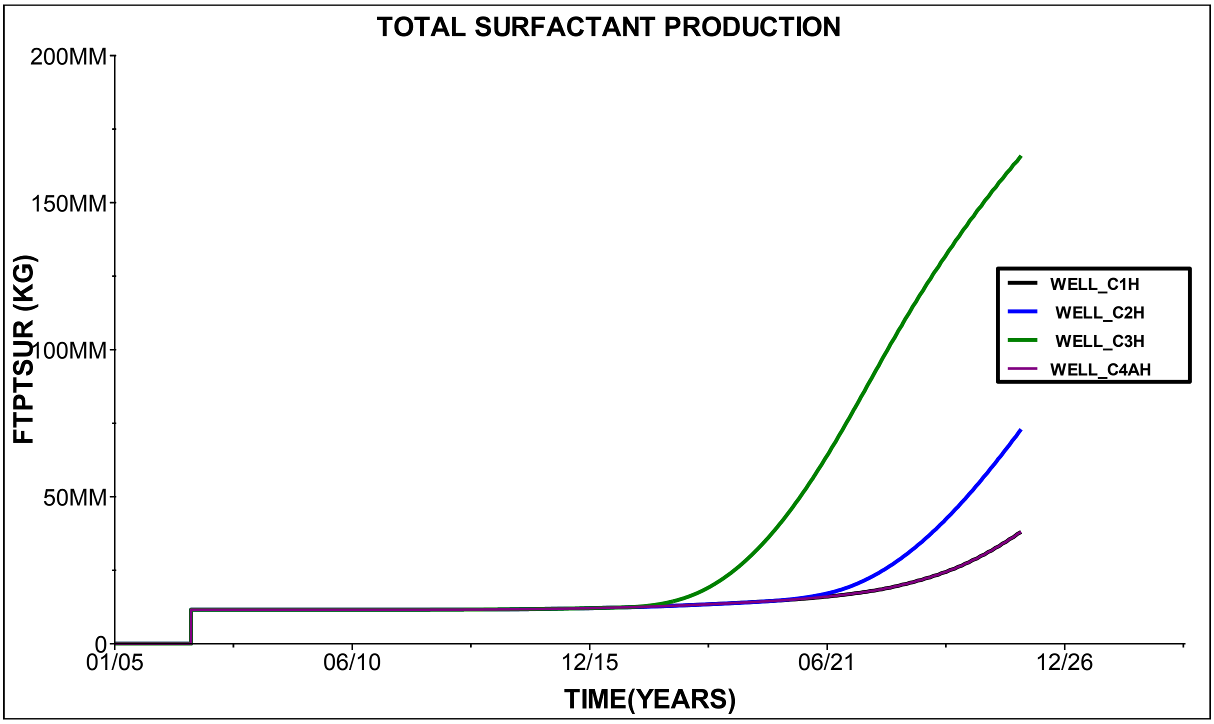


Figure 22: Injectors Total Surfactant Production during Well Selection

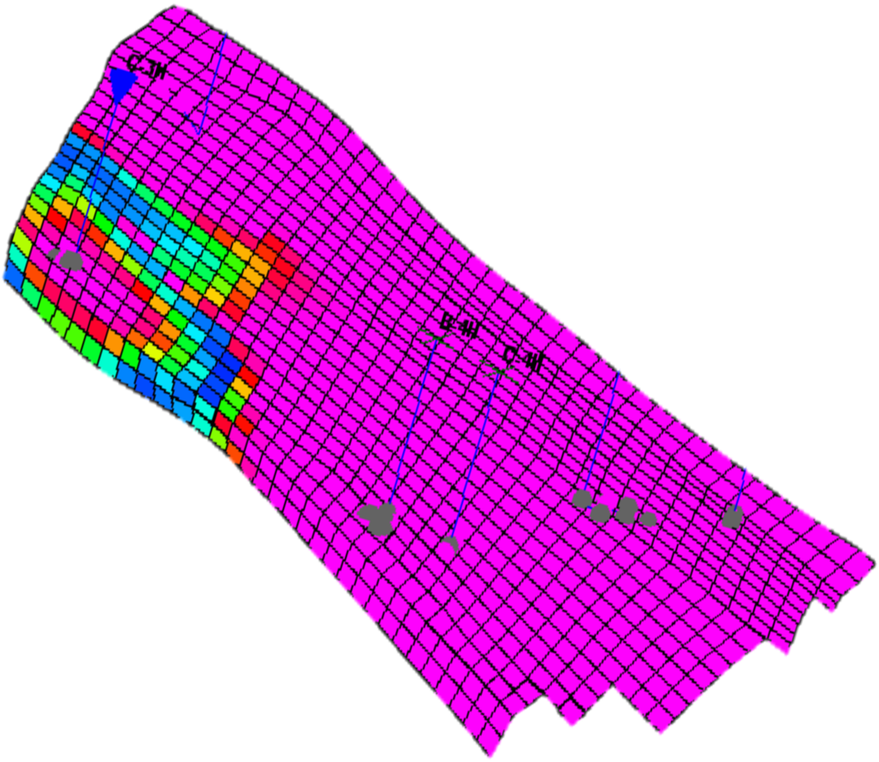


Figure 23: *Showing Surfactant Front in well C-3H*

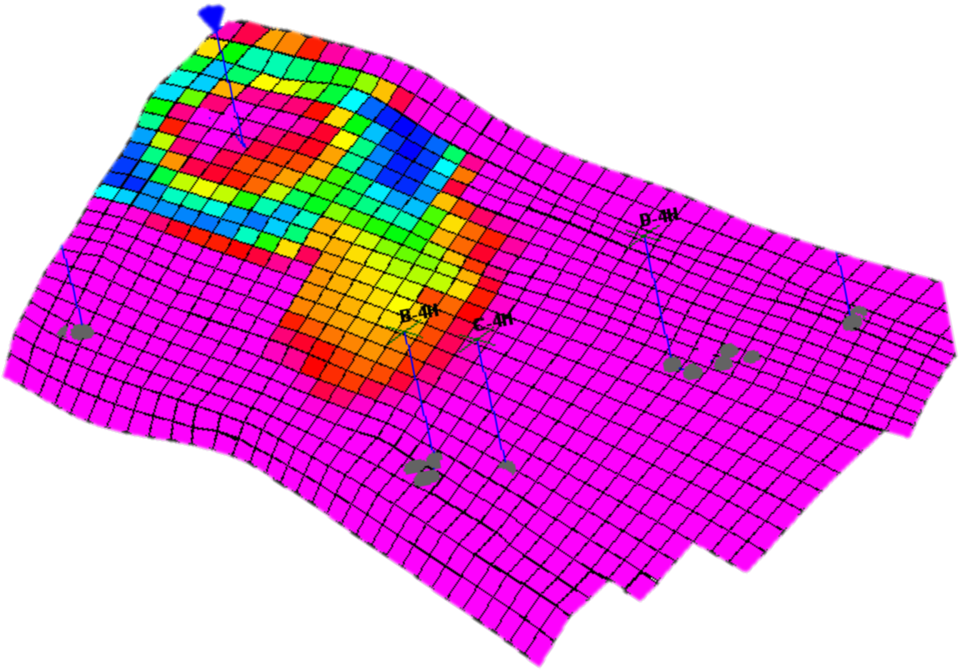


Figure 24: *Showing Surfactant Front in well C-2H*

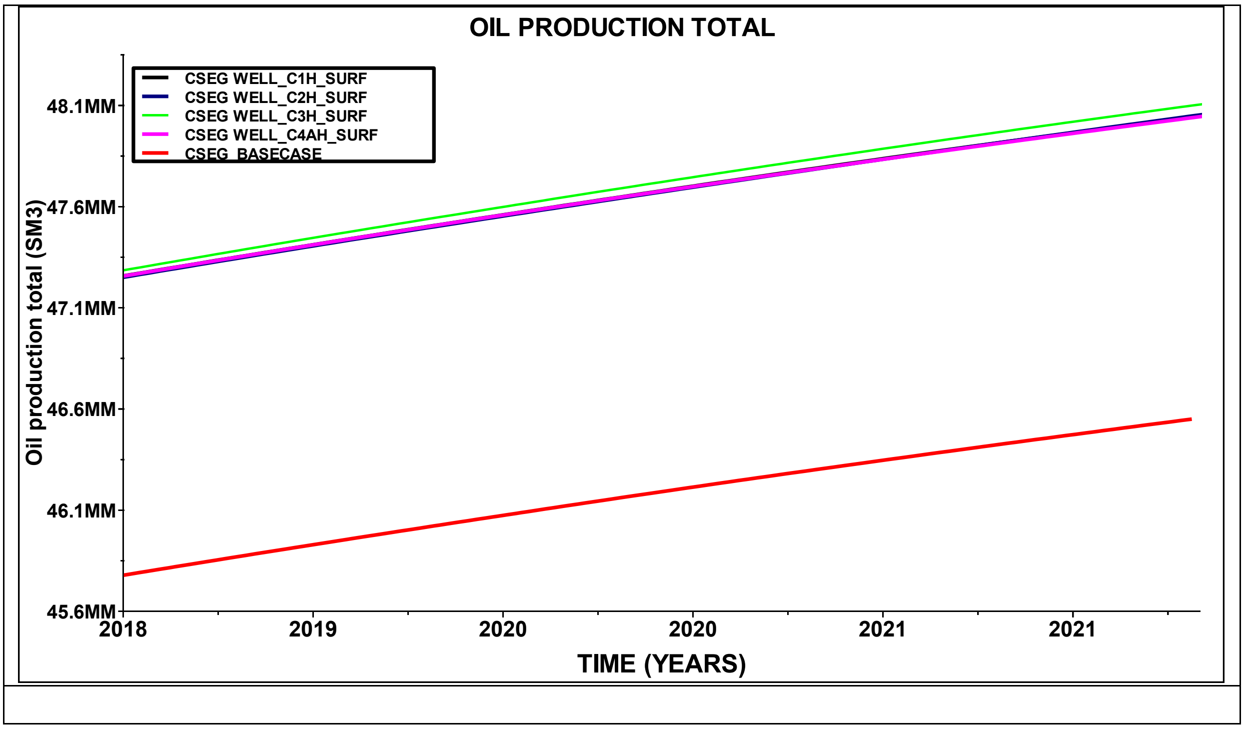


Figure 25: Oil Production Total by Surfactant Flooding during Injector Selection

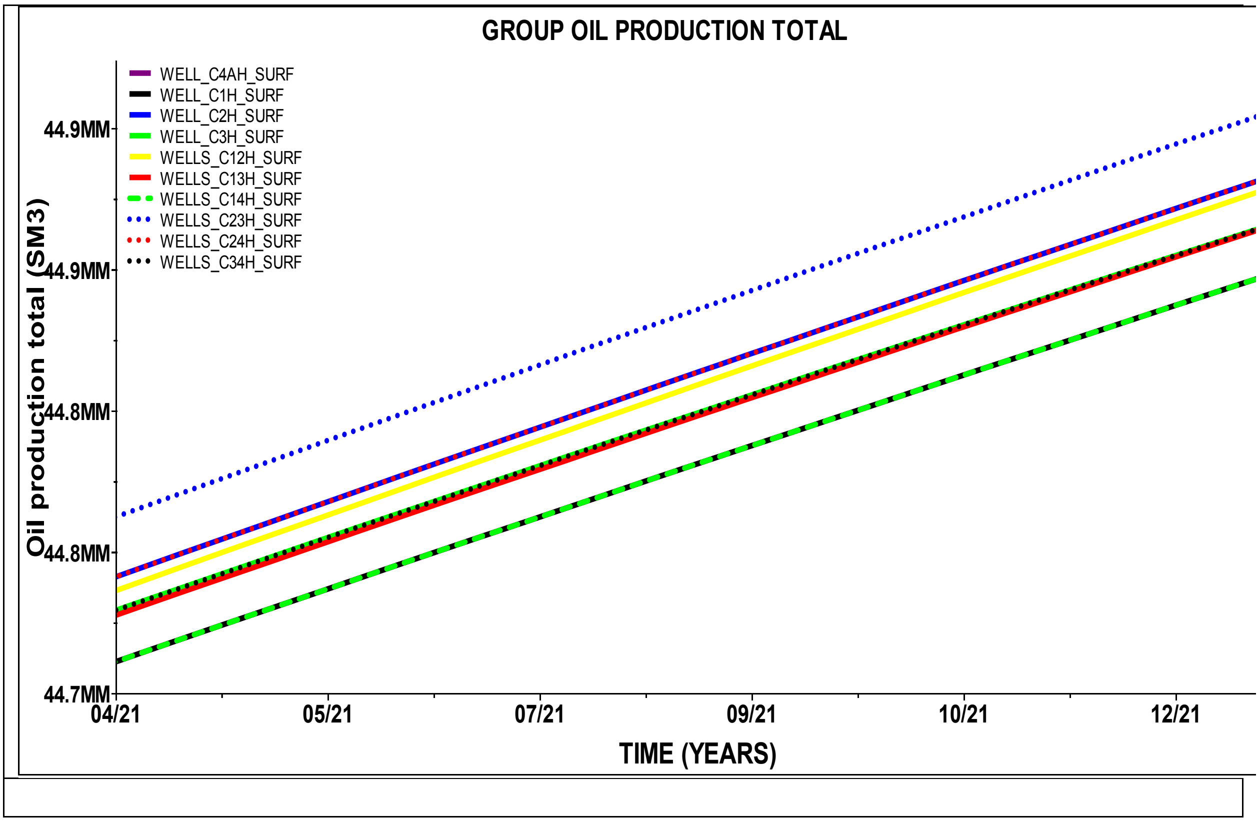


Figure 26: Oil Production Total by Surfactant Flooding for Injectors Combinations

5.5.2 Polymer Flooding for Injector Selection

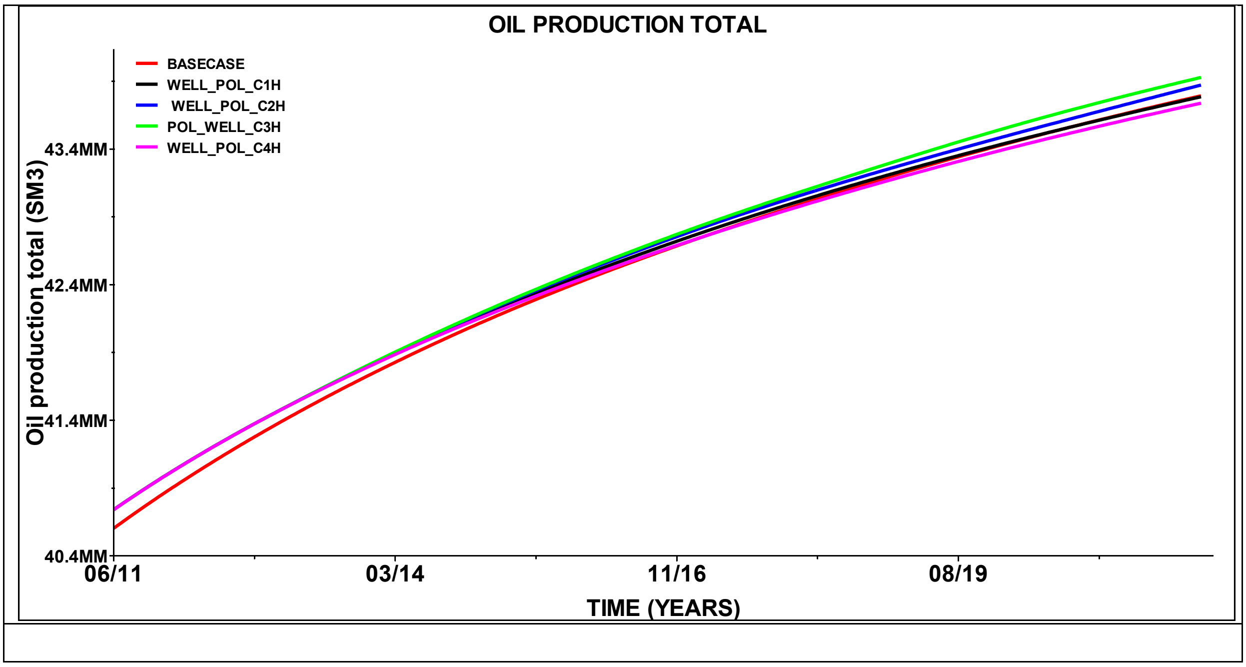


Figure 27: Oil Production Total by Polymer Flooding during Injector Selection

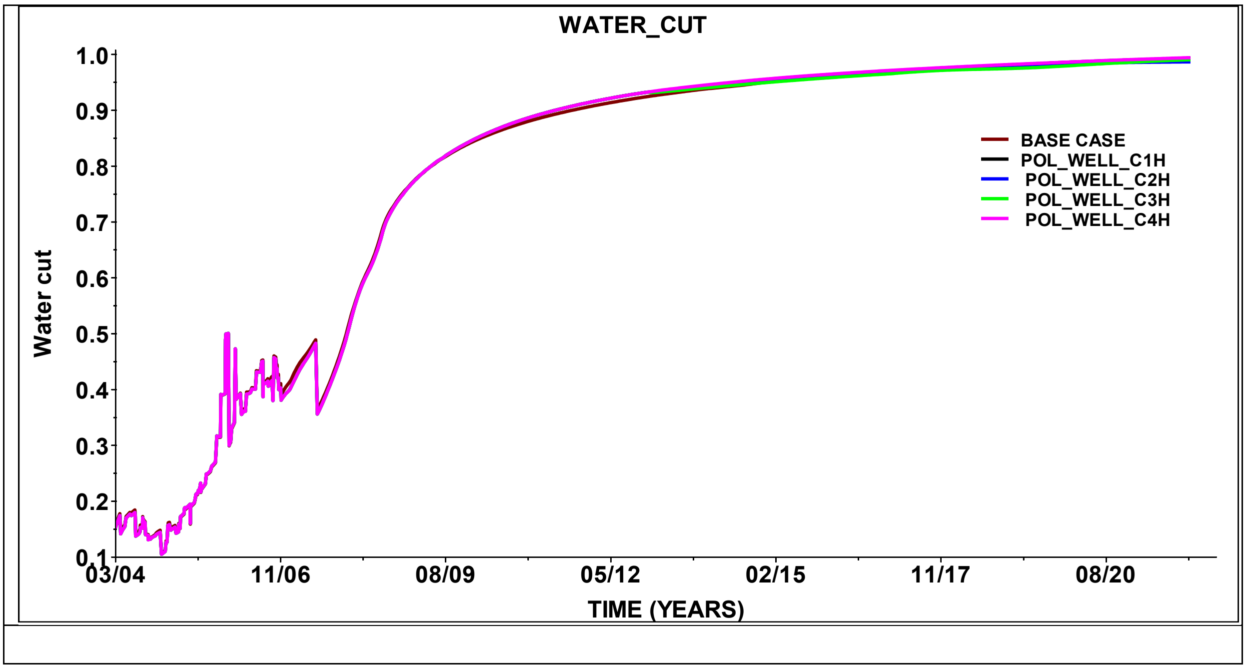


Figure 28: Water cut during Injector Selection

5.6 History Matching of Norne C-Segment

This is the act of adjusting a model of a reservoir until it closely reproduces the past behavior of a reservoir. The historical production and pressures are matched as closely as possible. The accuracy of the history matching depends on the quality of the reservoir model and the quality and quantity of pressure and production data. Once a model has been history matched, it can be used to predict future reservoir behavior with higher degree of confidence, particularly if the adjustments are constrained by known geological properties in the reservoir. The modifications entail changing parameters that have higher degree of uncertainties. History match parameter depends on:

- Reservoir architecture
- Data quality
- Study objective
- Drive mechanisms

A reservoir model can be history matched by any of these methods:

5.6.1 Traditional History Matching

This is a trial-and –error method in which adjustment is made to the simulated data in order to conform to the observed data. Absolute conformity is often difficult to achieve but difference in simulated and observed data must be minimized to the barest minimum.

5.6.2 Computer-Based History Matching

Computer based history matching is a means of using computer to normalize the mismatch between simulated and history data.

5.7 Production Prediction

Following history match process, future production performance of a given well or reservoir can be made. A production prediction, in this context simply means the forecast or projection of production capacity of a particular well, group of wells, reservoir or field in term of oil, gas and water putting into consideration production limitations and constraints. Planning, decision making, economic evaluation and revenue projection of any oil field hinges on the confidence placed on the production forecast made. This implies that production forecast is essential in determining the lifespan of a producing field and also used as indicator for implementing enhanced oil recovery mechanism (Odusote O. Adepoju et al, 2000).

There are factors that hinder both accuracy and reliability of production prediction. These are geological uncertainties (structure, permeability, porosity, fluid saturations, and fluid contacts), dynamic uncertainties (relative permeability, residual oil saturation, irreducible water saturation, fluid properties) and operational uncertainties (allowable production rate, GOR and so on).

5.8 History Matching Results

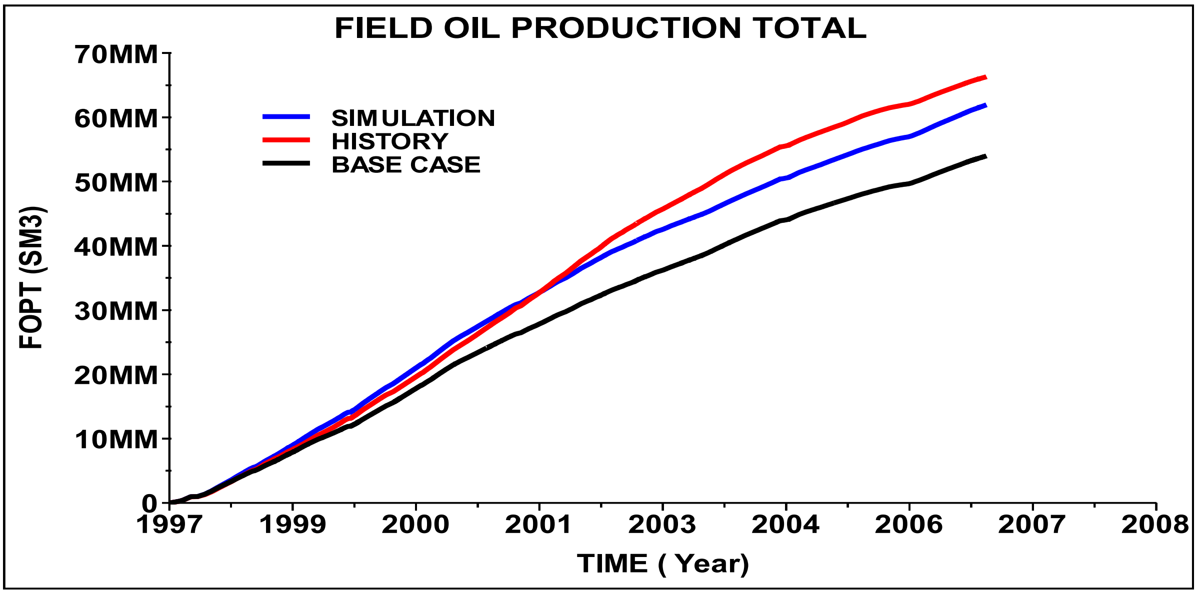


Figure 29: Field Oil Production Total Norne C-Segment during History-Matching.

An attempt was made to get a good history match by changing the sealing of faults in C-segment. The way this was done was to include a fault multiplier file. In this file all the faults are listed and given different multiplication values. A fault with value 1.0 is an invisible fault, while a fault with value 0 means totally sealed fault and 0.1 indicates partially sealed fault.

Table 5: List of Faults in Norne Fields

Old multply	New multiply	Faultnames	Old multply	New multply	Faultnames	Old multply	New multply
0.1	0.1	C_02	0.01	0.001	EF	1	1
0.01	0.01	C_04	0.05	0.02	GH	1	1
3.9	3.9	C_05	0.1	0.001	G_01	0.05	0.002
0.01	0.001	C_10	0.00029	0.0029	G_03	1	1
0.00075	0.0075	C_12	0.1	0.1	G_05	0.5	0.05
0.015	0.0015	C_20	0.5	0.5	G_07	0.05	0.005
20	20	C_20_Lto	0.5	0.4	G_08	0.05	0.005
0.1	0.001	C_21	0.00005	0.0005	G_09	0.05	0.05
0.01	0.001	C_21_Ti	0.00005	0.0005	G_13	0.05	0.05
0.01	0.1	C_22	0.001	0.01	H_03	1	1
0.1	0.001	C_23	0.1	0.01	IH	1	1
1	1	C_24	0.1	0.01	m_east	1	1
0.1	0.001	C_25	0.1	0.1	m_east_2	1	1
0.01	0.001	C_26	0.00368	0.0368	m_north	1	1
0.01	0.1	C_26N	0.00368	0.0368	m_northe	1	1
0.01	0.001	C_27	0.00237	0.000237	m_west	1	1
0.1	0.01	C_28	1	1	C_06	0.1	0.01
0.01	0.001	C_29	0.1	0.01	G_02	0.05	0.5
1	1	DI	0.1	0.01			
1	1	DI_S	0.1	0.01			
0.1	0.01	D_05	0.01	0.001			

The matching process was focused on fault multipliers. Several trials-and-errors attempts were made to reduce the difference between simulation and history cases. Table 5 shows list of all faults in Norne field and the new values that were used.

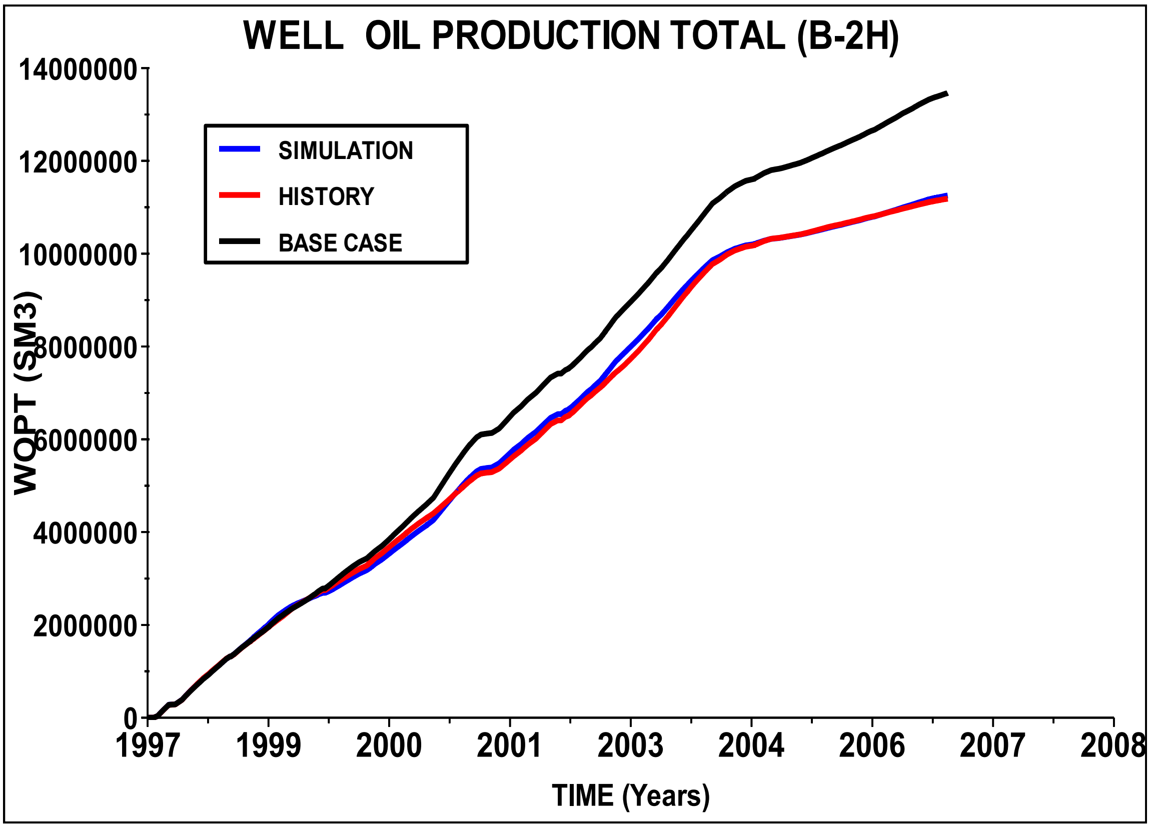


Figure 30: Well (B-2H) Oil Production Total

A fairly good match for well oil production total (B-2H) as shown above when local vertical transmissibility for the different layers were included which varied the flow in the z direction especially in area close to B-2H.

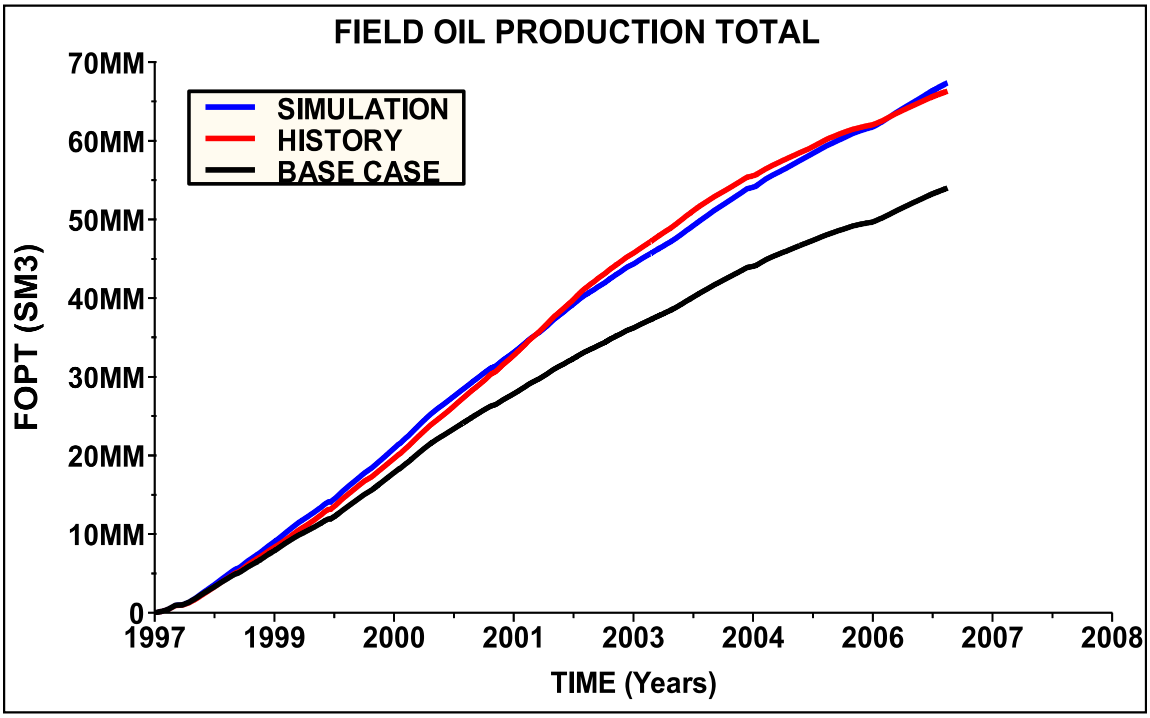


Figure 31: Oil Production When Horizontal Permeability, Vertical and Fault Transmissibility were changed

Different values of local vertical transmissibility, fault-multipliers and permeability in x direction were changed to get a better match. Figures 31, 32 and 33 show field oil production total, field water-cut and gas-oil-ratio.

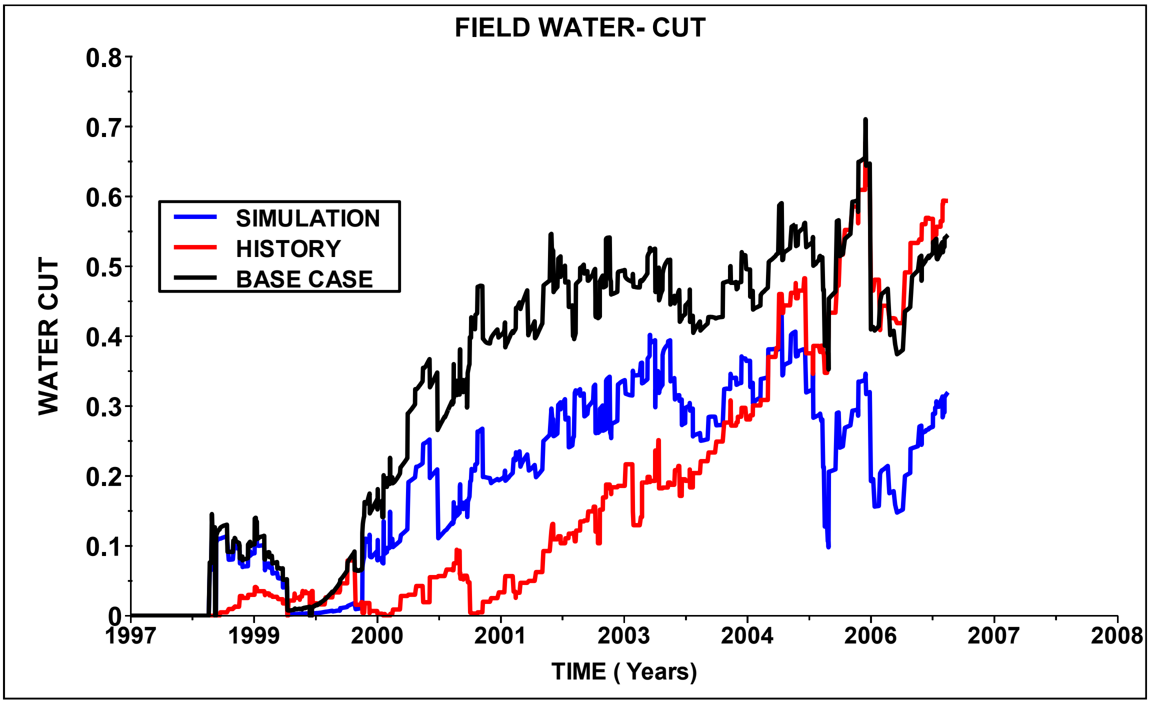


Figure 32: Water-Cut When Horizontal Permeability, Vertical and Fault Transmissibility were changed

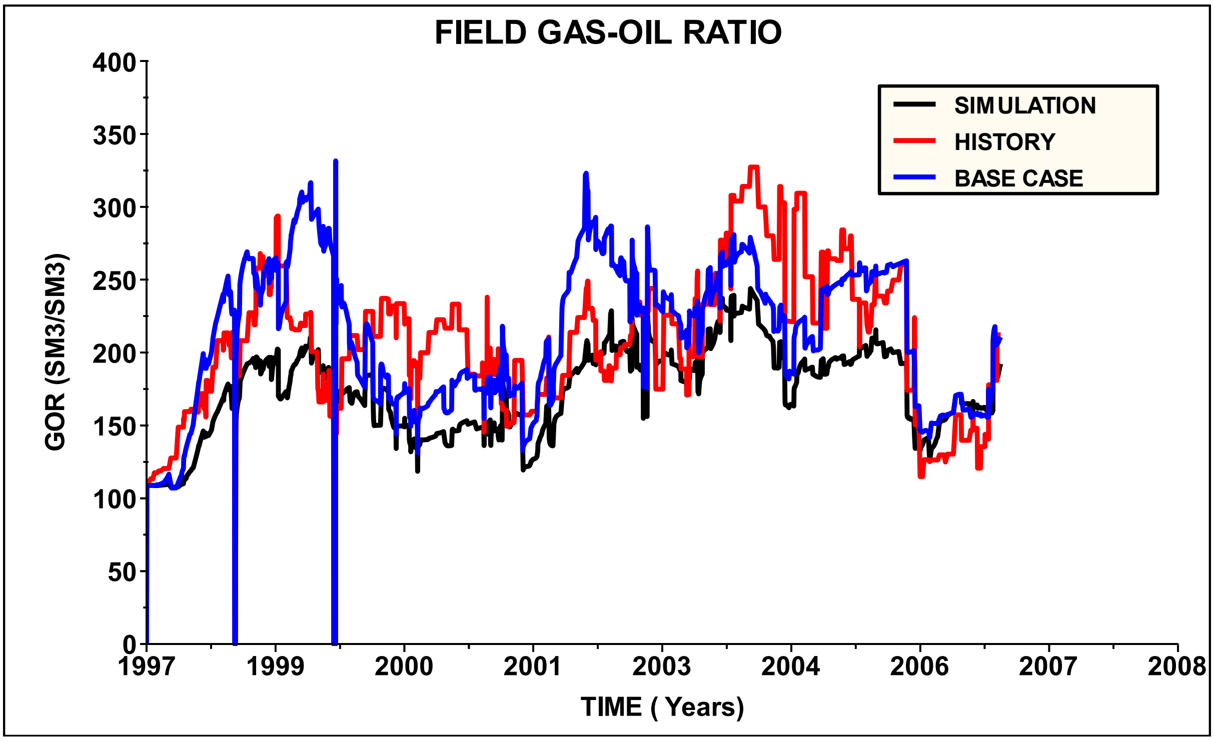


Figure 33: GOR When Horizontal Permeability, Vertical and Fault Transmissibility were changed

CHAPTER 6

ALKALINE, SURFACTANTAND POLYMER SIMULATION MODELS

Alkaline, surfactant and polymer models were made and tested on 2 and 3-dimensional synthetic grids system before they were applied to the Norne C-segment. The synergetic chemical effects were also simulated; alkaline-surfactant (AS) flooding, surfactant-polymer (SP) as well as alkaline-surfactant-polymer (ASP) using eclipse-100.

6.1 The Alkaline Model

This is a model that takes into account the reaction between the saponifiable components and alkali in which surfactant are formed in-situ. Petroleum acids are referred to as saponifiable components in this context. The important objectives of alkaline flooding are interfacial tension and anionic surfactant adsorption reduction. The reaction of acid and alkaline to generate soap and its subsequent effect on phase behavior is the most vital for oils containing naphthenic acids.

6.2 The Surfactant Model

The eclipse surfactant model does not aim at modeling detailed reactions of surfactant processes, but rather to model important features of surfactant flood. The distribution of injected surfactant is modeled by solving a conservation equation for components within the water phase. Concentrations are updated fully-implicitly at the end of each time-step after oil, water and gas flows have been computed.

The way the model works; surfactant solution is injected into the reservoir, surfactant concentration is solved by conservation equation in the water phase, interfacial tension is calculated as a function of surfactant concentration, capillary number is calculated as a function of interfacial tension, oil and water phase relative permeability is interpolated as function of capillary number , water-oil capillary pressure is reduced as a function of surfactant concentration, surfactant adsorbs by the reservoir rock and finally wettability of the rock changes as a function of amount of surfactant adsorbed.

6.3 The Polymer Model

The successful design of a polymer flood relies on the ability to properly model the distribution of polymer concentration in the reservoir. The effects on fluid properties such as water viscosity increase as a function of in-situ polymer concentration and loss of polymer due to adsorption. Therefore, to capture the inter-pattern sweep efficiency usually caused by well rate imbalances, reservoir architecture and reservoir heterogeneity, a well-established numerical modeling of polymer flooding should be made.

6.4 Synthetic Models for Alkaline/Surfactant/Polymer

A whole chapter was dedicated to homogenous synthetic modeling in my semester project where a detailed sensitivity analyses for different scenarios were tested. In this study, heterogeneous models are used to test the performances of alkaline/surfactant/polymer flooding using Norne fluid properties.

6.4.1 Three-Dimensional Case

A three-dimensional model (low permeability inclusion) of 10, 10, 3 in I, J and K direction as shown in figure 36 is used to demonstrate the chemical injection behavior in a low-permeability inclusion model.

6.4.2 Inclusion Case

An inclusion case is used to illustrate variation in permeability distribution in some part of the reservoir compare to entire reservoir matrices. It is a representation of heterogeneity that mostly occurs in mixed-wet rocks including Norne. When fluids flow in a porous medium, the rock's heterogeneous property could result into capillary trapping of one or more phases flowing. This effect was captured in the synthetic model.

6.4.3 Two-Dimensional Case

Similarly, a two-dimensional model (layered case) of 10, 1, 5 in I, J and K direction is equally used to test chemical flooding using Norne fluid properties. See figure 42, a vertical permeability as represented by stratified model is an illustration of Norne reservoir simulation studies. Different layers which are synonymous to various formations in Norne field as a result of successive transgression and progression deposits of sea level forming alternative strata of formation of varying permeability. In the 2-D model, a thin layer is placed between two oil-rich layers to take into account the effect of cross flow between Ile and Tofte formations as present in Norne C-segment. The dimensions used are stated thus:

DX = 10, DY = 1 and DZ = 5

Length = 10 * 50 = 500m

Width = 1* 50 = 50m

Height = (1 * 20 + 1* 50 + 1 * 10 + 1 * 50 + 1 * 20) = 150m

This model is divided into five different strata with varying permeability. This distribution is shown in table 6 below.

Table 6: Permeability distribution in 2-D heterogeneous model

Layers (up to down)	Permeability (mD)	Thickness (m)
1	10	20
2	100	50
3	2	10
4	100	50
5	10	20

6.5 Saturation Dependent Parameter

The relative permeability and capillary pressure curves used in the synthetic models as shown in figures 34 and 35 are obtained from the Norne C-segment saturation dependent data (see table 7).

Table 7: Norne C-Segment Relative Permeability Data

S_w	K_{rw}	K_{ro}	P_c
0.5000	0.0000	0.9000	1.7675
0.0975	0.0000	0.7767	0.8754
0.1450	0.0001	0.6641	0.4279
0.1925	0.0012	0.5620	0.2775
0.2400	0.0039	0.4699	0.2014
0.2875	0.0093	0.3875	0.1549
0.3350	0.0182	0.3144	0.1233
0.3825	0.0315	0.2503	0.1001
0.4300	0.0500	0.1948	0.0823
0.4775	0.0746	0.1474	0.0679
0.5250	0.1062	0.1077	0.0559
0.5725	0.1458	0.0752	0.0457
0.6200	0.1941	0.0494	0.0368
0.6675	0.2519	0.0299	0.0288
0.7150	0.3203	0.0159	0.0216
0.7625	0.4005	0.0068	0.0149
0.8100	0.4921	0.0019	0.0087
0.8575	0.5972	0.0001	0.0027
0.8800	0.6518	0.0000	0.0000
0.9050	0.7163	0.0000	0.0000
0.9525	0.8503	0.0000	0.0000
1.0000	1.0000	0.0000	0.0000

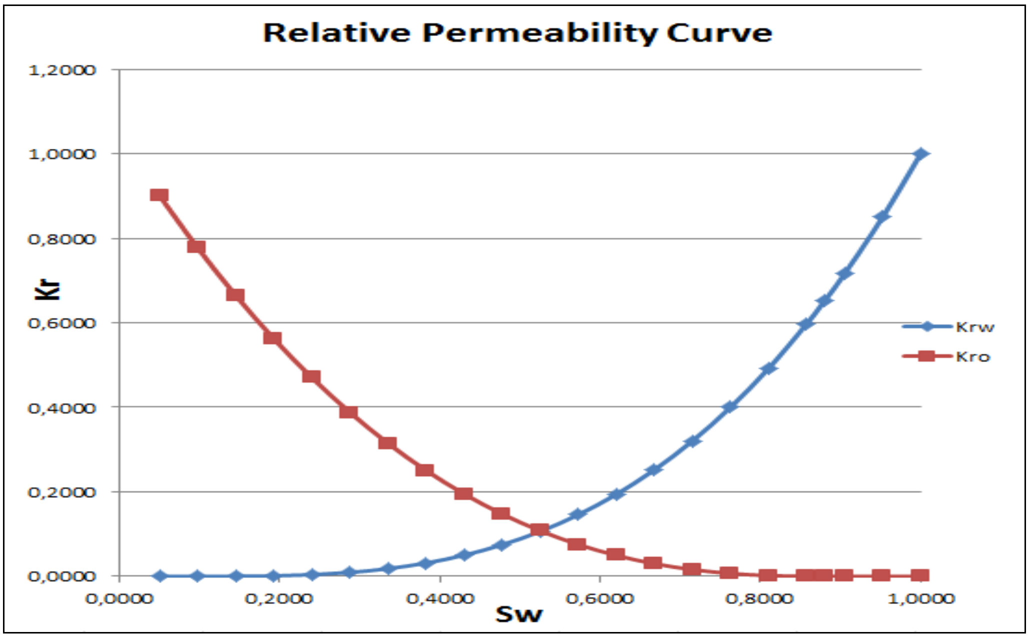


Figure34: Relative PermeabilityCurve

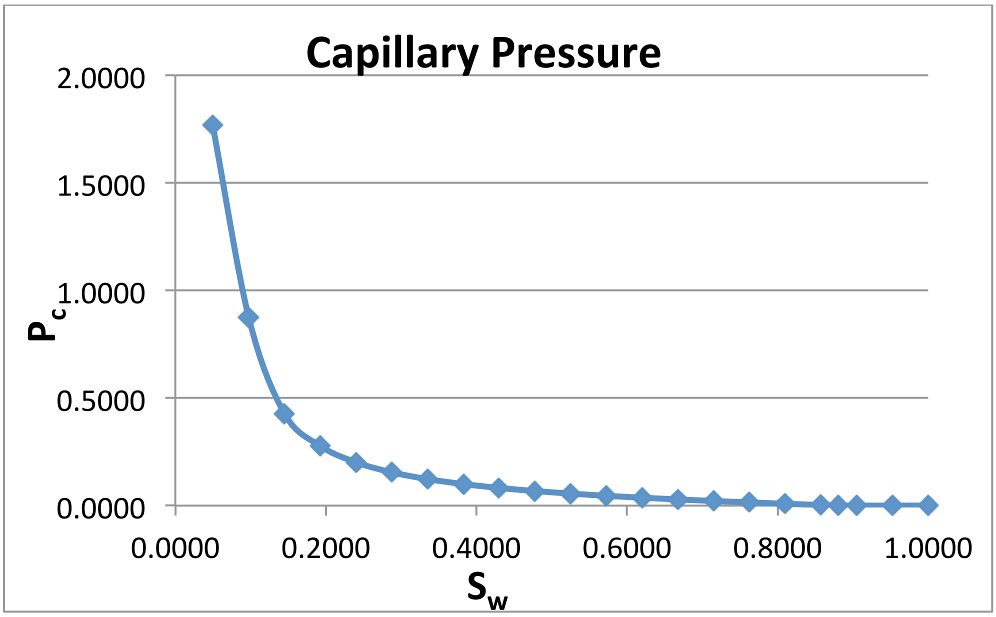


Figure 35: Capillary Pressure

6.6 Input Parameters

Different properties used in the simulation are stated in the table below.

Table 8: Simulation Input Parameters

Oil Viscosity. μ_o	0.318cp
Oil FVF. β_{oi}	1.038Rm^3/Sm^3
Gas Oil Ratio, GOR	111Sm^3/Sm^3
Bubble point	251bar
API	32.7
Oil Density.ρ_{oi}	859.5Kg/m^3
Water Density.ρ_w	1033Kg/m^3
Reservoir Temp.	98^{o}C
Initial Pressure.$P_{res.i}$	277bar

6.7 Low Permeability Inclusion

Inclusion forms a significant volume of the model and is oriented perpendicular to the flow in order to avoid by-passing of injected liquid as shown in figure 37.

Permeability of inclusions = 2 mD
Permeability of other matrix = 100 mD

Therefore, effective permeability needed for capillary number calculation can be estimated using Darcy's Law.

$$K_{eff} = c_f * Q_w \frac{\Delta X \ \mu_w}{A \Delta P K_{rw}} \tag{6.1}$$

C_f= Conversion Factor

Permeability contrast between inclusions and surrounding matrix is used to illustrate the effect of reduced IFT on capillary trapping. High permeability inclusion could exist as a fracture in a real reservoir.

6.8 Effect of Gravity Segregation

Effects of gravity segregation were ignored in the early years because it could not be properly handled in reservoir engineering calculations. The introduction of reservoir simulation provided the capability to handle gravity and gravity segregation importance in reservoir performance became known.

(Craig et al, 1957) carried out laboratory investigation on effects of gravity segregation during water, gas, and solvent flooding. They discovered that segregation of fluids due to gravity effects could result in oil recoveries at breakthrough as low as 20 percent of the expected result. This investigation also revealed that, other than gravitational effect, heterogeneity could also influence production performance to a greater extent. Gravity segregation as a result of interfacial tension reduction could occur in heterogeneous porous media. This can be estimated through a ratio of viscous to gravitational forces which depends upon injection rates as a proportion of pore volume, absolute horizontal permeability of reservoir, density difference and vertical permeability.

Figure 42 shows impermeable shale that restricts vertical movement of oil segregated due to gravity and accumulates below the streak. This accumulated oil beneath impermeable layers in the 2D-model might have an effect on the recovery factor especially when injection rate is low. This phenomenon is studied in the synthetic model in order to handle gravity effect between Ile, Tofte and Tiljie formations of Norne C-segment.

6.9 Chemical Concentrations

The keywords WSURFACT, WALKALINE and WPOLYMER are used to specify concentrations of surfactant, alkaline and polymer respectively in the injection stream of each well when the chemical model is active. For example, if WSURFACT keyword does not appear schedule section of data file, a concentration value of zero is assumed. It is important that the well is defined as a water injection well and used in the SCHEDULE section of the model as shown in appendix A1.4.

6.10 Chemical Properties Used in Models

Chemical properties (alkaline, surfactant and polymer) used in the models are similar to that of (Maheshwari Y. Kishore 2011) used in his academic research about comparative simulation study of chemical EOR methodologies in Norne E-segment. These data were provided by Statoil ASA and available in appendix B.

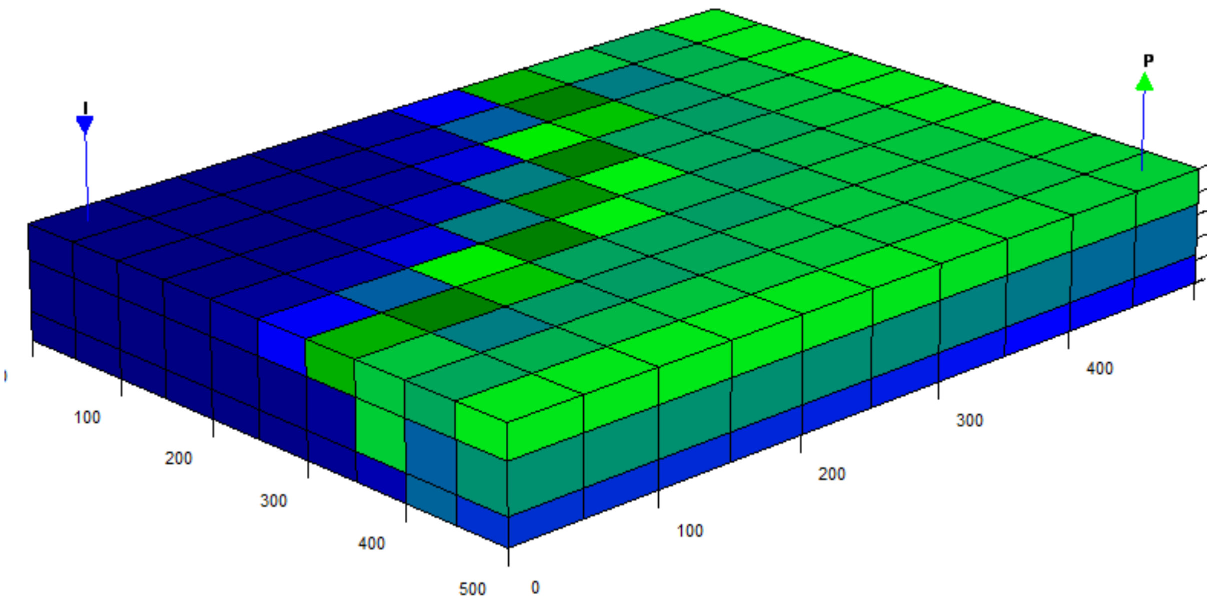
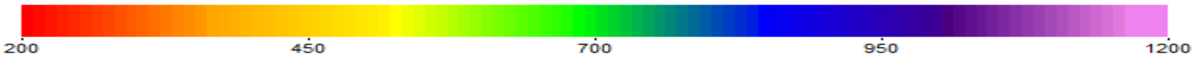


Figure 36: Three-Dimensional Heterogeneous Model



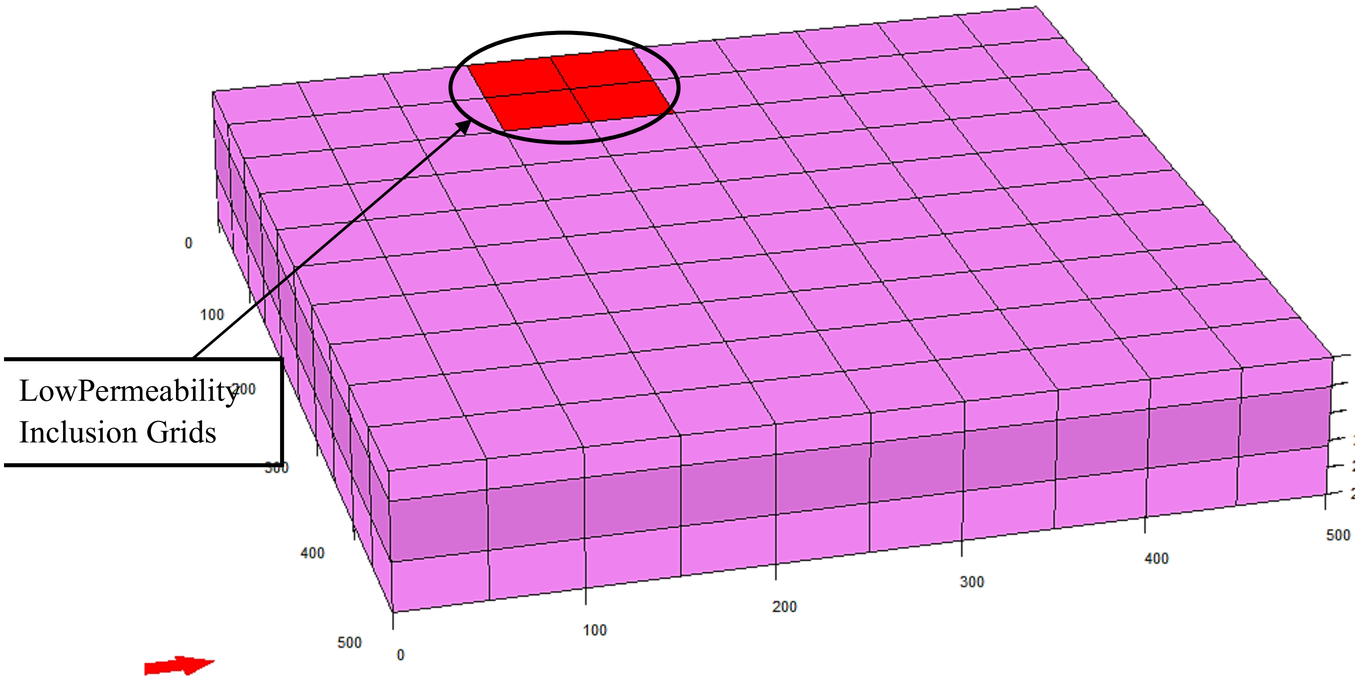


Figure 37: Three-Dimensional Heterogeneous Model Showing Low Permeability Inclusion Grids

6.11 Results of Synthetic Simulations

6.11.1 Effect of Chemical Flooding on Recovery Factor

As shown in figure 38 below, a layered three-dimensional heterogeneous reservoir is pre-flushed with water for 150 days, followed by chemical injection for 250 days and water is injected for the last 300 days. ASP slug gave highest recovery factor of 88 percent while AS follows with a recovery factor of 84 percent with water injection being 74 percent.

The 88 percent efficiency shows extra recovery of oil that is obtained because interfacial tension between oil and water was lowered resulting to extra oil production.

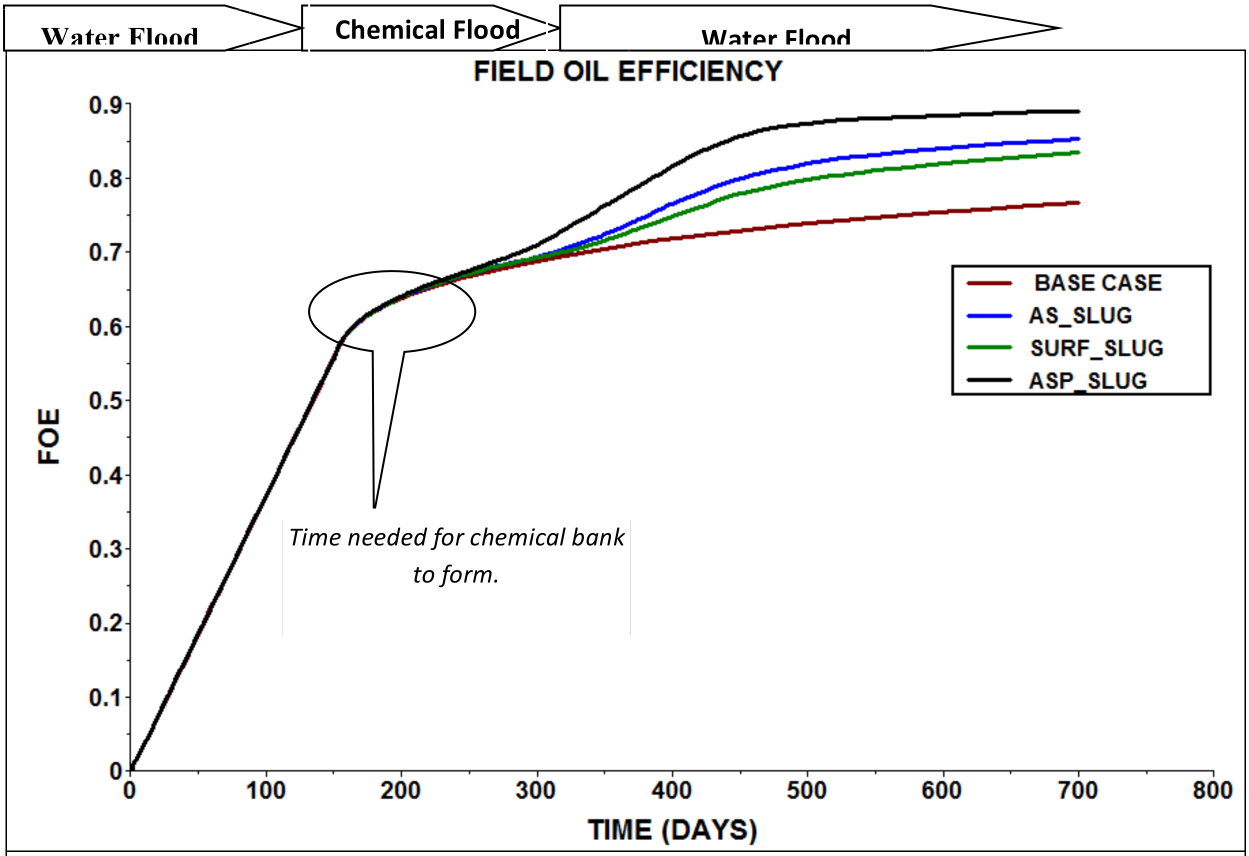


Figure 38: Effect of Chemical Flooding on 3D Recovery Factor

6.11.2 Effect of Chemical Flooding on Oil Production Rate

Figure 39 below illustrates effect of chemical injection on production rate. Water injection (base case) shows continuous decline in production rate throughout the production period. ASP rate increased to 150Sm^3/day followed by AS which jumped to 97Sm^3/day.

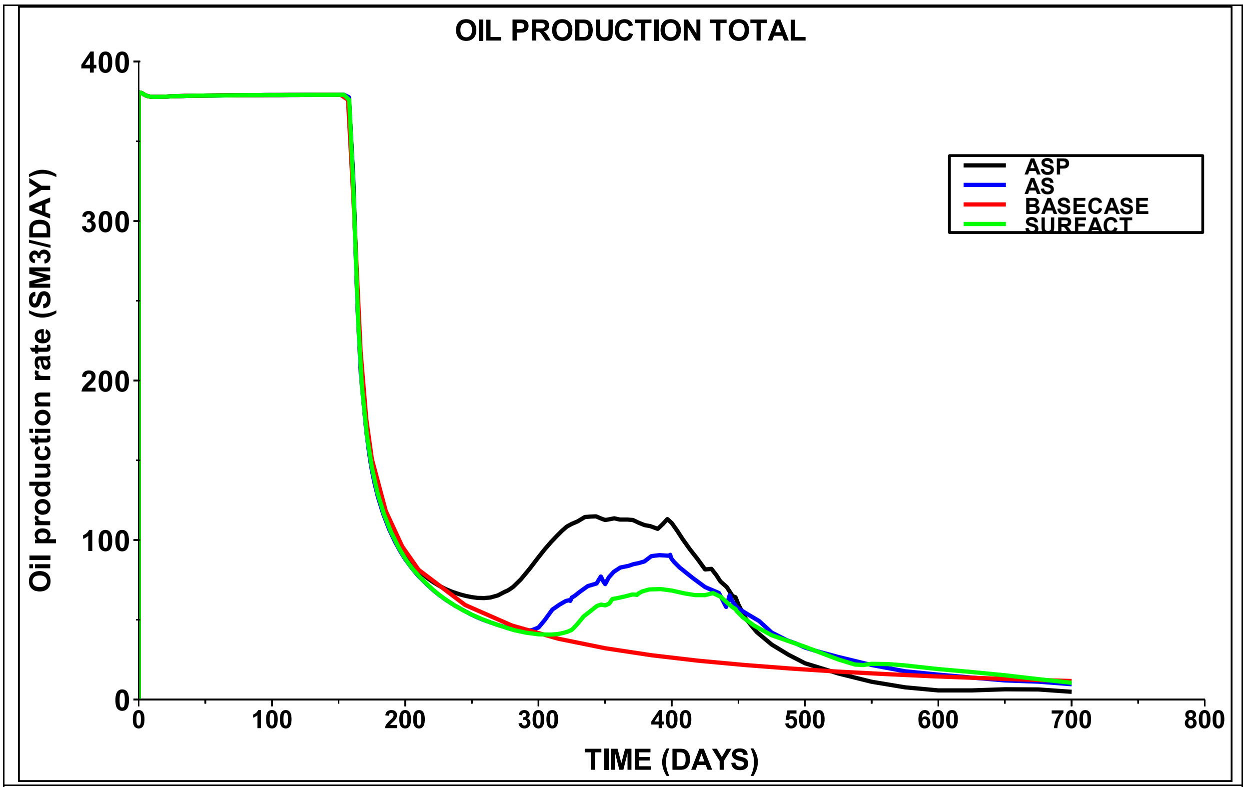


Figure 39: Effect of Chemical Flooding on 3D Oil Production Rate

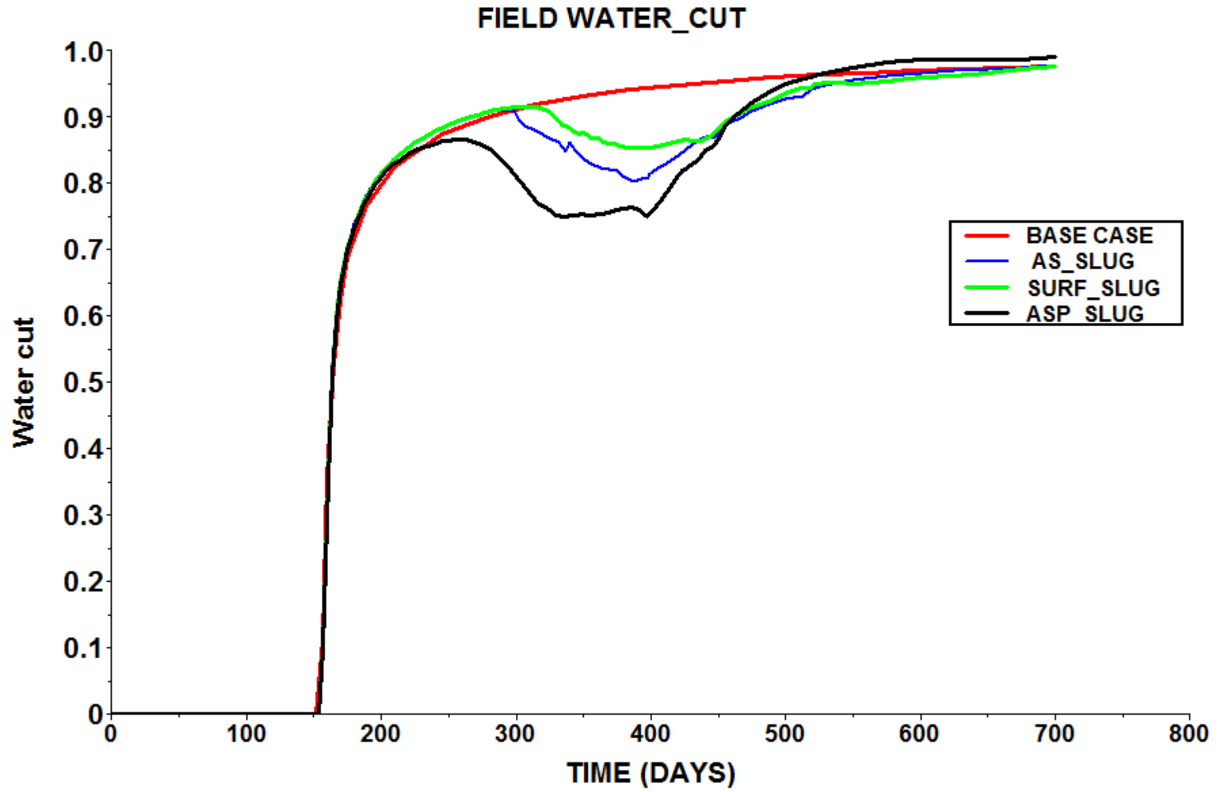


Figure 40: Chemical Effect on 3D Field Water-Cut

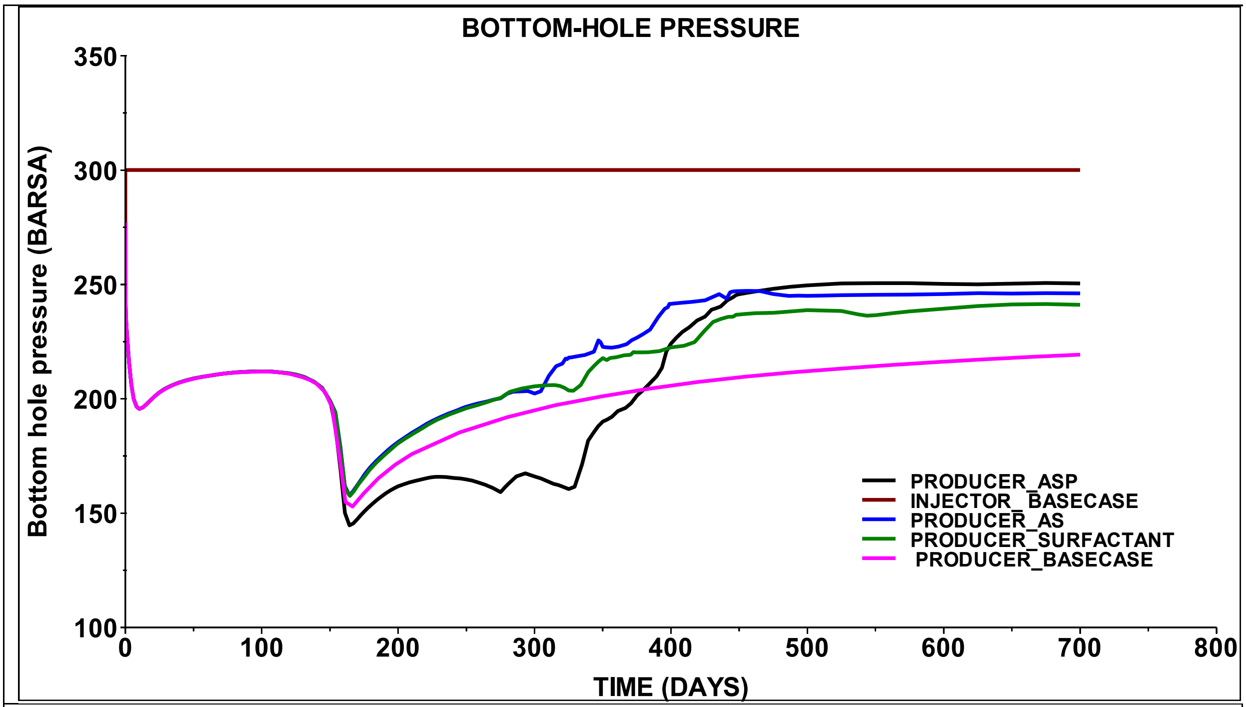


Figure 41: Effect of Chemical Injection on 3D Bottom-Hole Pressure

6.11.3 Effect of Chemical Injection on Bottom-Hole Pressure

As shown in figure 41 above, injector bottom pressure is fixed at 300bara and different chemicals were injected at the same rate. Base case maintained stable pressure increase while producer witnessed lowest bottom pressure when ASP was injected through the injector. More oil production implies high pressure drop between injector and producer bottom pressures.

Table 9: Effect of different chemical slugs on a 3D-stratifield model.

Cases	Recovery Factors (%)	Remaining Oil Saturation (ROS)
Base case	77.18	0.217
Polymer	78.42	0.458
Surfactant	83.91	0.152
Alkaline/surfactant	85.79	0.135
Alka/surfactant/polymer	89.48	0.205

The injector BHP is fixed for 300Bara and producers are left un-fixed for different chemical slug injections. The initial average reservoir pressure is 277bara. For all the chemical slugs tested. a minimum pressure drop (Δp) of 50bara between the injection and production wells is experienced as shown in figure 41 above while the base case (water) gave highest pressure drop**.**

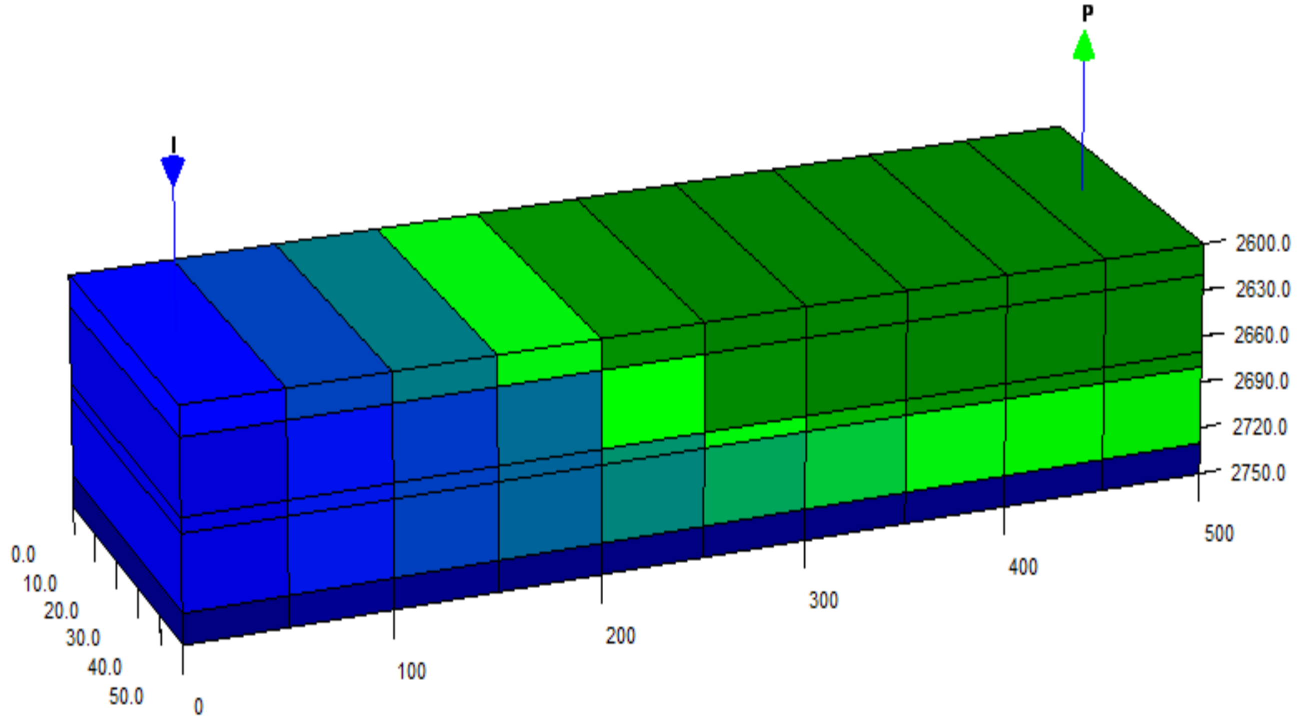


Figure 42: Two-Dimensional Layered Heterogeneous Model

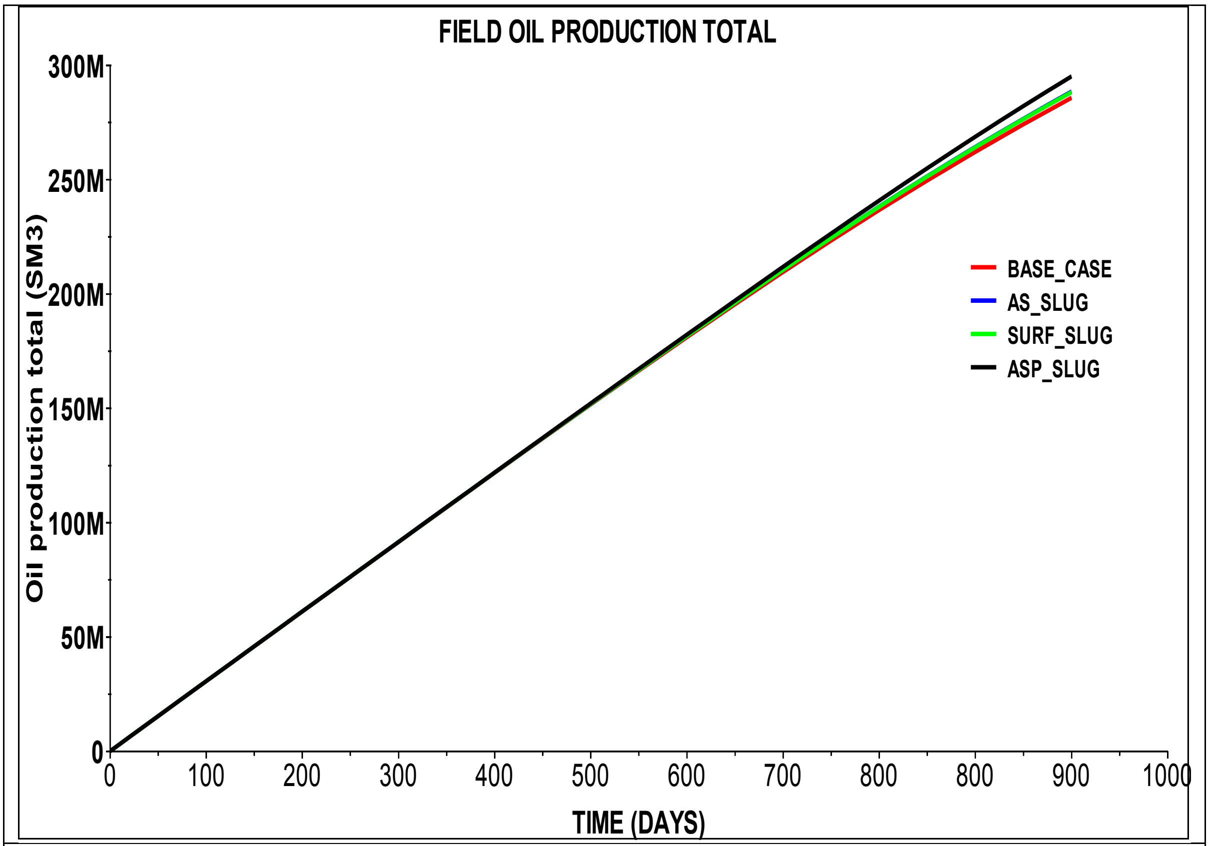


Figure 43: Effect of Chemical Flooding on 2D Oil Production Rate

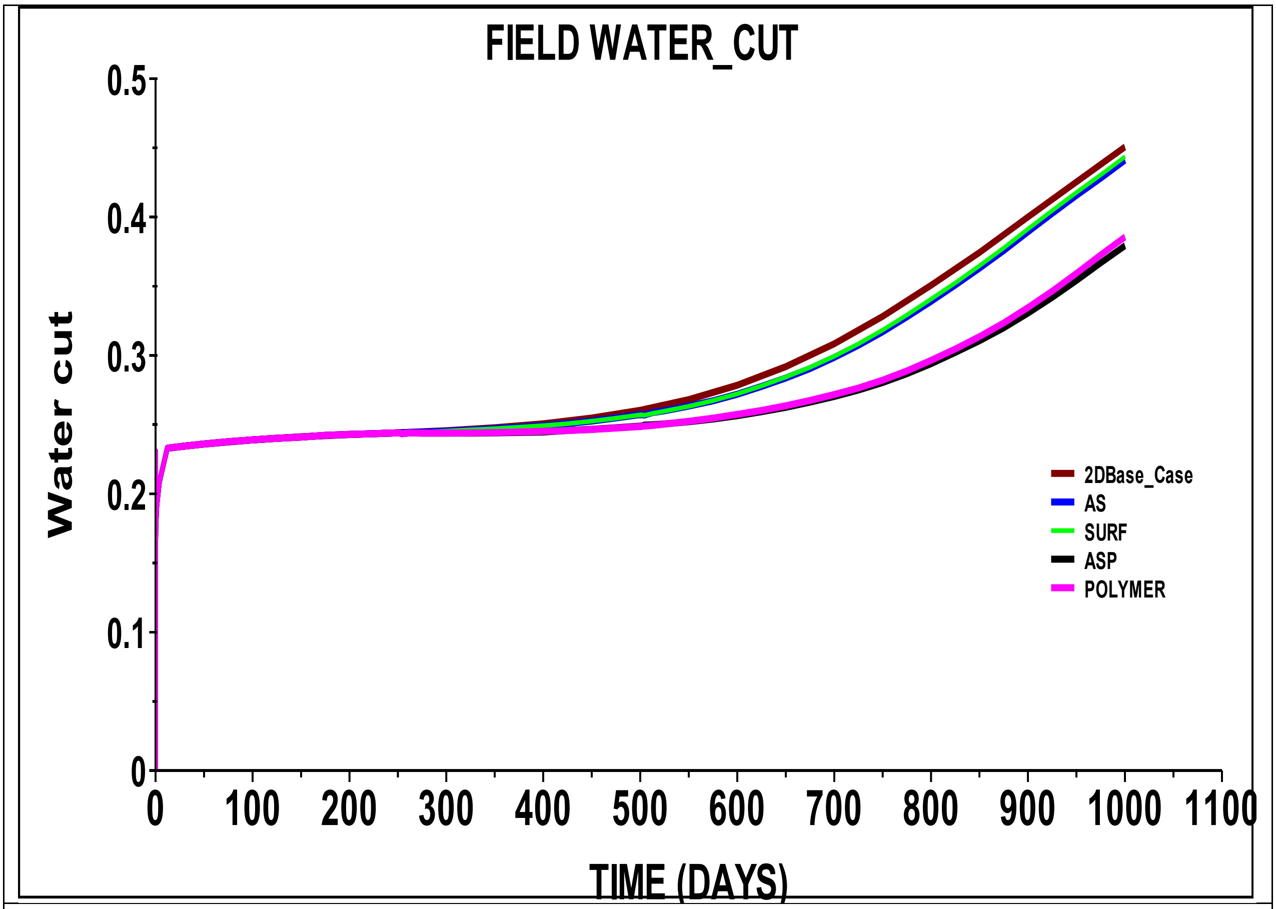


Figure 44: Effect of Chemical Flooding on 2D Water-Cut

The table 10 below summarizes recovery factors and remaining oil saturations for different cases simulated under vertical heterogeneity. In all, original oil in place is 6.53 x 10^5Sm^3 and injection rate of 500m^3/day is used. Alkaline concentration of 5.0m^3/kg, surfactant concentration of 3.0m^3/kg and polymer concentration of 0.2m^3/kg are used.

Table 10: Effect of different chemical slugs in a 2D-stratifield model.

Cases	**Recovery Factors (%)**	**Remaining Oil Saturation (ROS)**
Base Case	43.7	0.426
Polymer	45.1	0.417
Surfactant	44.1	0.424
Alkaline/Surfactant	44.2	0.423
Alka/Surfac/Polymer	45.2	0.416

CHAPTER 7

FIELD SIMULATION RESULTS

Admittedly, after producing for some years via water injection, an estimated fraction of the original oil in place were noticed to have been trapped in the rock. This is especially noticeable in the water swept areas of Ile and Tofte formations which hold 80% of the oil in the reservoir. This observation demands for an EOR method by which extra oil production can be achieved with pressure maintenance. Thus, there is need for enhancing agents like alkaline, surfactant and/or polymer. Figures 45 shows oil remaining in Ile formation (layer 5 and 8) in 2008 and 2010 respectively after long time production from the field.

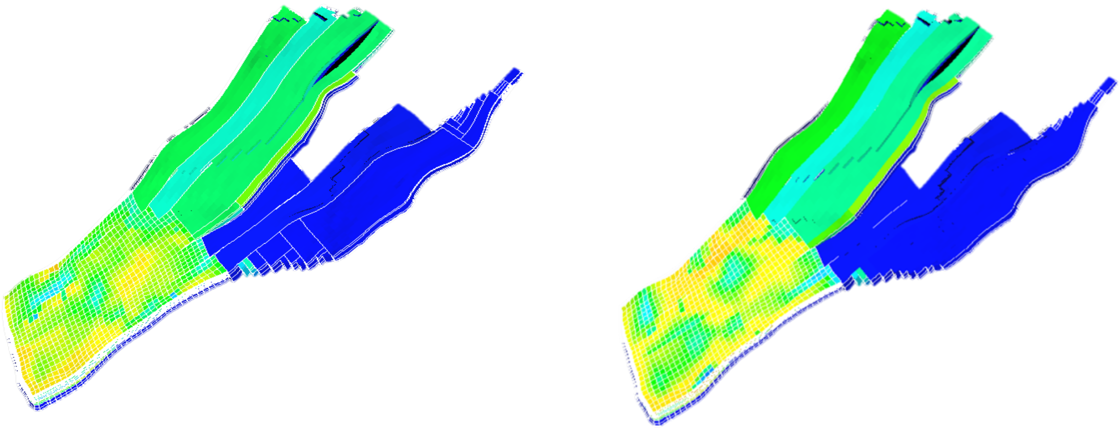


Figure 45: Ile (layer 5) oil saturation in 2008 Ile (layer 8) oil saturation in 2010

The co-injection of a mobility control agent and interfacial tension reducing agents into Norne C-segment was performed to improve two efficiency factors simultaneously. Areal sweep efficiency (E_A) and vertical displacement efficiency (E_V) were increased by addition of polymer to the injected solution. Pore-to-pore displacement efficiency (E_D) was increased by decreasing the interfacial tension between oil and water by adding alkaline and surfactant to the injected solution.

Designing injection of chemicals into an oil reservoir should be properly structured. This is because chemicals, especially surfactant are expensive and it is important to ensure that unnecessary waste is prevented during the course of injection. For example, if cyclic injection of chemical could give similar increased oil recovery as continuous injection, then the latter becomes unnecessary as this will give rise to increased expenditure while also resulting to excess production of chemicals at the producing wells. In this study, there is a step by step modeling of what method of chemical injection to use. Several cases were examined ranging from continuous injection with different periods of flooding, to cyclic injection with different intervals. Also, appropriate chemical concentration was determined and the most profitable chemical combinations were examined. Different chemical injection scenarios used for justification is shown in Table 17 on appendix C1.3

Different chemical systems; surfactant flooding, alkaline-surfactant (AS) flooding, polymer flooding, surfactant-polymer (SP) flooding, alkaline-surfactant-polymer (ASP) flooding and economical evaluations of these systems were tested in order to see which is the most viable and profitable method in terms of Net Present Value (NPV) for the Norne C-segment. In addition, sensitivity analysis (Tornado chart) was used to compare the relative importance of variables. Sensitive variable was modeled as uncertain value while all other variables were held at baseline values (stable).

- **Surfactant Flooding System**
  - Suitable Surfactant Concentration
  - Surfactant Time of Injection
- **Polymer Flooding System**
  - Suitable Polymer Concentration
  - Appropriate Injection Rate
- **Surfactant-Polymer Flooding System**
  - Continuous versus Cyclic Surfactant-Polymer Injection
- **Alkaline-Surfactant Flooding System**
  - Suitable Alkaline Concentration;
    - Surfactant (2Kg/m3) and Alkaline (7Kg/m3)
    - Surfactant (2Kg/m3) and Alkaline (10Kg/m3)
    - Surfactant (2Kg/m3) and Alkaline (15Kg/m3)
    - Surfactant (2Kg/m3) and Alkaline (20Kg/m3)
  - Continuous and Cyclic Alkaline-Surfactant Injection
  - Injection Time (Early and Late AS Injection)
- **Alkaline-Surfactant-Polymer Flooding System**
  - Continuous and Cyclic ASP Injection
  - AS Injection Followed By Polymer
  - Injection Time (Early and Late ASP Injection)
  - Mixed ASP Injection;
    - Started in 2008 AS (6 Months Cyclic) Followed By Polymer For a year
    - Started in 2013 AS (6 Months Cyclic) Followed By Polymer For a year
- **Estimation Of NPV For All The Flooding Systems**

7.1 Basic Assumptions in Modeling

1. The following assumptions have been made in developing chemical injection model in Eclipse 100.
2. Reservoir is isothermal. Temperature changes resulting from chemical reactions are negligibly small.
3. Chemical adsorption is assumed to be instantaneous and it is a function of available chemical concentration.
4. Chemicals are assumed to exist only in the water phase and the input to the reservoir is specified as a concentration at a water injector.
5. Well grouping option is enabled and group profile is assumed as field profile.
6. Rock capillary pressure is assumed to vary with interfacial tension (IFT).
7. Ideal chemical mixing holds (i.e. volume changes of mixing are zero).
8. Alkaline, surfactant and polymer do not occupy any pore space.
9. Effect of salinity on chemical is ignored.
10. Fluid and rock are slightly compressible.
11. Darcy's law is applicable.
12. The solid phase is immobile.
13. Fluid and rock are slightly compressible.
14. Pressure and volume changes resulting from chemical reactions are negligibly small.
15. All sunk costs are assumed to be zero.
16. Chemical costs are assumed to be the major expenses.

7.2 Surfactant Flooding System

In order to achieve sufficient incremental oil production, optimum conditions for surfactant injection on C-segment must be established. These optimum conditions take into consideration an appropriate concentration as well as the right time to initiate injection.

7.2.1 Suitable Surfactant Concentration

Based on previous theoretical studies, several concentrations were tested on Norne C-segment by trial and error method in order to come up with a threshold concentration; the right amount of surfactant that would give a profitable recovery and thereby reducing residual oil saturation to the possible minimum. Concentrations of 5 kg/m3, 10 kg/m3, 15 kg/m3, 20 kg/m3 and 30 kg/m3 were considered and modeled. GOPR and GOPT among other plots made indicated 10Kg/m3 as good concentration. Figure 46 shows oil production total for all cases when the injection starts in 2013 and lasts for four years. Concentration value of 30Kg/m3 yielded the highest oil production but a substantial fraction was adsorbed on the rock as shown in figure 47.

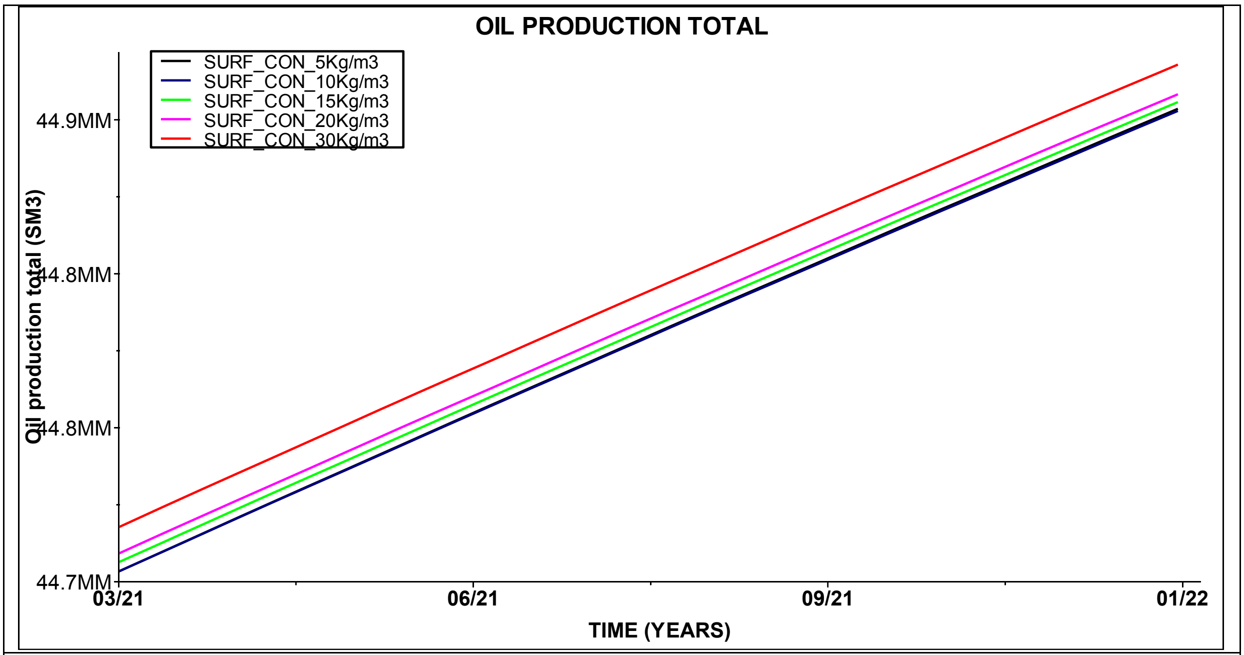


Figure 46: Effect of Surfactant Concentrations on Field Oil Production Total

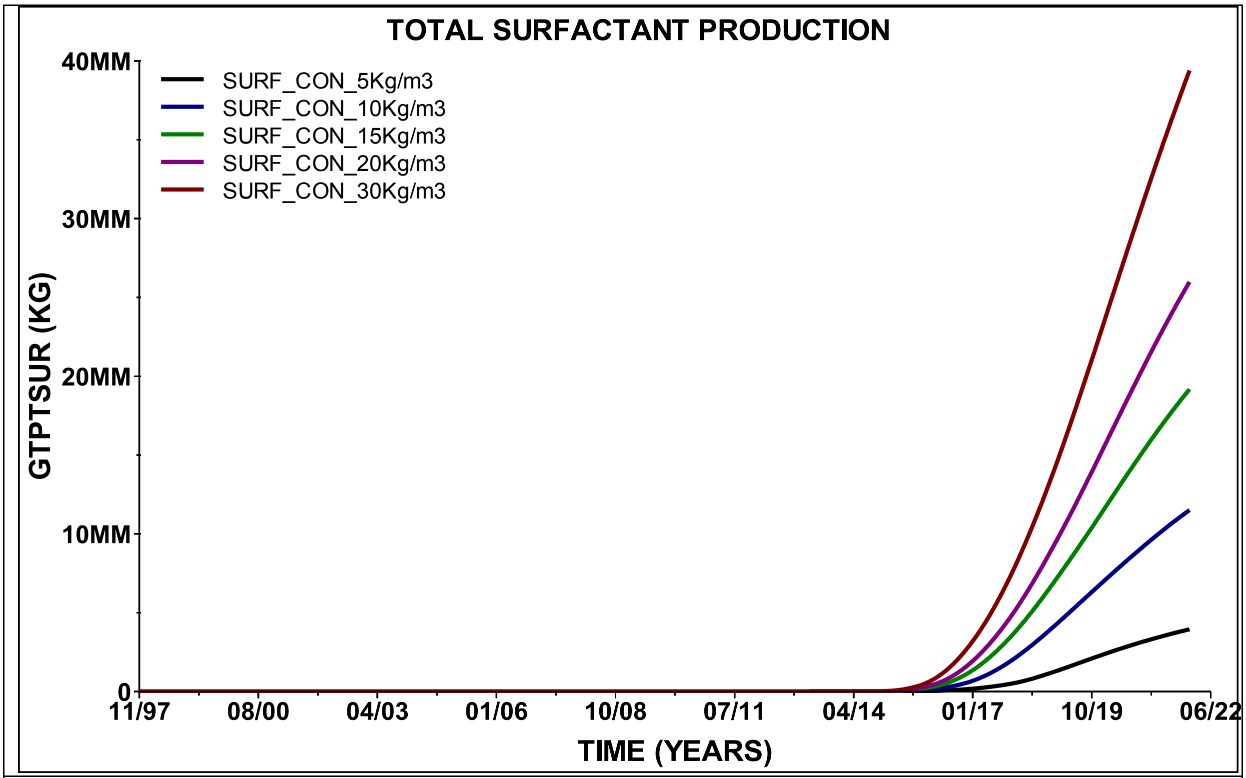


Figure 47: Effect of Surfactant Concentrations on Field Surfactant Production

7.2.2 Surfactant Time of Injection

Injecting surfactant concentration of 10 kg/m3 for a four year period starting in 2006, 2012, 2013 and 2015 gave different production rates and cumulative oil production for the group. Since Norne field is scheduled to be shut down in 2022, it is most profitable to inject surfactant in 2006. As shown in Figure 48, the group production total was peaked for surfactant flooding in 2006, followed by 2012 and 2015 giving the least result. Average reservoir pressures for different cases are shown in Figure 49. Since same injection rate was used for all the cases and surfactant concentrations were also equal, it is expected that we will see more or less similar pressure behaviors.

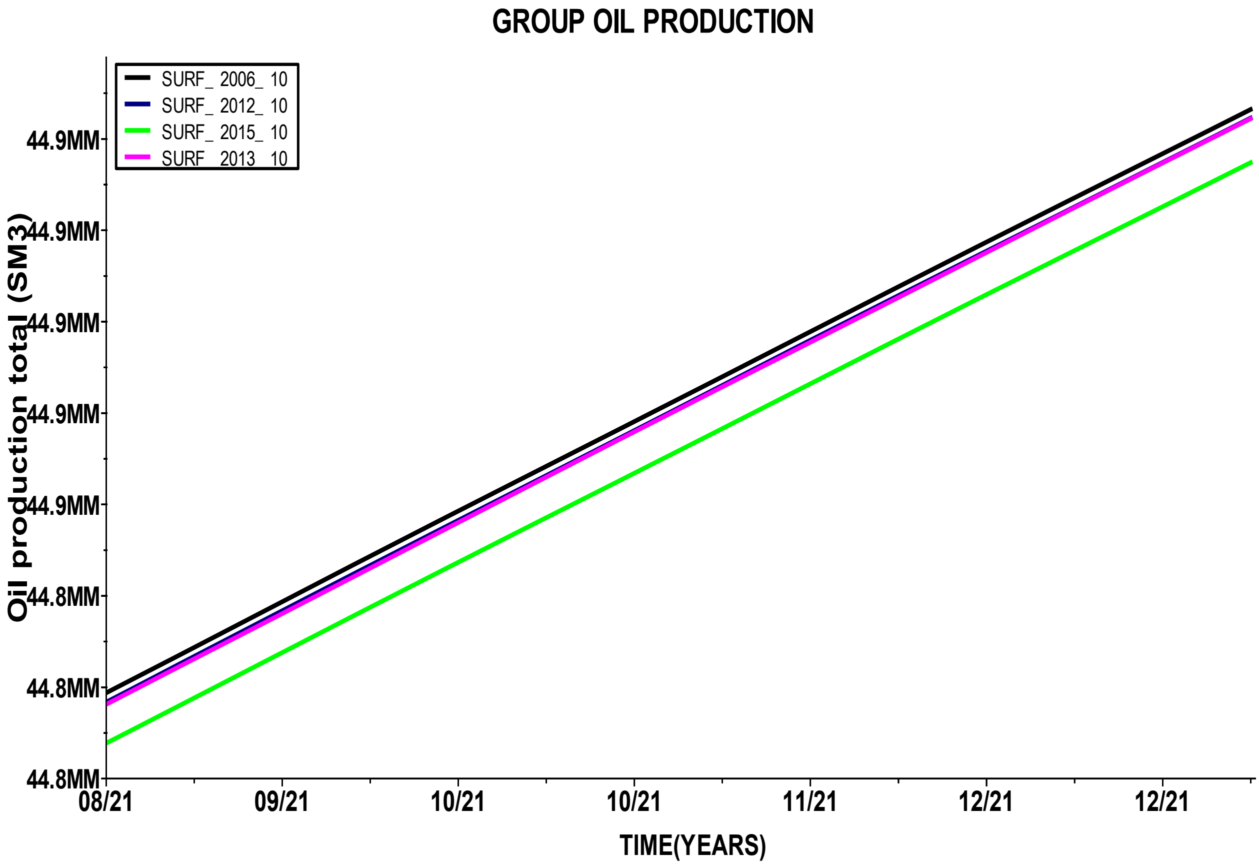


Figure 48: Effect of Surfactant Injection Time on Oil Production Total

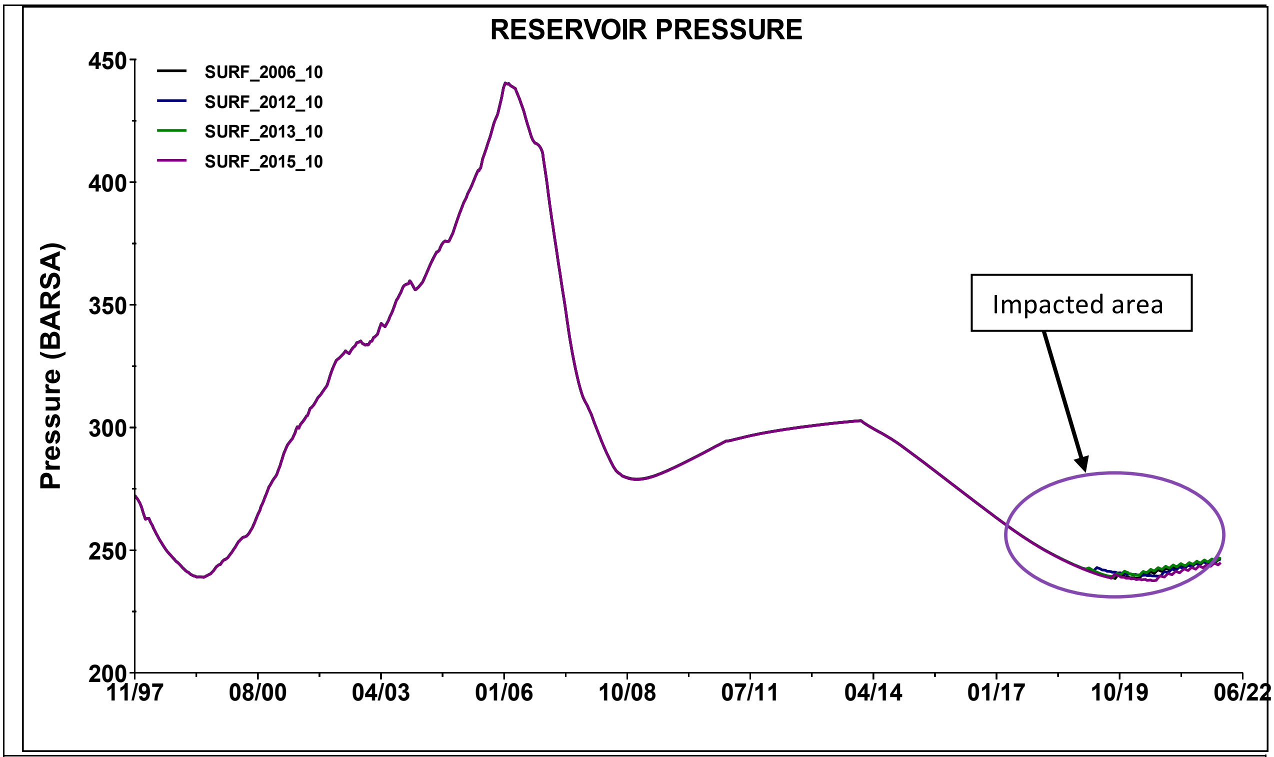


Figure 49: Effect of Surfactant Injection Time on Reservoir Pressure

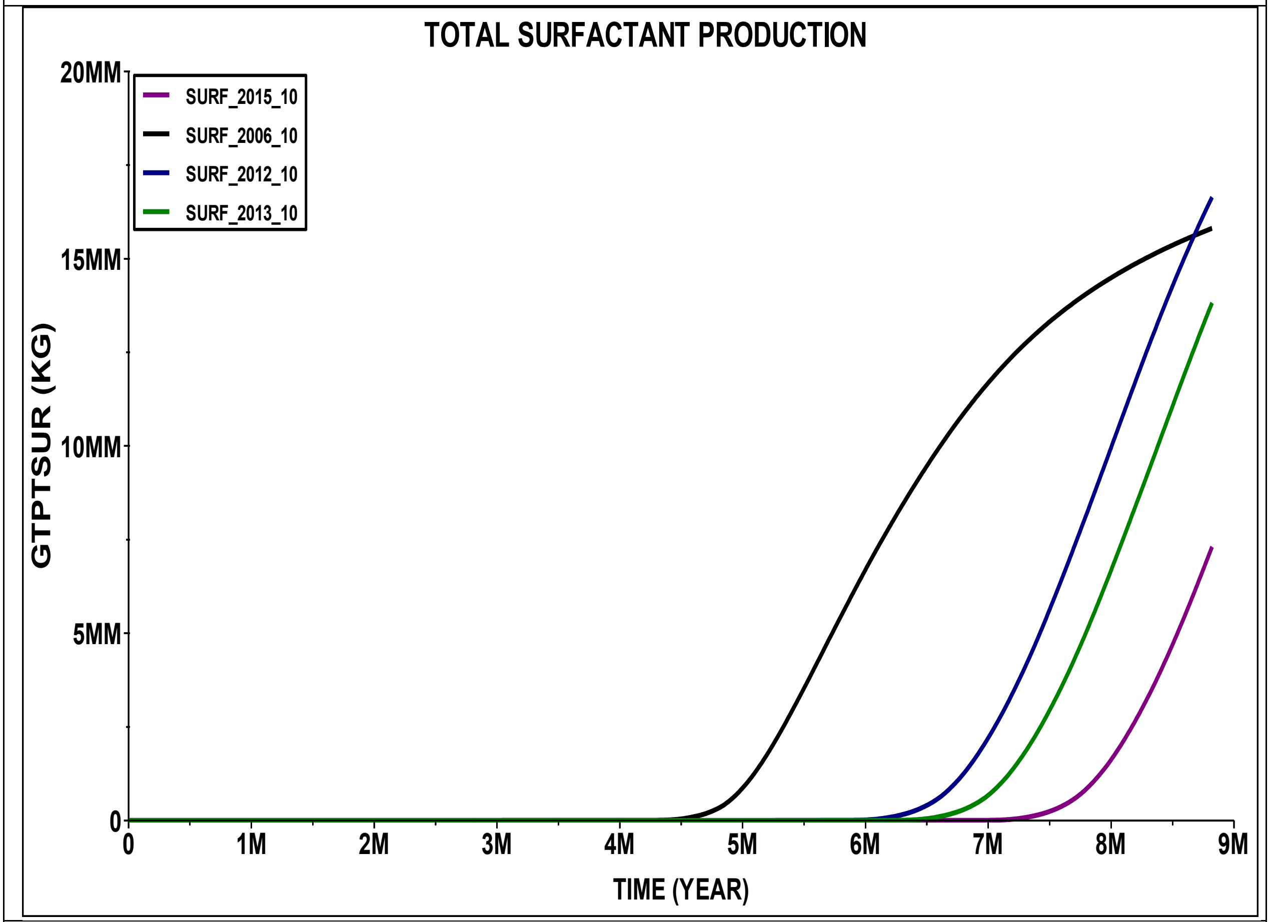


Figure 50: Effect of Surfactant Injection Time on Surfactant Production

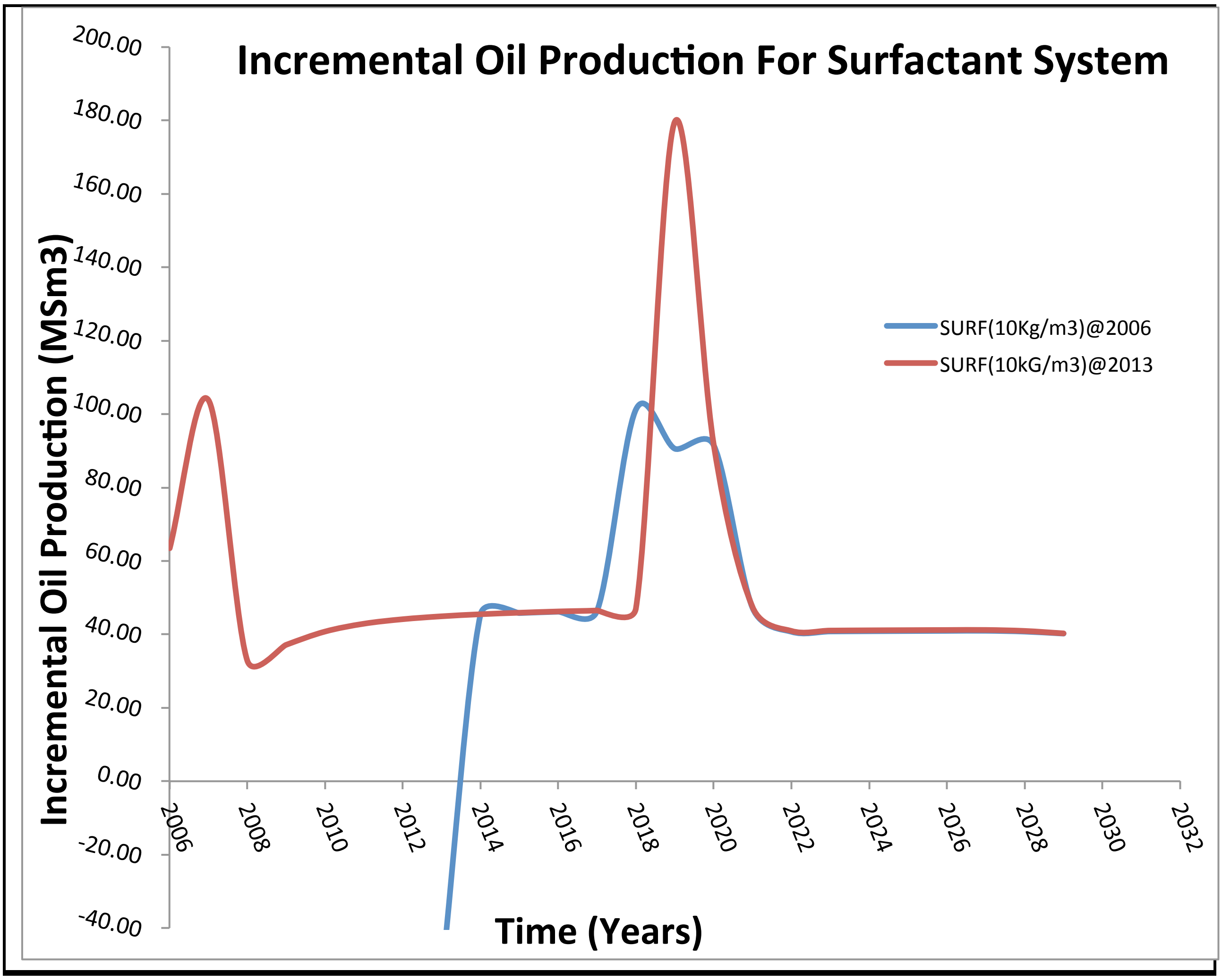


Figure 51: Incremental Oil Production for Surfactant System

7.3 Polymer Flooding System

In the reservoir, oil and water are immiscible fluids. As a result, neither one can completely displace the other in the subsurface condition. This is reflected by the non-zero irreducible water (S_{wir}) and residual oil saturation (S_{or}) on an oil-water relative-permeability curve. In the laboratory, no matter how large volume of water that has been injected into a core, the oil saturation will never be lower than S_{or} only by the conventional water flooding. However, it has been known for many years that the efficiency of a water flooding can be greatly improved by lowering the water-oil mobility ratio in the system. Such a change may lead to better sweep efficiency and also to more efficient oil displacement in the swept zone. By adding of suitable polymer solutions to injected water, the water mobility can be reduced and oil production increased as shown in figure 52.

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 Sor, but it is still an efficient way to reach the Sor more quickly or/and more economically. According to (Guan et al, 2004), polymer solutions may lead to an increase in oil recovery over that from conventional water flooding by three potential ways:

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

The above three effects can make the polymer flooding process more efficient.

7.3.1 Suitable Polymer Concentration

Different polymer concentrations were modeled in a bid to identifying which concentration would satisfy required profitability criteria in term of incremental oil production. These include;

- Polymer concentration of 0.15Kg/m3
- Polymer concentration of 0.3Kg/m3
- Polymer concentration of 0.5Kg/m3
- Polymer concentration of 0.8Kg/m3

All the cases listed above produced figures with similar trends. Increase in injected polymer concentration is directly proportional to the quantity of extra oil produced. Water break-through is delayed. This is related to the fact that the residual oil is mobilized and begins to form an oil bank while water fills spaces released by the residual oil thereby creating reduction in water production. Higher polymer concentration directly reduces the mobility ratio by increasing the water phase viscosity and reducing effective water permeability as well. Concentration of 0.3Kg/m3 is adopted for subsequent polymer simulations in this study.

7.3.2 Appropriate Polymer Injection Rate

The effect of changes in injection rate on group oil production is illustrated in figure 52. The polymer concentration used was 0.3Kg/m^3. An injection rate of 8000 Sm^3/d gave a high injector bottom-hole pressure which jumps away from the fixed average pressure value of 277bara. As shown in figure 53, during simulation trials, higher rate of 15000Sm3/d was discovered to be too high and could lead to formation fracture.
All injection rates gave incremental oil productions with 8000Sm3/d being the least. This was because 6000Sm^3/d was an optimized rate and further increase was credited to corresponding increase in cross flow. Extra oil production due to polymer injection creates void spaces in the reservoir leading to decline in average reservoir pressure.

Chemical EOR methods are known to be expensive, it is therefore imperative to evaluate the amount of chemical that will be adsorbed to the rock surface during flooding. Injection rate influences the chemical fraction that will be subsequently left on the rock surface. If the injection rate is too low, the chemical will have ample time to reside on the rock surface. Therefore, an appropriate chemical injection rate will save cost.

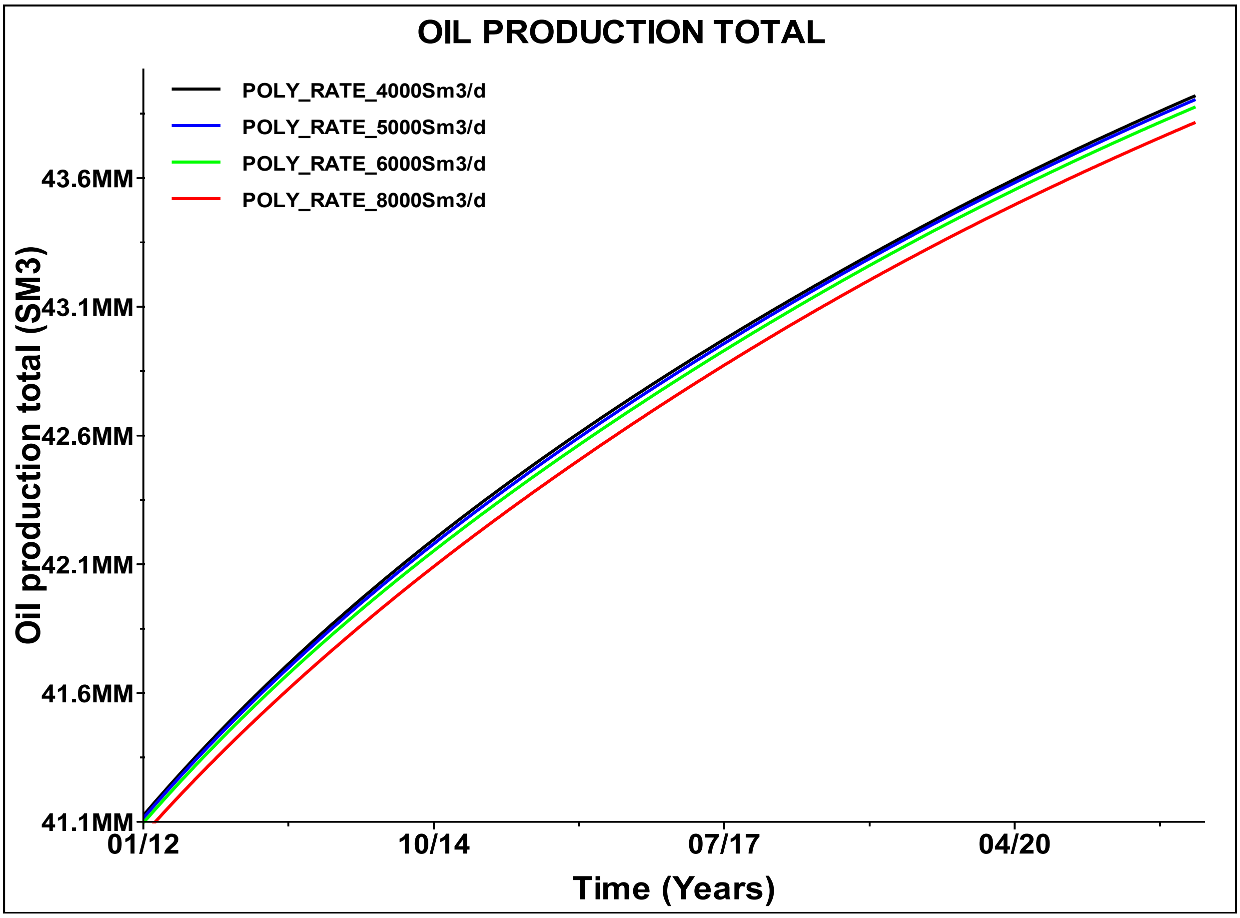


Figure 52: Effect of Polymer Injection Rate on Oil Production

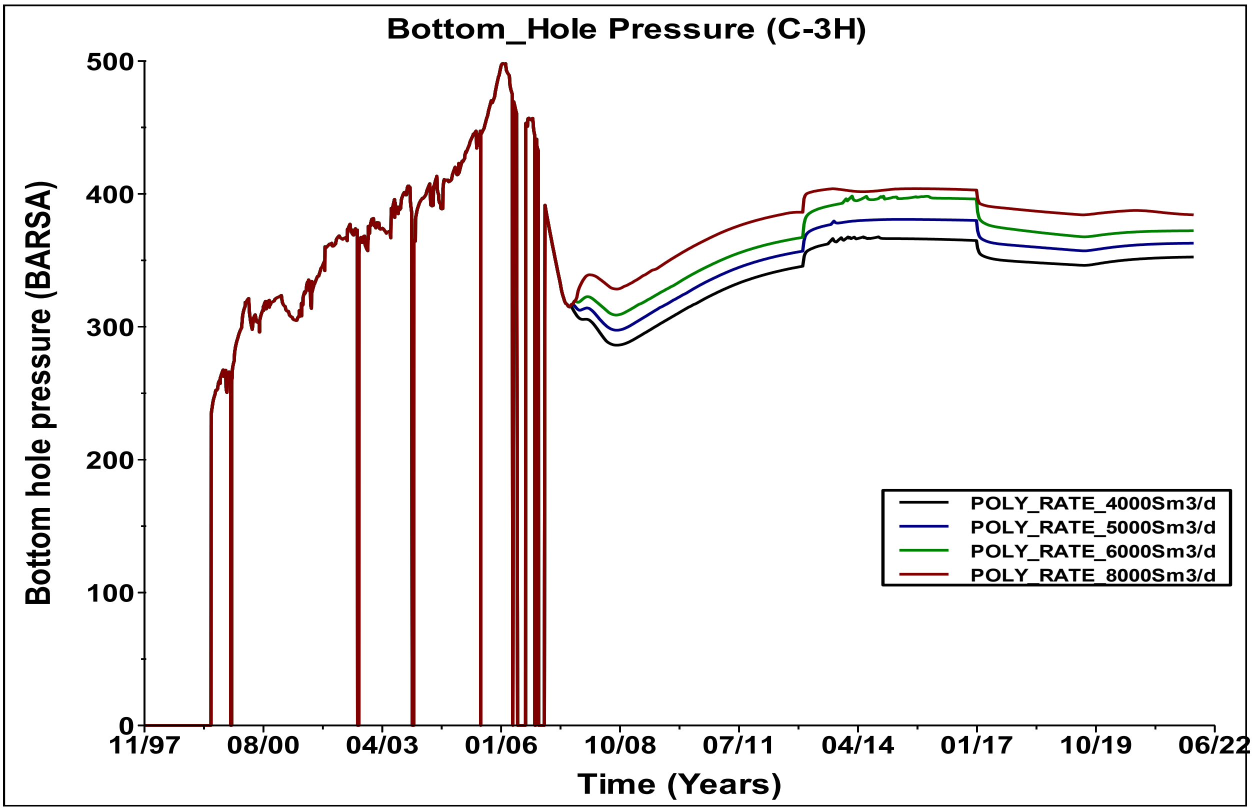


Figure 53: Effect of Polymer Injection Rate on Bottom _Hole Pressure

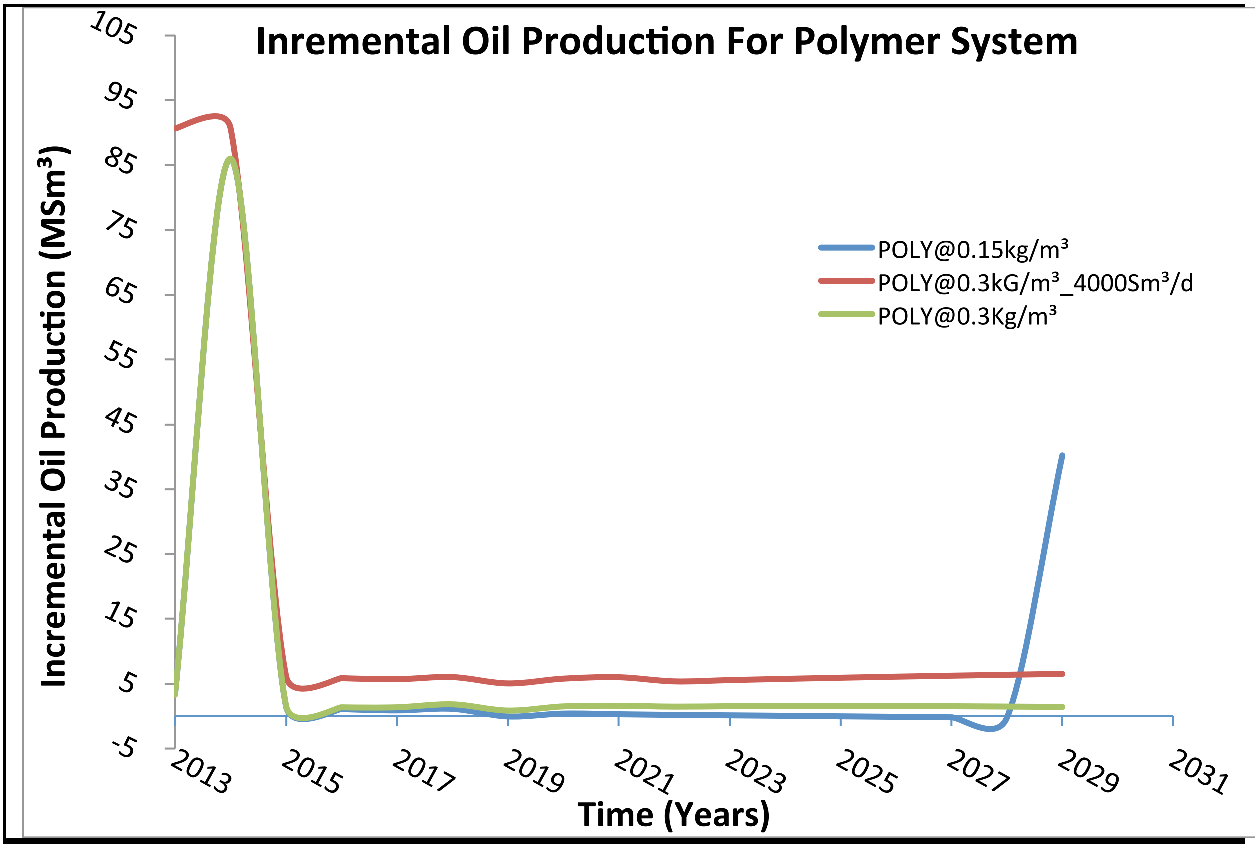


Figure 54: Incremental Oil Production for Polymer System

7.4 Surfactant-Polymer (SP) Flooding System

Mobility control is essential to maintain the integrity of surfactant slug during surfactant-polymer flooding method. Mobility control is needed in the surfactant slug to prevent it from fingering to the oil bank ahead of it. According to (Betaweel et al, 2012) if fingering occurs, this can cause surfactant to dissipate by dispersive mixing between slug and mobility buffer, and between the water drive and the mobility buffer or to the water bank trailing it. The combined flooding processes can not only improve sweep efficiency but also improve displacement efficiency through increased capillary number.

7.4.1 Continuous versus Cyclic Surfactant-Polymer Injection

In this system, three different cases were modeled and simulated;

- Continuous SP of 10Kg/m^3 and 0.3Kg/m^3 respectively for 4years starting from 2013
- Six-months cyclic (6 months-SP and 6 months water) of 10Kg/m^3 and 0.3Kg/m^3 respectively for 4years starting from 2013.
- Only surfactant (10Kg/m^3) for 4 years followed (post-flush) by polymer for 3-years.

Figure 55 shows cumulative oil production for the three cases with the "continuous case" leading others. The "Surf plus Poly" case was least in term of cumulative production. This was because those capillary-trapped oils that were released by surface active agent needed thickening agent (polymer) to push them towards producing wells.

By using cycles when injecting, you may not decrease the production rate significantly, but save the amount surfactant used drastically. Using a cyclic rate of six months of injection with surfactant-polymer and six months of injection without will reduce the amount of chemical used by half. As shown from Figure 55 the decrease in cumulative oil is not that significant for a cyclic injection process. The difference in cumulative oil produced will be about 17.98 MSm^3, while the amount of saved surfactant-polymer will be about 48.9 million kg for a cycle of four years. Therefore it will not be profitable to inject continuous compared with cyclic injection.

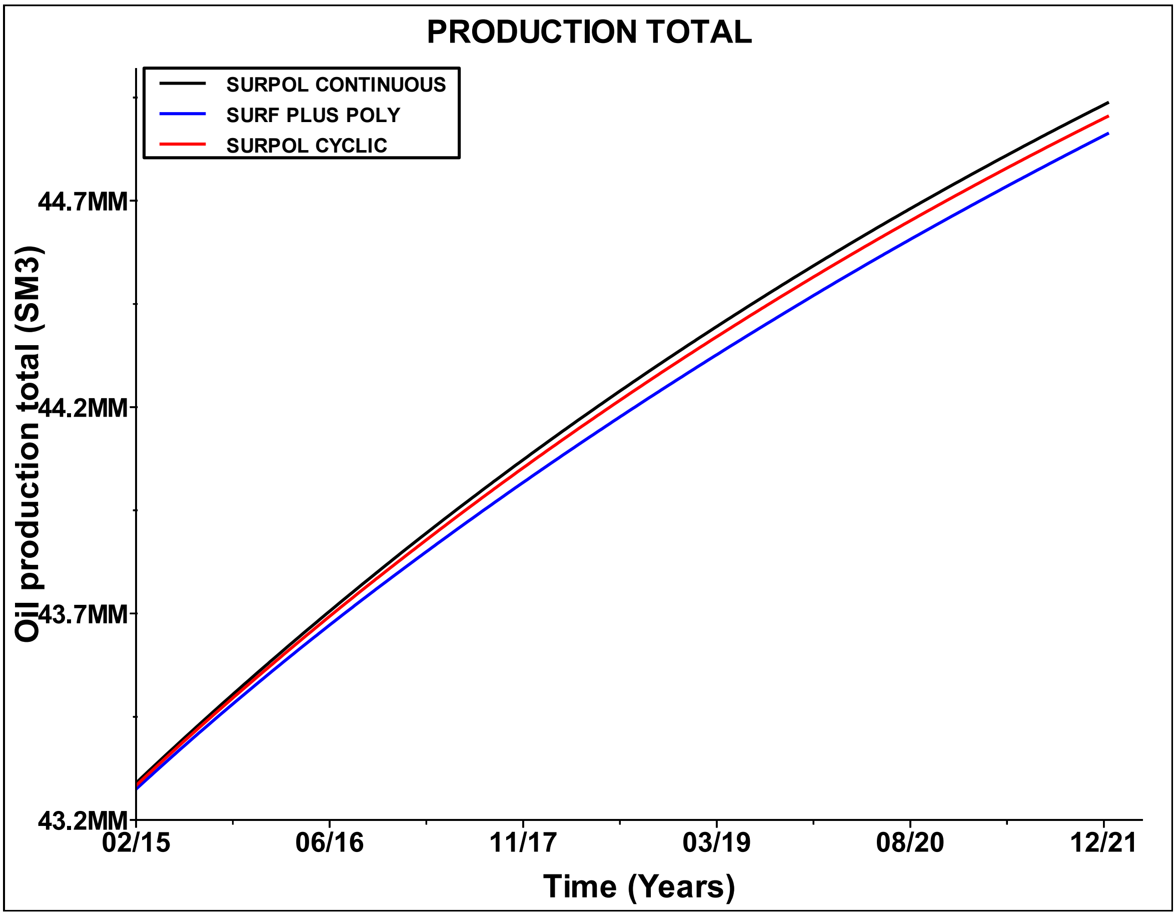


Figure 55: Effect of Continuous and Cyclic Surfactant-Polymer Injection on Oil Production

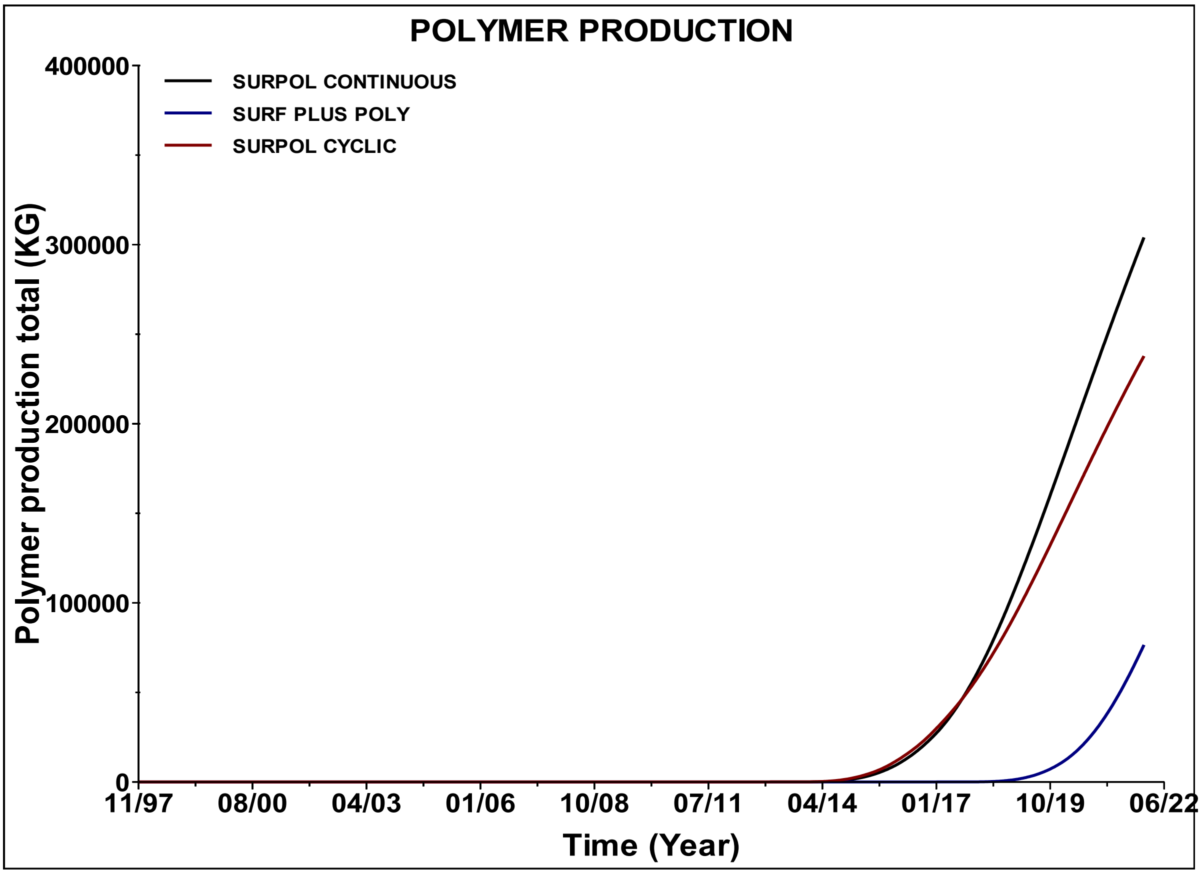


Figure 56: Effect of Continuous and Cyclic Surfactant-Polymer Injection on Polymer Production

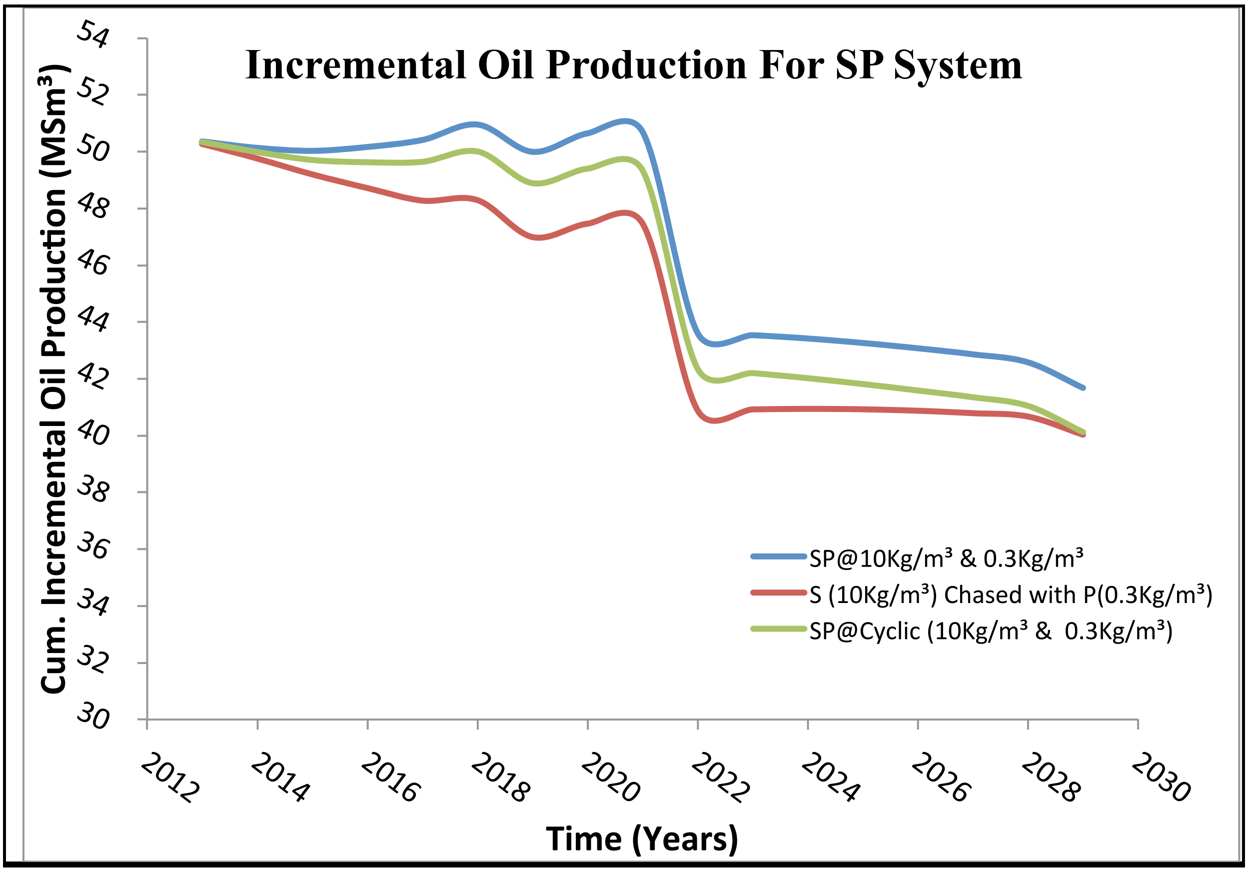


Figure 57: Incremental Oil Production for Surfactant-Polymer System

7.5 Alkaline-Surfactant Flooding System

The alkaline agent is intended to react with the acids to generate in-situ surfactant to overcome the surfactant depletion in the liquid phases due to retention. It also alters rock wettability and adjusts pH and salinity. When water or other fluids are injected under pressure, they seek the path of least resistance to the point of lowest pressure, which is generally the producing well. Because high permeability zones and fractures offer the least resistance to flow, most of the injected fluid follows this path and hence most of the oil remaining in the lower permeability zones is by-passed. After conventional waterflood processes the residual oil in the reservoir remains as a discontinuous phase in the form of oil drops trapped by capillary forces. The synergistic effect of alkaline and surfactant results in less surfactant required to recovering significant incremental (oil Ajay et al, 2008).

7.5.1 Suitable Alkaline Concentration in AS Flooding

As listed below, surfactant concentration was fixed at 2Kg/m^3 but the alkaline concentrations were varied. Slugs were injected for four years starting from 2013. In practice, the reason for this synergy is to minimize expenses incurred on surfactant. Figure 58 shows group oil efficiency for the four cases. AS (20Kg/m^3 and 2Kg/m^3) recorded highest recovery but not the most economically viable since the oil efficiency at the 7kg/m^3 surfactant concentration is same as with 15kg/m^3 concentration, and then it is rather wasteful to inject 15kg/m^3.
Similarly, figure 59 illustrates group surfactant adsorption cases. The higher the alkaline concentration in the slug, the lower the surfactant adsorbed. Surfactant adsorptions were substituted by alkaline adsorptions on the rock surface.

- Surfactant (2Kg/m^3) and Alkaline (7Kg/m^3)
- Surfactant (2Kg/m^3) and Alkaline (10Kg/m^3)
- Surfactant (2Kg/m^3) and Alkaline (15Kg/m^3)
- Surfactant (2Kg/m^3) and Alkaline (20Kg/m^3)

7.5.2 Continuous and Cyclic Alkaline-Surfactant Injection

Figure 58 and Figure 59 show comparison between continuous and 6 months cyclic injection over a period of 4 years. It can be seen from Figure 58 that total oil production for continuous and cyclic injection is more or less the same, whereas a big difference is observed in alkaline-surfactant injected (figure 60). The case of continuous injection required an amount of AS, twice the quantity needed by a 6-months cyclic case for a same period of time. Thus, alkaline-surfactant slug injection at 6 months interval would be a right choice.

7.5.3 Injection Time (Early and Late AS Injection)

As shown in figure 58 (GOE), there was no clear distinction between early and late AS slug injection. Injecting AS slug (10 kg/m3 and 2Kg/m3) for 4 years period from 2008 and 2013 gave relatively same oil efficiency for the group. Since Norne field is scheduled to be shut down in 2022, it is most profitable to inject surfactant in 2008.

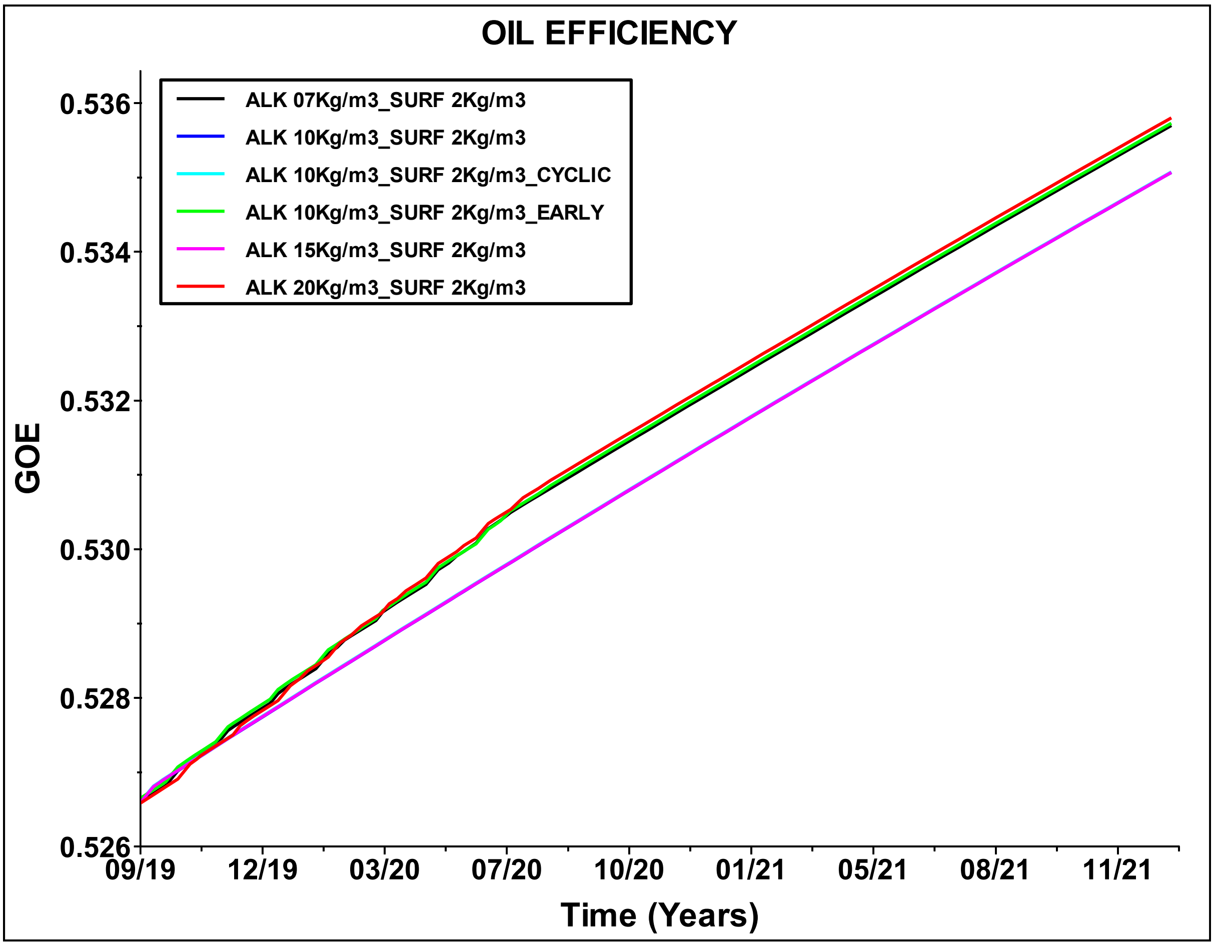


Figure 58: Effect of Alkaline Concentration on Group Oil Efficiency.

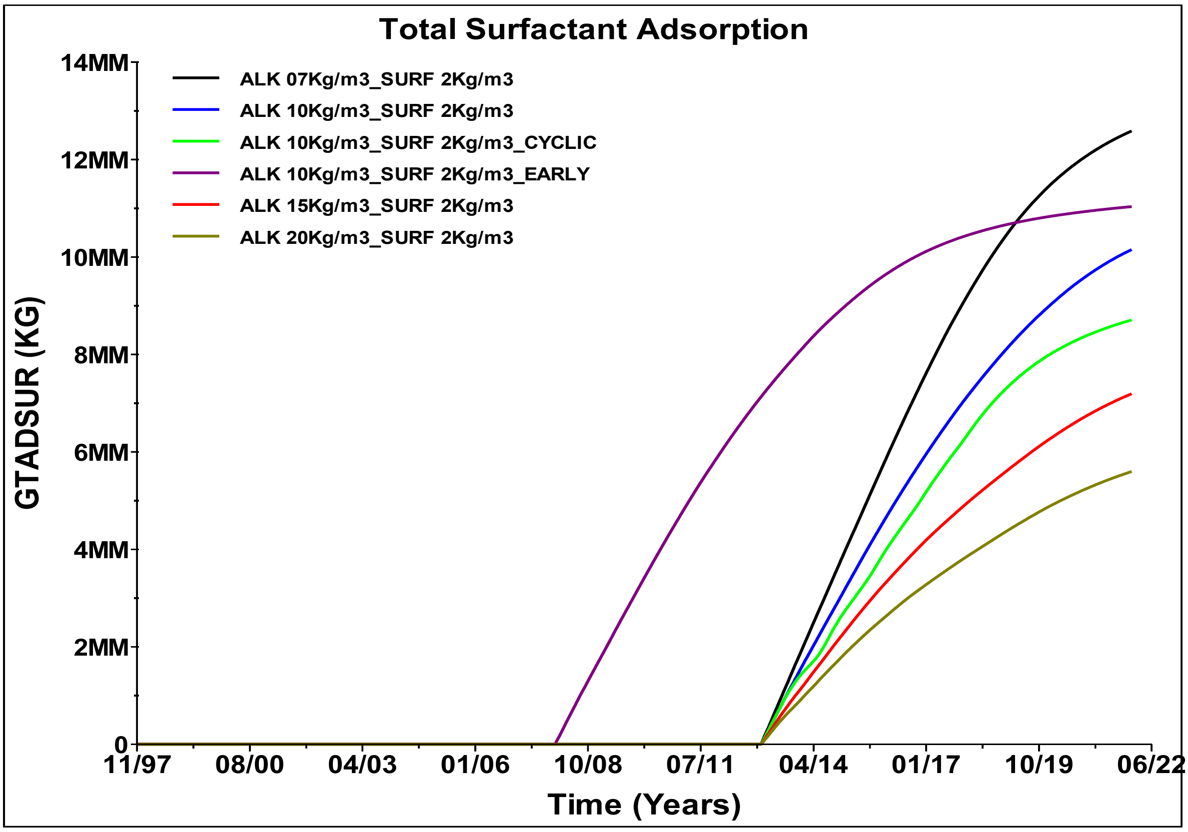


Figure 59: Effect of Alkaline Concentration on Surfactant Adsorption

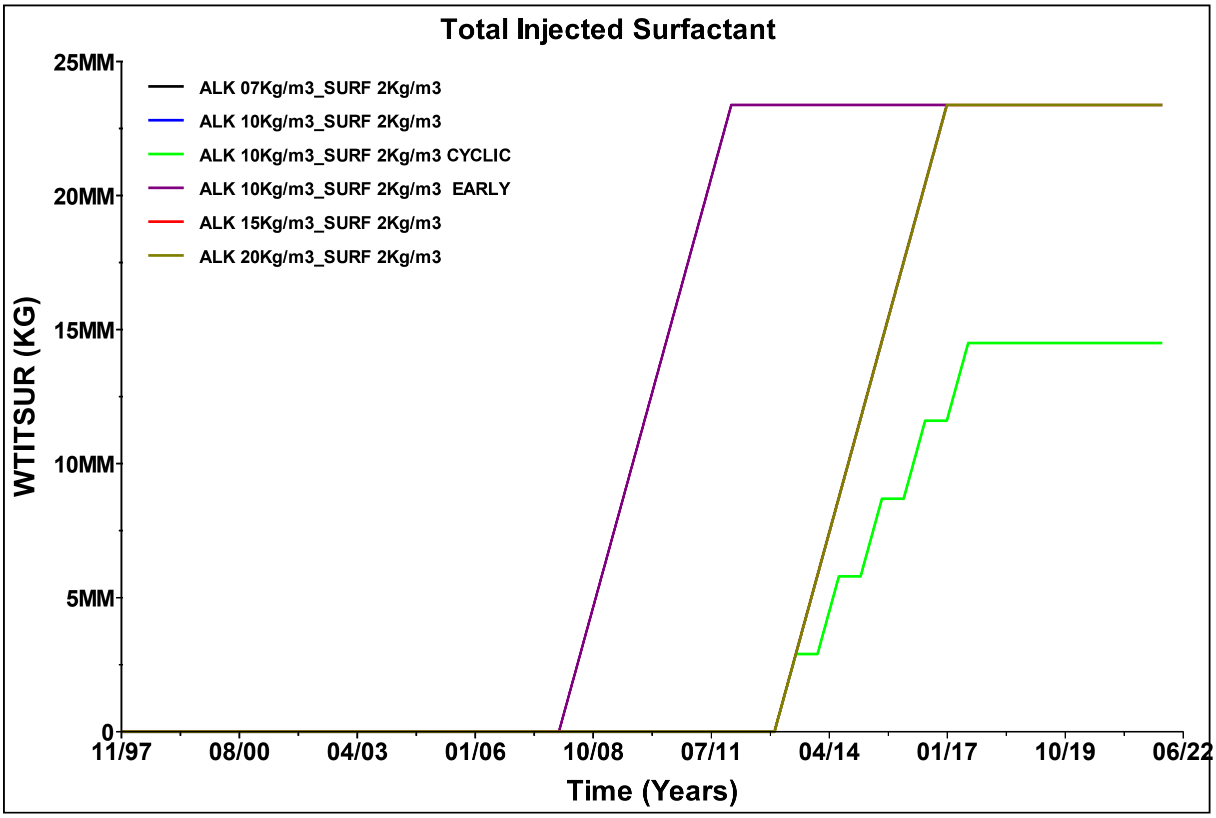


Figure 60: Amount of Surfactant Injected During Alkaline-Surfactant Flooding

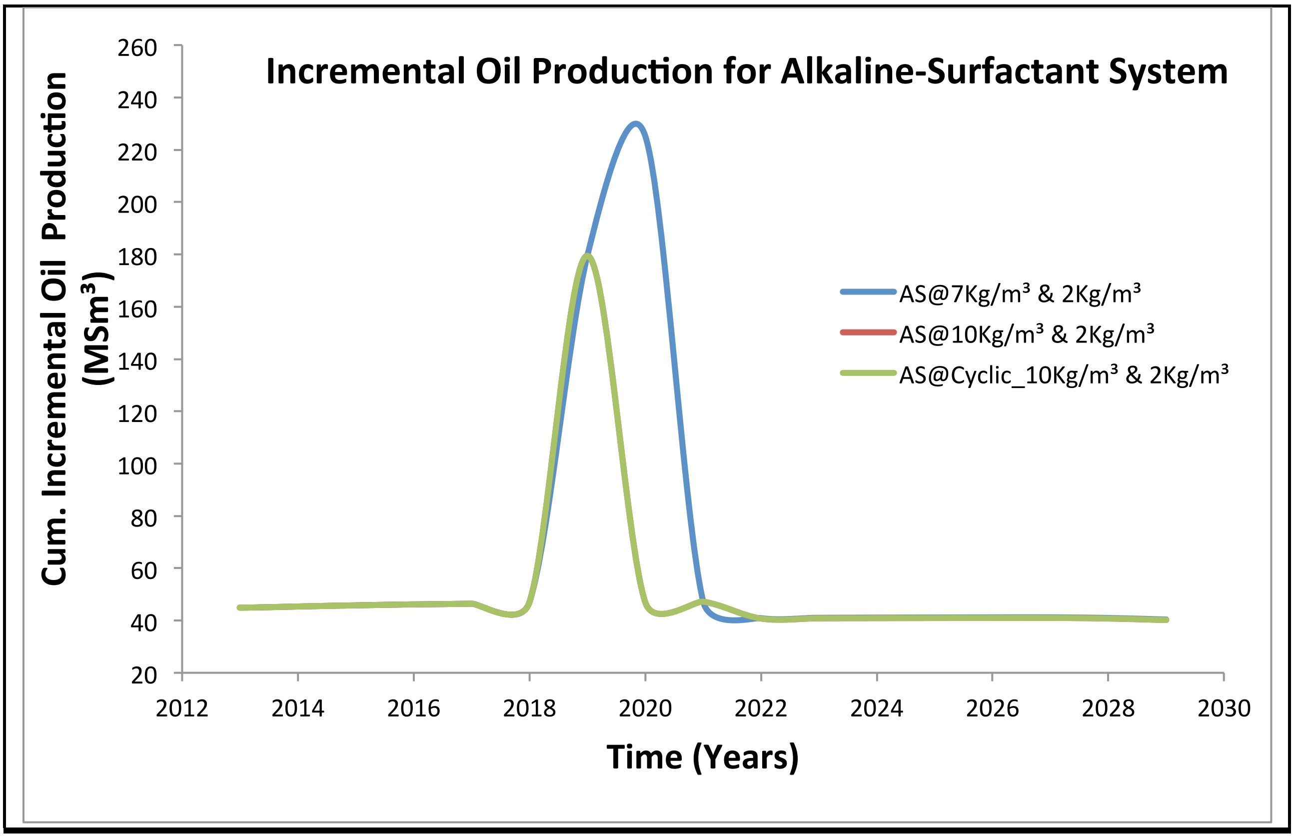


Figure 61: Incremental Oil Production for Alkaline-Surfactant System

7.6 Alkaline-Surfactant-Polymer Flooding System

Those injection scenarios exhibited in other chemical flooding systems mentioned previously were modeled and evaluated in alkaline/surfactant/polymer system. In all the cases tested, ASP concentration of 7Kg/m^3, 2Kg/m^3 and 0.3Kg/m^3 respectively was used.

7.6.1 Effect of Continuous / Cyclic ASP Injection

Effect of continuous and cyclic ASP injection on oil recovery is shown in figure 62. ASP continuous case started from 2008 and lasted for 4 years. Second case: alkaline-surfactant flooding for 3 years starting from 2013, followed by polymer chasing for 1 year. Third case; AS injection for 3 years (started from 2008) chased with polymer for 1 year using 6-months cycles. Case 4; involved ASP slug injection for 4 years with 6-months cycles. The last ASP case was similar to case 3 except that injection started in 2013 instead of 2008. From figure 62, base case (water injection) had a recovery factor of 53.31%, ASP continuous case recorded the highest recovery factor (55.96%). But it is however more economical to consider the ASP cyclic case (55.92%) as being profitably viable since this little difference in oil production could not compensate for the high chemical consumption.

- Continuous and Cyclic ASP Injection
- AS Injection Followed By Polymer
- Injection Time (Early and Late ASP Injection)
- Mixed ASP Injection;
  - Started in 2008 AS (6 Months Cyclic) Followed By Polymer For a year
  - Started in 2013 AS (6 Months Cyclic) Followed By Polymer For a year

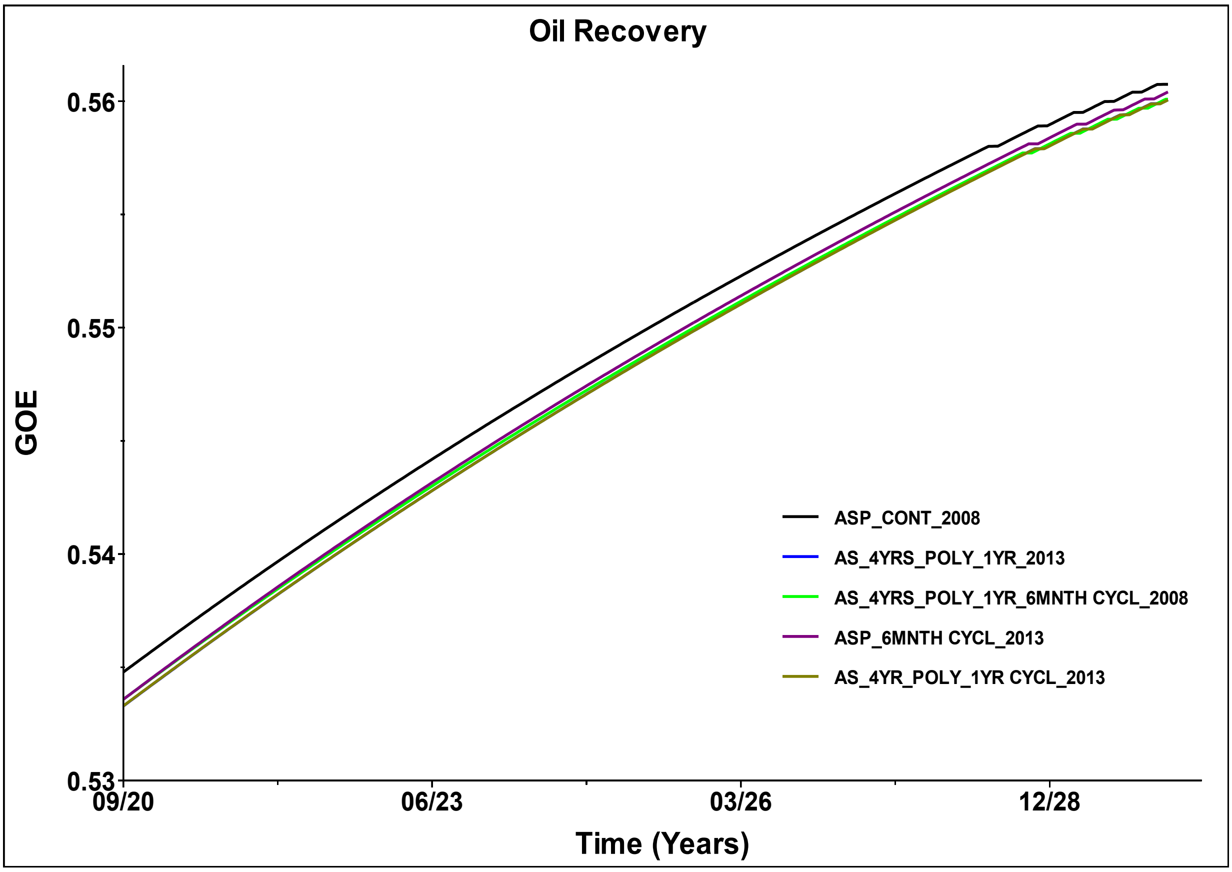


Figure 62: Effect of Continuous and Cyclic ASP Injection on Oil Recovery

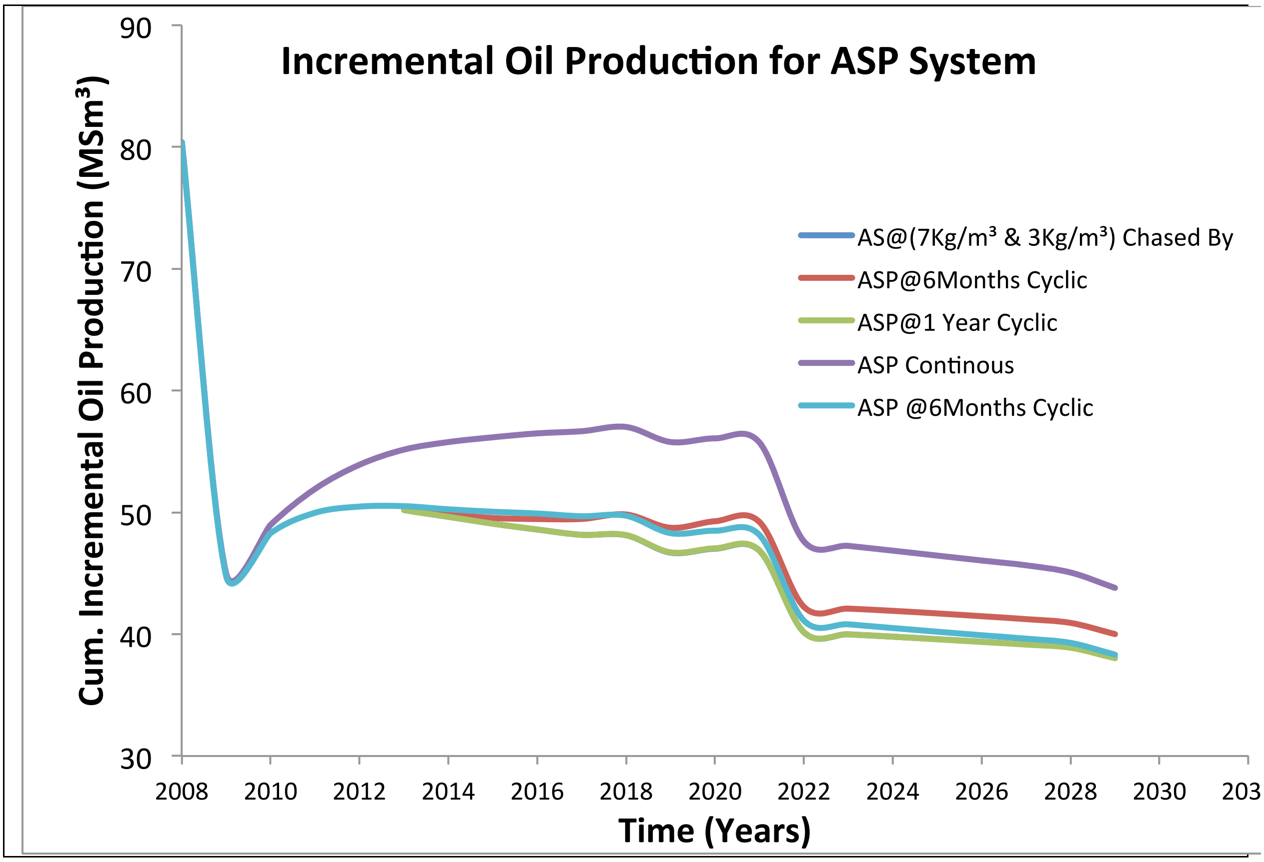


Figure 63: Incremental Oil Production for Alkaline-Surfactant-Polymer System

CHAPTER 8

ECONOMIC EVALUATION

8.1 Prediction of Oil Price

The price of a barrel of oil is the result of a number of competing factors such as; how much oil is available; how much oil is demanded by consumers; how much it costs to get oil from the ground to the consumer; the price of dollars and the potential that oil speculators see for the price to rise or fall (Trygve Strom, 2011).

Many of the long-term global trends point to steady increases in the price of oil. Reserves are finite so the commodity is slowly becoming scarcer something that pushes the price up. The explosion of development in countries like China, Brazil, Russia, South-Africa and India has created more demand as those and other developing regions industrialize. They build more roads and increase manufacturing, all of which requires oil.

The bearish argument is that technological new energy developments (solar,wind,etc.) should begin to reduce the world's dependence on oil. Supply is fettered by the countries that export it. The Organization of the Petroleum Exporting Countries (OPEC) meets regularly to set the amount they are willing to release onto the market. OPEC oil accounts for approximately 35 million of the 80 million barrels released onto the global market each day (Norwegian Statistic Agency, 2010).

OPEC can reduce output as a means to push prices higher and can increase it to meet greater demand. It is tempting to think that all the producers are motivated simply by a high price. In fact, for some countries it may be beneficial to have a lower price if it means they can maintain, or increase, the volumes they sell. Oil is priced in dollars so movements in that currency also impacts on crude. The weaker the dollar, the higher the dollar price of oil because it takes more dollars to buy a barrel.

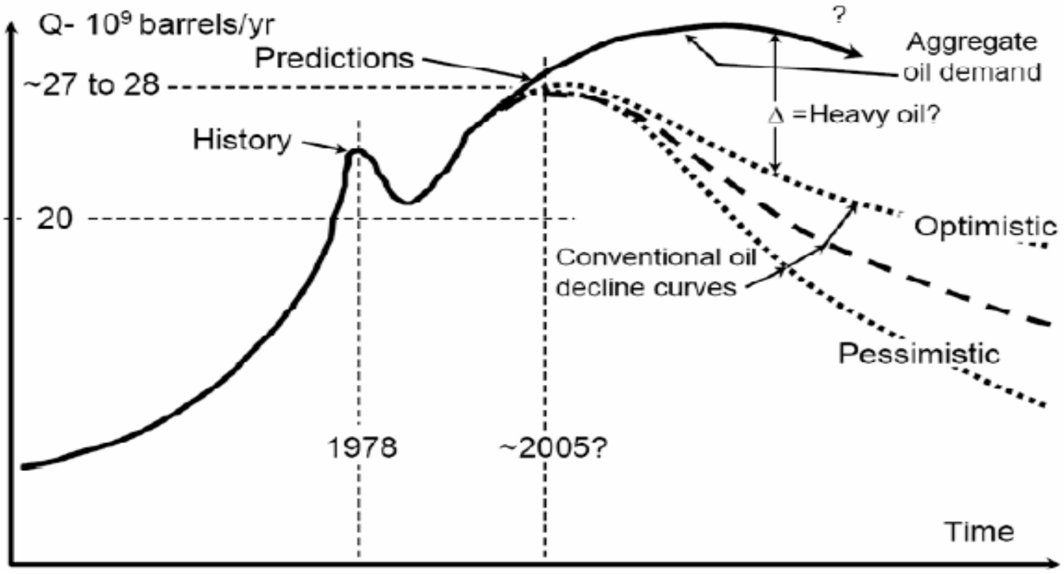


Figure 64: the future for oil production, expectation in 2005 (British Petroleum Report, 2011)

8.2 Evaluation

To make an economical evaluation of the chemical injections, a simple NPV evaluation was made. NPV of a time series of cash flows, both incomes and expenses, is defined as the sum of the present values of the individual cash flows (Equation 8.1).

$$\mathrm{NPV} = \sum_{i=1}^{t} \frac{\mathrm{R_t}}{(1+\mathrm{r})^{\mathrm{t}}} - \mathrm{R_0} \tag{8.1}$$

R_t = cash inflow
R_0 = cash outflow
r = discount rate
t = the time of the cash flow

NPV compares the value of a dollar today to the value of the same dollar in the future, taking inflation and returns into account. If the NPV of a project is positive, it should be accepted. However, if the NPV is negative, the project should probably be rejected because cash flow will also be negative. Many oil companies work with high discount rates, and a rate between 5-12 % is reasonable. In this evaluation, a discount rate of 8% was used.

This implies that the oil price, chemicals costs and discount rate play a very important role in the economical evaluation. In addition, operational cost and chemical facilities costs might be considered. But for simplicity, all these sunk costs are excluded and the focus was only on the profitability associated to chemical costs. A comprehensive NPV calculations is done in an excel format (see appendix D) for all the simulated cases in each chemical system and attached to this report.

Table 11: Oil Price, Chemical Price and Discount Rate for Economical Analysis (Tornado Chart)

Cases	Oil Price (USD/bbl)	Alkaline (USD/Kg)	Surfactant (USD/Kg)	Polymer (USD/Kg)	Discount Rate
Low	75	1.00	2.00	2.50	0.10
Base	100	1.50	3.30	4.00	0.08
High	120	2.00	4.60	5.50	0.06

8.3 Incremental NPV for Injection Systems

The assumed chemical prices used in calculating Net Present Value (NPV) is shown in table 11. Comparing different NPVs for different chemical slugs, the NPV calculation for the ASP (cyclic case) concentration of 7kg/m^3, 2kg/m^3 and 0.3kg/m^3 whose injection commenced in 2008 appeared best as it can be seen in appendix D. Also, figure 65 revealed that the oil production does not necessarily increase with increase in chemical concentration.

Similarly, ASP (1 year cyclic) and continuous SP cases have almost same NPV. From all the ASP cases it is noted that mobility control is instrumental to incremental oil production. This is because when the interfacial tension is lowered, a viscous fluid (polymer) is needed to chase the residual oil towards the producers. Therefore, ASP (6-months cyclic case) should be considered for C-segment and injection should commence as early as possible.

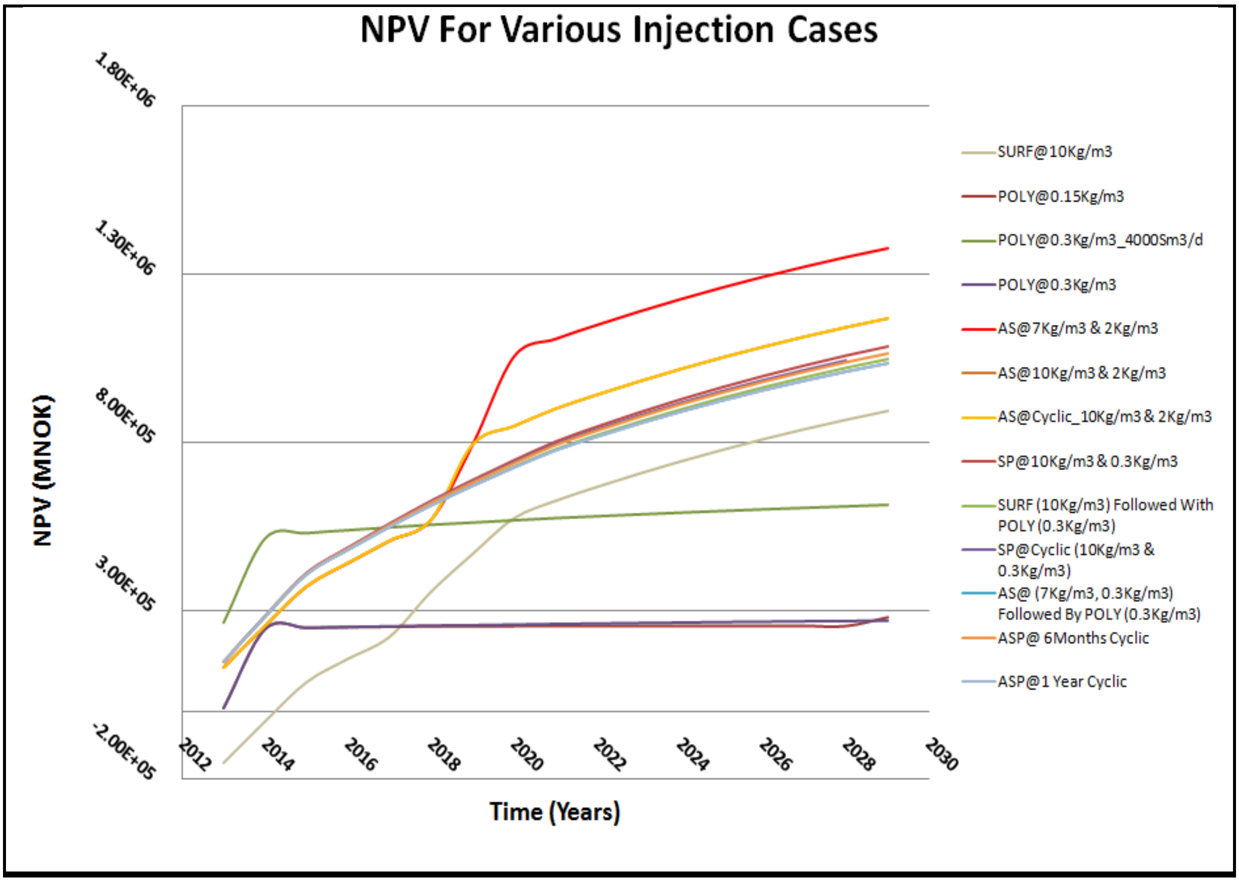


Figure 65: incremental NPV for various injection cases

8.4 Sensitivity Analysis (Tornado Chart)

Sensitivity analysis describes how the uncertainty in the output of a numerical model can be apportioned to different sources of uncertainty in the model input. Tornado chart is a sensitivity instrument used for comparing the relative importance of variables. The sensitive variable is modeled as uncertain value while all other variables are held at baseline values.

As shown in figure 65, NPV is sensitive to oil price, discount rate, surfactant price, polymer price and alkaline price in decreasing order of magnitude.

Table 12: Sensitivity Anaysis

	OIL PRICE		
	Low case(l)	**Base case(b)**	**High case(h)**
Oil price (NOK/Sm3)	75.00	100.00	120.00
Change (%)	-25.00%	0.00%	20.00%
NPV	1.73E+06	2.31E+06	2.77E+06
Change (%)	-25.11%	0.00%	19.91%
	ALKALINE PRICE		
	Low case(l)	**Base case(b)**	**High case(h)**
Alkaline price (NOK/kg)	1.00	1.5	2.00
Change (%)	-33.33%	0.00%	33.33%
NPV	2.31E+06	2.31E+06	2.31E+06
Change (%)	0.004900 %	0.000000 %	-0.004900 %
	POLYMER PRICE		
	Low case(l)	**Base case(b)**	**High case(h)**
Polymer price (NOK/kg)	2.00	3.3	4.60
Change (%)	-39.39%	0.00%	39.39%
NPV	2.31E+06	2.31E+06	2.31E+06
Change (%)	0.01%	0.00%	-0.01%
	DISCOUNT RATE		
	Low case(l)	**Base case(b)**	**High case(h)**
Discount Rate	0.10	0.08	0.06
Change (%)	25.00%	0.00%	-25.00%
NPV	1.77E+06	2.31E+06	2.69E+06
Change (%)	-23.05%	0.00%	16.56%

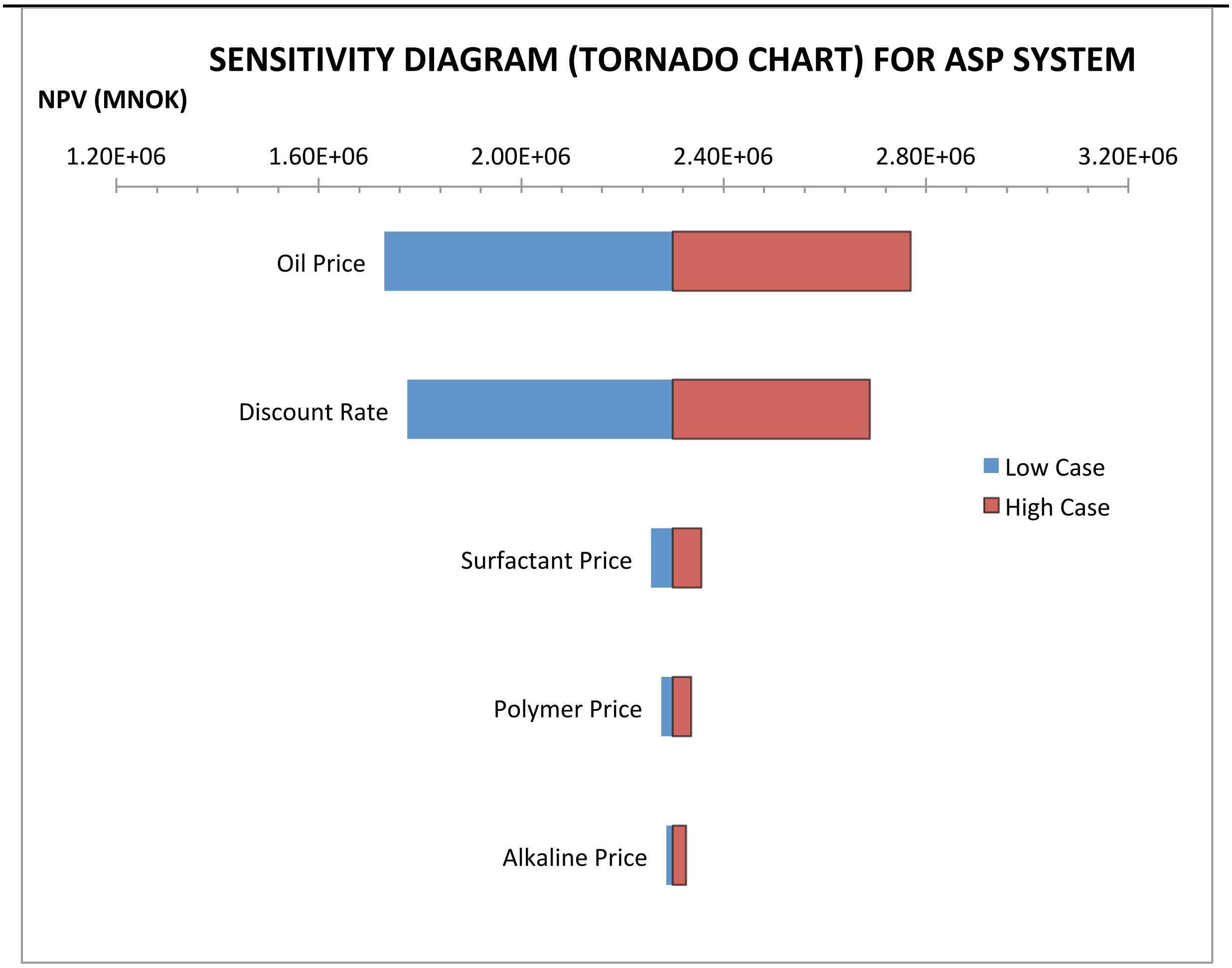


Figure 64: Sensitivity Diagram (Tornado Chart) for ASP System

CHAPTER 9

DISCUSION

The success of oil recovery by chemical flooding is strongly influenced by increasing pore-to-pore displacement efficiency, areal sweep efficiency and vertical displacement efficiency. Pore-to-pore displacement is achieved by lowering interfacial tension and areal sweep is achieved by using thickening agent to control mobility. After the reservoir has been over-flooded with water, there are bound to be many pockets of immobile or capillary trapped oil.

In this thesis, the synergetic effects of alkaline-surfactant-polymer are modeled considering different system of injection. Individual and combined effects of C-1H, C-2H, C-3H and C-4AH injectors were simulated. Although the results were good but however has some limitation and this deviation was traced to fairly good reservoir model. Using C-3H for surfactant injection returned high oil efficiency with relatively low surfactant adsorption. Understanding the flow pattern among other factors informed the decision about injector selection.

Surfactant flood system was firstly investigated. Injecting different concentrations (i.e 7Kg/m^3, 10Kg/m^3, 15Kg/m^3 and 20Kg/m^3) in well C-3H showed that an increase in amount of surfactant did not necessarily give a corresponding increase in oil production. Higher concentrations gave higher oil production rate and higher cumulative oil production, but it did not show to be profitable due to the cost of surfactants. The result showed that applying a concentration between 7–10Kg/m^3 appears to be the best choice for surfactant injection. It also showed using more than one injector lead to a much higher total injection rate but it would be a good option to only inject in one well.

The second approach to improved recovery was to compare different polymer concentration and injection rates. Polymer flooding, unlike surfactant, is not aimed at reducing the interfacial tension but it improves volumetric sweep efficiency by increasing water viscosity. Different concentrations; 0.15Kg/m^3, 0.3Kg/m^3, 0.5Kg/m^3 and 0.8Kg/m^3 as well as rates, 4000Sm^3/d, 5000Sm^3/d, 6000Sm^3/d and 8000Sm^3/d were analyzed. Incremental oil production (relative to water injection case) for polymer system is shown in figure 54. Polymer slug of 0.3Kg/m^3 at 4000Sm^3/d looks better than other (i.e other polymer slug with different concentrations) with much reduction in water cut. It is pertinent to ascertain the right injection rate that would improve recovery and which would not result into formation fracturing. The net present value (NPV) for 0.3Kg/m^3 (4000Sm^3/d) polymer case is comparatively the highest among polymer flooding system.

Thirdly, having established surfactant and polymer concentrations and also appropriate rate for injection as discussed above, SP continuous and cyclic effects were modeled and evaluated. By using cyclic injection, the surfactant has ample time to attack the residual oil and reduced quantity of surfactant would be injected (usually half or depending on the cycle of injection). Another benefit of cyclic injection is that a more precise amount of surfactant can be injected. Cyclic injection will be a better choice even though it does not produce corresponding high oil as continuous injection.

The effect of wettability alteration and pH adjustment confirmed ultra-lowering of IFT as demonstrated by spectacular incremental oil production in AS system as compared with surfactant system. The first step was to have a fixed surfactant concentration while alkaline concentration was varied. Alkaline concentration of 7Kg/m^3, 10Kg/m^3, 15Kg/m^3 and 20Kg/m^3 were tested. As shown in figure 58 there is no clear distinction in term or production efficiency of 7Kg/m^3, 10Kg/m^3 and 20Kg/m^3 but surfactant adsorption increases with surfactant concentration (see figure 59). Figure 60 depicts amount of AS slug injected. In terms of NPV, AS continuous case is seen to be higher than that of cyclic case but cyclic injection will be a better alternative, even though it does not produce equally high amount of oil as continuous case.

In the same vein, a study was conducted to assess the suitability of alkaline/Surfactant/Polymer (ASP) flooding for C-segment reservoir. On the basis of screening criteria in the literature, the Norne reservoir condition is favourable for ASP flooding. The displacement mechanism of an ASP flood is similar to that of surfactant-polymer flooding except that much of the surfactant is replaced by low-cost alkali. Therefore, the overall cost is lower even though the chemical slugs can be larger. It has been recognized that oil recovery can be greatly improved by the synergism of chemicals used in the ASP formulations.

From figure 62, base case (water injection) had a recovery factor of 53.31%, ASP continuous case recorded highest recovery factor (55.96%) but it is more economical to consider ASP cyclic case (55.92%) as being profitably viable since this little difference in oil production could not compensate for the high chemical consumption. ASP cyclic case witnessed an incremental recovery factor of 2.61% with a net present value of 1.66 x10^{6}MNOK. From the economic evaluations it is seen that surfactant cost, polymer cost, discount rate and oil price are very important. The cases with high surfactant concentration showed up to be marginally profitable. Early time injection, and also cyclic injection were much more beneficial than continuous and late time injections. It is also important to note that this is a simple NPV evaluation, and that very few cases might show up to be profitable when all development and operational costs have been taken into account.

Lastly, tornado chart was used as sensitivity instrument to analyze the varying parameters. That is, the level of dependency of NPV on oil price, alkaline price, surfactant price, polymer price as well as discount rate. It was noted that change in oil price has greater influence on NPV compared with other variables while alkaline price is the least sensitive variable.

CHAPTER 10

CONCLUSION AND RECOMMENDATION

Continuous ASP case gave the best recovery, but it was far from the most profitable solution. Late injection time did not prove to be significantly better than early time injection since some time is needed for the chemical bank to be formed, and cyclic slug injection will be the best solution for ASP flooding. From the simulation studies, using more than one injector gave higher incremental oil production but was not economically profitable and not a good option. If using one well for ASP flooding, injector C-3H is a better choice compared with other injectors in C-segment.

The most efficient way of injecting ASP slug is to be targeted in the layers having residual oil and therefore loss of chemical into the aquifer will relatively be minimized. ASP (7Kg/m3, 2Kg/m3 and 0.3Kg/m3) with six-month cyclic injection for 4-years proved to be the most profitable with recovery factor (i.e incremental) of 2.61%.

The economic evaluation indicated that profitability was highly dependent on oil price and chemical costs. With reasonably high oil price and realistic chemical costs, alkaline-surfactant-polymer flooding would be a good EOR method for the Norne C-segment and flooding should commence as early as possible for a better efficiency. Extra costs associated with ASP injection should be incorporated into NPV evaluations. Base on the observations made during the simulation studies, the following recommendations are made:

- ASP project evaluations for Norne C-segment should also be tested in another simulator apart from Eclipse 100 for better comparison.

- Proper laboratory design of alkaline and surfactant is recommended that will overcome complex and deleterious effects of hardness ions, mineral surfaces and Norne fluid salinity

- As part of further work, NPV comparison should be made between re-completed C-3H and a newly introduced injector.

Uncertainties

- Reservoir model and history matching of reservoir model
- The Chemical Model and Chemical properties
- Inflation and Exchange rate
- Possible reactions between chemicals
- Consideration of operation costs as sunk costs
- Oil and chemical prices
- Total unrecoverable reserves

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APPENDICES

Appendix A

A1.1 Keywords Used to Activate Alkaline Model in Eclipse 100 Simulator

The following keywords listed in table 13 should be activated while using alkaline model in eclipse 100 simulators.

Table 13: Alkaline model activation keywords in Eclipse 100 simulator

Keywords	Purpose	Section	Status
ALKALINE	Used for alkaline model activation	Runspec	Mandatory
ALSURFST	Description of interfacial tension as a function of alkaline concentration	Props	Mandatory if SURFADS is active
ALSURFAD	Surfactant adsorption which depends on alkaline concentration	Props	Mandatory if SURFADS is active
ALPOLADS	Polymer adsorption which depends on alkaline concentration	Props	Mandatory if POLYMER option is used
ALKADS	Used to enable adsorption functions	Props	Optional
ALKROCK	Used to state alkaline-rock properties	Props	Compulsory if ALKADS is activated
WSURFACT	Used to highlight alkaline concentration to be injected	Schedule	Mandatory

A1.2 Keywords Used to Activate Surfactant Model in Eclipse Simulator

Table 14: Surfactant model activation keywords in eclipse 100 simulator

Keywords	Purpose	Section	Status
SURFACT	Used for surfactant model activation	Runspec	Mandatory
SURFST	Interfacial tension behavior in the presence of surfactant	Props	Mandatory
SURFVISC	Resultant water viscosity	Props	Mandatory
SURFCAPD	Capillary de-saturation properties	Props	Mandatory
SURFROCK	Surfactant adsorption on rock	Props	Compulsory if SURFADS is activated
SURFNUM	Relative permeability data	Region	Mandatory
SURFADS	Used for adsorption isotherm	Props	Optional
WSURFACT	Used to specify injected surfactant concentration	Schedule	Mandatory

A1.3 Keywords Used to Activate Polymer Model in Eclipse 100 Simulator

Table 15: Polymer model activation keywords in eclipse 100 simulator

Keywords	Purpose	Section	Status
POLYMER	Enables polymer flood model	Runspec	Mandatory
BRINE	Enables polymer salt sensitivity option	Runspec	Optional
MISCIBLE	Maximum number of mixing parameter region	Runspec	Optional
RPTGRID	Controls output from the GRID section	Grid	Mandatory
PLYADS	Used for polymer adsorption isotherm	Props	Mandatory
ADSORP	Used in adsorption isotherms which is a function of salinity and permeability	Props	Mandatory
PLYMAX	Concentration used for mixing calculations	Props	Mandatory
PLYROCK	Polymer-rock properties	Props	Mandatory
PLYSHEAR	Polymers shear thinning data	props	Optional
PLYVISC	Polymer solution viscosity function	Props	Mandatory
RPTPROPS	Props section output controller	Props	Optional
SALTNODE	Concentration (salt) nodes for polymer solution viscosity	Props	Optional
TLMIXPAR	Todd-Longstaff mixing parameters	Props	Mandatory
MISCNUM	Miscibility number	Region	Mandatory
RPTREGS	Region section output controller	Region	Optional

A1.4 Chemical Concentration

Chemical concentration must be specified in the schedule section of simulation data file. If this is not stated, a concentration value of zero will be assumed.

Example

```
WSURFACT
----Well name          Concentration
        'C-3H'                10 /
        'C-2H'                15 /
```

Appendix B

Chemical Properties Used in Model

B1.1 Alkaline Properties Keywords

```
ALSURFST

--Water/oil surface tension multipliers which depends on concentration

--Concentration (Kg/m3)      Tension Multiplier
        0.0                  1.0
        6.0                  0.5
        15.0                 0.3
        20.0                 0.1
        30.0                 0.0 /
        /
ALPOLADS

--Alkaline multipliers for polymer adsorption
--Concentration (Kg/m3)      Multiplier
        0.0                  1.0
        3.0                  0.7
        6.0                  0.5
        9.0                  0.3 /

ALSURFAD

--Alkaline multipliers for surfactant adsorption
--concentration (Kg/m3)      Multiplier
        0.0                  1.0
        3.0                  0.7
        6.0                  0.5
        9.0                  0.0 /

ALKADS

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

ALKROCK

-- No desorption
2 /
```

B1.2 Surfactant Properties Keywords

```
SURFST
Concentration (Kg/m3)        Water/oil surface Tension (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 /
        /
SURFVISC

--Surfactant Conc. (Kg/m3)    Water viscosity (cp)
        0.0                   0.42
        5.0                   0.449
        10.0                 0.503
        15.0                 0.540
        20.0                  0.630 /
        /

SURFADS
--Surfactant Adsorption by rock
--Surf. Conc. (Kg/m3) Adsorbed Mass (Kg Surf. /Kg Rock)
        0.0                  0.00000
        1.0                  0.00017
        5.0                  0.00017
        10.0                 0.00017 /

SURFCAPD
--Capillary De-saturation curve
--Log10 (Capillary Number)  Miscibility Function (Immiscible = 0, Miscible = 1)
        -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
--No Desorption

1    2650/
```

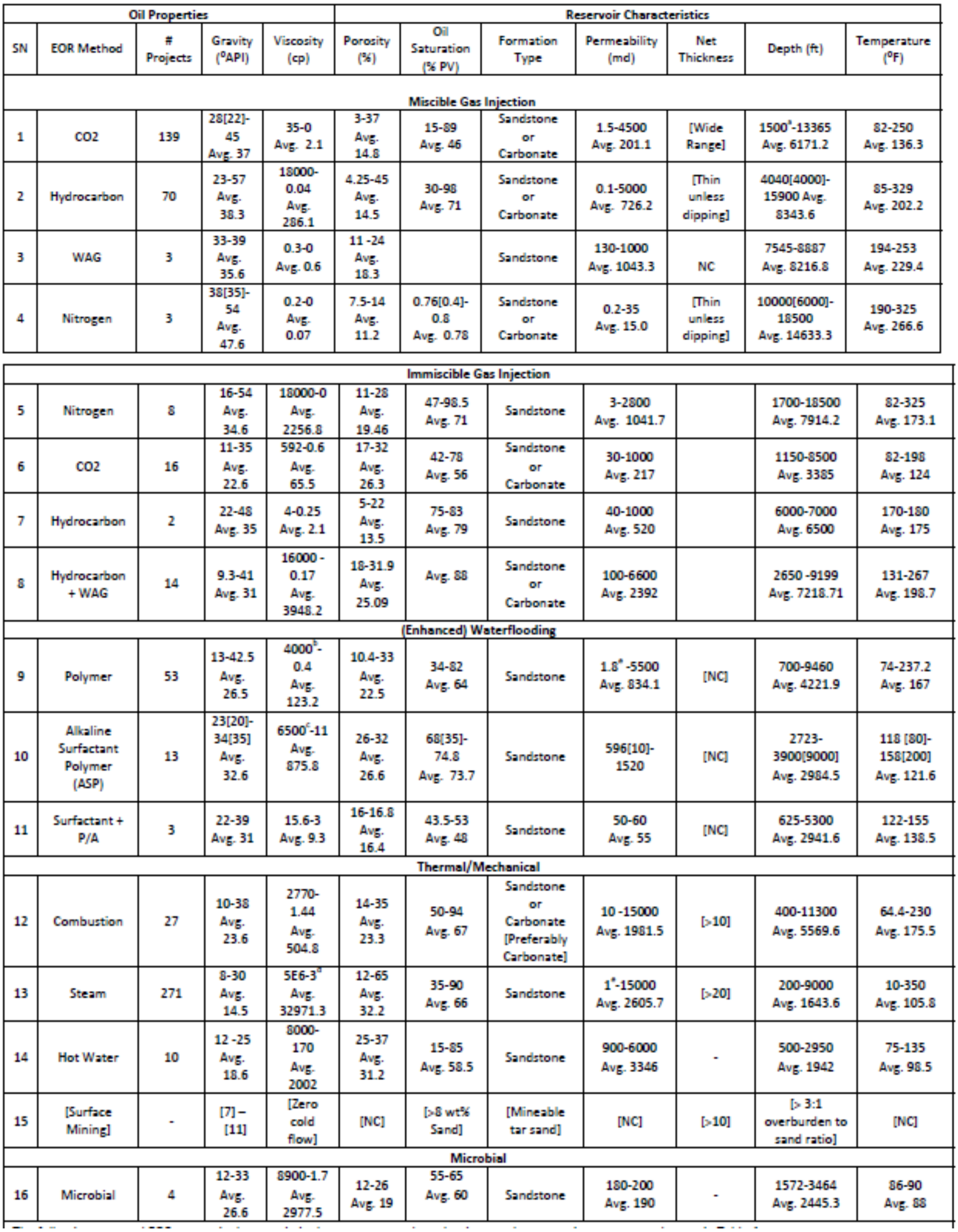
B1.3 Polymer Properties Keywords

```
PLYSHEAR
--Polymer shear thinning data
-- Water. Velocity (m/day)        Visc. Reduction (CP)
          0.0                     1.0
          2.0                     1.0        /

PLYVISC
-- Polymer solution Viscosity Function
-- Poly conc. (Kg/m3)             Wat. Visc. Mult.
          0.0                     1.0
          0.1                     1.55
          0.3                     2.55
          0.5                     5.125
          0.7                     8.125
          1.0                     21.2 /
          /
PLYADS
-- Polymer Adsorption Function
-- Ply conc.( kg/m3)  Ply conc. Adsorbed by rock (kg/kg)
          0.0         0.0
          0.5         0.0000017
          1.0         0.0000017 /

TLMIXPAR
-- Todd-Longstaff Mixing Parameters

          1 1* /

PLYMAX
-- Polymer-Salt concentration for mixing maximum polymer and salt concentration
-- Ply conc. (kg/m3)  Salt conc. (kg/m3)
          1.0                 0.0 /

PLYROCK
--Polymer-Rock Properties
--dead         residual              mass       Ads.            Max.
--pore         resistance            density    Index           Polymer
--space        factor                                           adsorption

0.16           1.0                   2650.0       2            0.000017 /
```

Appendix C

C1.1 Advances in EOR Technologies

Table 16: Detailed Guidelines for EOR Methods



Oil Properties					Reservoir Characteristics						
SN	EOR Method	# Projects	Gravity (^{o}API)	Viscosity (cp)	Porosity (%)	Oil Saturation (% PV)	Formation Type	Permeability (md)	Net Thickness	Depth (ft)	Temperature (^{o}F)
Miscible Gas Injection											
1	CO2	139	28[22]-45 Avg. 37	35-0 Avg. 2.1	3-37 Avg. 14.8	15-89 Avg. 46	Sandstone or Carbonate	1.5-4500 Avg. 201.1	[Wide Range]	1500^{a}-13365 Avg. 6171.2	82-250 Avg. 136.3
2	Hydrocarbon	70	23-57 Avg. 38.3	18000-0.04 Avg. 286.1	4.25-45 Avg. 14.5	30-98 Avg. 71	Sandstone or Carbonate	0.1-5000 Avg. 726.2	[Thin unless dipping]	4040[4000]-15900 Avg. 8343.6	85-329 Avg. 202.2
3	WAG	3	33-39 Avg. 35.6	0.3-0 Avg. 0.6	11 -24 Avg. 18.3		Sandstone	130-1000 Avg. 1043.3	NC	7545-8887 Avg. 8216.8	194-253 Avg. 229.4
4	Nitrogen	3	38[35]-54 Avg. 47.6	0.2-0 Avg. 0.07	7.5-14 Avg. 11.2	0.76[0.4]-0.8 Avg. 0.78	Sandstone or Carbonate	0.2-35 Avg. 15.0	[Thin unless dipping]	10000[6000]-18500 Avg. 14633.3	190-325 Avg. 266.6
Immiscible Gas Injection											
5	Nitrogen	8	16-54 Avg. 34.6	18000-0 Avg. 2256.8	11-28 Avg. 19.46	47-98.5 Avg. 71	Sandstone	3-2800 Avg. 1041.7		1700-18500 Avg. 7914.2	82-325 Avg. 173.1
6	CO2	16	11-35 Avg. 22.6	592-0.6 Avg. 65.5	17-32 Avg. 26.3	42-78 Avg. 56	Sandstone or Carbonate	30-1000 Avg. 217		1150-8500 Avg. 3385	82-198 Avg. 124
7	Hydrocarbon	2	22-48 Avg. 35	4-0.25 Avg. 2.1	5-22 Avg. 13.5	75-83 Avg. 79	Sandstone	40-1000 Avg. 520		6000-7000 Avg. 6500	170-180 Avg. 175
8	Hydrocarbon + WAG	14	9.3-41 Avg. 31	16000 - 0.17 Avg. 3948.2	18-31.9 Avg. 25.09	Avg. 88	Sandstone or Carbonate	100-6600 Avg. 2392		2650 -9199 Avg. 7218.71	131-267 Avg. 198.7
(Enhanced) Waterflooding											
9	Polymer	53	13-42.5 Avg. 26.5	4000^{b}-0.4 Avg. 123.2	10.4-33 Avg. 22.5	34-82 Avg. 64	Sandstone	1.8* -5500 Avg. 834.1	[NC]	700-9460 Avg. 4221.9	74-237.2 Avg. 167
10	Alkaline Surfactant Polymer (ASP)	13	23[20]-34[35] Avg. 32.6	6500^{c}-11 Avg. 875.8	26-32 Avg. 26.6	68[35]-74.8 Avg. 73.7	Sandstone	596[10]-1520	[NC]	2723-3900[9000] Avg. 2984.5	118 [80]-158[200] Avg. 121.6
11	Surfactant + P/A	3	22-39 Avg. 31	15.6-3 Avg. 9.3	16-16.8 Avg. 16.4	43.5-53 Avg. 48	Sandstone	50-60 Avg. 55	[NC]	625-5300 Avg. 2941.6	122-155 Avg. 138.5
Thermal/Mechanical											
12	Combustion	27	10-38 Avg. 23.6	2770-1.44 Avg. 504.8	14-35 Avg. 23.3	50-94 Avg. 67	Sandstone or Carbonate [Preferably Carbonate]	10 -15000 Avg. 1981.5	[>10]	400-11300 Avg. 5569.6	64.4-230 Avg. 175.5
13	Steam	271	8-30 Avg. 14.5	5E6-3^{d} Avg. 32971.3	12-65 Avg. 32.2	35-90 Avg. 66	Sandstone	1*-15000 Avg. 2605.7	[>20]	200-9000 Avg. 1643.6	10-350 Avg. 105.8
14	Hot Water	10	12 -25 Avg. 18.6	8000-170 Avg. 2002	25-37 Avg. 31.2	15-85 Avg. 58.5	Sandstone	900-6000 Avg. 3346	-	500-2950 Avg. 1942	75-135 Avg. 98.5
15	[Surface Mining]	-	[7] – [11]	[Zero cold flow]	[NC]	[>8 wt% Sand]	[Mineable tar sand]	[NC]	[>10]	[> 3:1 overburden to sand ratio]	[NC]
Microbial											
16	Microbial	4	12-33 Avg. 26.6	8900-1.7 Avg. 2977.5	12-26 Avg. 19	55-65 Avg. 60	Sandstone	180-200 Avg. 190	-	1572-3464 Avg. 2445.3	86-90 Avg. 88

C1.2 Grouptree

Grouptree is included in the schedule section when grouping structure is needed with up to three levels in the hierarchy. That is: Field-Groups-Wells

```
SCHEDULE

GRUPTREE
   'INJE'   'FIELD'  /
'PROD'      ‘FIELD’ /
'MANI-B2'  'PROD'  /
'MANI-B1'  'PROD'  /
'CSEG'     'PROD' /
/
```

C1.3 Different Chemical Injection Scenarios

Table 17: Different Chemical Injection Scenarios

Injection time	Injection Wells	Duration	Injection Interval	Surfactant Concentrations
From 2006	C-2H	2 Yrs	Continuous	5Kg/Sm3
From 2012	C-3H	4 Yrs	4 months	10Kg/Sm3
From 2013	C-2H & C-3H	5 Yrs	6 months	15Kg/Sm3
From 2015	C-1H & C-4AH	6Yrs	Irregular	20Kg/Sm3
				30Kg/Sm3

Appendix D

In order to give detailed account of all the NPV calculation for all the cases, an excel file is attached to this report.

NPV for Surfactant System

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

Table 18: Prices for NPV Calculations

Price			Equivalent	
Oil Price (2013 Money)	100.00	USD/Bbl	3899.18	NOK/SM3
Oil Price (2006 Money)	81.31	USD/Bbl	3170.39	NOK/SM3
Surfactant Price	3.30	USD/Kg	20.46	NOK/Kg
Oil Price Inflation Rate	0.03			
Exchange rate	6.20	NOK/USD	6,289bbl/Sm3	
Discount rate	0.08			

Table 19: Surfactant Case1(10Kg/m3 for 5Years starting from 2006)

Incremental oil production (MSm3)	Net Present Value (NPV) (MNOK)
63.51	2.01E+05
103.88	5.14E+05
32.94	6.09E+05
37.15	7.10E+05
40.77	8.17E+05
42.91	9.24E+05
44.14	1.03E+06
44.94	1.13E+06
45.49	1.23E+06
45.91	1.33E+06
46.26	1.42E+06
46.52	1.50E+06
47.13	1.59E+06
179.67	1.90E+06
91.73	2.05E+06
47.42	2.12E+06
40.95	2.18E+06
41.05	2.24E+06
41.12	2.29E+06
41.16	2.35E+06
41.2	2.40E+06
41.22	2.45E+06
40.95	2.49E+06
40.28	**2.54E+06**

Table 20: Surfactant Case2 (10Kg/m3 for 5 Years starting from 2013)

Incremental oil production (MSm3)	Net Present Value (NPV) (MNOK)
-53.12	-2.08E+05
45.36	-3.96E+04
45.81	1.22E+05
46.17	2.34E+05
46.42	3.41E+05
101.28	5.65E+05
90.59	7.56E+05
91.54	9.39E+05
47.19	1.03E+06
40.72	1.10E+06
40.80	1.18E+06
40.86	1.24E+06
40.92	1.31E+06
40.96	1.37E+06
40.99	1.43E+06
40.76	1.48E+06
40.22	**1.54E+06**

NPV for Polymer System

Table 21: Polymer Case1 (0.15Kg/m3 for 4 Years @8000Sm3/d)

Incremental oil production (MSm3)	Net Present Value (NPV) (MNOK)
3.31	1.29E+04
85.96	3.33E+05
1.52	3.38E+05
1.10	3.41E+05
0.89	3.43E+05
1.13	3.45E+05
-0.04	3.45E+05
0.40	3.46E+05
0.30	3.46E+05
0.19	3.47E+05
0.13	3.47E+05
0.06	3.47E+05
-0.02	3.47E+05
-0.10	3.47E+05
-0.18	3.47E+05
-0.25	3.46E+05
40.22	**3.99E+05**

Table 22: Polymer Case2 (0.3Kg/m3 for 4 Years @4000Sm3/d)

Incremental oil production (MSm3)	Net Present Value (NPV) (MNOK)
90.63	3.53E+05
90.66	6.91E+05
6.19	7.12E+05
5.86	7.27E+05
5.70	7.40E+05
6.03	7.53E+05
5.05	7.64E+05
5.79	7.75E+05
6.00	7.87E+05
5.36	7.97E+05
5.56	8.06E+05
5.75	8.16E+05
5.93	8.25E+05
6.09	8.35E+05
6.24	8.44E+05
6.38	8.52E+05
6.52	8.61E+05

Table 23: Polymer Case3 (0.3Kg/m3 for 4 Years @8000Sm3/d)

Incremental oil production (MSm3)	Net Present Value (NPV) (MNOK)
3.32	1.29E+04
85.98	3.33E+05
1.63	3.38E+05
1.37	3.42E+05
1.37	3.45E+05
1.83	3.49E+05
0.86	3.51E+05
1.51	3.54E+05
1.60	3.57E+05
1.47	3.60E+05
1.54	3.62E+05
1.57	3.65E+05
1.58	3.67E+05
1.57	3.70E+05
1.53	3.72E+05
1.48	3.74E+05
1.42	3.76E+05

NPV for Alkaline-Surfactant Syste

Table 24: AS Case1(Alkaline (7Kg/m3) & Surfactant (2Kg/m3) for 4 Years @8000Sm3/d)

Incremental oil production (MSm3)	Net Present Value (NPV) (MNOK)
44.80	1.74E+05
45.36	3.43E+05
45.80	5.05E+05
46.16	6.17E+05
46.43	7.24E+05
47.02	8.28E+05
179.51	1.21E+06
225.31	1.66E+06
47.36	1.75E+06
40.92	1.82E+06
41.03	1.90E+06
41.11	1.96E+06
41.16	2.03E+06
41.20	2.09E+06
41.21	2.15E+06
40.97	2.21E+06
40.38	2.26E+06

Table 25: AS Case2: Alkaline (10Kg/m3) & Surfactant (2Kg/m3) for 4 Years @8000Sm3/d

Incremental oil production (MSm3)	Net Present Value (NPV) (MNOK)
44.80	1.74E+05
45.36	3.43E+05
45.80	5.05E+05
46.17	6.17E+05
46.43	7.24E+05
47.02	8.28E+05
179.49	1.21E+06
47.01	1.30E+06
47.21	1.39E+06
40.75	1.46E+06
40.84	1.54E+06
40.91	1.60E+06
40.95	1.67E+06
40.99	1.73E+06
41.00	1.79E+06
40.76	1.85E+06
40.18	1.90E+06

Table 26: AS (Cyclic) Case3: Alkaline (10Kg/m3) & Surfactant (2Kg/m3) for 4 Years @ 6 Months Interval

Incremental oil production (MSm3)	Net Present Value (NPV) (MNOK)
44.80	1.74E+05
45.36	3.43E+05
45.80	5.05E+05
46.16	6.17E+05
46.42	7.25E+05
47.02	8.28E+05
179.50	1.21E+06
47.02	1.30E+06
47.21	1.39E+06
40.75	1.47E+06
40.84	1.54E+06
40.90	1.60E+06
40.94	1.67E+06
40.98	1.73E+06
40.99	1.79E+06
40.76	1.85E+06
40.18	1.90E+06

NPV For Surfactant-Polymer System

Table 27: SP (Continuous Flooding) Case1: Surfactant (10Kg/m3) & Polymer (0,3Kg/m3) for 4 Years.

Incremental oil production (MSm3)	Net Present Value (NPV) (MNOK)
50.36	1.96E+05
50.14	3.82E+05
50.03	5.59E+05
50.17	6.80E+05
50.41	7.97E+05
50.96	9.10E+05
50.00	1.01E+06
50.65	1.12E+06
50.69	1.21E+06
43.61	1.29E+06
43.54	1.37E+06
43.42	1.44E+06
43.26	1.51E+06
43.08	1.57E+06
42.86	1.64E+06
42.58	1.70E+06
41.68	**1.75E+06**

Table 28: SP Case2: Surfactant (10Kg/m3) for 4 Years Followed By Polymer (0,3Kg/m3) for 3 Years.

Incremental oil production (MSm3)	Net Present Value (NPV) (MNOK)
50.28	1.95E+05
49.76	3.80E+05
49.20	5.54E+05
48.72	6.72E+05
48.28	7.84E+05
48.29	8.90E+05
46.99	9.89E+05
47.47	1.08E+06
47.46	1.18E+06
40.88	1.25E+06
40.92	1.32E+06
40.94	1.39E+06
40.93	1.45E+06
40.88	1.52E+06
40.79	1.57E+06
40.67	1.63E+06
40.03	1.68E+06

Table 29: SP (Cyclic) Case3: (Surfactant (10Kg/m3) & Polymer (0,3Kg/m3) for 4 Years @ 6 Months Interval)

Incremental oil production (MSm3)	Net Present Value (NPV) (MNOK)
50.34	1.96E+05
49.99	3.82E+05
49.71	5.58E+05
49.63	6.78E+05
49.65	7.93E+05
50.01	9.03E+05
48.89	1.01E+06
49.40	1.11E+06
49.33	1.20E+06
42.35	1.28E+06
42.20	1.35E+06
42.02	1.42E+06
41.82	1.49E+06
41.59	1.55E+06
41.35	1.61E+06
41.05	1.67E+06
40.13	**1.72E+06**

NPV for Alkaline-Surfactant-Polymer System

Table 30: ASP Case1(Alkaline (7Kg/m3), Surfactant (3Kg/m3) for 4 Years Followed By Polymer (0,3Kg/m3) for 1 Years).

Incremental oil production (MSm3)	Net Present Value (NPV) (MNOK)
50.17	1.95E+05
49.64	3.79E+05
49.08	5.53E+05
48.60	6.71E+05
48.16	7.82E+05
48.13	8.89E+05
46.69	9.87E+05
47.02	1.08E+06
46.85	1.17E+06
40.16	1.24E+06
39.99	1.31E+06
39.80	1.38E+06
39.59	1.44E+06
39.38	1.50E+06
39.17	1.56E+06
38.91	1.61E+06
38.04	1.66E+06

Table 31: ASP (Cyclic) Case2 (Alkaline (7Kg/m3), Surfactant (3Kg/m3) & Polymer (0,3Kg/m3) By 6 Months Cyclic for 4 Years).

Incremental oil production (MSm3)	Net Present Value (NPV) (MNOK)
50.22	1.96E+05
49.84	3.81E+05
49.54	5.56E+05
49.45	6.76E+05
49.46	7.91E+05
49.83	9.01E+05
48.74	1.00E+06
49.27	1.10E+06
49.22	1.20E+06
42.25	1.27E+06
42.10	1.35E+06
41.92	1.42E+06
41.71	1.48E+06
41.48	1.55E+06
41.24	1.60E+06
40.93	1.66E+06
40.01	**1.71E+06**

Table 32: ASP (Cyclic) Case3: Alkaline (7Kg/m3), Surfactant (3Kg/m3) & Polymer (0,3Kg/m3) By 1 Year Cyclic for 4 Years.

Incremental oil production (MSm3)	***Net Present Value (NPV) (MNOK)***
50.17	*1.95E+05*
49.64	*3.80E+05*
49.08	*5.54E+05*
48.59	*6.72E+05*
48.16	*7.83E+05*
48.14	*8.89E+05*
46.72	*9.88E+05*
47.06	*1.08E+06*
46.88	*1.17E+06*
40.17	*1.25E+06*
39.99	*1.31E+06*
39.79	*1.38E+06*
39.58	*1.44E+06*
39.37	*1.50E+06*
39.15	*1.56E+06*
38.89	*1.61E+06*
38.03	***1.66E+06***

Table 33 ASP (Continuous) Case4: Alkaline (7Kg/m3), Surfactant (3Kg/m3) & Polymer (0,3Kg/m3) for 5 Years.

Incremental oil production (MSm3)	**Net Present Value (NPV) (MNOK)**
80.40	2.70E+05
45.00	4.14E+05
48.98	5.64E+05
51.93	7.15E+05
53.91	8.64E+05
55.15	1.01E+06
55.77	1.15E+06
56.17	1.29E+06
56.49	1.42E+06
56.67	1.54E+06
57.02	1.66E+06
55.78	1.77E+06
56.08	1.88E+06
55.74	1.98E+06
47.63	2.06E+06
47.25	2.14E+06
46.86	2.22E+06
46.45	2.28E+06
46.05	2.35E+06
45.66	2.41E+06
45.07	2.47E+06
43.80	**2.53E+06**

Table 34: ASP (Cyclic) Case5: Alkaline (7Kg/m3), Surfactant (3Kg/m3) 6 Months Cyclic for 4 Years Followed with Polymer (0,3Kg/m3) For 1 Year.

Incremental oil production (MSm3)	Net Present Value (NPV) (MNOK)
80.34	2.70E+05
44.78	4.14E+05
48.29	5.61E+05
49.97	7.07E+05
50.48	8.47E+05
50.51	9.81E+05
50.25	1.11E+06
50.06	1.23E+06
49.91	1.34E+06
49.68	1.45E+06
49.73	1.56E+06
48.30	1.65E+06
48.50	1.75E+06
48.15	1.83E+06
41.12	1.90E+06
40.81	1.97E+06
40.51	2.04E+06
40.21	2.10E+06
39.92	2.15E+06
39.63	2.21E+06
39.29	2.26E+06
38.32	2.31E+06

Appendix E

```
-- Alkaline-Surfactant-Polymer Model
------------------------------------
RUNSPEC

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

DIMENS
 46 112 22   /

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

OIL

WATER

GAS
ALKALINE
SURFACT
POLYMER

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 mxlalg lstack interp
--       4   2000   0      1      4      20  'INTERP'   /

TABDIMS
--ntsfun ntpvt nssfun 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/norne6/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/norne6/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 transmissibilites 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 trougth 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 trougth 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. lmar
--
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/AS4_1P6CYCLIC2008.SCH' /
END
```