

Pendaeli Kaanaeli Mbise

Enhanced Oil Recovery for Norne Field E-Segment using Alkaline Surfactant-Polymer Flooding

Master's thesis in Petroleum Engineering

Supervisor: Prof. Richard Rwechungura & Prof. Jon Kleppe

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Norwegian University of Science and Technology
Faculty of Engineering
Department of Geoscience and Petroleum

Abstract

In life of the oil field, reservoir pressure tends to decrease with the development of the production. The use of primary and secondary recovery techniques enables recovery of only 35-50% of the oil in the reservoir. That means a significant amount of oil is left in the reservoir untapped. The remaining oil can either be residual oil to the water flooding or oil bypassed by water flooding. Residual oil mainly contains capillary trapped oil. The injection of chemicals such as Surfactant, Alkaline and Polymers or their combinations is one of the potential techniques that can influence the recovery of the oil remaining in the reservoir after water flooding.

For the Norne field, the situation is not far from this reality. The use of water flooding alone has recovered about 60% of the oil reservoir. Although this recovery rate is high compared to the rest of the sub sea fields, the use of water flooding alone will not be able to recover the remaining amount of oil as now the production is declining sharply and the rate of increase in water cut is high. The use of appropriate EOR process will help to produce the remaining amount of the oil. Basing on the screening done on different EOR methods using EORgui software in the first part of the study, Norne E-segment was found to be a good candidate of chemical EOR technique.

The aim of this study was to confirm the suitability of different chemical methods on Norne E-segment by doing comparative simulation study compared to water flooding basing on incremental oil production that was used to find the most promising method with high incremental Net Present Value. A number of different simulation plans were run, where Alkaline, surfactant, polymer as well as their mixtures were tested in various ways including different concentrations, injection time as well as injection duration.

From simulation results and economic analysis, Polymer flooding was confirmed to be the best chemical method for Norne E-segment having an incremental NPV of +68.7 million USD in 2020. This was obtained when polymer flooding at concentration of 1.5 kg/m^3 was run for five years from 2006. Polymer flooding reduces the effect of viscous fingering for heavy oil and also performs better for heterogeneous reservoir with light oil. Alkaline and surfactant flooding were found to be poor candidates for this field as their incremental oil production could not cover the operational cost including chemical cost. The combination of Polymer with alkaline and surfactant (ASP and SP flooding) had higher incremental oil production compared to polymer alone. However, the incremental NPV for ASP and SP flooding was low compared to Polymer flooding alone.

Nevertheless, the NPV calculation did not include all the costs including pumping cost as well as extra operational expenditures for all chemical flooding. On the other hand these costs can be compensated by using the most compatible chemicals after doing a laboratory evaluation and finding the accurate chemical properties that will comply with fluid and rock properties of the Norne E-segment.

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Nomenclature

μ	Viscosity
<i>API</i>	American Petroleum Institute gravity
<i>ASP</i>	Alkaline, surfactant and polymer
<i>CDC</i>	Capillary Destruction Curve
<i>CMC</i>	Critical Micelle Concentration
<i>EOR</i>	Enhanced Oil Recovery
<i>FAWAG</i>	Foam-assisted WAG
<i>FPSO</i>	Floating production, storage and offloading body
<i>HCPV</i>	hydrocarbon pore volume
<i>HLB</i>	hydrophile–Lipophile Balance
<i>IEP</i>	isoelectric point
<i>IFT</i>	inter-facial tension
<i>LPG</i>	Liquidified petroleum gas
<i>M</i>	Mobility ratio
<i>MEOR</i>	Microbial Enhanced Oil Recovery
<i>Nc</i>	Capillary Number
<i>NCS</i>	Norwegian Continental Shelf
<i>NPV</i>	Net Present Value
<i>OOIP</i>	Oil Originally in Place
<i>PDO</i>	Plan for development and operation
<i>SAGD</i>	Steam assisted gravity drainage
<i>SP</i>	Surfactant and polymer
<i>SRB</i>	sulphate-reducing bacteria
<i>SWAG</i>	simultaneous water-and-gas injection
<i>WAG</i>	Water alternating Gas
box	

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Chapter 1

Introduction

The primary stage of oil production involve the use of energy naturally found in the reservoir to displace oil to the well-bore and up to the surface. The major sources of this energy include rock and fluid expansion, solution gas, water influx, gas cap, and gravity drainage. In the secondary stage, fluids are injected to the reservoir (mainly water or gas) for reservoir pressure maintenance and displacing oil towards the well bore. After the application of both primary and secondary recovery methods, still about two third of the oil originally in place (OOIP) is left behind (Al-Adasani & Bai, 2010).

According to J. Sheng (2010), the total discovered oil by 1993 in US was 536 billion barrels with the total produced being 162 billion barrels (30% of the total discovered) and the reserve of 23 billion barrels equivalent to 4 % of the total discovered. This is the number that can be produced economically using conventional methods which leave behind about 351 billion barrels (66% of the total discovered) as shown in figure 1.1. He urges that if half of the remaining oil would be recovered by EOR method, about 176 billion barrels would be produced. This would double the currently projected recoverable reserves (J. Sheng, 2010).

High Oil prices led to many researches on EOR methods in 1980s where many oil companies had research centers for EOR processes. The situation changed due to fall of the oil price which reached about 20\$ per barrel in 1986 to 2003. However, oil price has recently gone high to about 60\$ per barrel and even more. Due to this new price of oil, with regard to increased oil demand world wide , few discoveries and rapid maturation of the field, EOR remain of high interest (Al-Adasani & Bai, 2010). The increase of recovery factor is termed of great important as discovering the new field especially for the Norwegian continental shelf (NCS) (Equinor, 2019).

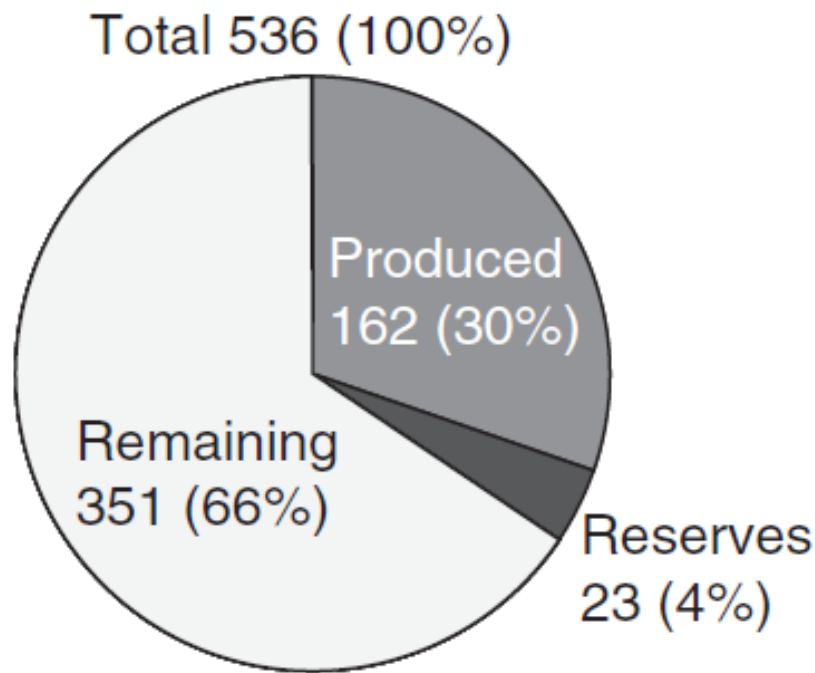


Figure 1.1: US Oil volume distribution, 1993 (J. Sheng, 2010)

The current average oil recovery rate on the Norwegian Continental Shelf (NCS) is 50% which is above the worldwide industry average of 35%. The target now is put to reach 60% average recovery factor for all fields in NCS. To meet this target needs extra work on research and technology that will help to combat the challenges like immobile oil, complex reservoirs and falling reservoir pressure is needed. Variety of techniques to increase the recovery factor for Norne field have been given by different researchers among which EOR technique has been proposed (Equinor, 2019).

By 2005, about five EOR methods had been initiated in the North sea including hydrocarbon (HC) miscible gas injection, water-alternating-gas (WAG) injection, simultaneous water-and-gas (SWAG) injection, foam-assisted WAG (FAWAG) injection, and microbial EOR (MEOR). Among these five, WAG was found to be the most successful EOR method in North sea (Awan et al., 2008). By the year 2011, none of the chemical EOR methods (polymer, surfactant or alkaline flooding) had been tested in North sea although there has been plan to be done later. This is due to environmental concern for the chemical methods and as they require large investments both in the testing and implementation phase. The use of chemical methods as well as low salinity water have been reported to have positive impact on residual recovery (NPD, 2019).

Norne field which has been in operation since November 1997 uses water injection as the drive mechanism though gas injection was also done until 2005. Basing on initial development plan, the field was scheduled to operate until 2014. However, the good condition of the Norne FPSO and the discovery of the new satellite fields to be tied back to Norne field nullifies this plan. In 2015, the company announced their aim to extend the life time for Norne field to 2030 (Statoil, 2015). The

current recovery factor for Norne for the whole field is reported to be 60% which meets the target rate for the fields in the Norwegian continental shelf (BP, 2013) and (Statoil, 2004b). However, recovery factor of 60% has been reached by the use of mainly water flooding alone, a technology which leaves significant amount of oil trapped in the pore by capillary forces and high interfacial tension. The use of chemical EOR techniques will enable recovery of residual and oil bypassed by water flooding and meet extra high recovery rate.

A reservoir needs to meet certain oil and reservoir characteristics in order to be a good candidate for a particular EOR method. However, oil price has much impact on the future EOR projects (J. Taber et al., 1997). Price depends on the demand for oil, which is still shooting up as oil is predicted to be the major source of energy for the next three decades. As the demand goes up, oil price will also increase. Therefore, it is now important than before to accept the lessons learned from the old EOR applications as well as developing new EOR techniques and methods. On the other hand, the response for the use of the EOR technologies in major oil producing countries remains in its conceptual stage, especially for chemical processes (Al-Adasani & Bai, 2010).

This thesis focuses on doing comparative simulation of different chemical EOR methods (Alkaline, Surfactant and Polymer) and their combinations by using Eclipse 100 software in order to find the most realistic EOR method for Norne E-segment. Using incremental NPV as the selection criterion, the most effective method for Norne E-segment among the simulated scenarios will be obtained. The alternatives for chemical EOR processes to be simulated involve Surfactant (S) flooding, Alkaline-Surfactant flooding (AS), Polymer (P) flooding, Surfactant-Polymer (SP) flooding and finally Alkaline-Surfactant-Polymer (ASP) flooding.

This simulation work will not be the first study to look on the applicability of the chemical EOR techniques to the Norne E-segment as many graduates have already done so in their project and master thesis. These include Clara (2010) who in her master thesis proposed the use of surfactant flooding to enhance the recovery oil in Norne E-segment (Emegwalu, 2010). Again Maheshwari in his thesis (2011) found ASP flooding to be the most promising chemical EOR method for the Norne E-segment (Maheshwari, 2011).

None of the simulation study had proposed for polymer flooding in the Norne E-segment. Despite the fact that the work done was good, something more needs to be done as there has been many changes in the industry since then including changes in oil price, technology and general expenses in overall. These changes may sort out the proposed method(s) and bring in new or the combination of them and even deny of all options.

1.1 Objective

Since only water flooding has been used to enable the recovery of oil from Norne E-segment, there must be more oil untapped from the reservoir especially in Ile and Tofte formations which needs the appropriate technology to enhance the recovery. The researchers have proposed chemical EOR methods to be the potential methods that can boost the recovery of oil from this field.

Therefore, this study mainly aim at evaluating the applicability and suitability of the chemical EOR methods on Norne E-segment by conducting simulation study using Eclipse 100 software. The most effective chemical method will be obtained basing on incremental oil production over water flooding that will be used to find the most positive Net Present Value (NPV) for this segment. The following simulation cases will be done in order to meet this goal.

Plan 1: Surfactant flooding

Plan 2: Alkaline Surfactant(AS) flooding

Plan 3: Polymer flooding

Plan 4: Surfactant Polymer (SP) flooding

Plan 5: Alkaline Surfactant Polymer (ASP) flooding

1.2 Description of the recovery techniques

Traditionally, oil recovery has been subdivided into three stages: Primary, Secondary and Tertiary stage. Historically, these stages described production from the reservoir in chronological order as elaborated here under (Green & Willhite, 1998).

1. Primary recovery - at this stage of oil production, the recovery of the oil field is done by using natural energy found in the reservoir to make the flow to the well. These sources of energy involve solution gas drive, gas-cap drive, natural water drive, fluid and rock expansion as well as gravity drainage.
2. Secondary recovery - the second stage of production involve injection of the fluids to the reservoir for pressure maintenance. Water injection is the most common used practice in secondary recovery although gas injection is practice in some field
3. Tertiary recovery - the third stage of production is obtained after the secondary process becomes uneconomical and intends to recovery additional oil by using miscible gas, chemical and /or thermal energy.

Traditional classification of oil production has some drawbacks due to the fact that the production process does not necessarily follow the prescribed order (Green & Willhite, 1998). For instance, in heavy oil production the use of natural drive becomes negligible. Again, it is not feasible to use

water flooding if the oil is sufficiently viscous. Therefore, the use of thermal energy becomes the only way to enable flow at economic rate. For this case, the method which was used traditionally as the tertiary process becomes the first and eventually the final method of recovery. Following this complication in classification of the oil production chronologically, it is now common to classify oil production basing on the process description. So, the most used classification is the one that subdivides production into primary, secondary and EOR processes (Green & Willhite, 1998). However, EOR should not be used as the synonyms of tertiary recovery.

1.2.1 EOR Processes

EOR is defined as a group of methods that comprises of energy or fluids injection in order to improve oil recovery factor at any level of production with the aim of boosting the total recovery above what is possible by conventional methods (Alvarado & Manrique, 2010).

1.2.1.1 Principles of Enhanced Oil Recovery methods

A given EOR method performs one or more of the following goals

- **Improving Mobility Ratio**

Mobility is given by effective permeability divide by viscosity. Mobility ratio is equal to the mobility of the displacing fluid (e.g water in water flooding) divide by the mobility of the fluid which is being displaced (e.g oil).

$$M = \frac{\lambda_{displacing}}{\lambda_{displaced}} \quad (1.1)$$

where M denotes Mobility ratio while

$$\lambda = \frac{k_i}{\mu} \quad (1.2)$$

where k = effective permeability and μ = viscosity

Maximum displacement efficiency is achieved when the mobility ratio is less than or equal to one. In-case mobility ratio M is greater than one, the displacing fluid moves more easily than the fluid being displaced. This is not desired because the displacing fluid will channel past the displaced fluid and lead to a situation known as ‘viscous fingering’. The viscous fingering causes inefficient displacement that bypasses significant amount of recoverable oil and at its severe case causes an early water breakthrough to the adjacent producer well. When mobility ratio is greater than one in absence of viscous fingering, this indicates that more displacing fluid will be injected to recover the oil to the desired residual saturation. This marks the importance of Mobility ratio as far as displacement efficiency is concerned. Mobility ratio can be improved through the following approaches (Ali & Thomas, 1994)

- lowering viscosity of the displaced fluid
- increasing viscosity of displacing fluid
- lowering the effective permeability to the displacing fluid
- increasing the effective permeability to the oil

- **Increasing the Capillary number**

Capillary number is a dimensionless group used in analysis of fluid flow that characterizes the ratio of viscous forces to surface or inter-facial tension force. It is given as

$$N_c = Ca = \frac{\mu \times v}{\delta} \quad (1.3)$$

where $N_c = Ca =$ Capillary Number, $\mu =$ Liquid Dynamic viscosity, $v =$ liquid velocity and $\delta =$ surface or interfacial tension

Reduction of oil viscosity and the increase in the pressure gradient leads to increase in capillary number. Another way of increasing capillary number is by decreasing the Inter-facial tension. When capillary number is increased the residual oil saturation is reduced. Increase in the capillary number has significant importance in increasing the oil recovery (Ali & Thomas, 1994).

1.2.2 Classification of EOR methods

According to Lake & Venuto (1990), Enhanced Oil Recovery methods may be classified into four groups :

1. Thermal Recovery - This includes steam simulation or huff and puff, steam flooding, steam assisted gravity drainage SAGD and insitu combustion or in contemporary term air injection.
2. Chemical process - This family of methods generally deals with the injection of interfacial active components such as surfactants and Alkalis or caustic soda, polymers and chemical blends.
3. Miscible or Solvent Injection - These are frequently associated with the form of gas injection using gases like Hydrocarbon, Carbon-dioxide and Nitrogen.
4. Others (Microbial, Electrical, Chemical leaching and Mechanical).

Figure 1.2 describes a typical EOR process while figure 1.3 shows clear classification of recovery methods. While waterflooding works perfectly in almost all reservoirs, no single EOR is cure-all. Each EOR method is suited for particular type of reservoir, therefore; thorough geological study is mandatory before applying any EOR method as unexpected or unknown reservoir characteristics may lead to failure of the particular EOR method. Practically it is common to use the combination of these methods rather than individual method for the purpose of increasing efficiency (Lyons et

al., 2015).

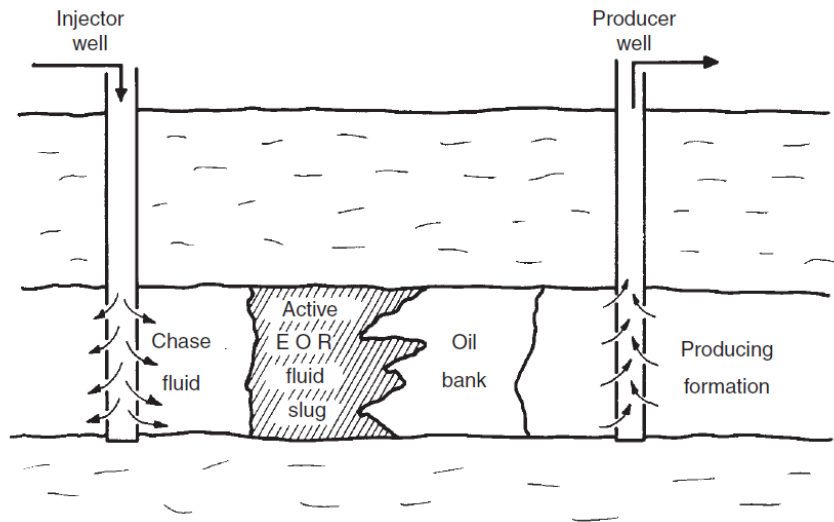


Figure 1.2: General schematic of enhanced oil recovery (Lyons et al., 2015)

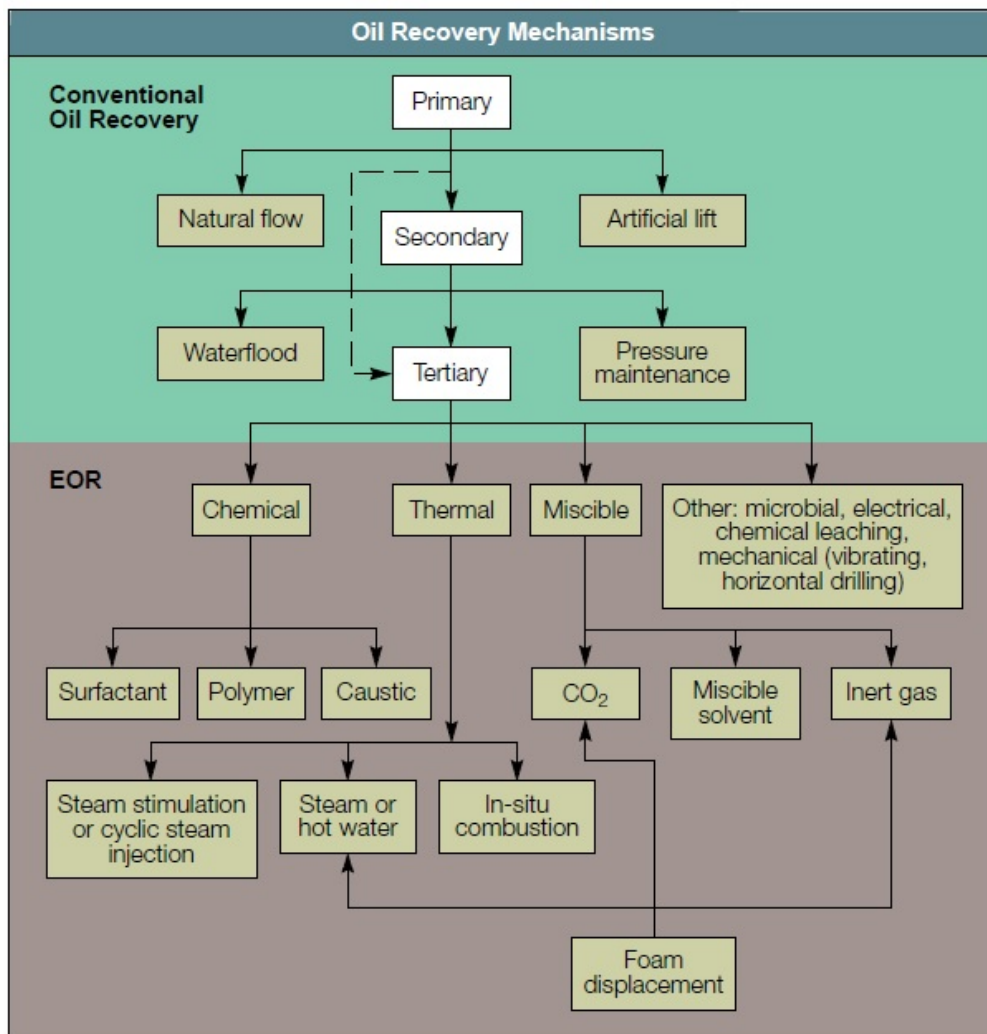


Figure 1.3: Oil Recovery Mechanism (Islam & Khan, 2007)

Chapter 2

Norne Field

Norne field is located in blocks 6508/1 and 6608/10 in the Southern part of the Nordland II area 80 km from Heidrum field. It is an oil field which was discovered in December, 1991 on a horst rock block of approximately 9km by 3 km. Based on discovery, a total hydrocarbon bearing column of 135 meters was found in which 110 meters are oil and the overlaying gas cap of about 25 meters (Rwechungura et al., 2010). The water depth in the area is 380 m. The reservoir lies at the depth of 2500 meters and has good quality. Oil is mainly found in Ile and Tofte formations while gas is in Not formation (Rwechungura et al., 2010; Statoil, 2004a). Currently, the field is operated by Equinor Energy AS and licence partners Eni Norge AS and Petoro AS. Figure 2.1 shows the location of the Norne field in Norwegian sea.

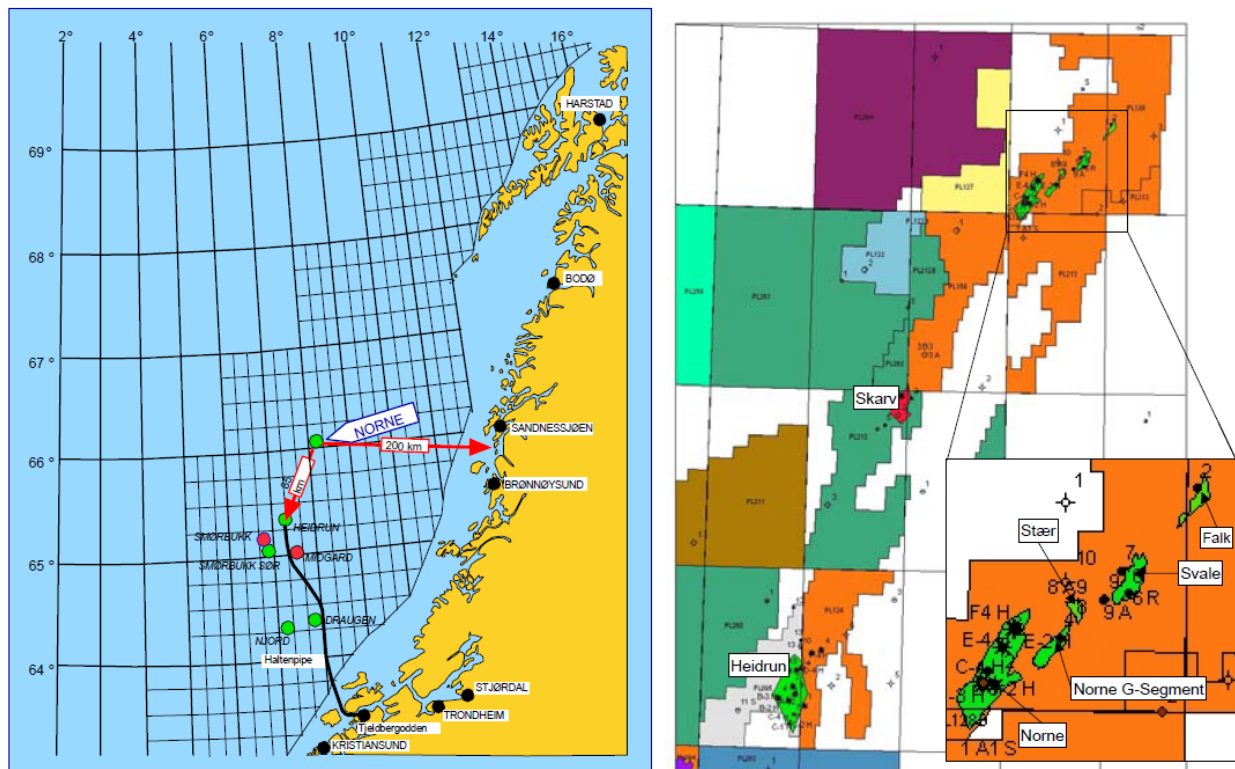


Figure 2.1: Location of Norne field (Statoil, 2004a)

The Norne field consists of two separate oil compartments; Norne Main Structure (Norne C-, D and E-segment, which was discovered in 1991), and the North-East Segment (Norne G-segment) as shown in figure 2.1. About 98% of oil is found in the Norne main structure.

2.1 Field Development and Operation

The plan for development and operation (PDO) of Norne field was approved in 1995 and production started in 1997. The field has been developed with Production, storage and unloading vessel which is connected to seven subsea templates. Norne field produces oil and gas from Jurassic sandstone. The field is produced by water injection as the drive mechanism. Gas injection ceased in 2005 and all gas was exported (Statoil, 2004b).

2.2 Geological information

The Norne reservoir is subdivided into four geological formations: Garn, Ile, Tofte and Tilje with Garn being at the top and Tilje at the bottom, (figure 2.2). The reservoir consist of Jurassic sandstones mainly dominated by fine grained and well to very well stored sub-arkosic arenites. The reservoir sandstones lie at a depth of 2500 meters to 2700 meters. Due to this depth, the reservoir has experienced the effect of diagenetic processes as well as reservoir quality being reduced by mechanical compaction. However, most of the reservoir sandstone still have good quality. The porosity ranges from 25% to 30% and permeability ranges from 20 mD to 2500 mD (Rwechungura et al., 2010). Melke formation forms the cap rock which seals the reservoir and keeps oil and gas in place. Not formation is also impermeable layer and hinders communication between Gharn and Ile formations. The erosion has caused variation in reservoir depth where from Top Are to Top Garn the the thickness vary from 260 m in the Southern parts to 120 m in the northern parts of the reservoir. Ile and Tofte are the most important formations of the Norne field as they contain approximately 80% of the oil (Statoil, 2004b).

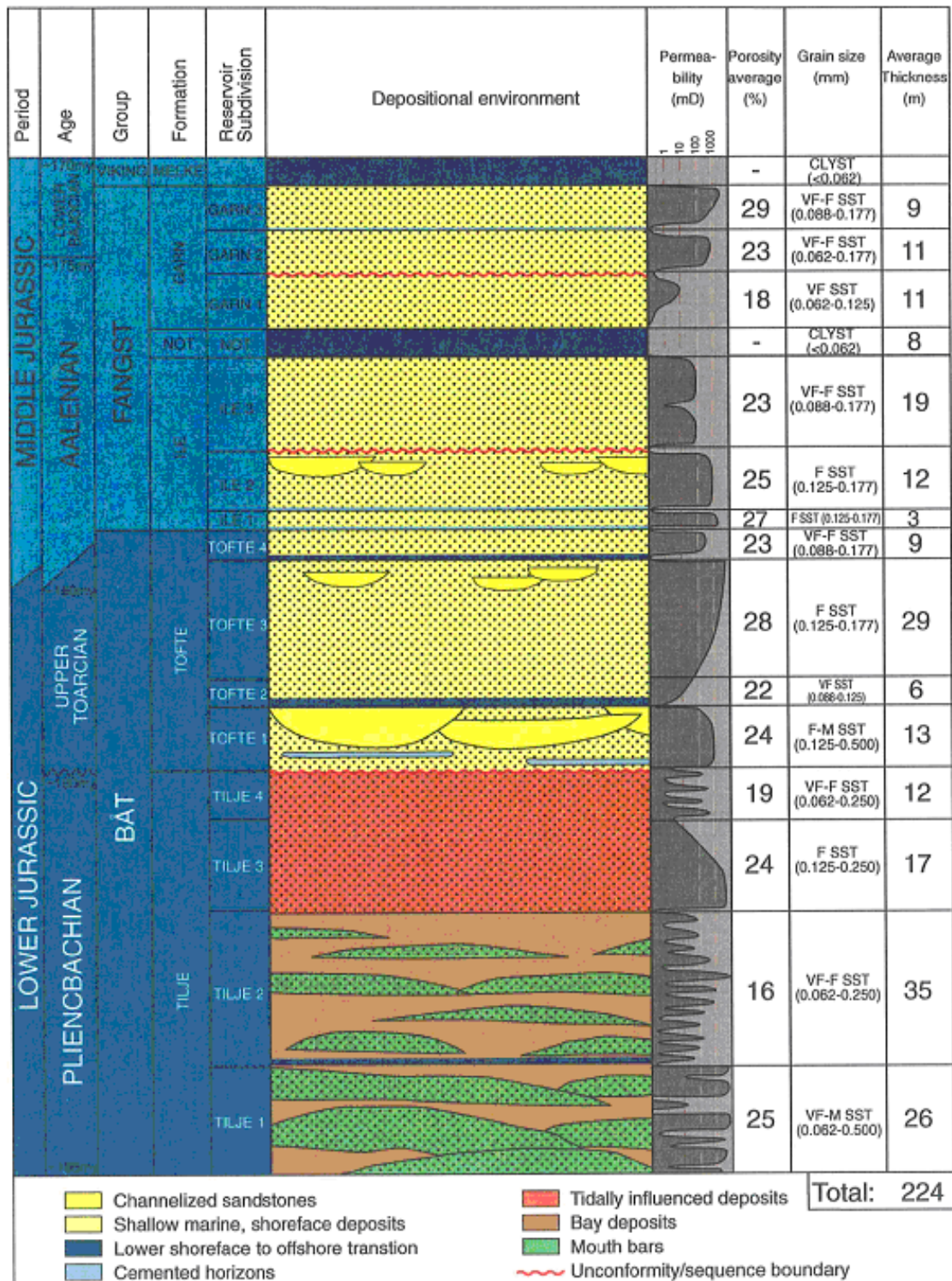


Figure 2.2: Stratigraphical sub-division of the Norne reservoir (Rwechungura et al., 2010; Statoil, 2004b)

2.3 Drainage strategy

The Norne field was developed with the main goal of obtaining an economic optimum production profile. They focused on optimizing the value creation by the following means (Statoil, 2004a).

- Safe and cost effective drainage of proven reserves
- Prove new reserves at optimal timing to utilise available infrastructure.
- Adjust capacities in cost effective way
- Improve drainage strategy with low cost infill wells as multilateral/MLT and through tubing drilled wells/TTRD
- Improved description and optimised drainage strategy to achieve recoverable reserves to more than 90 mill Sm³
- Increase reservoir pressure in Ile Formation at the Norne C-Segment.

Initially, the drainage strategy aimed at maintaining the reservoir pressure by re-injecting the produced gas into the gas cap and water into the water zone. However, it was revealed later that there was no communication between Ile and Gharn formations due to Not formation which acted as a seal between them. Therefore, the plan was changed and now gas was injected into the water zone and lower part of the oil zone (Statoil, 2004a). Water and gas had been injected up to 2004 and in 2005 gas injection was stopped and since then the main drive mechanism has been water injection, (figure 2.3). Different injection and production strategies that have been used since the commencement of the project are summarized in figure 2.4.

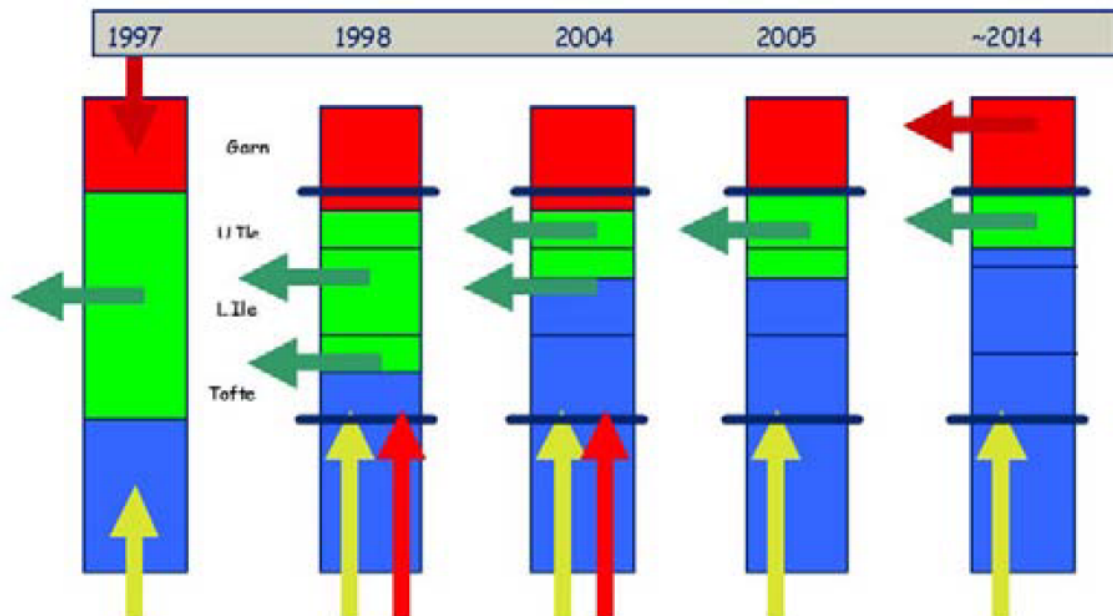


Figure 2.3: The drainage strategy for the Norne Field from pre-start until 2014.

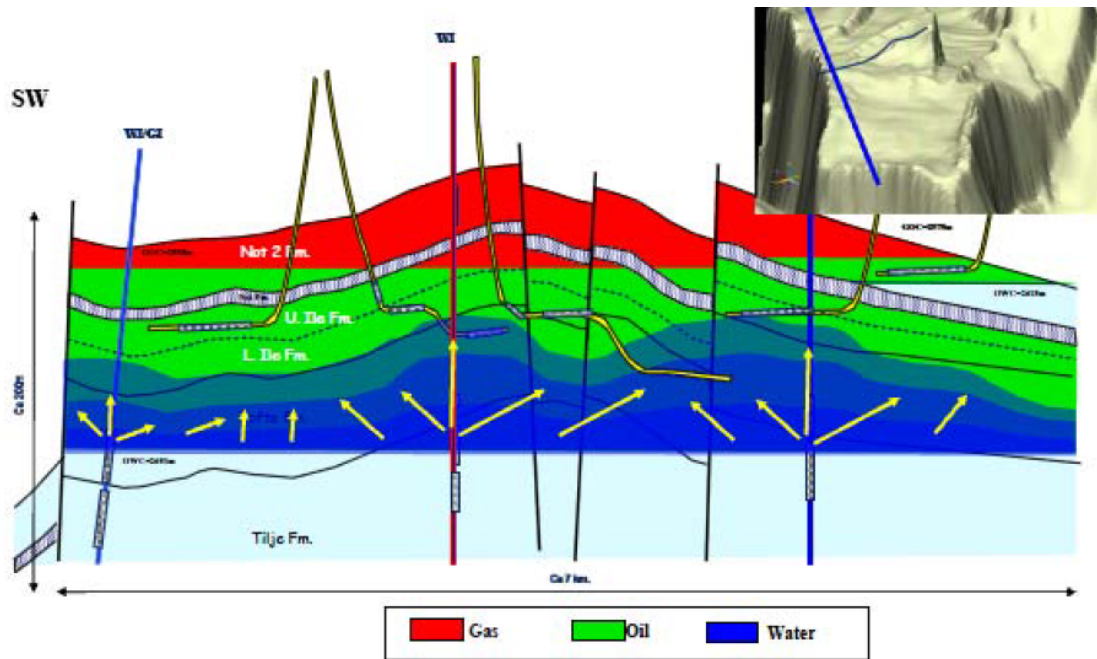


Figure 2.4: The General Drainage Pattern

2.4 Reservoir Simulation Model

The reservoir model for the whole Norne field is in the form of ECLIPSE 100. It is a three phase three dimensional black oil model with 44431 active cells. The model consist of 44 grids in the X direction, 112 in the Y direction and it has 22 layers. The geological zones are clearly defined in the model where layer 1-3 represent Garn formation, layer 4 is Not formation, layer 5 -11 represent Ile formation, layer 12 - 18 represent Tofte while layer 19 - 22 there is Tilje formation as shown in figure 2.5. The model runs from November 6, 1997 until November 1, 2004.

Layer number	Layer name
1	Garn 3
2	Garn 2
3	Garn 1
4	Not
5	Ile 2.2
6	Ile 2.1.3
7	Ile 2.1.2
8	Ile 2.1.1
9	Ile 1.3
10	Ile 1.2
11	Ile 1.1

Layer number	Layer name
12	Tofte 2.2
13	Tofte 2.1.3
14	Tofte 2.1.2
15	Tofte 2.1.1
16	Tofte 1.2.2
17	Tofte 1.2.1
18	Tofte 1.1
19	Tilje 4
20	Tilje 3
21	Tilje 2
22	Tilje 1

Figure 2.5: Reservoir zonation from the Eclipse model

2.5 Description of Norne E-segment

The E segment is a part of the Norne main structure which consist of C, D and E segments. The E segment has 8733 active cells and it covers between 80 m and 100 m in horizontal direction. In the ECLIPSE reservoir model, E segment is isolated from other segments by keeping the E segment as initial grids and coarsening the rest. Basing on the Reservoir simulation model (2004) for E segment, a total of five (5) wells have been drilled in the E segment alone of which three (3) are producer and two (2) injectors wells.

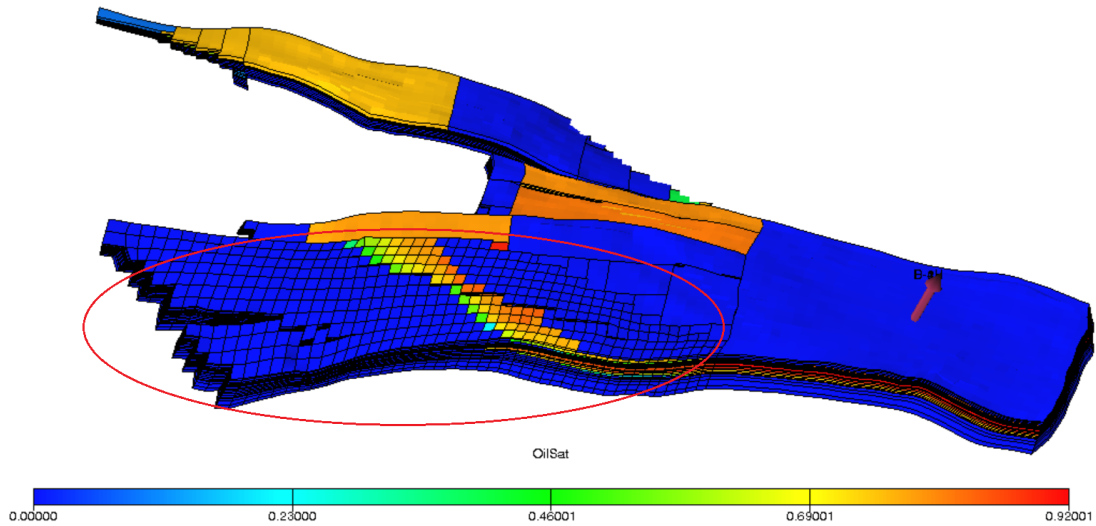


Figure 2.6: Reservoir model for Norne field showing E-segment with other segments being coarsened

Table 2.1: Description of the E-segment by grid cells positions

I_1	I_2	J_1	J_2	K_1	K_2
6	6	45	88	1	22
7	7	45	90	1	22
8	8	47	91	1	22
9	9	49	92	1	22
10	10	54	94	1	22
11	11	55	94	1	22
12	12	57	96	1	22
13	13	60	97	1	22
14	14	62	99	1	22
15	15	65	100	1	22
16	16	70	100	1	22

Table 2.2: Wells drilled in Norne E-segment until 2004

Well Name	Well Type	Status
F-1H	Injector(water)	Active
F-3H	Injector(water)	Active
E-2H	Oil Producer	Active
E-3H	Oil Producer	Shut
E-3AH	Oil Producer	Active

Chapter 3

Chemical EOR Methods

The most common chemical EOR processes that have been discussed by different authors are alkaline (A), surfactants (S), polymer (P), and any combination of these processes. They are always mixed with water and occasionally with other chemicals.

3.1 Polymer Flooding

In traditional water flooding method, water is pumped through the injector wells to push oil towards the producer wells. In many reservoirs, the water flood narrows its course between the injector wells and the producer wells. As a result, coning or fingering patterns occur. Due to this, significantly amount of oil is left behind by water flooding. To avoid this, the control of mobility becomes very important . This is achieved by injection of chemicals that change displacing fluid viscosity or preferentially reduce specific fluid relative permeability by injection of foams or chemicals that modify wettability. The common chemical used in mobility control is polymer due to its ability to increase sweep efficiency (J. Sheng, 2010)

How Polymer works: Polymer flooding increases sweep efficiency by the following ways

- Reducing of viscous fingering.
- Improving the water injection profile because of cross-flow between vertical, heterogeneous layers.
- Increasing effectiveness of water-flooding by reducing permeability.
- Reducing the relative permeability of water flow (k_{rw}) more than the permeability of oil flow (k_{ro}) through disproportionate permeability reduction.

It also plays an important role in synergism when used with other EOR methods.eg. surfactant or alkaline flooding (J. J. Sheng et al., 2015).

3.1.1 Types of Polymers used in EOR

The two most common types of polymers used in EOR are **synthetic polymers** and **bio-polymers**. A typical synthetic polymers are partially hydrolyzed polyacrylamide (HPAM) and its derivatives. A typical biopolymer is xanthan gum (J. J. Sheng et al., 2015) . Natural polymers and their derivatives are used rarely. eg. guar gum, sodium carboxymethyl cellulose, and hydroxyl ethyl cellulose (HEC) (J. Sheng, 2010)

Hydrolyzed Polyacrylamide,HPAM

HPAM is the most used polymer in EOR applications. It gives significantly greater recovery of oil as it exhibit greater visco-elasticity than Xanthan solutions. The polyacrylamide adsorbs strongly on mineral surface and make the polymer partially hydrolyzed and hence reduces adsorption by reacting polyacrylamide with base. eg. Sodium, Potassium hydroxide or Sodium carbonate. Some of the amide groups (CONH₂) are converted to carboxyl group (COO⁻) (J. Sheng, 2010). The mole fraction of amide groups that are converted by hydrolysis gives the degree of hydrolysis. The ranges degree of hydrolysis is between 15 to 35% for commercial products. The higher hydrolysis reduces the adsorption and increases the viscosity but also reduces chemical stability. EOR process takes long time and this increases the need for the polymer stability. In general, hydrolysis should not exceed 40% in a period of three months although acidic or basic conditions tends to fasten the process. HPAM also lack tolerance when exposed to high temperature or high salinity (J. Sheng, 2010).

Xanthan Gum

Apart from HPAM, Xanthan is another widely used polymer in EOR applications. Its popularity is a result of many favourable properties including the fact that Xanthan is relatively insensitive to salinity and has high pseudo-plastic behavior, low adsorption and high tolerance to mechanical degradation. In addition, Xanthan is now day produced at low cost towards the improvement of manufacturing process. Despite all these goodness, Xanthan still face some problems including both thermal-oxidative and microbial degradation as well as formation plugging at the time of Xanthan injection (Kolodziej, 1987)

3.1.2 Stability of Polymer solutions

Polymer degradation is very critical for polymer flooding as it can significantly influence the viscosity of the polymer solution which is an important property for polymer in enhanced oil recovery, EOR. The process involve the breakdown of the molecular structure of the macro-molecule (Puls et al., 2016). The type of degradation that occur during polymer flooding can be chemical, mechanical or biological degradation (J. J. Sheng et al., 2015). The effect of degradation vary depending on the type of the polymer used (synthetic polymers or bio-polymers) (Puls et al., 2016).

3.1.2.1 Chemical Degradation.

Chemical degradation refers to the breakdown of polymer molecules, either through short-term attack by contaminants, such as oxygen and iron, or through longer-term attack to the molecular backbone by processes such as hydrolysis. The presence of oxygen leads to oxidative degradation of HPAM. The effect of dissolved oxygen on the polymers solution viscosity depends much on the temperature. Under low temperature, there is small effect with the effect becoming significant even in small presence of oxygen at high temperature (J. Sheng, 2010). The amount of oxygen in the solution is minimized by using oxygen scavengers. The presence of ferric ions and Siderite may lead to Oxygen consumption. However, in a long run this may result into a chain reaction of Iron II

being oxidized to Iron III. This chain reaction reduces polymer viscosity significantly, almost to the viscosity of water (J. J. Sheng et al., 2015). Temperature and divalent ions has great effect on hydrolysis. The viscosity of polymer solution is highly reduced by divalent or multi-valent ions more than mono-valent ions (J. Sheng, 2010).

3.1.2.2 Biological Degradation

This is microbial breakdown of macro-molecules of polymers during storage or in the reservoir (J. Sheng, 2010). It affects bio-polymers more although synthetic polymers are also affected. HPAM has ability to give nutrition to sulphate-reducing bacteria (SRB) (J. J. Sheng et al., 2015). The effect of biological degradation is much severe only at low temperature or in the absence of effective biocides which are used to reduce biological degradation (J. Sheng, 2010)

3.1.2.3 Mechanical degradation

Mechanical degradation is the breakdown of molecules as the result of high mechanical stress on the molecule or high flow rates in the region close to the wellbore (J. J. Sheng et al., 2015). Mechanical degradation affects different parts of the injection-reservoir system as described in figure 3.1.

1. Surface facilities during mixing and pumping of polymers.
2. Pipelines and chokes
3. Near wellbore, high flowing rate lead to strong visco-elastic effects.
4. In the reservoir, polymers may be degraded following shear or visco-elastic effects.
5. In pumps, high shear rates are experienced.
6. in surface sampling high shear leads to degradation.

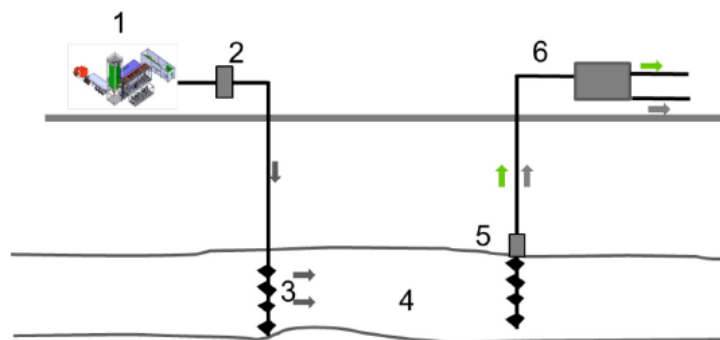


Figure 3.1: Location of mechanical polymer degradation in the injection-reservoir production system: (1)polymer slicing and mixing unit (2)pipelines and chokes (3) near wellbore (4) reservoir (5) pumps (6) surface sampling (Puls et al., 2016)

The degradation leads to reduction of the viscosity of the polymer solution. To reduce mechanical degradation, screw pumps are used to transport polymer solution, plunger pumps are used for injection and polymer injection wells are often completed through perforation. Also rate measuring

is done by using electromagnetic flow-meters which reduces shear effect (J. J. Sheng et al., 2015). Along with these processes, polymers are affected mainly by reservoir temperature, formation water salinity, divalent contents, clay contents, oil viscosity and formation permeability (J. J. Sheng et al., 2015).

3.2 Surfactant flooding

Water flooding leaves large amount of oil trapped in small pores due to strong surface tension. The use surfactants is the common method used to create low inter-facial tension and enhance the recovery of the trapped oil. Surfactant is a blend of surface acting agents with ability to adsorb on or concentrate at the surface or interface of the fluid and alter surface properties mainly reduction of surface tension or inter-facial tension (IFT) . Surfactants are organic compounds that are amphiphilic, meaning they are composed of a hydrocarbon chain (hydrophobic group, the “tail”) and a polar hydrophilic group (the “head”). Due to this property, surfactants are capable of dissolving in both organic solvent and water (J. Sheng, 2010; Schramm, 2000).

3.2.1 Classification of Surfactants

Basing on the ionic nature of the head group, surfactants are classified into the following groups:

1. Anionic surfactants,
2. Cationic surfactants,
3. Nonionic surfactants, and
4. Zwitterionic surfactants.

The most used surfactant in EOR projects are anionic surfactants since they have low adsorption on the sandstone rock whose surface is negatively charged. Although nonionic surfactants have good tolerance to high salinity, their ability to reduce the interfacial tension (IFT) is lower compared to Anionic surfactants. Most of time they are used as co-surfactants to improve system phase behavior. The mixture of nonionic and anionic surfactants is used to reduce the effect of high salinity. Anionic and nonionic surfactants only suit sandstone rock due to their high adsorption in the carbonate rocks. Again the use of cationic surfactants in sandstone reservoir is restricted by their ability to strongly adsorb in sandstone rock, therefore cationic surfactants are used in the carbonate rocks to change the wettability from oil-wet to water-wet. Zwitterionic surfactants also known as amphoteric surfactants contains two active groups, namely nonionic-anionic, nonionic-cationic, or anionic-cationic. They have high tolerance to high salinity and practically stable under high temperature. Also amphoteric surfactants have low adsorption to carbonate rocks as compared to the rest of the surfactants. Their use in the industry is limited by their price which is very high (J. Sheng, 2010). Figure 3.2 gives a summary of surfactants types, examples and their structures.

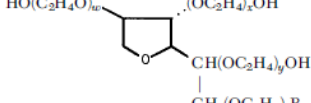
Class	Examples	Structures
Anionic	Na stearate	$\text{CH}_3(\text{CH}_2)_{16}\text{COO}^- \text{Na}^+$
	Na dodecyl sulfate	$\text{CH}_3(\text{CH}_2)_{11}\text{SO}_4^- \text{Na}^+$
Cationic	Na dodecyl benzene sulfonate	$\text{CH}_3(\text{CH}_2)_{11}\text{C}_6\text{H}_4\text{SO}_3^- \text{Na}^+$
	Laurylamine hydrochloride	$\text{CH}_3(\text{CH}_2)_{11}\text{NH}_3^+ \text{Cl}^-$
	Trimethyl dodecylammonium chloride	$\text{C}_{12}\text{H}_{25}\text{N}^+(\text{CH}_3)_3\text{Cl}^-$
Nonionic	Cetyl trimethylammonium bromide	$\text{CH}_3(\text{CH}_2)_{15}\text{N}^+(\text{CH}_3)_3\text{Br}^-$
	Polyoxyethylene alcohol	$\text{C}_n\text{H}_{2n+1}(\text{OCH}_2\text{CH}_2)_m\text{OH}$
	Alkylphenol ethoxylate	$\text{C}_9\text{H}_{19}-\text{C}_6\text{H}_4-(\text{OCH}_2\text{CH}_2)_n\text{OH}$
	Polysorbate 80	$\text{HO}(\text{C}_2\text{H}_4\text{O})_w \dots (\text{OC}_2\text{H}_4)_x\text{OH}$
	$w + x + y + z = 20$ $\text{R} = (\text{C}_{17}\text{H}_{33})\text{COO}$	
Zwitterionic	Propylene oxide-modified polymethylsiloxane	$(\text{CH}_3)_3\text{SiO}((\text{CH}_3)_2\text{SiO})_z(\text{CH}_3\text{SiO})_y\text{Si}(\text{CH}_3)_3$
	EO = ethyleneoxy	$\text{CH}_2(\text{OC}_2\text{H}_4)_2\text{R}$
	PO = propyleneoxy	$\text{CH}_2\text{CH}_2\text{CH}_2\text{O}(\text{EO})_m(\text{PO})_n\text{H}$
Zwitterionic	Dodecyl betaine	$\text{C}_{12}\text{H}_{25}\text{N}^+(\text{CH}_3)_2\text{CH}_2\text{COO}^-$
	Lauramidopropyl betaine	$\text{C}_{11}\text{H}_{23}\text{CONH}(\text{CH}_2)_3\text{N}^+(\text{CH}_3)_2\text{CH}_2\text{COO}^-$
	Cocoamido-2-hydroxy-propyl sulfobetaine	$\text{C}_n\text{H}_{2n+1}\text{CONH}(\text{CH}_2)_3\text{N}^+(\text{CH}_3)_2\text{CH}_2\text{CH}(\text{OH})\text{CH}_2\text{SO}_3^-$

Figure 3.2: Surfactants Classification (Schramm, 2000)

3.2.2 Methods used to Characterize Surfactants

The most used surfactants in flooding are sulfonated hydrocarbons. Petroleum sulfonates are sulfonates produced when an intermediate - molecular - weight refinery stream is sulfonated, and synthetic sulfonates are produced when a relatively pure organic compound is sulfonated. Sulfonate surfactants are stable above 200⁰C while sulfate surfactants decompose at temperature above 100⁰C. Sulfate Surfactants are easily available and tolerant to divalent ions although they are unstable at high temperature. On the other side sulfonate surfactants are stable at high temperature but they are sensitive to divalent ions. The following are the common methods used used to characterize surfactants (J. Sheng, 2010).

3.2.2.1 Hydrophile–Lipophile Balance

The hydrophile–Lipophile Balance (HLB) is a number that relatively indicates the tendency to solubilize in oil or water and thus the tendency to form water-in-oil or oil-in -water emulsions. The surfactants which are more soluble in oil and form water-in-oil emulsions are assigned small HLB number. The low HLB surfactants are used in low salinity formations because such surfactants can make middle micro-emulsion at low salinity. When the formation salinity is high, a high HLB surfactant should be selected. Such a surfactant is more hydrophilic and can make middle-phase microemulsion at high salinity (J. Sheng, 2010).

3.2.2.2 Critical Micelle Concentration (CMC),

CMC is defined as the concentration of a surfactant above which micelles are spontaneously formed. A micelle is an aggregate of surfactant molecules dispersed in a liquid colloid. Towards introduction of surfactants into a system, they are initially partitioned into the interface , reducing the system free energy by lowering the energy of the interface and removing the hydrophobic parts of the surfactants from contacts with water. As the surface coverage by the surfactants increases and the

surface free energy (surface tension) has decreased, the surfactants start aggregating into micelles, which lead to the decreasing of the system-free energy by reducing the contact area of hydrophobic parts of the surfactants with water. When CMC is reached, further addition of surfactants will only increase the number of micelles while surface tension stays more or less constant 3.3. For a given system, micellization occurs over a narrow concentration range almost in the range of a few to tens of parts per million (J. Sheng, 2013, 2010)

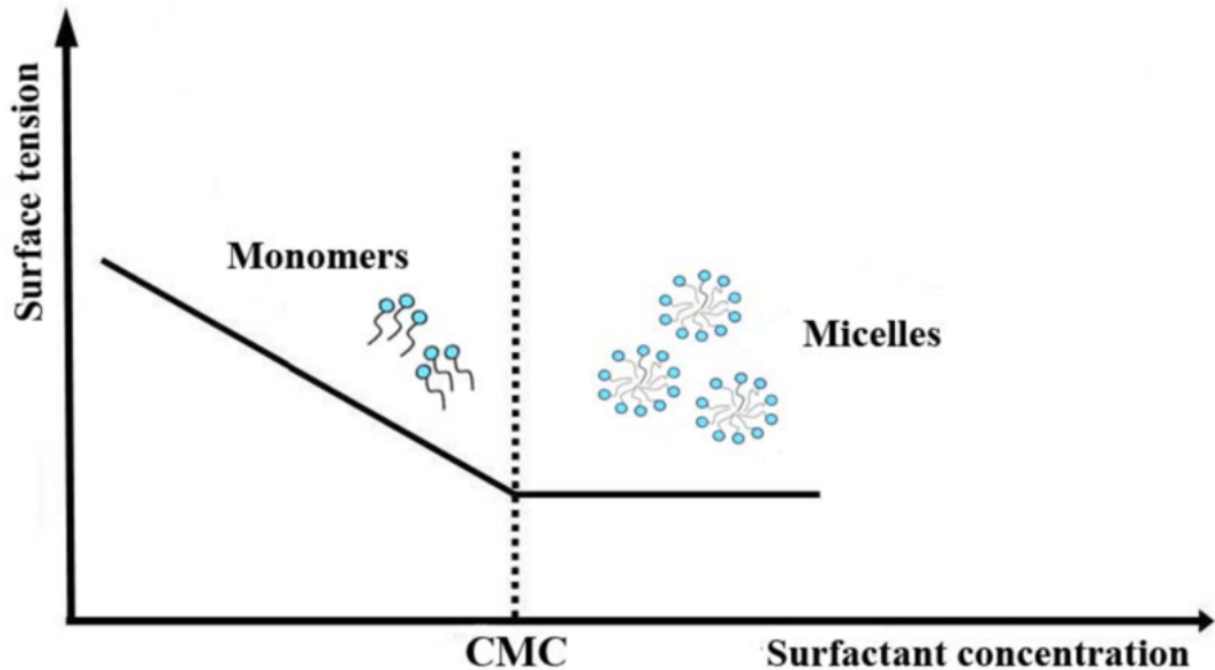


Figure 3.3: The critical micelle concentration (CMC) for surfactants (Pacwa-Płociniczak et al., 2011)

3.2.2.3 Solubilization Ratio

Solubilization is the process of increasing the solubility of a certain material in a given medium. Solubilization ratio for oil or water is defined as the ratio of the solubilized oil or water volume to the surfactant volume in the microemulsion phase. There is a close relation between solubilization ratio and IFT in such a way that, when the solubilization ratio for oil is equal to that for water, the IFT reaches its minimum (J. Sheng, 2010).

3.2.2.4 R-ratio

This is the ratio used to describe the affinity of surfactant to oil or water phase. It is given by equation 3.1, where R = R-ratio, A_{co} = the interaction between oil molecules and surfactant molecules and A_{cw} = the interaction between water molecules and surfactant molecules. This equation did not consider the effect of the repulsive interactions between oil molecules A_{oo} , between water

molecules A_{ww} , between lipophilic tails or between hydrophilic heads A_{hh} (J. Sheng, 2010, 2013).

$$R = \frac{A_{co}}{A_{cw}} \quad (3.1)$$

When $R < 1$, the relative miscibility with water has increased and/or that with oil has decreased. When $R > 1$, the relative miscibility with oil has increased and/or that with water has decreased (J. Sheng, 2010).

3.2.2.5 Packing Factor

Another parameter used in characterization of the surfactant is packing factor. The packing factor is given by the equation (3.2) where V is the volume occupied by the hydrophobic group in the micellar core, a_o is the cross-sectional area occupied by the hydrophilic group at the micelle surface, and L_c is the length of the hydrophobic group. The minimum IFT is obtained when the packing factor is equal to 1. Figure 3.4 shows packing factors for different aggregate structures (J. Sheng, 2010).

$$\phi = \frac{V}{a_o * L_c} \quad (3.2)$$

Packing Factors for Aggregate Structures	
< 0.33	Spherical, ellipsoidal micelles
0.33–0.5	Rod-like micelles
0.5–1.0	Vesicles, bilayers
1.0	Planar bilayers
> 1.0	Reverse micelles (small head and large tail)

Figure 3.4: Packing Factors for Aggregate Structures (J. Sheng, 2010)

3.2.3 Application of surfactants in Petroleum Industry

The main aim of surfactants flooding is to recover the capillary trapped oil after waterflooding. The injection of the surfactant solution enables the mobilization of the residual oil through strong reduction in the interfacial tension (IFT) between oil and water. The coalescence of these drops leads to a local increase in oil saturation. An oil bank will start to flow and mobilize (incorporate) any residual oil in front. Behind the oil bank, the surfactant now prevents the mobilized oil from being retrapped. The ultimate residual oil saturation will therefore be determined by the interfacial tension between oil and surfactant solution behind the oil bank. For efficient surfactants, IFT is reduced by a factor of 10^4 which corresponds to a value close to $1 \mu\text{N/m}$.

A large number of field tests carried out on surfactants application to improve oil recovery gave some discouraging results where the actual recovery was lower than the one predicted in the laboratory tests. However, some of the larger field tests (90 to 400 acres) have been technically successful, recovering 25 to 30% of the residual oil with a volume ratio of 9 to 27 Sm^3 of oil per ton surfactant. Surfactants are very expensive so only small portion of the pore volume can be injected. To compensate this, surfactant slug is displaced by water usually with polymer to avoid fingering and breakdown of the slug (Skjæveland & Kleppe, 1992). Below are the main aspects of the surfactants flooding.

3.2.3.1 Capillary Desaturation

The waterflooded zone contains high saturation of residual oil trapped in the pores. To reduce the residual oil saturation, the pressure drop across the trapped oil needs to overcome the capillary forces that keeps them trapped. This is achieved by injection of surfactants which reduce the IFT between oil and water. The study shows that there is correlation between the residual oil saturation with the capillary number. Capillary number is a dimensionless ratio between the viscous and the capillary forces. The relationship between residual saturation and the capillary number is illustrated by the Capillary Destruction Curve (CDC) which depends on the pore size distribution and the wettability, see figure 3.5 and 3.6 . Narrowing the pore size distribution makes the oil saturation start to drop at high capillary number while zero residual saturation is obtained at lower capillary number. The CDC for the displacement of the wetting phase is shifted to the right of the CDC for the displacement of the nonwetting phase by approximately two orders of magnitude. A surfactant flood therefore should perform best in a waterwet reservoir (Skjæveland & Kleppe, 1992).

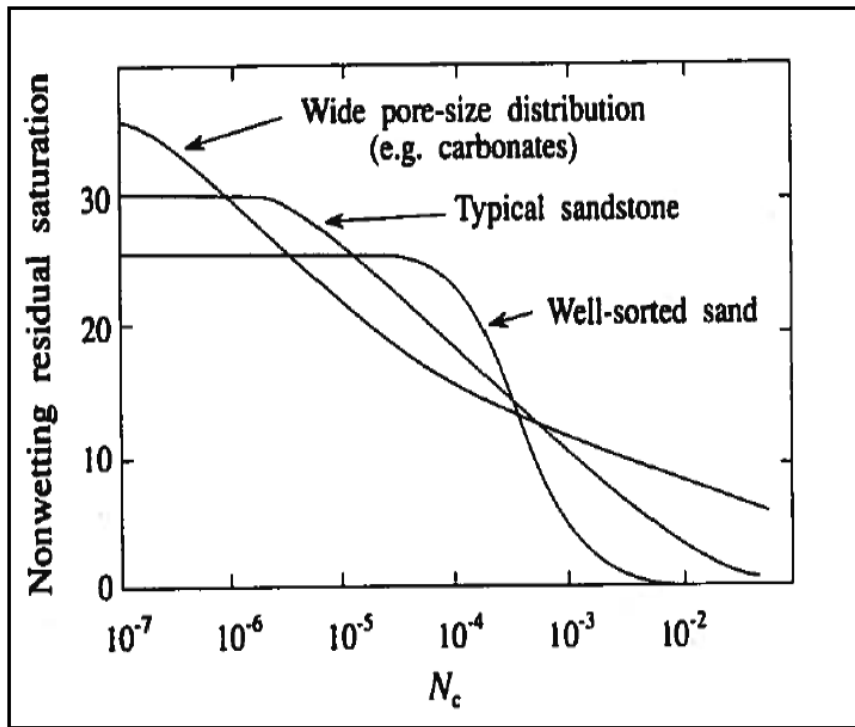


Figure 3.5: The effect of pore size distribution on CDC (Skjæveland & Kleppe, 1992)

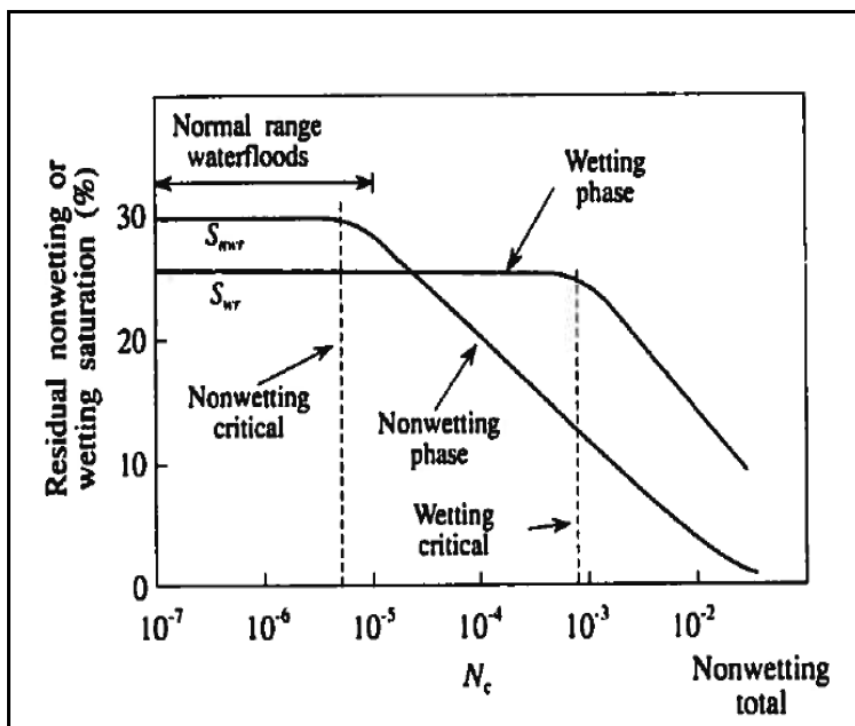


Figure 3.6: Effect of wettability on the residual saturation of wetting and non-wetting phase (Skjæveland & Kleppe, 1992)

3.2.3.2 Relative permeability in surfactant flooding

The classical relative permeability curves represents situation in which fluid distribution is controlled by capillary forces. When capillary forces becomes lower relatively to viscous forces, the situation changes and now the concept of relative permeability does not apply. The reduction of IFT during surfactant flooding makes the residual saturation to decrease which also changes relative permeability. The general observation made on this was that, the relative permeabilities tend to increase and have less curvature as the IFT decreases or the capillary number increases (J. Sheng, 2010).

3.2.3.3 Volumetric sweep efficiency

Mobility ratio is vital during displacement of oil towards the production well. The efficient displacement is achieved when the mobility ratio is kept as low as possible. This helps in preventing fingering of the surfactant fluid into the oil bank as well as reducing large scale dispersion which may caused by permeability contrasts, gravity segregation and the well pattern. A low mobility slug increases the volumetric sweep efficiency by forcing more of the injected fluids into low-permeable layers and into areas far from the line between the injection well and the producer. This makes the spread of the capillary number be less leading to lower residual oil saturation in the low-permeable zones and higher residual oil saturation in the high permeable zones. In addition to this, the simulation study on surfactant floods in layered reservoirs found the mobility ratio to be of great important for improving oil recovery (Skjæveland & Kleppe, 1992)

3.2.3.4 Effects of salinity on surfactant flooding

For a given type of oil and surfactant, the brine salinity strongly affects the phase behavior of the oil-water-surfactant system. The solubility of anionic surfactants in the brine is greatly affected by the increase in the salinity of the brine. The interaction between oil-water system and surfactant leads to formation of micelles in either the oleic phase or the aqueous phase depending upon the hydrophobicity of the surfactant and the salt concentration (J. Sheng, 2010; Skjæveland & Kleppe, 1992). These micelles solubilize some of the excesses of the oleic or the aqueous phase to generate a microemulsion which help to efficciently recover the residual oil due to their low interfacial tension. Generally, microemulsions are classified into three groups: Type II- (oil in water), Type II+ (water in oil), and Type III (middle phase). Other authors have used different names to present the groups of microemulsion. Winsor (1954) used type I, II and III while Fleming et al. (1978) used γ , β , α . The microemulsion phase can be changed from Type II- to Type II+ by tuning the salinity at constant temperature and pressure (Kamal et al., 2017; Skjæveland & Kleppe, 1992).

When the brine salinity is low, the typical surfactant exhibits good aqueous phase solubility and the system has two phases: an excess oil phase and a water-external microemulsion phase. Due to density difference, microemulsion in the aqueous phase resides below the oil phase and this is called a lower-phase microemulsion (Type II-). When the salinity is high, the system divides into an

oil-external microemulsion and an excess water phase. In this case, the microemulsion is called an upper-phase microemulsion (Type II-). At some optimum range of salinities, the system could have three phases: an excess oil phase, a microemulsion phase, and an excess water phase. In this case, the microemulsion phase resides in the middle and is called a middle-phase microemulsion (Type III) (J. Sheng, 2010). The study shows that, the increase of salinity helps to lower the IFT and hence improve the recovery of the residual oil. However, further increase beyond a certain level leads to increase of IFT which again lower the recovery (Kamal et al., 2017).

For long time ternary diagram have been used to describe the phase behaviour for oil-water-surfactant system. Each of three corners of the diagram represent 100% of each of the component. If the top apex of the ternary diagram represents the surfactant pseudocomponent, the lower left represents water, and the lower right represents oil, the tie lines within the lower microemulsion environment have negative slopes and represent type II(-). Again the upper - and middle phase environment are represented by type II(+) and type III respectively. Figure 3.7 gives a good summary of types of microemulsions and effect of salinity on the phase behavior (J. Sheng, 2010; Kamal et al., 2017).

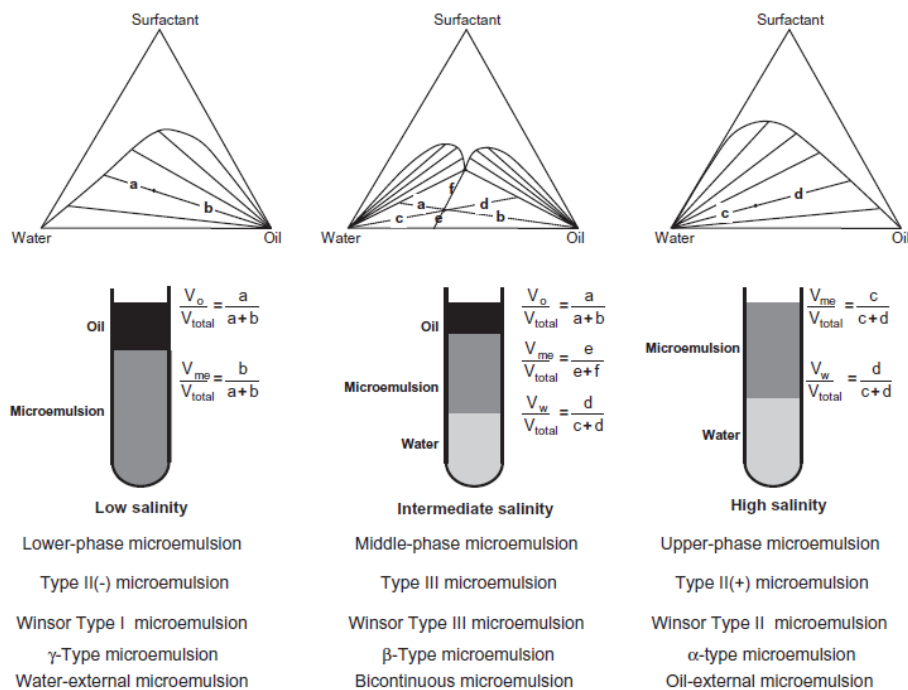


Figure 3.7: Three types of microemulsions and effect of salinity on the phase behavior (J. Sheng, 2013)

3.2.4 Surfactant Loss/ Retention

The economics of the surfactant flooding project is much affected by surfactant retention. This is due to the fact that, some of the amount of the surfactant flooded into the reservoir gets lost through different mechanisms including precipitation, adsorption, or phase trapping. Surfactant loss through precipitation and phase trapping can be stopped by selecting right type surfactant that are temperature and salt tolerant and adjusting relevant parameters. For the case of loss due to adsorption on reservoir rock, it is difficult to avoid although some means to minimize it are present. Surfactant loss may decrease the efficiency of the chemical slug and leads to the increase of IFT between water and oil which reduces the recovery. Practically, surfactant retention of less than 1 mg/(g of rock) can be tolerated (Kamal et al., 2017). Surfactant retention depends on surfactant type, surfactant equivalent weight, surfactant concentration, rock minerals, clay content, temperature, pH, redox condition and flow rate of the solution (J. Sheng, 2013)

3.2.4.1 Adsorption

The solid or liquid interface are either positive charged or negative charged depending on the PH and ionic strength. The charge of a particular surface or molecule depends whether its PH is below or above isoelectric point (IEP) which is a PH at which surface or molecules carries no net electric charge. At the PH below IEP the surface carries positive charge and at Ph above IEP the surface posses negative charge. At neutral pH carbonate rock posses positive charge while sandstone is negatively charged. The adsorption of the surfactant on the surface of the rock occur main due to electrostatic interaction and van der Waals interactions between the surfactant hydrophobic group and the solid surface. Surfactant loss can also occur through ion exchange, mineral transformation due to hydrophobic bonding, ion paring, π electron polarization, and the precipitation of surfactant with dissolved minerals. Anionic surfactant are highly adsorbed by carbonate surface and cationic surfactants have adsorbs much on the sandstone surface. Figure 3.8 shows four distinct regions for a typical adsorption isotherm (Kamal et al., 2017; J. Sheng, 2010, 2013).

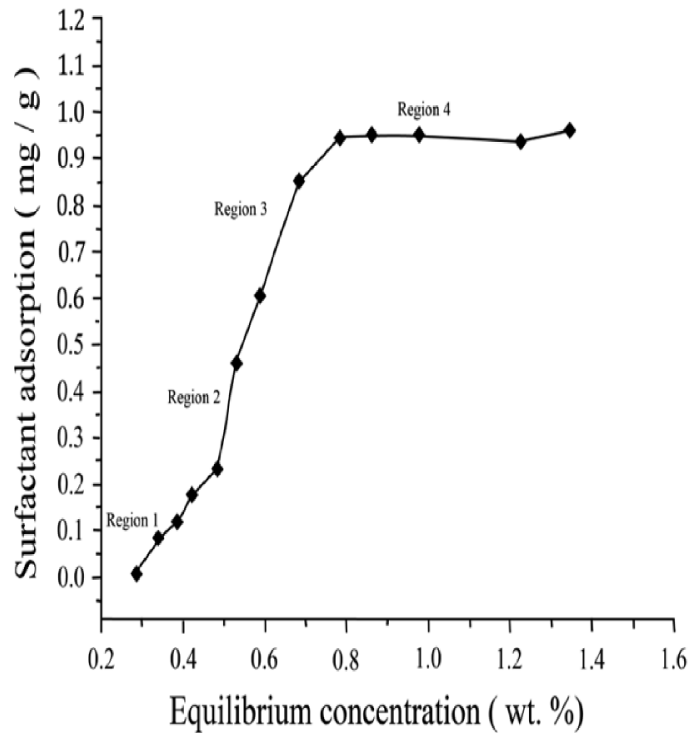


Figure 3.8: Typical surfactant adsorption isotherm on Berea sandstone (Kamal et al., 2017)

Region 1: This region is characterized by low surfactant concentration and the main mechanism for adsorption is electrostatic interactions between the surfactant head group and the net charge present on the solid surface. The adsorption increases linearly.

Region 2: This region is characterized by high concentration of surfactant and the lateral interactions between the adsorbed surfactant molecule helps to increase the adsorption density due to the formation surface aggregates. There is a sharp increase in the surfactant adsorption which is mainly due to lateral interactions and electrostatic attractions.

Region 3: In this region there is neutralization of the solid surface by the adsorbed surfactant ions which reduces electrostatic interactions. Due to this, lateral interaction remains as the only means of adsorption and as a result there is little increase in adsorption.

Region 4 : At this region, the critical micelle concentration (CMC) is reached and further additional of the surfatants contributes only in micellization and adsorption remains constant, this leads to the formation of plateau.

3.2.4.2 Phase Trapping

Surfactant phase trapping occur as a result of mechanical trapping, phase partitioning, and hydrodynamic trapping. The mechanism of its occurrence is complicated though is it is well known and accepted that phase trapping is related to types of microemulsion. Phase trapping occur when chaser

water due to its lower viscosity and high IFT in the rear of microemulsion slug manage to by pass the microemulsion phase. This occur much in Winsor II microemulsion system than in a Winsor I environment where the microemulsion is the water-external phase, which can be displaced miscibly by the chase water (J. Sheng, 2010, 2013).

3.3 Alkaline Flooding (A)

Alkaline flooding involve the injection of alkali agents which reduces surfactant adsorption on the surface of the rock and react with the organic acid (saponifiable components) in the crude oil to produce insitu surfactant that helps to lower the IFT . Alkaline addition helps to improve oil recovery by forming emulsions . Alkaline flooding is also known as caustic flooding. The alkalis used in EOR projects include sodium hydroxide, sodium carbonate, sodium orthosilicate, sodium tripolyphosphate, sodium metaborate, ammonium hydroxide, and ammonium carbonate. Due to the emulsion and scale problems, the use of weaker alkalis such as Sodium carbonate instead of Sodium hydroxide is encouraged. Again, to minimize the corrosion and scale problems, organic alkalis are preferred over inorganic alkalis (sodium hydroxide and sodium carbonate). Practically, its not common to use alkaline flooding alone but it is used in conjunction with other chemical methods like polymer and surfactants (J. Sheng, 2010, 2013).

3.3.1 Alkaline Reactions

In this section, the alkaline reactions with crude oil, rock and water are discussed.

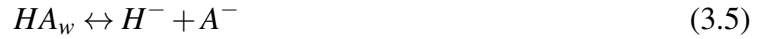
3.3.1.1 Reaction of Alkaline with Crude Oil

Upon flooding of the alkaline in the reservoir, reaction between alkalis and petroleum acid present in the crude oil occur. In presence of alkaline, the pseudoacid component present in oil do partition between the oleic and aqueous phases and undergo subsequent hydrolysis to form a soluble anionic surfactant. The overall hydrolysis and extraction are given by equation (3.3). This reaction occur at the oil/watar interface and depends mainly on the aqueous solution PH (J. Sheng, 2010).



Some of the organic acid present in oil are ionized by alkali while the other portion remain electronically neutral. The hydrogen bonding interation of the ionized and neutral acid lead to the formation of acid soaps. The overall equation 3.2 is decomposed into a distribution of the molecular acid between the oleic and aqueous phases as shown in equation (3.4) and an aqueous hydrolysis, equation (3.5) (J. Sheng, 2010, 2013).





HA stand for a single acid species, A stand for a long organic chain, and the subscripts o and w stand for oleic and aqueous phases, respectively.

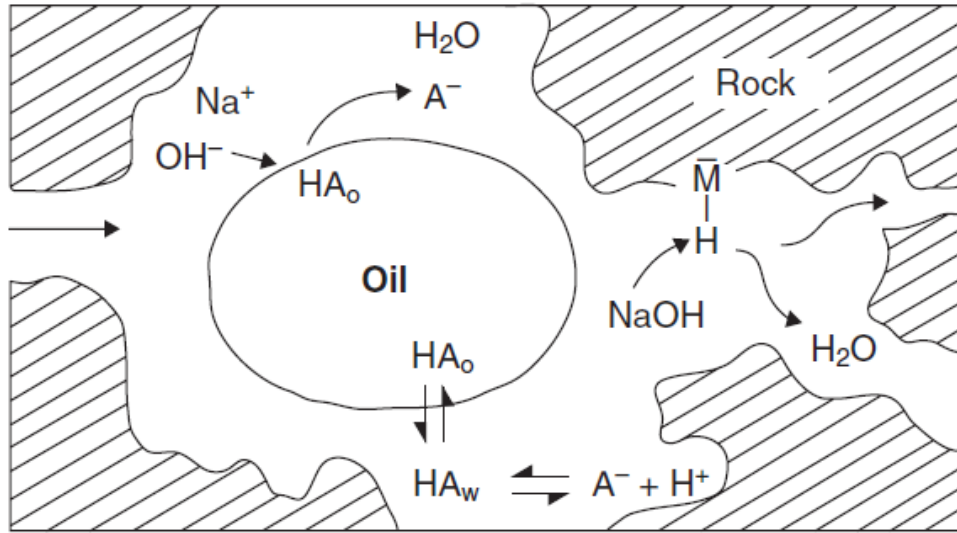
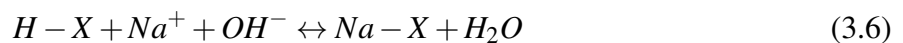


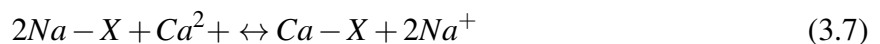
Figure 3.9: Schematic of alkaline recovery process (J. Sheng, 2013)

3.3.1.2 Interaction of Alkaline with the rock surface

The alkali or rock reaction is the difficult thing to quantify due to the fact that the rock contains complex mineralogy and the number of possible reactions with the alkali becomes large. Clay due to its large surface area has great interaction with the alkali. Upon introduction of alkali in the reservoir, the equilibrium that existed between clay and formation water before is disturbed. The system tries to restore it by exchanging ions between the solid surfaces and alkaline solution. The hydrogen ions on the surface react with the hydroxide ions in the flood solution, lowering the PH of the alkaline solution, equation (3.6). Other elements that contribute to the alkali/rock reaction are the Calcium and Magnesium ions present in the clay, see equation 3.7. In short the interaction of alkali with rock is complicated process which can involve both ion exchange and hydrolysis, congruent and incongruent dissolution reactions, and insoluble salt formation by reaction with hardness ions in the pore fluids and exchanged from the rock surfaces (J. Sheng, 2010, 2013).



where X denotes mineral-base exchange sites. Also, for Sodium and Calcium ions the reaction becomes:



3.3.1.3 Alkaline Reaction with water

The reaction alkali with the formation water is very important as it reduces the activity of multivalent cations like Calcium and Magnesium in the oil field. It helps formation of precipitates of calcium and magnesium hydroxide, carbonate, or silicate depending on the pH, ion concentrations and temperature. These precipitates play an important role of directing the injected fluid to the less permeable zones something which improve the recovery. They also help to reduce the IFT as it reduces the brine salinity. Generally, alkali is consumed in several ways in the reservoir as it can be summarized by equation (3.8).

$$C_i - (t) = \Delta C_o - \Delta C_w - \Delta C_e - \Delta C_D \quad (3.8)$$

where C_i and $C(t)$ are the initial and the current concentrations respectively, ΔC_o is the alkali consumption caused by alkali/oil reaction to form soap, ΔC_w is the alkali consumption as alkali react with the multivalent ions in the formation water, ΔC_e is the alkali consumption caused by reaction of alkali solution with the rock, and ΔC_D is the alkali consumption due to dissolution reaction between the alkali and the rock (J. Sheng, 2010, 2013).

3.4 Alkaline-Surfactant-Polymer Flooding

Alkaline-surfactant-polymer flooding is the combination of alkaline flooding, surfactant flooding, and polymer flooding. In an ASP process, alkali, surfactant and polymer are added in the same solution slug. The technology relies on reducing the expensive surfactant concentration by 20-70 folds by adding the much lower-cost alkali as one of the main ingredients of the injected ASP slug. Because of the synergy of these three components, ASP is widely practiced in both pilot and field operations with the objective of achieving optimum chemistry at large injection volumes for minimum cost. Polymer is used for improving mobility ratio which greatly contributes to the expansion of sweep efficiency. The use of the alkali and the surfactant is to reduce interfacial tension between the displacing phase and the oil phase so as to improve the oil displacement efficiency. Alkali could also reduce the adsorption of expensive surfactants. The effectiveness of this method depends on the proper selection of alkali, surfactant, and polymer and they should be combined in a perfect formulation that will yield on good crude oil emulsification / mobilization, low chemical losses and good mobility control. The two most common alkaline agents used for ASP flooding are soda ash (sodium carbonate [Na₂CO₃]) and caustic soda (sodium hydroxide [NaOH]) (J. Sheng, 2010)

3.4.1 Displacement mechanisms

In ASP flooding, the surfactants mixes with alkali, crude oil and formation water to form emulsions. The primary mechanisms are the alkali emulsification and soap generation which occur due to its reaction with the crude oil. Surfactant stabilizes the emulsions through reduced IFT, increases

interface (film) strength, and generates charge at the interface. On the other side, added surfactant makes the low IFT salinity range wider because of the synergism with in situ generated soap. Polymer tends to increase the viscosity of water. As a result, higher external viscosity can reduce the diffusion of droplets, resulting in less probability of coalescence. The increase in number of dispersed droplets increases and stabilizes the emulsion viscosity and stability. Displacement mechanisms in ASP may be summarized as follows (J. Sheng, 2010; Ahmed & Meehan, 2011).

- Increased capillary number effect to reduce residual oil saturation because of low to ultralow IFT.
- Improved macroscopic sweep efficiency because of the viscous polymer drive.
- Emulsification, entrainment, and entrapment of oil droplets because of surfactant and alkaline effects.
- Improved sweep efficiency by emulsions.
- Improved microscopic sweep efficiency and displacement efficiency as a result of polymer viscoelastic property.

3.4.2 ASP flooding procedures

ASP flood proceeds in the four traditional distinct phases (Ahmed & Meehan, 2011). Figure 3.10 gives more description of the ASP flooding process.

1. *Preflush*: Due to the adverse effect of the reservoir brine, the preflush bank water is injected ahead the slug in order to separate hard formation brine from a slug. The preflush water, which is compatible with the ASP solution, flushes the formation brine out of the reservoir.
2. *ASP slug*: ASP slug: The slug size can range from 15% to 30% pore volume. The slug moves through the formation and displaces 100% of the oil contacted in a miscible-type displacement. The areal sweep efficiency is controlled by the mobility ratio. A specific amount of polymer is added to the ASP slug to adjust its mobility to favorable ratio.
3. *Mobility buffer*: The use of water as the displacing fluid results to an unfavorable mobility ratio which reduces areal sweep efficiency as well as water fingering. To avoid this situation, mobility buffer of thickened water is injected immediately behind the slug. The thickened water is solution of water and polymer.
4. *Chase water*: The mobility buffer is displaced by chase water until the economic limit of the project is reached. At high temperature, the chemicals used in ASP are degraded. The chemicals should be handle with care as they have potential to spread to the environment and affect water supply quality.

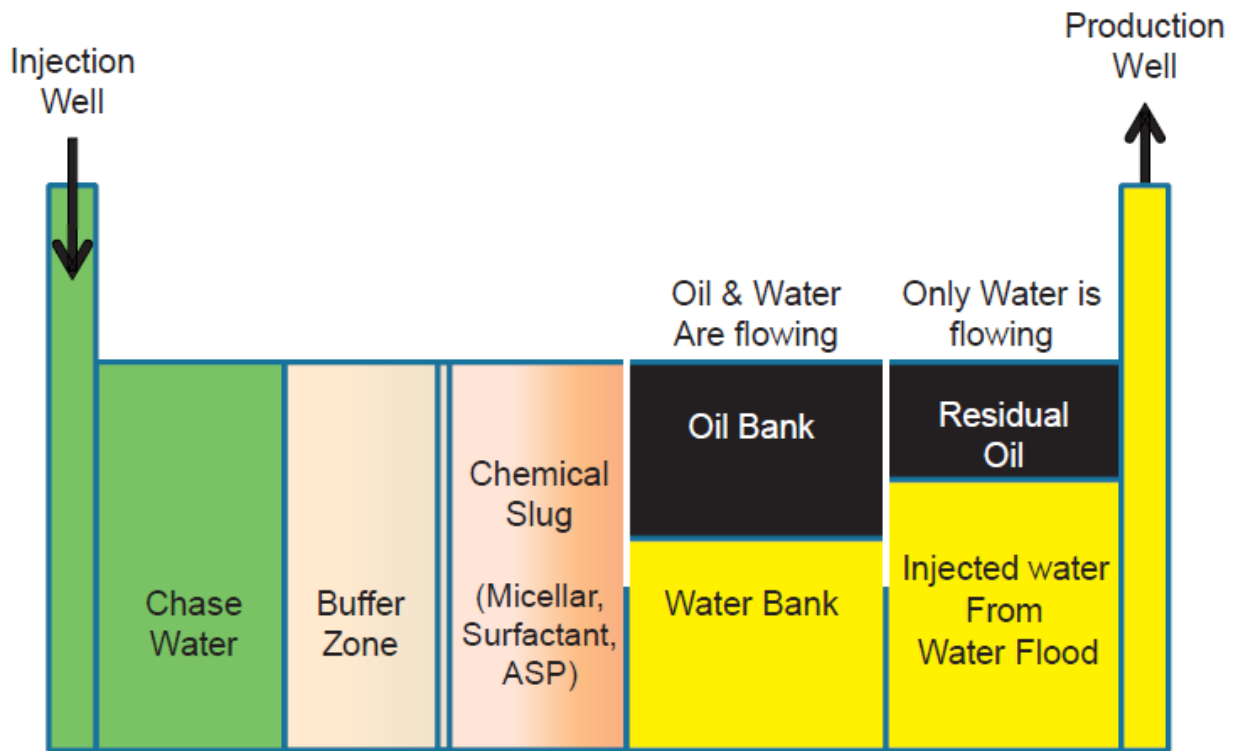


Figure 3.10: Chemical flood as an EOR process (Ahmed & Meehan, 2011)

ASP flooding is subjected to different operational problems including low injectivity, polymer degradation, difficulty to separate produced water from oil, pump failure, bacterial growth, corrosion, problems related to logistic and handling especially for offshore fields (J. J. Sheng, 2014).

Chapter 4

EOR Application in Norne Field

4.1 Reservoir Pressure

The pressure profile for Norne field is shown in figure 4.1. Initially, the reservoir pressure was 277 bars which kept on decreasing due to the production of oil and gas and reached about 238 bars in March 1999. Then after, there was an increase of reservoir pressure caused by the injection of gas and water in the reservoir. Under the support of gas and water injection, the reservoir pressure seems to be enough to support production of more oil from the field.

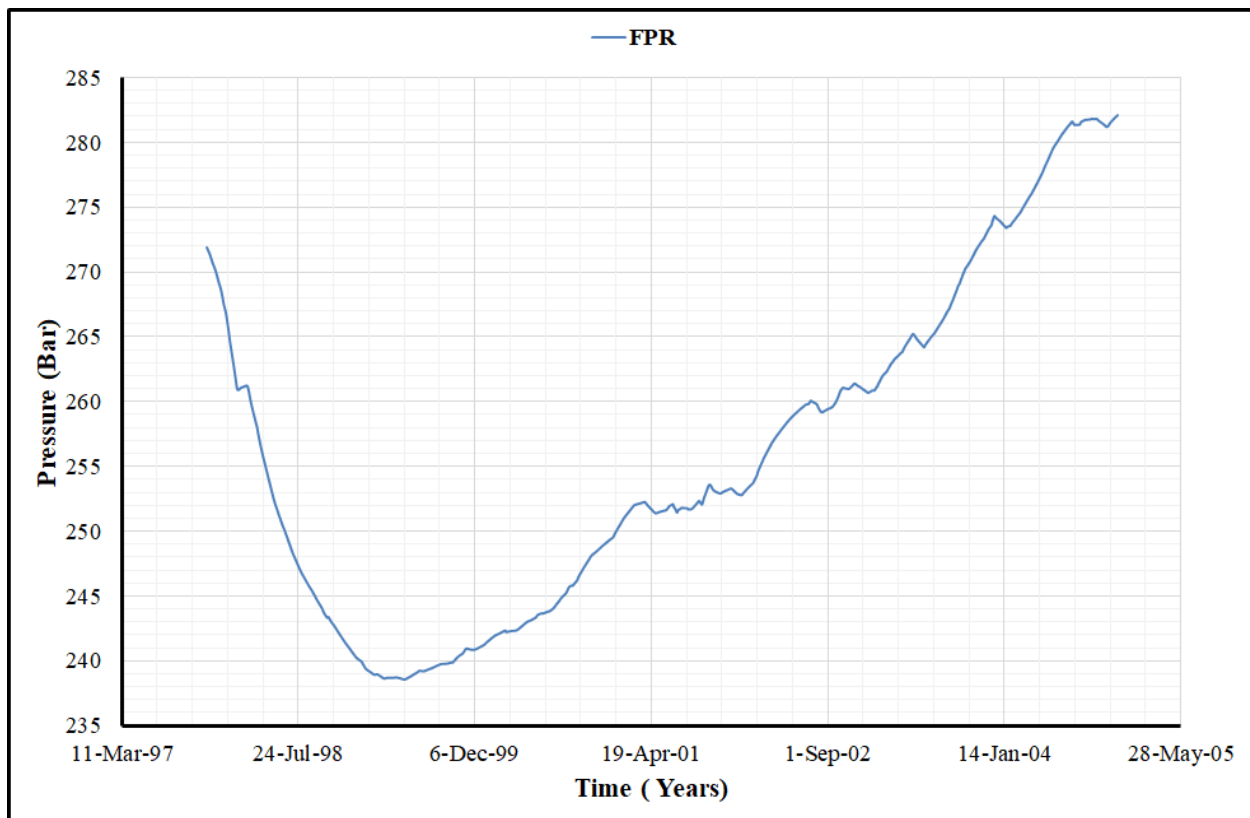


Figure 4.1: Reservoir pressure for Norne field

4.2 Production profile for Norne E-Segment

Figures 4.2, 4.3 and 4.4 show the production rates for oil, gas and water respectively. The water production rate peaked to $3859 \text{ Sm}^3/\text{day}$ in December 2003 while the maximum oil production of $9053 \text{ Sm}^3/\text{day}$ was attained in June, 2001. The graphs show the inverse proportionality between water production rate and oil production rate. The more water is produced the less oil is being produced. This is attributed by poor sweep efficiency which leads to water coning and fingering

effect something which can be rectified by the use of appropriate EOR method. From figure 4.5 the total oil produced from Norne E-Segment by 2004 was $8.79E+06 Sm^3$ while figure 4.6 shows the total produced gas to be $1.50E+09 Sm^3$. Also figure 4.7 shows the total water produced from Norne E -segment to be $2.90E+06 Sm^3$ by 2004.

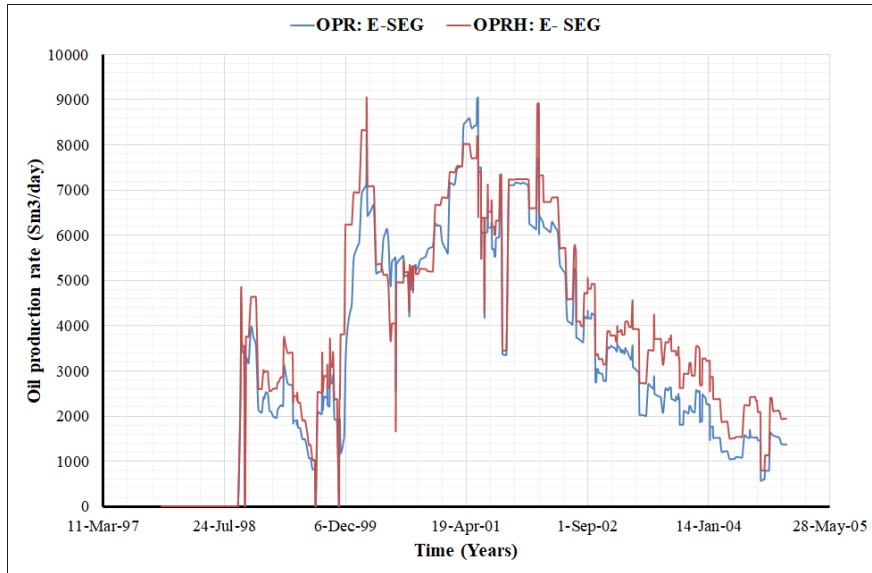


Figure 4.2: Oil production rate, Norne E-Segment

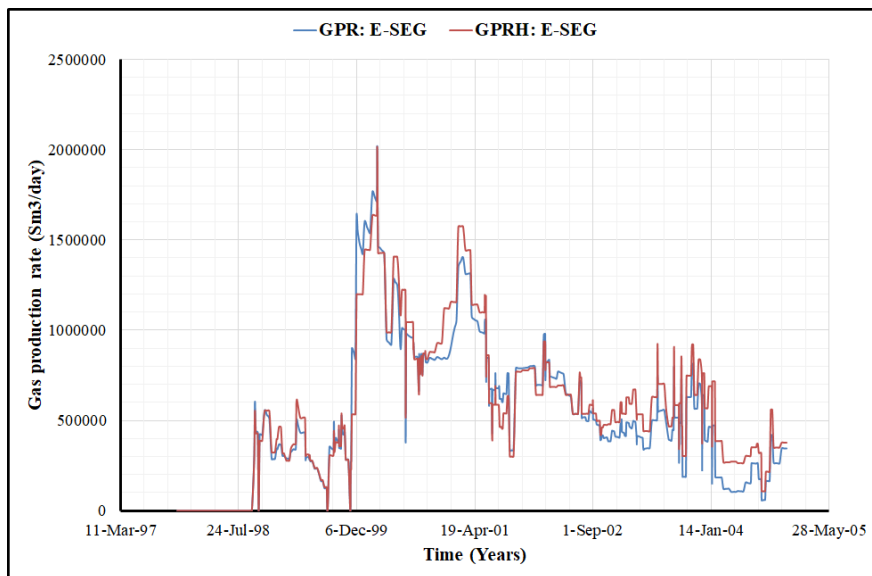


Figure 4.3: Gas production rate, Norne E-Segment

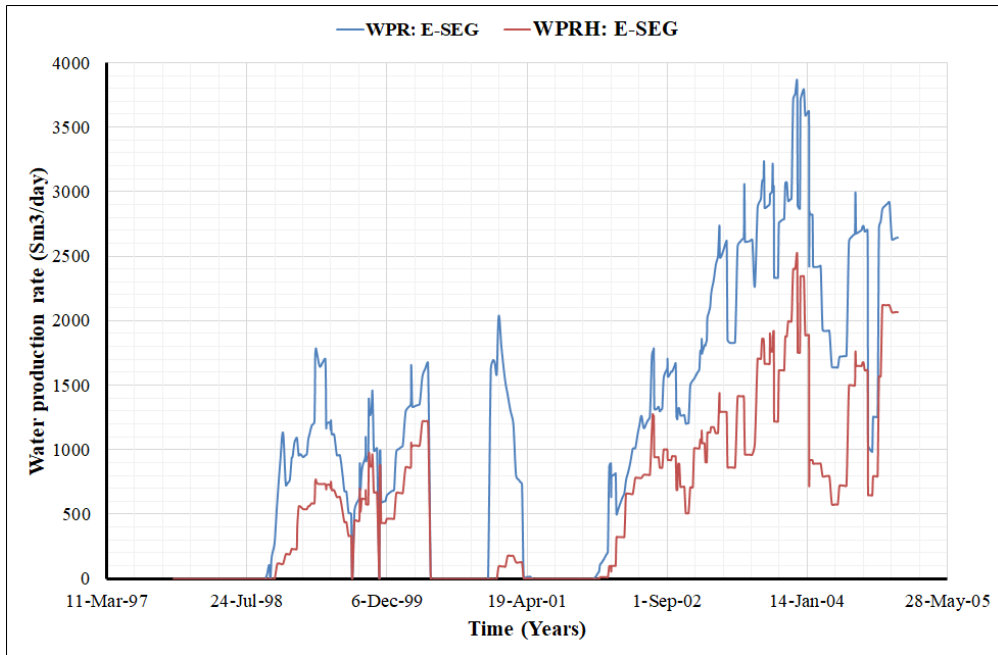


Figure 4.4: Water production rate,Norne E-Segment

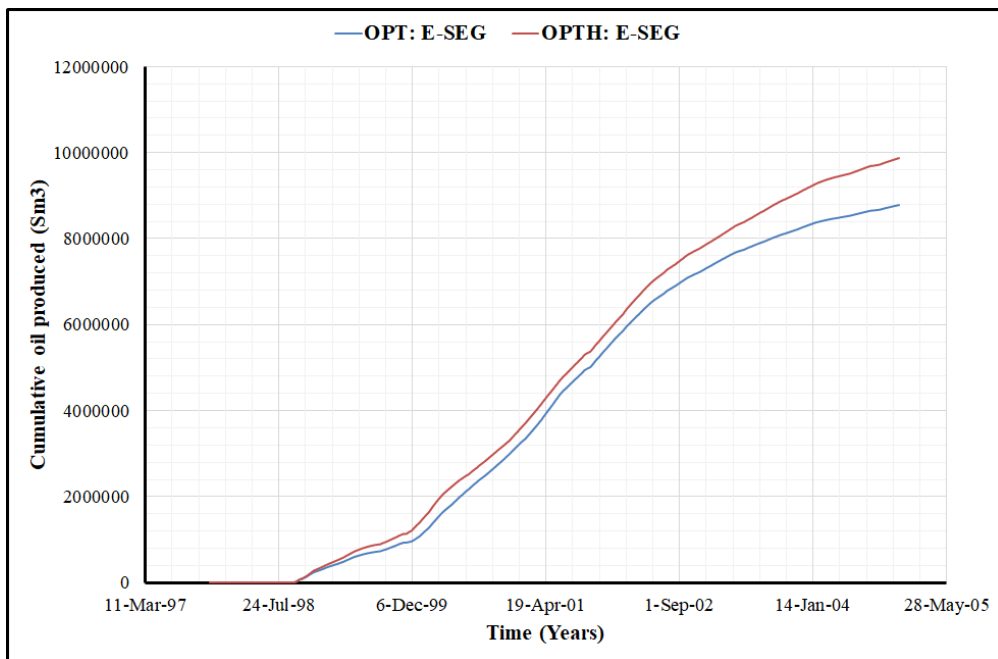


Figure 4.5: Total oil produced from Norne E-Segment

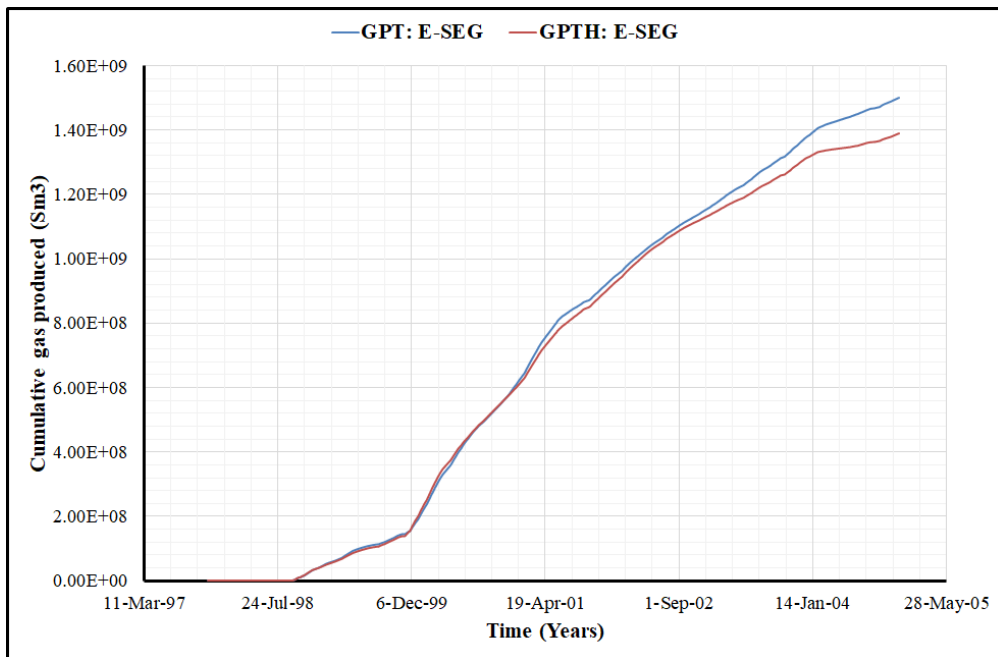


Figure 4.6: Total gas produced from Norne E-Segment

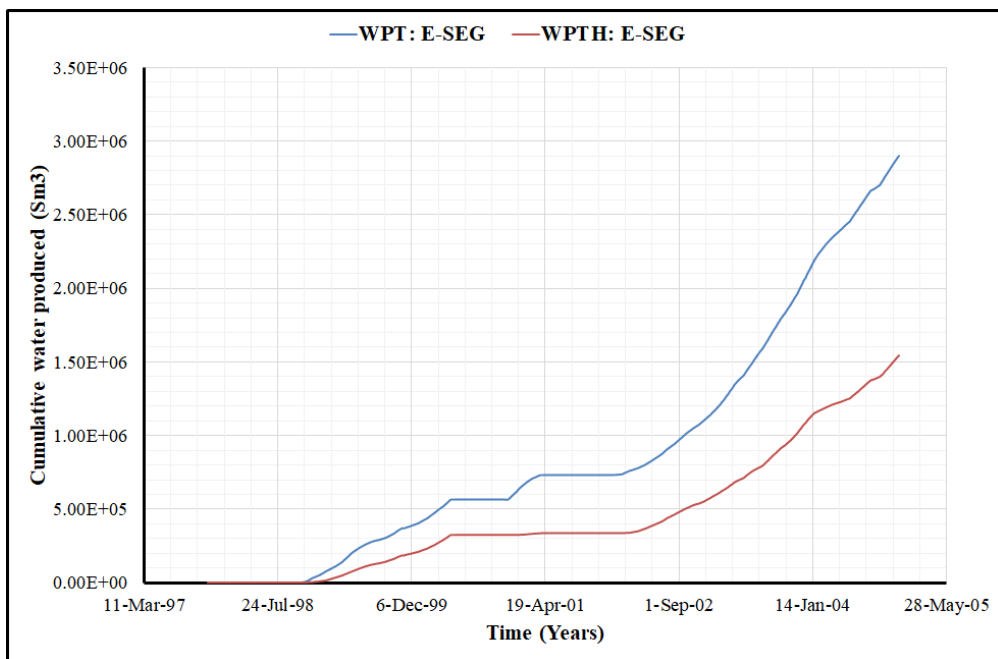
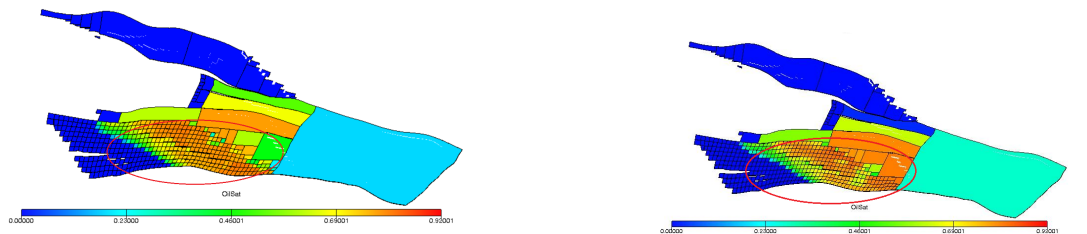


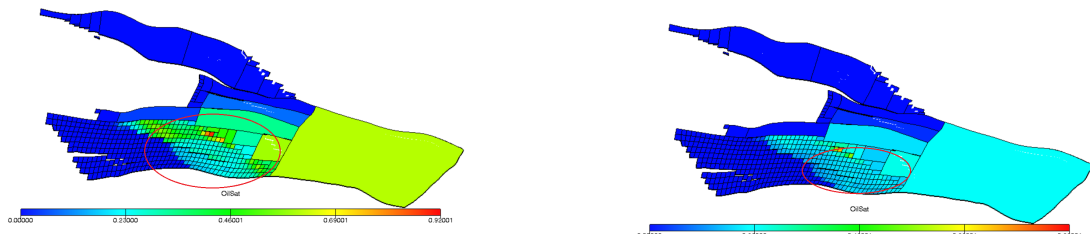
Figure 4.7: Total water produced from Norne E-Segment

4.3 EOR potential at Norne field

Ile and Tofte formations alone contain about 80% of all oil present in the Norne field. Ile formation is located in layer 5 to 11 of the reservoir eclipse model while Tofte formation is in layer 12 to layer 18 of the model. To improve the recovery of the Norne field, these are the two essential formations that one has to deal with. The observation made on the simulation run from 1997 to 2004 shows large amount of oil remaining in these formations. Figure (4.8a) to (4.8d) show oil saturation in layer 5 and 7 in ile formation and layer 13 and 14 in Tofte formation. From the figure it can be observed that, there are still high saturation of oil in Ile formation which seems to decrease when you move in lower layers of the Tofte formation. The presence of oil remaining in the pore attract the application of EOR methods that have potential to mobilize and recover the oil trapped in the pore after the use of water method.



(a) Oil saturation in layer 5 (Ile formation)-November 2004 (b) Oil saturation in layer 7 (Ile formation)-November 2004



(c) Oil saturation in layer 13 (Tofte formation)-November 2004 (d) Oil saturation in layer 14 (Tofte formation)-November 2004

Figure 4.8: Oil saturation in different layers (November 2004)

4.4 EOR Screening Criteria

EOR projects are very expensive projects and highly subjected to many uncertainties which include fluctuation of oil price as well as poor performance of the methods. The successful implementation of the EOR projects depends on the appropriate selection of the EOR method for a given reservoir. Different authors have written on economic and technical criteria to be used in EOR screening for different reservoirs. J. J. Taber et al. (1997) established the most popular EOR screening criteria as summarized in table 4.9. The technical selection of the right EOR method that will suit a particular reservoir is done based on the rock and fluid properties as well as considering the mechanism through which the EOR method works. The main reservoir data that are used in EOR screening include permeability (md), porosity(%), depth (ft), irreducible water saturation (%), oil saturation (%) reservoir pressure (psi), reservoir temperature ($^{\circ}F$), viscosity (cp), formation (type), layer dip (degree), gross pay (ft), Net pay (ft), API (degree), Rock heat capacity($Btu/ft^3 \cdot ^{\circ}F$) and OOIP (bbl). In this work, EORgui software was used to do quick screening of the EOR methods to be used in Norne field. EORgui software gives an opportunity to apply EOR screening criteria of eight EOR methods to any reservoir. The software is based on the EOR screening criteria which were developed by Taber et al, figure (4.9).

Detail Table in Ref. 16	EOR Method	Oil Properties			Reservoir Characteristics					
		Gravity ($^{\circ}API$)	Viscosity (cp)	Composition	Oil Saturation (% PV)	Formation Type	Net Thickness (ft)	Average Permeability (md)	Depth (ft)	Temperature ($^{\circ}F$)
Gas Injection Methods (Miscible)										
1	Nitrogen and flue gas	>35 \nearrow 48	<0.4 \searrow 0.2 \searrow	High percent of C ₁ to C ₇	>40 \nearrow 75 \nearrow	Sandstone or carbonate	Thin unless dipping	NC	>6,000	NC
2	Hydrocarbon	>23 \nearrow 41 \nearrow	<3 \searrow 0.5 \searrow	High percent of C ₂ to C ₇	>30 \nearrow 80 \nearrow	Sandstone or carbonate	Thin unless dipping	NC	>4,000	NC
3	CO ₂	>22 \nearrow 36 \nearrow ^a	<10 \searrow 1.5 \searrow	High percent of C ₅ to C ₁₂	>20 \nearrow 55 \nearrow	Sandstone or carbonate	Wide range	NC	>2,500 ^a	NC
1-3	Immiscible gases	> 12	< 600	NC	>35 \nearrow 70 \nearrow	NC	NC if dipping and/or good vertical permeability	NC	> 1,800	NC
(Enhanced) Waterflooding										
4	Micellar/ Polymer, ASP, and Alkaline Flooding	>20 \nearrow 35 \nearrow	<35 \searrow 13 \searrow	Light, intermediate, some organic acids for alkaline floods	>35 \nearrow 53 \nearrow	Sandstone preferred	NC	> 10 \nearrow 450 \nearrow	> 9,000 \searrow 3,250	>200 \nearrow 80
5	Polymer Flooding	> 15	< 150, > 10	NC	>50 \nearrow 80 \nearrow	Sandstone preferred	NC	> 10 \nearrow 800 \nearrow ^b	< 9,000	>200 \searrow 140
Thermal/Mechanical										
6	Combustion	> 10 \nearrow 16 \rightarrow ?	< 5,000 \downarrow 1,200	Some asphaltic components	>50 \nearrow 72 \nearrow	High-porosity sand/ sandstone	> 10	> 50 $^{\circ}C$	<11,500 \searrow 3,500	> 100 \nearrow 135
7	Steam	> 8 to 13.5 \rightarrow ?	< 200,000 \downarrow 4,700	NC	>40 \nearrow 66 \nearrow	High-porosity sand/ sandstone	> 20	>200 \nearrow 2,540 \nearrow ^d	< 4,500 \searrow 1,500	NC
—	Surface mining	7 to 11	Zero cold flow	NC	>8 wt% sand	Mineable tar sand	> 10 $^{\circ}E$	NC	> 3:1 overburden to sand ratio	NC

Figure 4.9: Screening criteria for successful EOR Method (J. Taber et al., 1997)

In doing EOR screening by using EORgui software, reservoir and fluid parameters as indicated in table 4.1 were used. The Norne field has a depth that ranges from 2500 m to 2700 m, therefore the average depth of 2600m (8530 ft) was used in the software. The reservoir permeability also ranges from 20mD to 2500mD and for this case the approximate permeability of 1000mD was used. Another important parameter was the saturation of oil in the reservoir. From the observation made from simulation model, by November 2004, the oil saturation in layers 5 - 11 (Ile formation) is still higher despite the fact that the reservoir has been in production for about seven years. Figures 4.10a to 4.10d shows variation of oil saturation in different layers with minimum saturation being set to 0.6 and maximum to 0.92. The oil saturation in Tofte formation (layer 12 to 18) seems to be lower as discussed in section 4.3. Since the reservoir does not have a single number for oil saturation, different values were introduced in to the software where different results were obtained, see table 4.2 to 4.4. Other parameters that were used include formation type, API gravity, Oil viscosity and reservoir temperature

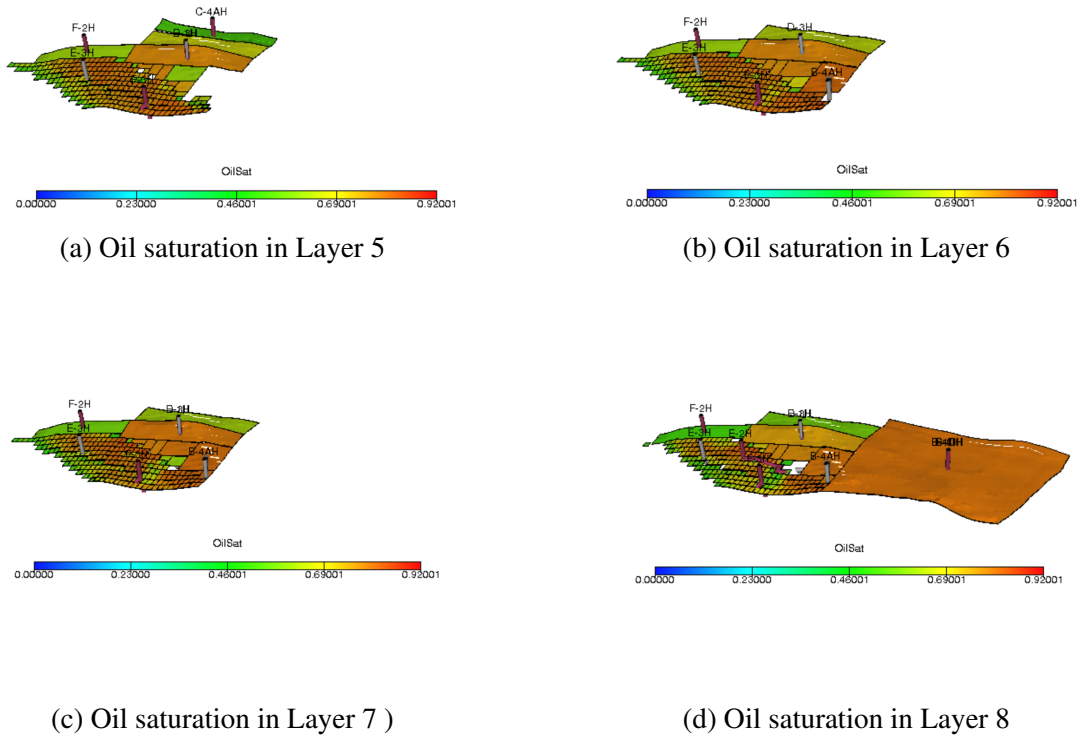


Figure 4.10: Oil saturation in different layers at cut off point of 0.6 (November 2004)

Table 4.1: Rock and fluid properties for Norne E-segment

Rock and fluid Properties	figure	Units
oil gravity	32.7	API
Initial Pressure	273	bar
Oil formation volume factor	1.32	unitless
Reservoir Temperature	98	⁰ C
Rock wettability	mixed	
Pore compressibility	4.84*10-4	1/bar
Initial Reservoir Pressure	273	bar
Gas Oil Ratio	111	Sm3/Sm3
porosity	24 to 28	%
oil viscosity	0.5	Cp
Oil formation volume factor	1.32	Rm3/Rm3
Gas formation volume factor	0.0047	Rm3/Rm3
Reservoir depth	2500 -2700	m
Permeability	20 -2500	mD
Oil saturation	0.6 - 0.9	fraction
Formation type	Sandstone	

Table 4.2 summarizes the results for the quick screening done by using EORgui software. For this case the oil saturation of 0.6 was used. The screening finds SP/ASP Flooding to be the most suitable EOR method for the Norne field. In-situ Combustion is ranked the second potential method with 75% accuracy while CO₂ injection acquires the third number. Other methods like Nitrogen and Hydrogen injection find themselves at the last positions, there fore are less recommended for Norne field.

Table 4.2: Results summary of EOR screening (Oil saturation = 0.6)

Method	Criteria <i>Fit</i> *
Gas Injection Methods	
Nitrogen Injection	40%(8)
Hydrogen Injection	50%(7)
CO ₂ Injection	67%(3)
Immiscible Injection	67%(4)
Chemical Flooding Methods	
Polymer Flooding	60%(5)
SP/ASP Flooding	91%(1)
Thermal Recovery Methods	
Steam Flooding	60%(6)
In-situ Combustion	75%(2)

When oil saturation of 0.7 is used, the results does not change much. Table 4.3 gives the summary of the results from which SP/ASP Flooding and In-situ combustion takes the same position as the case in table 4.2. Now for this case steam flooding is ranked the third method exchanging position with CO_2 injection which occupies the fourth position. Polymer flooding and immiscible flooding have accuracy of 60% and 67% respectively. Nitrogen and Hydrogen injection takes the last position as in the previous case.

Table 4.3: Results summary of EOR screening (Oil saturation = 0.7)

Method	Criteria <i>Fit</i> *
Gas Injection Methods	
Nitrogen Injection	40%(8)
Hydrogen Injection	50%(7)
CO_2 Injection	67%(4)
Immiscible Injection	67%(5)
Chemical Flooding Methods	
Polymer Flooding	60%(6)
SP/ASP Flooding	91%(1)
Thermal Recovery Methods	
Steam Flooding	70%(3)
In-situ Combustion	75%(2)

Table 4.4 gives a summary for a result when oil saturation of 0.8 is used. SP/ASP flooding and In-situ combustion acquires the same positions. Immiscible injection and polymer flooding become the the third and fourth methods in accuracy. Nitrogen and Hydrogen flooding are not strongly recommended for this case as they are ranked the last two methods in priority.

Table 4.4: Results summary of EOR screening (Oil saturation = 0.8)

Method	Criteria <i>Fit</i> *
Gas Injection Methods	
Nitrogen Injection	50%(8)
Hydrogen Injection	50%(7)
CO_2 Injection	67%(6)
Immiscible Injection	83%(3)
Chemical Flooding Methods	
Polymer Flooding	70%(4)
SP/ASP Flooding	91%(1)
Thermal Recovery Methods	
Steam Flooding	70%(5)
In-situ Combustion	83%(2)

For both cases, the most promising EOR methods have found to be SP/ASP flooding, In-situ combustion, Steam flooding, CO_2 flooding as well as polymer flooding. From this finding, further study will be done by doing simulation analysis that will give more light on the appropriate EOR method to be used in Norne field. Figure 4.11 to 4.13 represent graphically the obtained accuracy for the screened EOR methods.

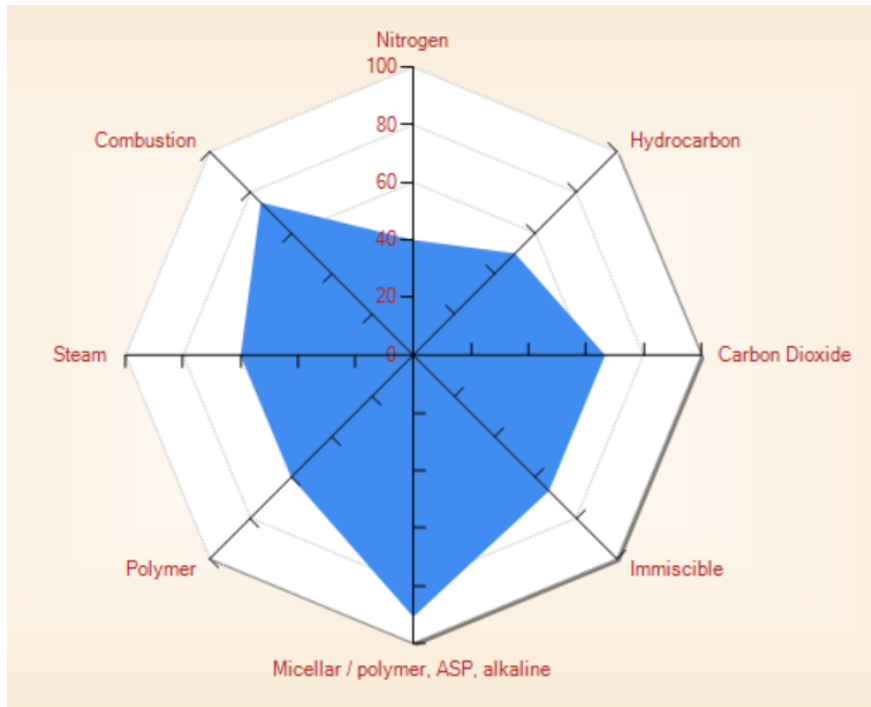


Figure 4.11: Graphical results of screened EOR methods (Oil saturation = 0.6)

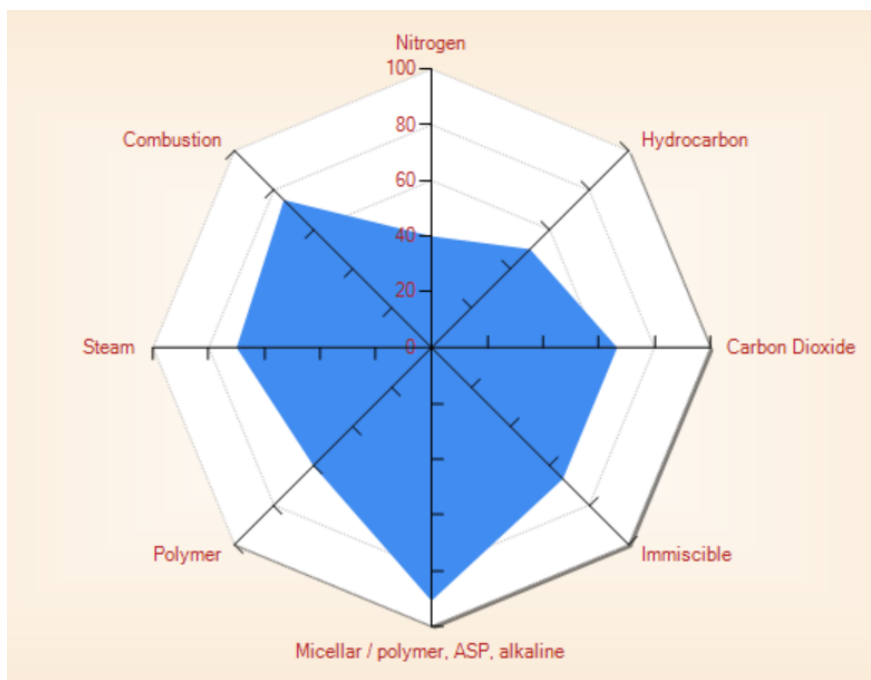


Figure 4.12: Graphical results of screened EOR methods (Oil saturation = 0.7)

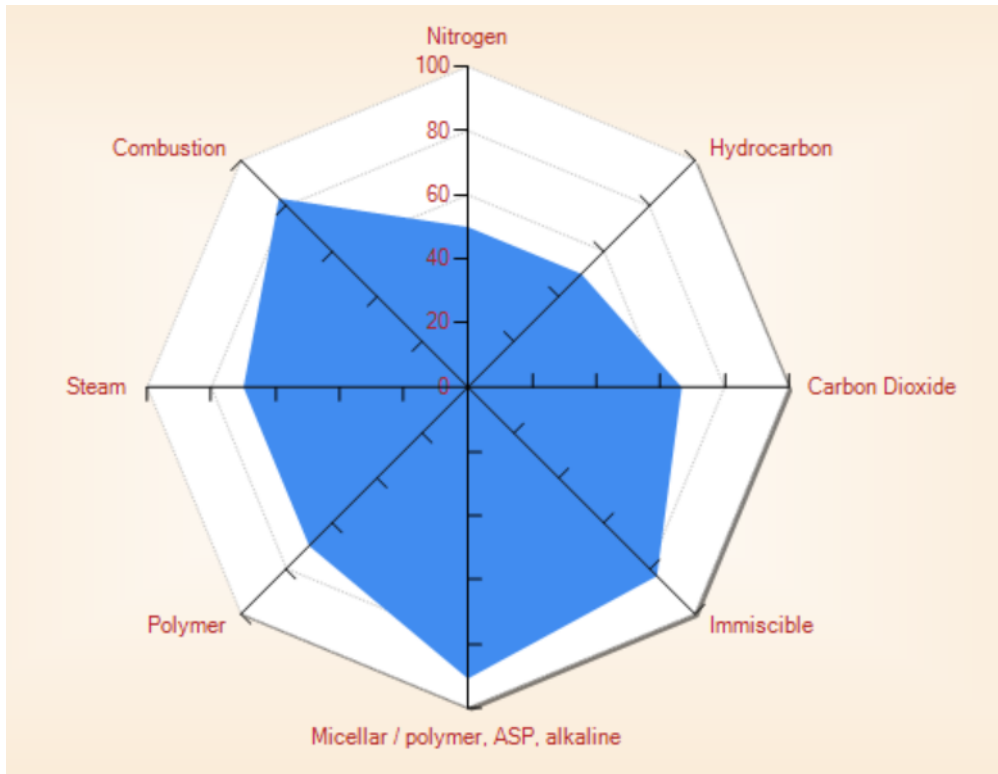


Figure 4.13: Graphical results of screened EOR methods (Oil saturation = 0.8)

Chapter 5

Alkaline, Surfactant and Polymer Simulation

The screening of the EOR methods for Norne E-segment was done in the first part of the study as discussed in section 4.4. By using the EORgui software, the most accurate method for this field was found to be chemical methods, see table 4.2, 4.3, and 4.4. Therefore, the simulation of different chemical EOR methods such as polymer injection, surfactant injection, surfactant polymer (SP) injection, alkaline surfactant (AS) injection as well as Alkaline-Surfactant Polymer (ASP) injection in the Norne E-segment is done by the use of Elcipse 100 software. The aim of the study is to find the practical suitability of the mentioned EOR methods in Norne E-segment compared to water flooding in terms of incremental oil production. The study also put into account the economic evaluation by finding the Net Present Value (NPV) for the proposed methods.

5.1 Surfactant flood model

The eclipse surfactant model in Eclipse 100 does not give a complete chemistry of a surfactant process instead it models the vital features of the surfactant flood on a full field basis. The surfactant distribution is modeled by solving a conservation equation for surfactant within the water phase. The concentrations are updated fully-implicitly at the end of each time step after the oil, water and gas flows have been computed. The surfactant is assumed to exist only in water phase and the amount of injected surfactant into the reservoir is described as the concentration in the water injector. Surfactant model is activated by specifying the key word SURFACT in the RUNSPEC section. There are three obligatory keywords in the PROPS section and two optional keywords which are used in cases where adsorption takes place. Table B.1 in Appendix B summarizes the surfactant keywords and their description (Schlumberger, 2014)

5.2 Polymer flood model

The main reason for polymer flooding is to decrease the mobility of the injected water. This becomes possible as the viscosity of polymer solution is higher than that of pure water, also the passage of polymer solution through the rock tends to reduce the rock permeability to water although that for oil remains unchanged. The polymer model in eclipse 100 is activated by specifying the keyword POLYMER in the RUNSPEC section. Table B.2 in Appendix B gives a summary of other fundamental keywords in the polymer flood model in eclipse 100.

5.3 Alkaline flood model

The alkaline model in Eclipse 100 is a simplified model that takes into account the effect of alkaline on ASP flooding rather than in-situ surfactant creation and the phase behavior. It helps to analyze the effect of the alkaline on the water-oil surface tension and adsorption reduction of both surfactant and polymer. The model is activated by specifying the ALKALINE keyword in the RUNSPEC section. Table B.3 in Appendix B gives a summary of other basic keywords in the alkaline model for ASP.

5.4 Alkaline, Surfactant and Polymer properties

The Norne field has been using water flooding as the drive mechanism and no laboratory study on chemical EOR has been done. This study has used chemical (Alkaline, Surfactant and Polymer) properties which are not actually related to the Norne E-segment. The properties therefore may not be practically compatible with Norne reservoir and fluid properties. For good efficiency, these properties are supposed to come from laboratory study for the specific field. However, it is assumed that the used properties will compile with the Norne reservoir and fluid properties.

The used chemical properties in this study are the one used by Maheshwari his master thesis work (2011) . The summarized properties for alkaline, surfactant and polymer are found in appendix C.1, C.2 and C.3.

5.5 Selection of the Injector

The selection of the right point for the surfactant injection has great effect on the succession of the surfactant flooding. The injection of surfactant in oil zone is expected to have good results over water zone due to their working mechanism that tends to lower the interfacial tension between water and oil as well as reducing the residual oil saturation. In Norne E-segment there are two injection wells, F-1H and F-3H. The injection well F-3H is located in oil zone while F-1H is in the water zone. Two cases were run to choose the best injector where surfactant of $15\text{kg}/\text{m}^3$ concentration was injected in well F-1H and F-3H for continuous period of eight years starting from December 2005 to December 2013. The results showed that the injection well F-3H is more suitable for surfactant injection compared to the injection well F-1H. The injection of surfactant in well F-3H gave an incremental oil production of $1.342 \times 10^5 \text{ m}^3$ while the incremental oil production from well F-1H was only $6.24 \times 10^4 \text{ m}^3$. Figure 5.1 shows the comparison of total oil produced from the two injection wells, F-1H and F-3H. Presence of well F-1H in water zone leads to surfactant loss due to retention and adsorption, also it takes long time for surfactant to get interaction with oil as it needs to travel long distance before getting interaction with oil phase.

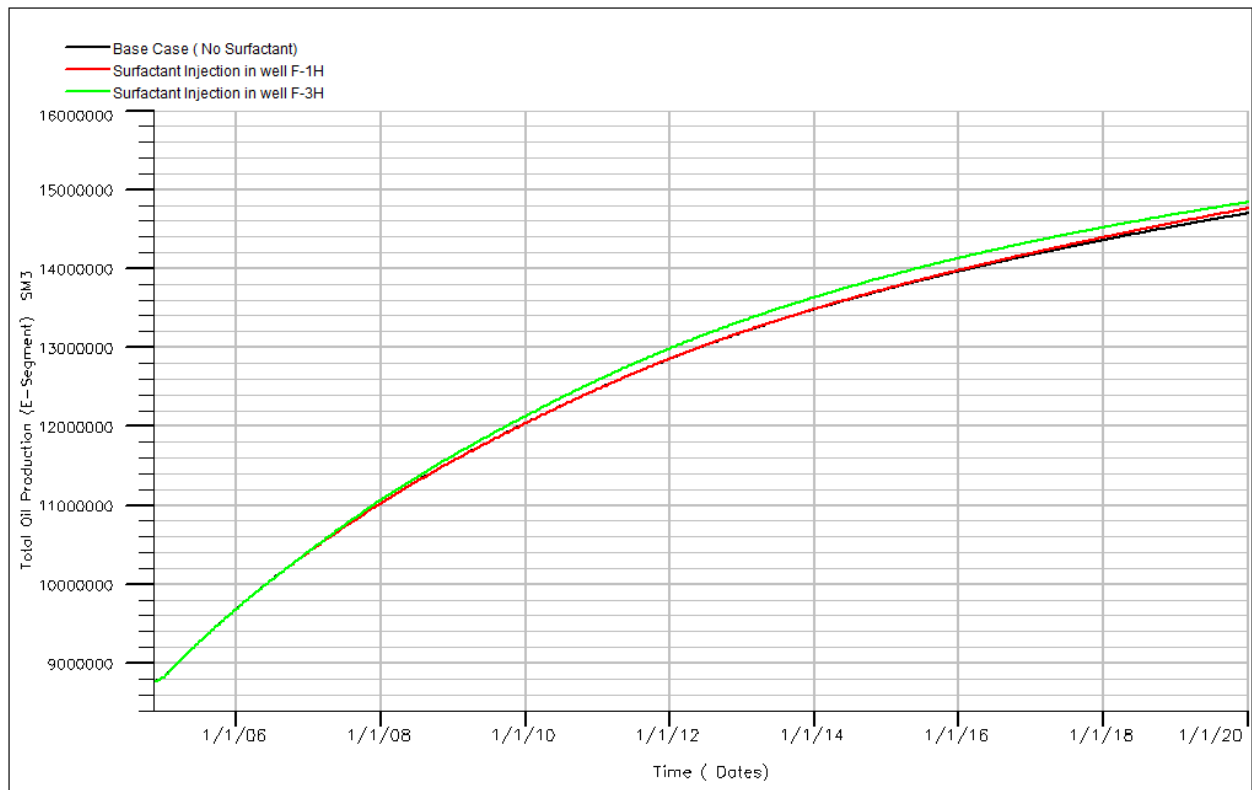


Figure 5.1: Total oil production for different surfactant injection wells

Chapter 6

Simulation Results and Discussion

The target of this study was to find the optimum way of doing chemical flooding (alkaline, surfactant and polymer) to the Norne field E-segment by maximizing the amount of incremental Net Present Value using chemical method. To implement that, five different cases of the chemical flooding were done. These include surfactant flooding, Polymer flooding, Surfactant polymer flooding (SP), Alkaline Surfactant flooding (AS) and Alkaline-surfactant polymer flooding (ASP)

Plan 1: Surfactant flooding

Plan 2: Alkaline Surfactant(AS) flooding

Plan 3: Polymer flooding

1. Polymer concentration [kg/m^3]
2. Polymer flood start time [years]
3. Polymer flood length [years]

Plan 4: Surfactant Polymer (SP) flooding

Plan 5: Alkaline Surfactant Polymer (ASP) flooding

1. Case 1: ASP flooding at concentration of $1 kg/m^3$, $0.2 kg/m^3$ and $2 kg/m^3$ for 5 years.
2. Case 2: ASP flooding at concentration of $1 kg/m^3$, $0.2 kg/m^3$ and $2 kg/m^3$ for 8 years.
3. Case 3: ASP flooding for 5 years followed by 2 years of WI and 2 years of Polymer flooding after.
4. Case 4: ASP flooding for 8 years followed by 2 years of WI and 2 years of Polymer flooding after.

6.1 Plan 1: Surfactant flooding

The injection of chemicals into reservoir is a very sensitive activity due to the expensive chemicals used and their misuses may eradicate their economical feasibility. Knowing the right concentration has a significant importance towards the succession of the process. In this plan, surfactant at different concentrations were run in eclipse 100 in order to get the most appropriate concentration that would have higher incremental oil production and economically be feasible.

6.1.1 Appropriate Surfactant Concentration

A range of surfactant concentrations from 5 kg/m^3 to 30 kg/m^3 were modeled for comparison with the base case (water flooding). The simulation was run for five years starting from 2006 to 2011. As expected, there was a direct relation between the surfactant concentration and incremental oil production. A low surfactant concentration (5 kg/m^3) had an incremental oil production of $34,645 \text{ m}^3$ compared to $129,045 \text{ m}^3$ obtained by surfactant concentration of kg/m^3 . Figure 6.1 shows comparison of total oil production for different surfactant concentrations.

Figure (6.3) shows the effect of surfactant injection on water production rate. The flooding of surfactant reduces the rate of water production and hence increases the production of oil. The extent at which water production is reduced increases with the increase of surfactant concentration in the water injector. From figure (6.3) it can be seen clearly that from the beginning of 2007 to end of 2013 water production rate for the surfactant cases was lower compared to water flooding case and after that time the situation became vice versa. This probably caused by the breakthrough of the lower viscosity water phase which causes water fingering and reduces the production of oil. This effect is always combated by the addition of polymer which increases the viscosity of water and improves the mobility ratio the scenario which is discussed in section (6.4)

The incremental oil production for the all surfactant concentrations was not satisfactory as it required injection of large amount of surfactant to cause small difference. Figure 6.2 shows the comparison in chemical consumption for different surfactant concentration. Appendix D gives a summary of NPV calculations for the different cases of surfactant flooding. Following the fact that very high surfactant concentration was needed to yield small amount of incremental oil production, none of the surfactant cases gave the positive NPV value. Though in all cases there was incremental oil production, the economic feasibility for this scenario depends much on chemical cost and oil price.

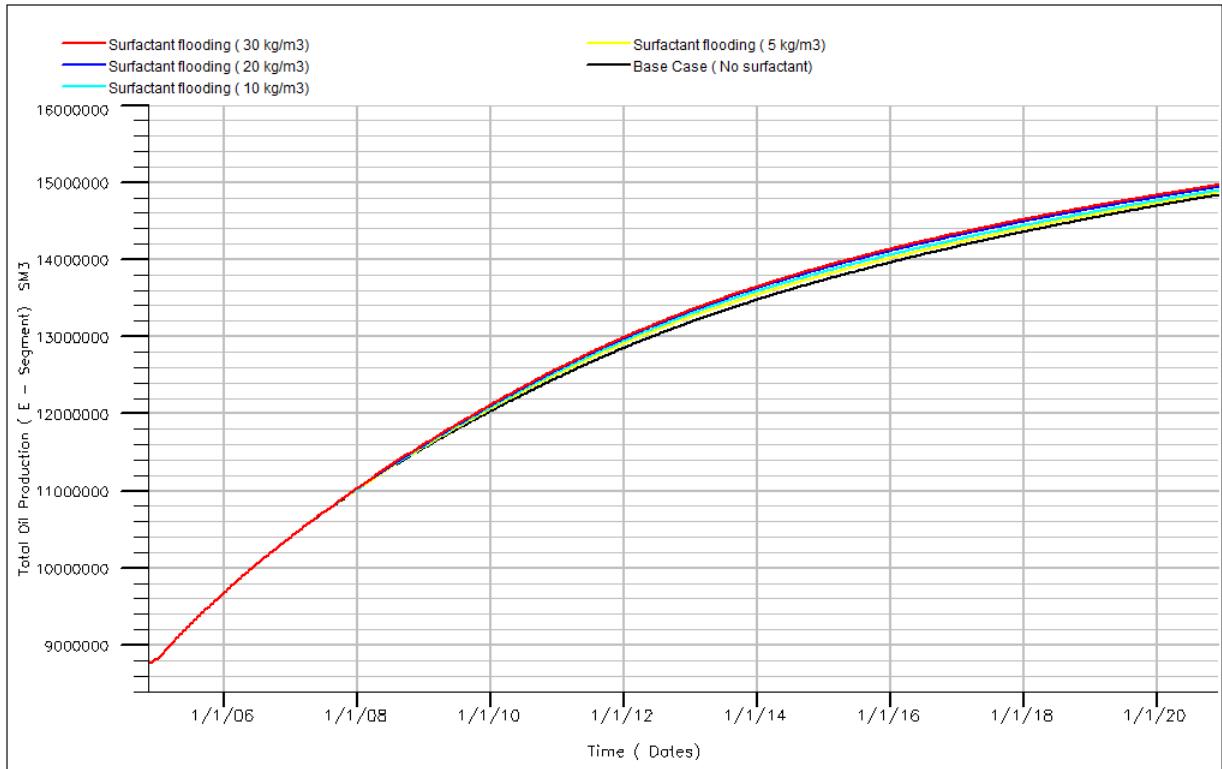


Figure 6.1: Total Oil Production for different surfactant concentration

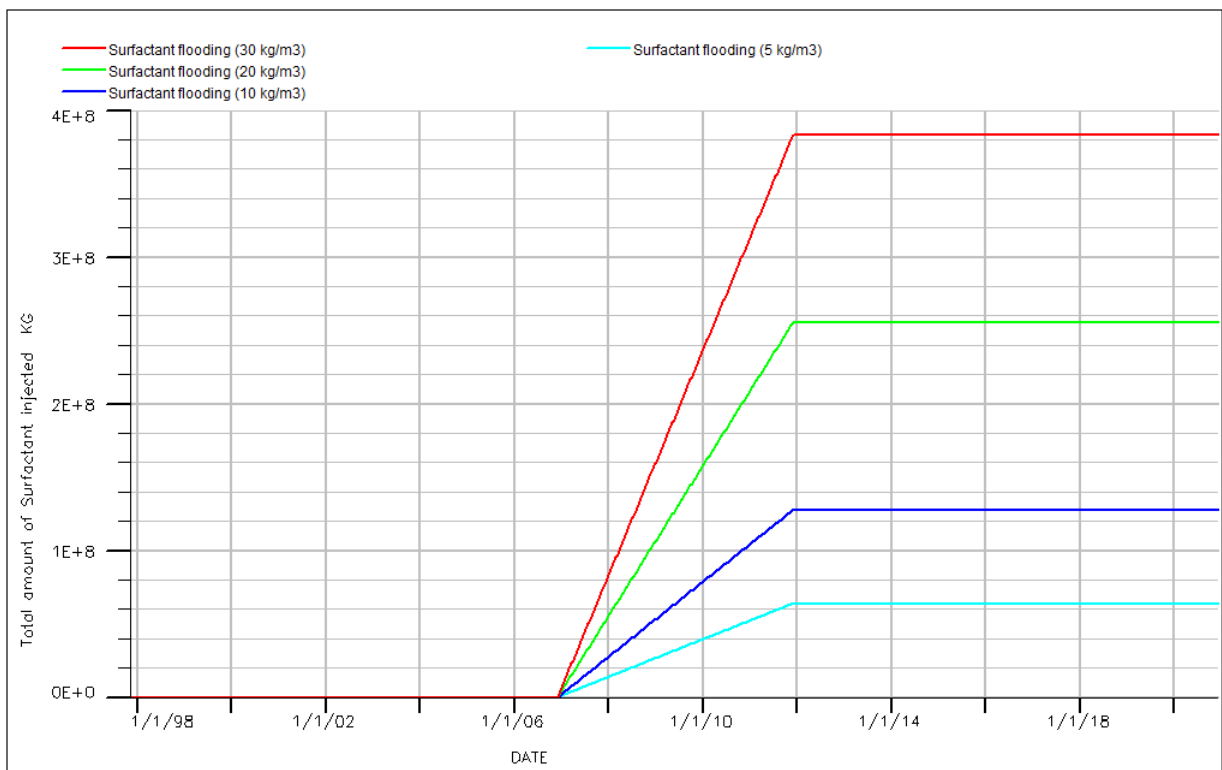


Figure 6.2: Total Surfactant Injection for different concentration

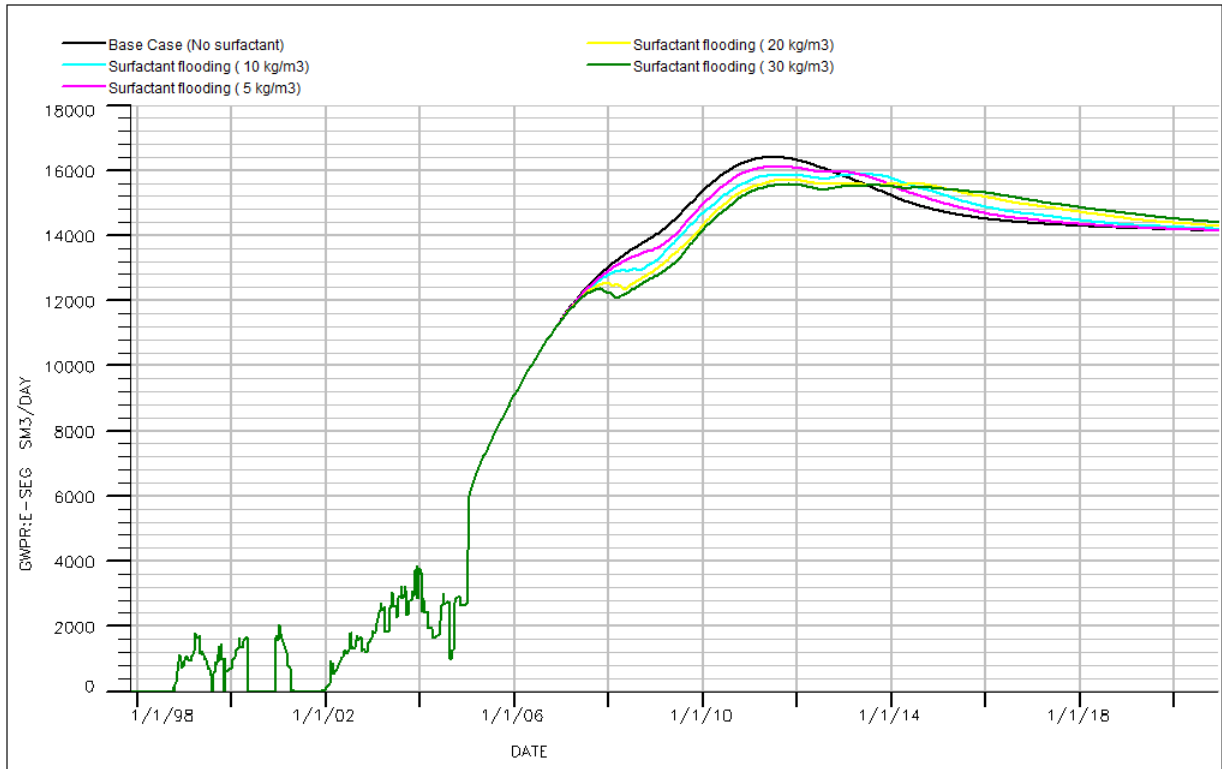


Figure 6.3: Water production rate for different surfactant concentrations to Norne E-segment

6.2 Plan 2: Alkaline Surfactant (AS) flooding flooding

This technique uses the effect of two sources of surfactant such as synthetic surfactant which is injected directly to the reservoir and the insitu generated surfactant as the injected alkaline react with the acidic component of the oil. The process work by reducing the interfacial tension between the oil and water and hence enables the production of the trapped oil.

In this case compared to the previous (6.1) the amount of surfactant was reduced and try to use the alkaline which is less expensive when compared to the surfactant. So , a fixed concentration of 2 kg/m^3 is used for surfactant while varying the alkaline concentrations in all the three cases. The used alkaline concentrations in the three cases are 5 kg/m^3 , 10 kg/m^3 and 15 kg/m^3 respectively.

The simulation model was run for five (5) years starting from December 2006 to December 2011. Figure 6.4 shows the annual incremental oil production for the three cases of AS flooding. From the figure it is clearly shown that there was a sharp increment to 2009 which later on seems to decline and reach negative increment in 2013. In 2014 the increment starts to increase again although it does not reach the positive value. The first increment is due to the effect of synthetic surfactant whose effect is affected by poor mobility ratio and lead to the first decline. The second increase is probably caused by the effect of the insitu generated surfactant as the alkaline react with acidic part of the oil.

Figure shows the total amount of chemicals used in the process where the results shows that huge amount of chemicals was needed to give minor incremental oil production. Appendix (E) gives the results for NPV calculation for AS flooding. None of the three cases of AS flooding gave positive incremental NPV. For this case AS flooding at the mentioned concentrations does not appear to be good candidate for Norne E-segment. May be the addition of polymer would help to improve the mobility ratio as will be discussed in section 6.5

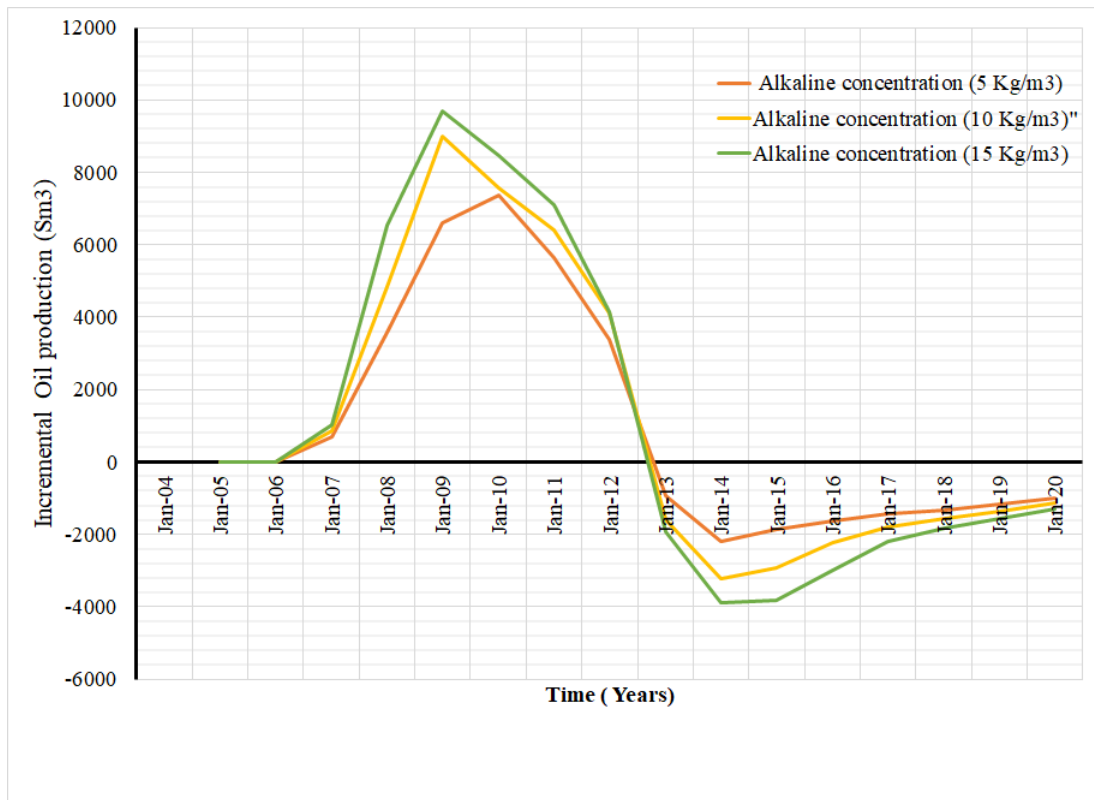


Figure 6.4: Annual incremental oil production for different Alkaline-Surfactant flooding to Norne E-segment

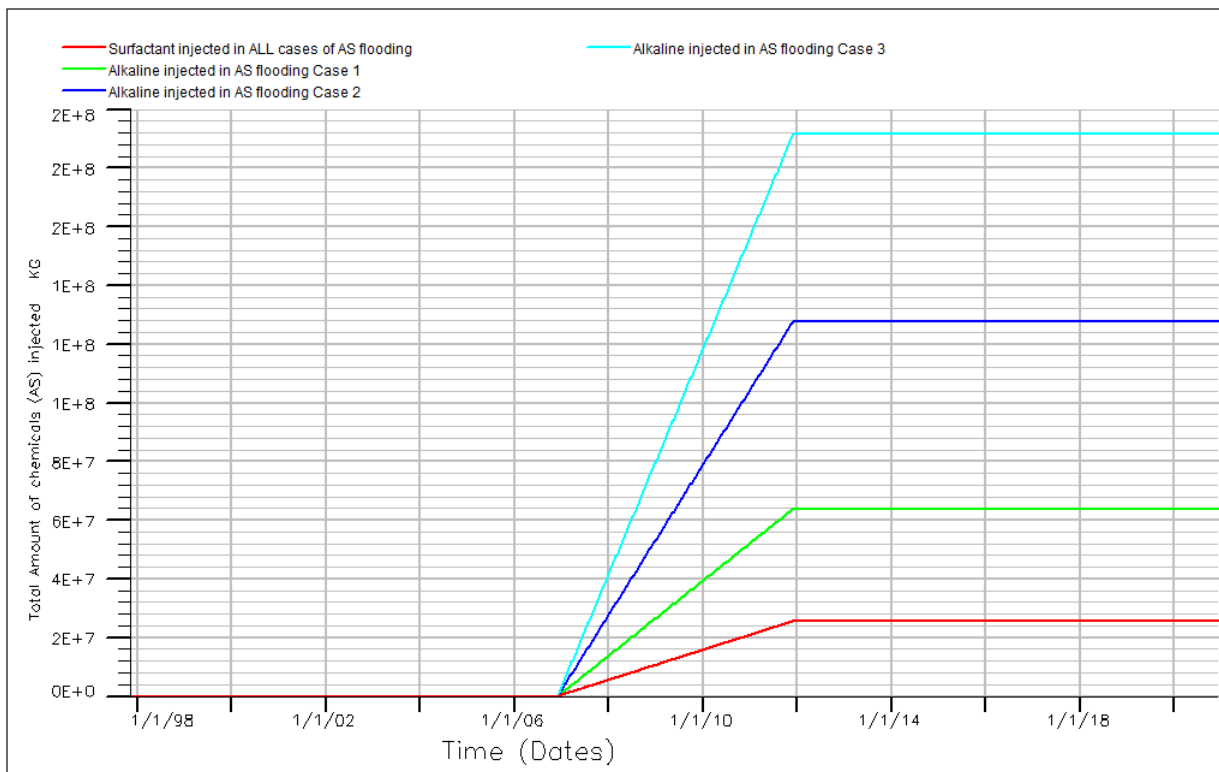


Figure 6.5: Total amount of injected chemical for the different AS flooding cases

6.3 Plan 3: Polymer flooding

Polymer flooding is one of the chemical EOR methods which has shown positive results in increasing oil recovery over conventional water flooding. In this process, a water-soluble polymer is added into the floodwater which tends to decrease water/oil mobility ratio by increasing the viscosity of the displacing water. The addition of water-soluble polymer to the waterflooding makes water to move through more of the reservoir rock, something which improves sweep efficiency and hence increases the recovery of the oil. In this plan, different cases of simulations were run in order to find the effect of polymer concentration, injection time and polymer flood length on the effectiveness of polymer flooding in Norne E-segment.

6.3.1 Effect of Polymer concentration

The use of optimum polymer concentration is very crucial in a design of the effective polymer flooding project. The selected polymer concentration profoundly affects the cost, economics, and performance of a polymer-flooding process. The right polymer concentration depends on many factors including reservoir properties, the nature of the reservoir's conformance problems, and the business objective of the polymer injection. In finding the most reliable polymer concentration for Norne E-segment, different cases were simulated as discussed here under.

1. Polymer flooding at concentration of 0.2 kg/m^3
2. Polymer flooding at concentration of 0.8 kg/m^3
3. Polymer flooding at concentration of 1.5 kg/m^3
4. Polymer flooding at concentration of 2.0 kg/m^3
5. Polymer flooding at concentration of 4.0 kg/m^3

The polymer flooding model was run for continuous period of five years starting from 2006 to 2011. Five cases of different polymer concentrations such as 0.2 kg/m^3 , 0.8 kg/m^3 , 1.5 kg/m^3 , 2.0 kg/m^3 and 4.0 kg/m^3 were modeled in this plan. Figure (6.6) shows oil production rates for Norne E-segment following the injection of polymer at different concentrations. The injection of polymer to the reservoir helped to improve the rate of oil production and the effect seems to increase with the increase in polymer concentration. This improvement in oil production rates results from polymer ability to reduce the effect of viscous fingering which usually affect the production of oil. As a result, Figure (6.7) shows the increase in total Oil production from the field following the injection of polymer which also increases with increase in polymer concentration in the injector well. However, a point is reached when the effect of increasing polymer concentration is no longer that much. That

is the total oil production for the three high polymer concentrations (1.5 kg/m^3 , 2.0 kg/m^3 and 4.0 kg/m^3) did not vary much. This is contributed by the fact that the amount of the polymer adsorbed on the rock increases with the increase in polymer concentration. This loss of polymer concentration on the rock surface reduces the viscosity of polymer and hence its efficiency is negatively affected.

Figure (6.8) display the effect of polymer flooding on water production rate at different stages. The higher the concentration the more water production rate is reduced. In the initial stage of polymer flood, the decrease of water rate is not significant, this stage is followed by response stage at which the decrease in water production rate is clearly seen. This is time when polymer had penetrated deep in the reservoir rock and form oil bank. After that, the water production rate became relatively stable between 2010 and 2013 before the stage of the rapid increase when the aerial sweep reached its maximum and oil production declined.

The injection of polymer also had positive effects on reservoir pressure as shown in figure (6.9) where the reservoir pressure is maintained above the bubble point pressure of 251 bara to avoid gas accumulation which would make the flow process more complicated. The effect of polymer flooding on reservoir pressure depends on polymer concentration too where higher concentration increased the pressure than lower case. The Norne reservoir is located at 2500 meters depth, taking the common and assuming a fracturing pressure gradient of 15.8 kPa/m in addition of 10% safety factor. The maximum pressure of 355 bar is assumed to avoid fracturing. After row the reservoir pressure for all cases lie with the maximum (355 bar) pressure constrain as shown in figure (6.9).

Although higher concentration (4.0 kg/m^3) of polymer solution had higher incremental oil production, its incremental NPV was not the highest compared to other polymer flood cases (0.2 kg/m^3 , 0.8 kg/m^3 , 1.5 kg/m^3 and 2.0 kg/m^3). This was contributed by the fact that the higher concentration of the polymer led to high consumption of expensive chemicals which lowered the profit. A summary of total polymer injected for various concentration is given in figure (6.10). The polymer concentration of 1.5 kg/m^3 had incremental NPV of 68.7 million USD which is higher compared to 19 million USD, 52.6 million USD, 66.6 million USD and 7.1 million USD for 0.2 kg/m^3 , 0.8 kg/m^3 , 2 kg/m^3 and 4.0 kg/m^3 respectively. The NPV calculations for the all cases are summarized in appendix F.1.

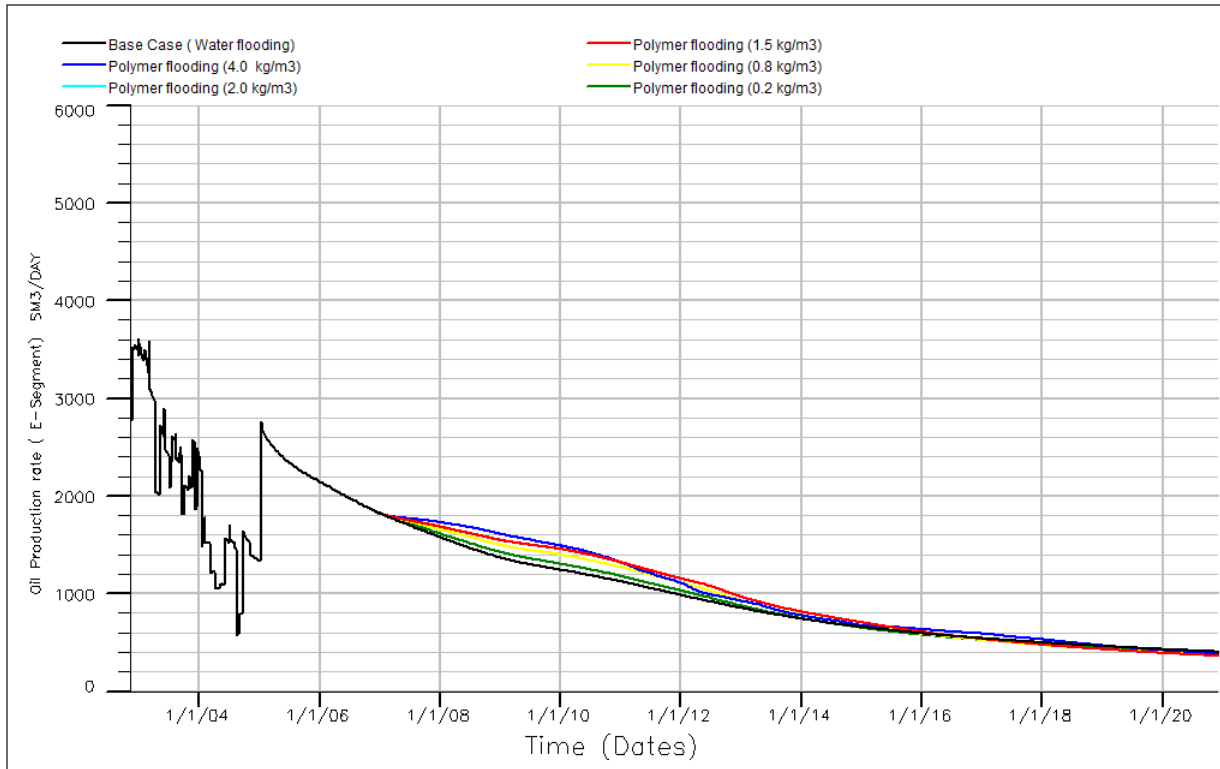


Figure 6.6: Oil production rate for different polymer concentrations

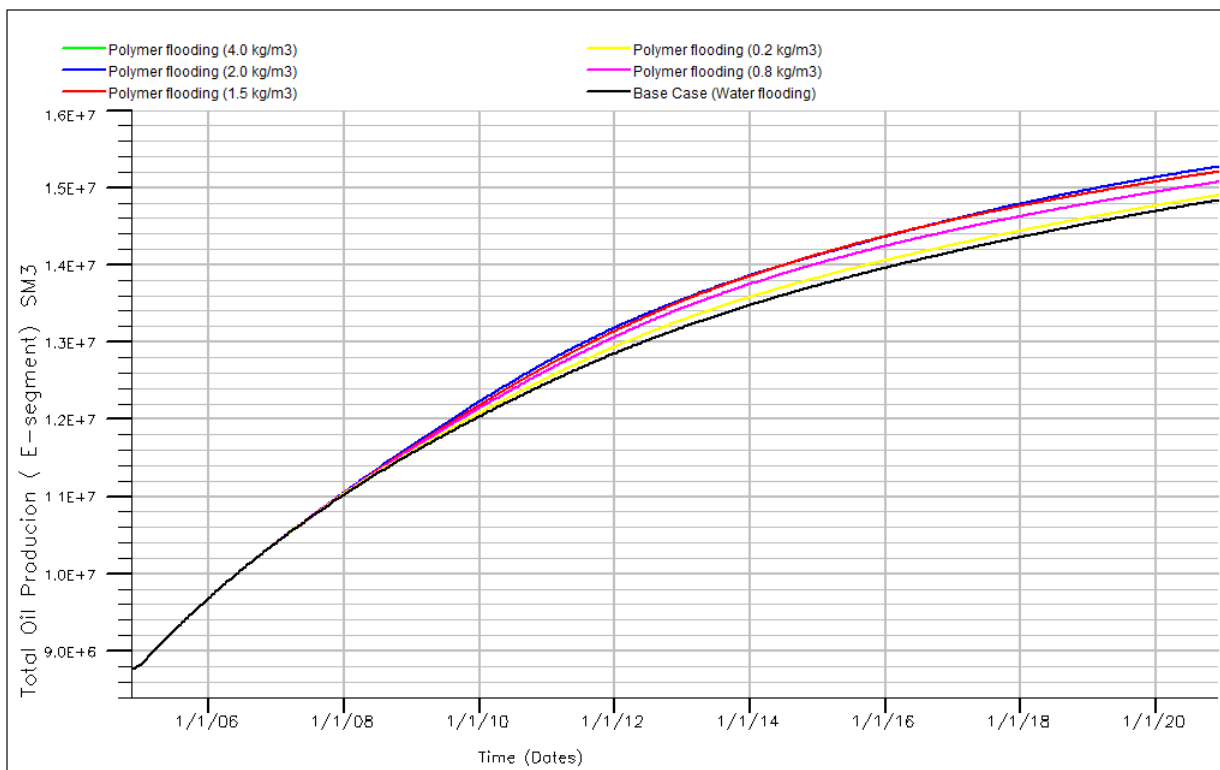


Figure 6.7: Total Oil Production for different polymer concentrations

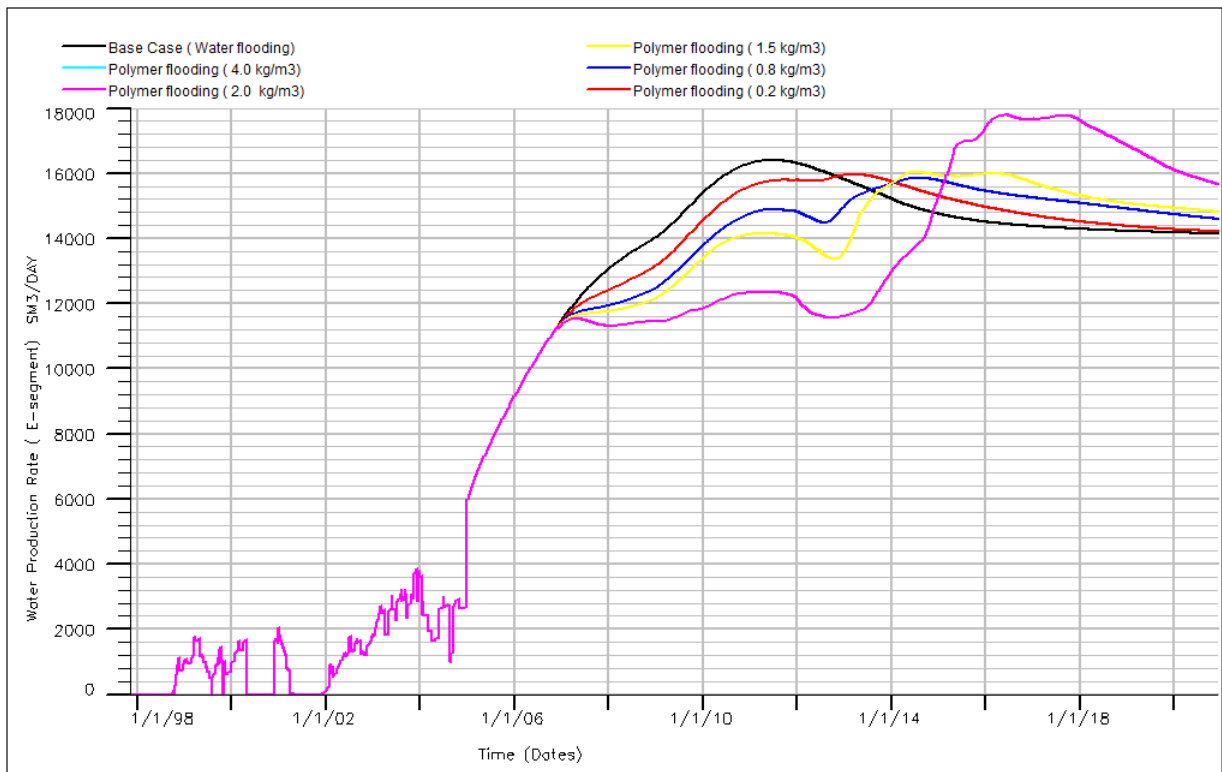


Figure 6.8: Effect of polymer flooding on water production rate

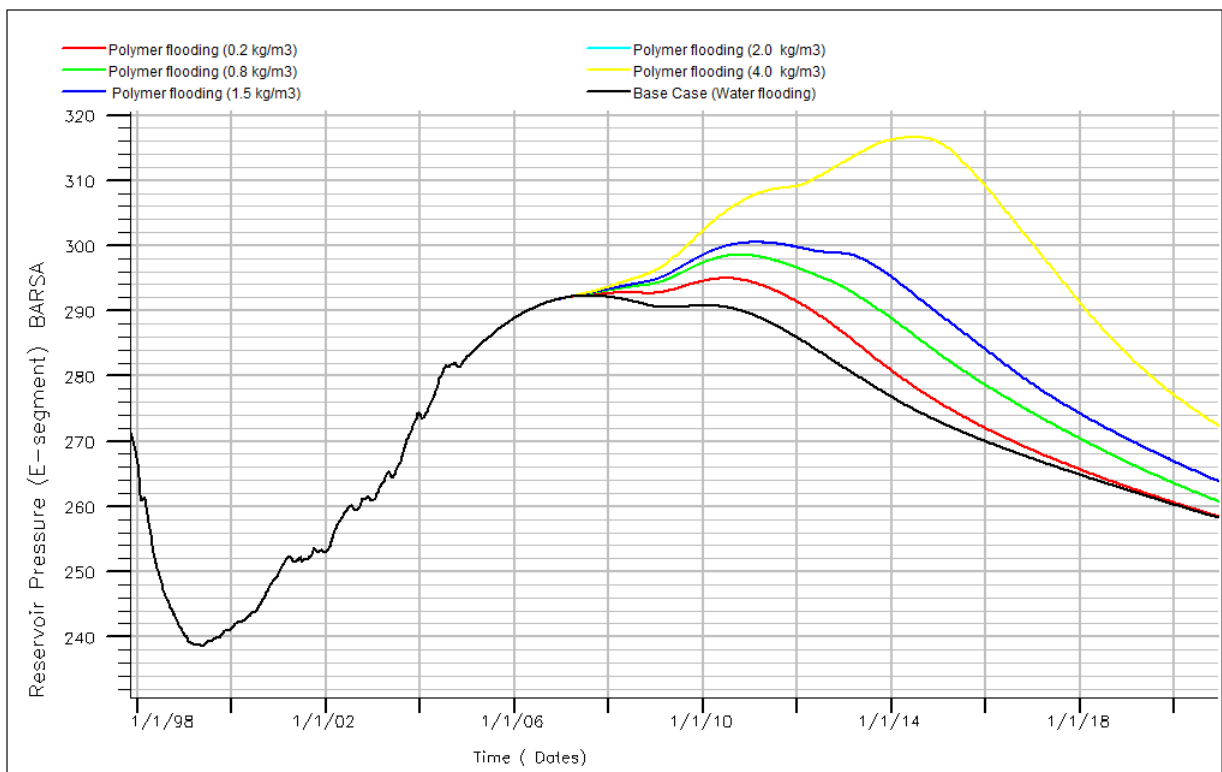


Figure 6.9: Effect of different polymer concentrations on reservoir pressure

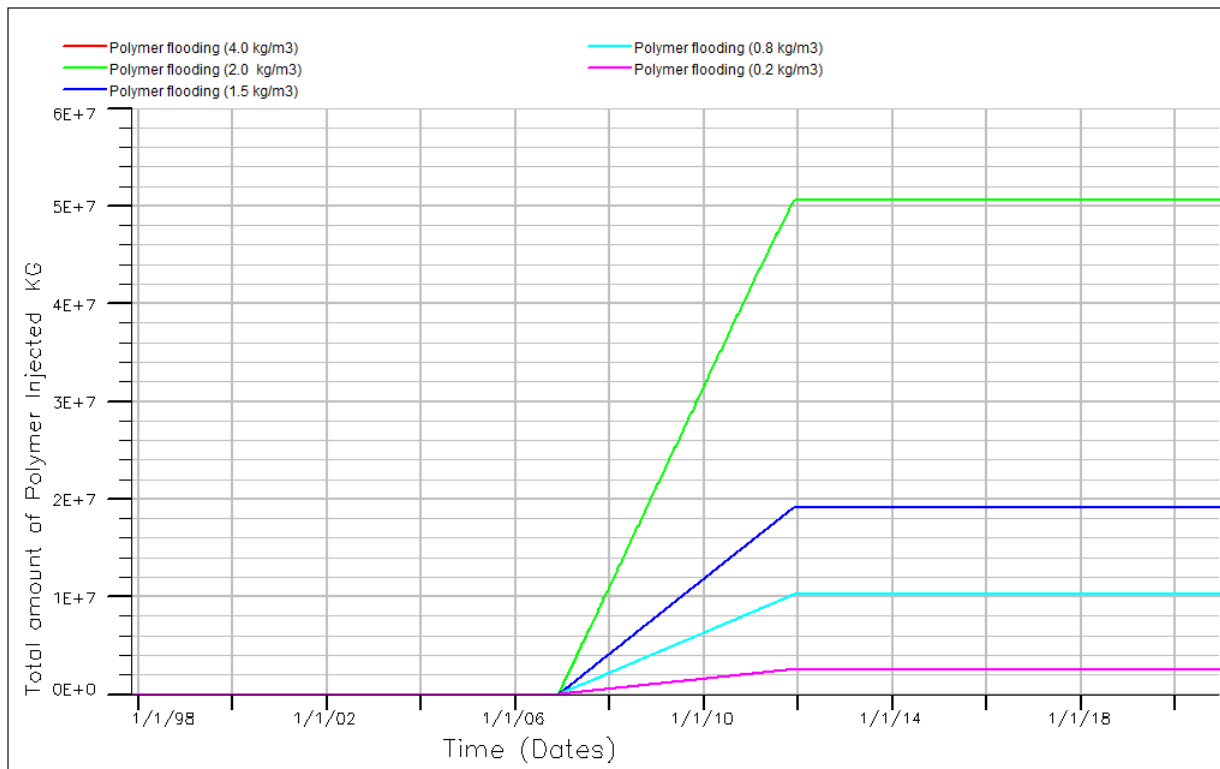


Figure 6.10: Total amount of polymer injected for different polymer concentrations

6.3.2 Effect of Polymer flood start time

Knowing the right time to shift from water flooding to polymer flooding is important for the effectiveness of the EOR process. Given the same oil saturation, the rate of increase in water cut is much higher for water flooding than polymer flooding at low water cuts. As the water cut increases the difference becomes small. Reaching the water cut of 92%, the rate of increase in water cut becomes the same for both polymer flooding and water flooding (J. Sheng, 2010). In this case, simulation for different polymer flood start time were run using the same polymer concentration of 1.5 kg/m^3 . About four start points such as 2006, 2008, 2010 and 2012 were investigated to see which year would be the best point to start the injection of polymer to the Norne E-segment.

Figure 6.11 gives the effect of different polymer flood start time on the total oil production. The figure shows early polymer injection to have better results on total oil produced than the case when the polymer flooding is delayed. The incremental NPV for the polymer flooding starting 2006 is higher compared to the one started in the rest years. The NPV for different starting time (2006, 2008, 2010 and 2012) are 68.7 million USD, 59 million USD, 46.1 million USD and 29.9 million USD respectively, the summarized tables for incremental NPV calculation is given in appendix F.2. The injection of polymer in early time helps significantly to delay the time for water breakthrough as a result of decreased flow rate as well as improved mobility ratio. The injection of polymer after water breakthrough has no significant effect on oil production as the the rate of increase in water cut does not differ with that for water flooding.

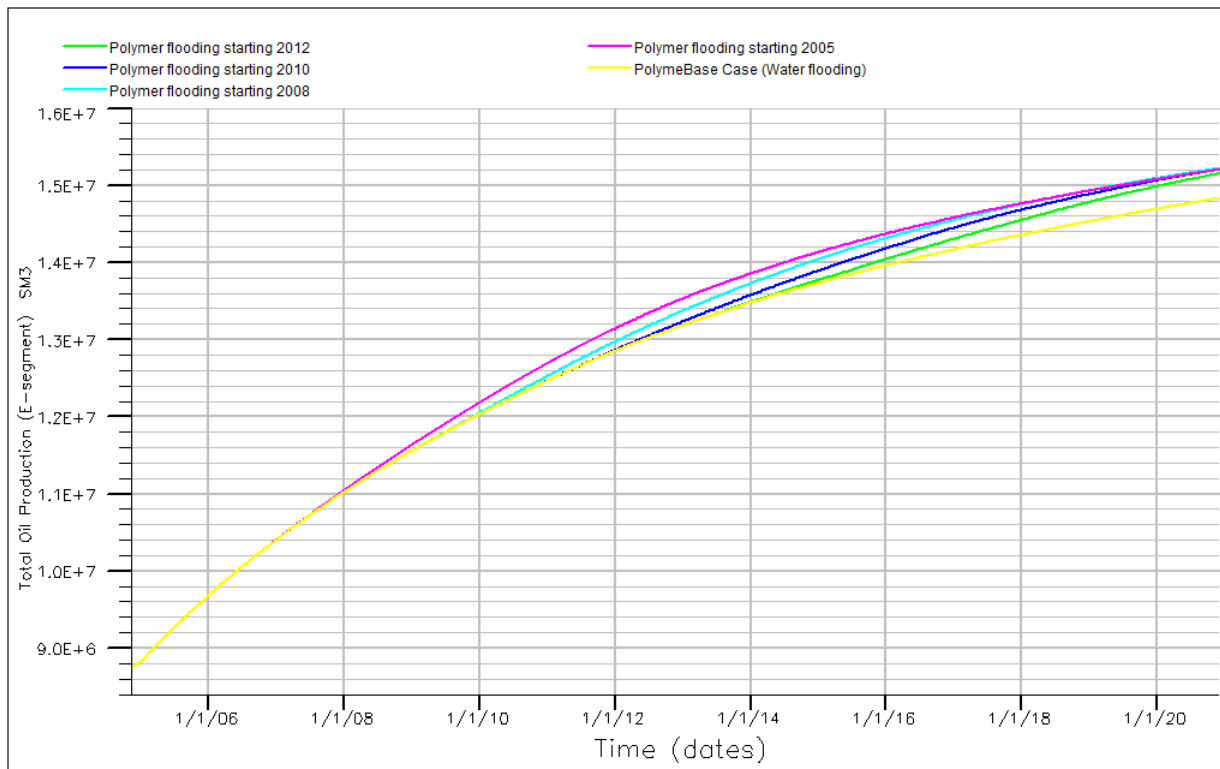


Figure 6.11: Effect of different start time for polymer flooding on total oil production

6.3.3 Effect of Polymer flood length

Two cases were simulated under this scenario where polymer at concentration of 1.5 kg/m^3 was run for different time length, that is 3 years and 5 years long. Figure 6.12 clearly shows the difference in total oil produced between these two cases. Injection of polymer for five years had better higher incremental oil production compared to the case when the simulation was run for three years. The injection of polymer for five years helped to control mobility therefore and delayed the water breakthrough. Having larger figure for incremental oil production does not justify the economic feasibility of any case. To prove whether the five years case was economical NPV calculation was done as summarized in appendix F.3 . From the result it was found that the flooding of polymer for 5 years was much better than three years as five years case had much higher incremental NPV (68.7 million USD) compared to 3 years case (48.7 million USD).

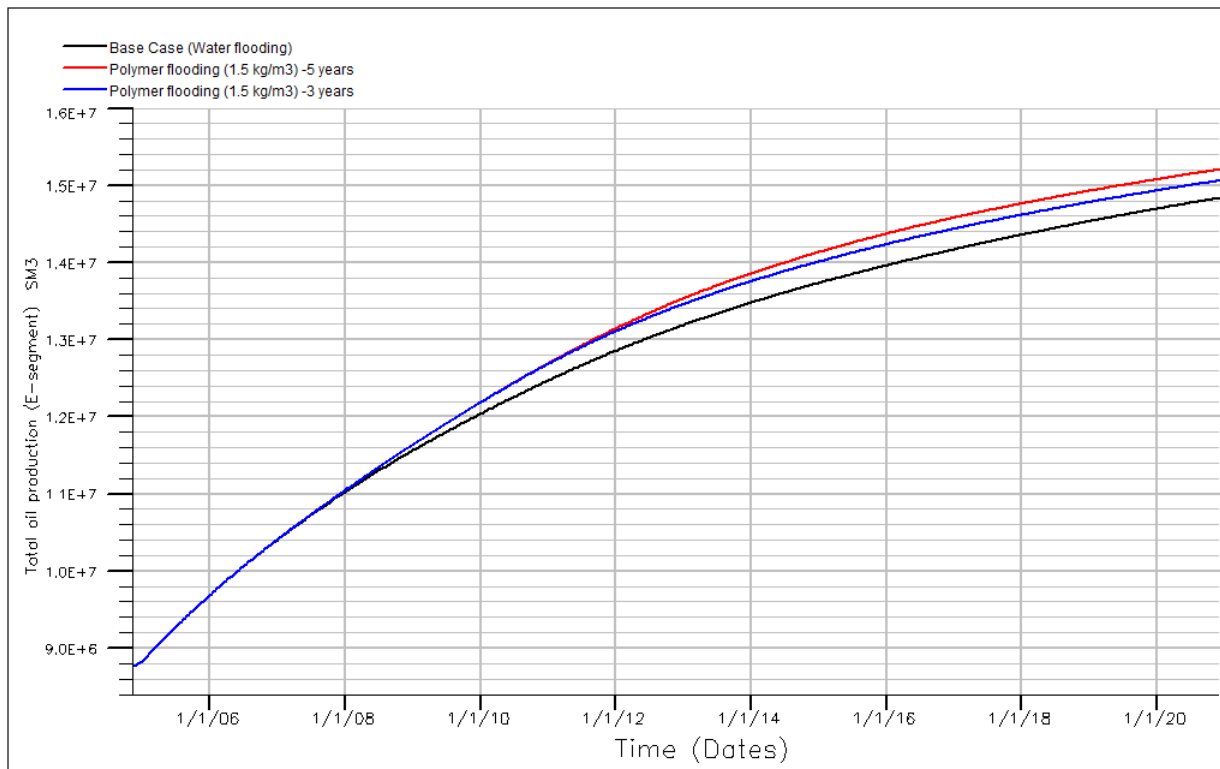


Figure 6.12: Effect of polymer flooding length time on total oil production

6.4 Plan 4: Surfactant Polymer (SP) flooding

In this technique, small concentration of surfactant is used to lower interfacial tension between the injected fluid and the trapped oil while the injection of polymer is done to increase the viscosity of water and hence improve the mobility ratio. When the two chemicals are combined, their interaction becomes mandatory towards the success-fulness of the process. It is not valid to consider the effect of the two chemicals as the independent process. The synergy of both chemicals affects the recovery factor. The transport of the each of these chemicals has a great influence on better working of the process.

In this plan, Surfactant-polymer solution was injected for continuous period of five years starting from December 2006 to December 2011. There were three cases where fixed surfactant concentration of 0.3 kg/m^3 was used and only polymer concentration was varied. The polymer concentration in these three cases were 1.5 kg/m^3 , 2.0 kg/m^3 and 2.5 kg/m^3 respectively.

Figure (6.13) shows the annual incremental oil production for the above three cases. The effect of SP flooding is observed soon after the injection, the peak production for all the three cases was reached in 2009 and remained nearly stable to 2010 then after started to drop gradually. The second increase of production was observed in 2014 and this again was for all the three cases. This was due to the break through of the the oil bank. After 2017, the oil production with SP flooding went

below the base case (water flooding) and now the incremental production became negative. This may have many reason behind and one of them may be the reservoir model that was used as the injection of SP would have increased the production of oil in other segments and not E-Segment alone. This becomes an issue as the segment was not totally separated from the rest of the segment. Thus the increase we see may not be the actual increase.

The effect of Polymer in SP on water production is shown in figure (6.14) where for the early period of Surfactant- Polymer injection, water production rate for the base case is higher compared to the SP case (2007 to 2014). Later, after the breakthrough of the front water production rate for the SP case shoot up and becomes higher than the base case. The reduction of water rate for the early period of SP injection is due to the ability of polymer to increase the viscosity of the chasing fluid and hence improve the mobility ratio. The reduction of water production rate increases with the in polymer concentration.

The SP flooding at polymer concentration of $2.5\text{kg}/\text{m}^3$ had higher incremental oil production ($450,497\text{ Sm}^3$) compared to polymer concentration of $1.5\text{ kg}/\text{m}^3$ and $2.0\text{kg}/\text{m}^3$ which had $368,616\text{ Sm}^3$ and $420,794\text{ Sm}^3$ respectively. Despite the fact that high concentration of polymer in SP solution yield to higher incremental oil production and lower water production rate, the SP flooding at polymer concentration of $1.5\text{ kg}/\text{m}^3$ SP had higher incremental NPV compared to the rest cases of SP flooding. This became possible as high concentration of polymer made the cost for chemicals to be higher. The surfactant concentration was kept constant for all the three cases. Appendix G gives the summary of the incremental oil production and incremental NPV calculation for the discussed cases of SP flooding.

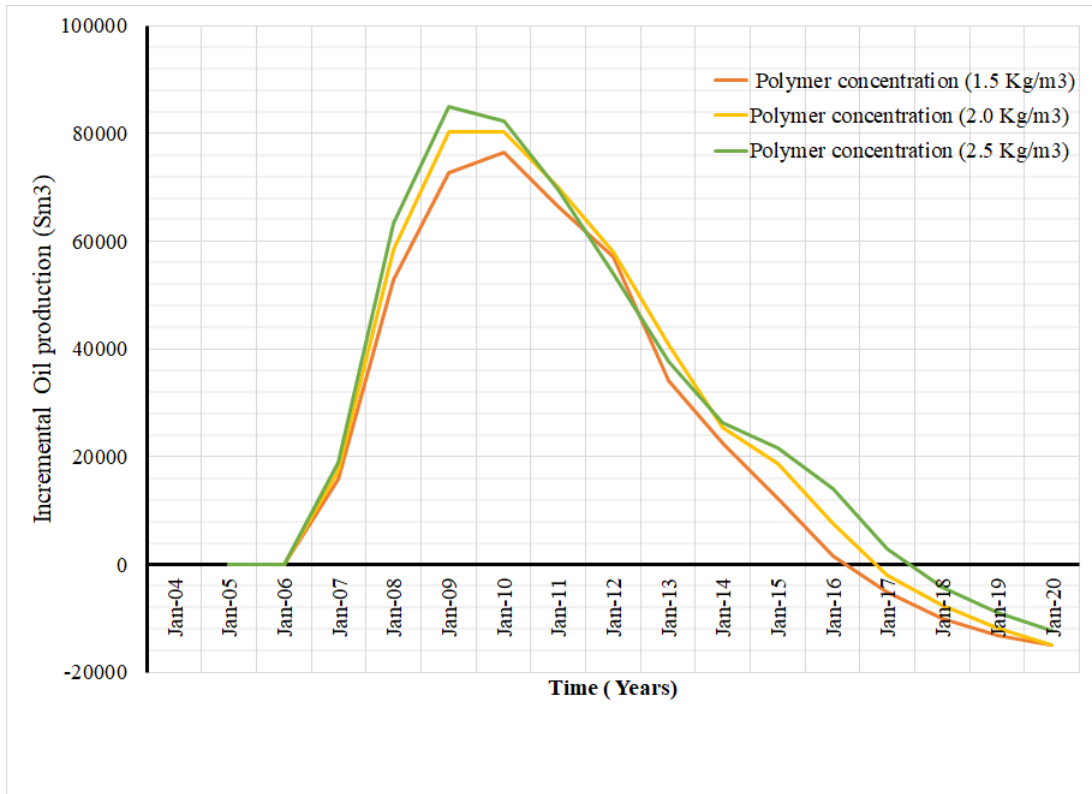


Figure 6.13: Annual Incremental Oil Production for different Surfactant-Polymer flooding

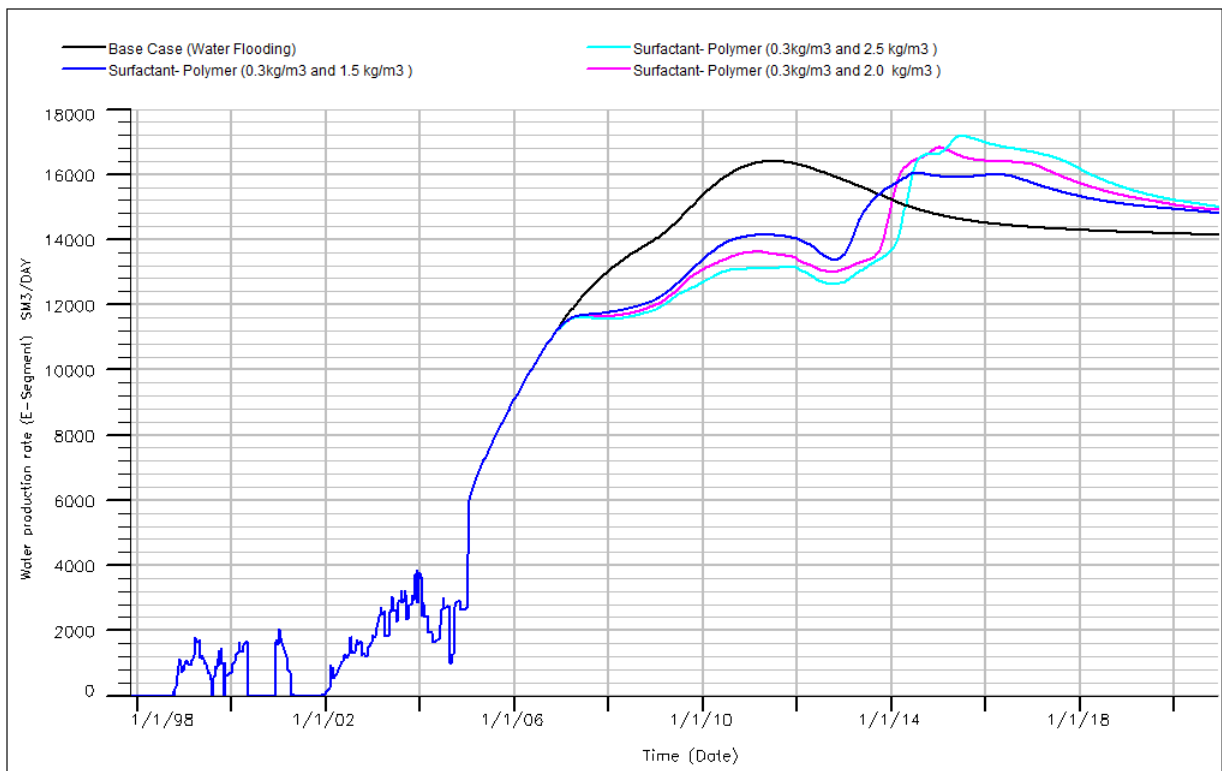


Figure 6.14: Effect of surfactant-polymer flooding on water production rate

6.5 Plan 5: Alkaline Surfactant Polymer (ASP) flooding

This process uses two sources of surfactant and a polymer to boost the production of oil, that is synthetic surfactant that is injected directly and the one that is produced insitu from the reaction of acidic component of the oil and the injected alkaline. Knowing the appropriate amount of each chemical in ASP is mandatory for the process to succeed. Considering this fact, different cases for ASP flooding were run in order to find the best way to increase oil production in Norne E- segment using ASP flooding. The simulation study focused on finding the best amount of chemicals and the appropriate time duration for ASP injection that would come up with the best oil production. In this section, four cases of continuous ASP flooding out of many trials are presented. The simulation started from December 2006 both at ASP concentrations of 1 kg/m^3 , 0.2 kg/m^3 and 2 kg/m^3 where in two cases the ASP flooding was followed by water injection and later polymer injection. The following were the cases which were simulated in this plan.

1. Case 1: ASP flooding at concentration of 1 kg/m^3 , 0.2 kg/m^3 and 2 kg/m^3 for 5 years.
2. Case 2: ASP flooding at concentration of 1 kg/m^3 , 0.2 kg/m^3 and 2 kg/m^3 for 8 years.
3. Case 3: ASP flooding for 5 years followed by 2 years of WI and 2 years of Polymer flooding after.
4. Case 4: ASP flooding for 8 years followed by 2 years of WI and 2 years of Polymer flooding after.

Figure (6.15) shows annual incremental oil production for different cases of ASP flooding. The trend is the same by 2011 as the same concentration of ASP was injected. The deviation of the graph is due to different injection time where the incremental oil production increases as the period time for injection is increased. The peak in later years, starting from 2014 and 2017 are due to injection of extra amount of polymer which boosts the production compared to the cases with ASP only. Case 4 of ASP flooding had higher cumulative incremental oil production compared to the rest of ASP cases. The values for cumulative incremental oil production for the four cases are $420,791 \text{ Sm}^3$, $557,553 \text{ Sm}^3$, $477,442 \text{ Sm}^3$ and $591,887 \text{ Sm}^3$ respectively. The presence of polymer in ASP mixture helps a lot in reducing the amount of water produced by increasing water viscosity as shown in figure (6.16). Case 4 of ASP flooding had lower water production compared to the rest of cases and hence high oil production. Although ASP flooding for longer time had higher incremental oil production, on the other hand the chemical consumption for this case was relatively higher and affected the economy of the process. Figure (6.17) and (6.18) give a summary of the amount of Alkaline, Surfactant and Polymer that were used in case 1 and case 2 of ASP flooding. Case 3 of ASP flooding is having higher incremental NPV value compared to the rest of ASP cases. The values for the incremental NPV in all the four cases of ASP flooding were 49.1 million USD, 41.1 million USD, 57.1 million USD and 44.1 million USD respectively, appendix H gives more detail on NPV calculation for the different cases of ASP flooding.

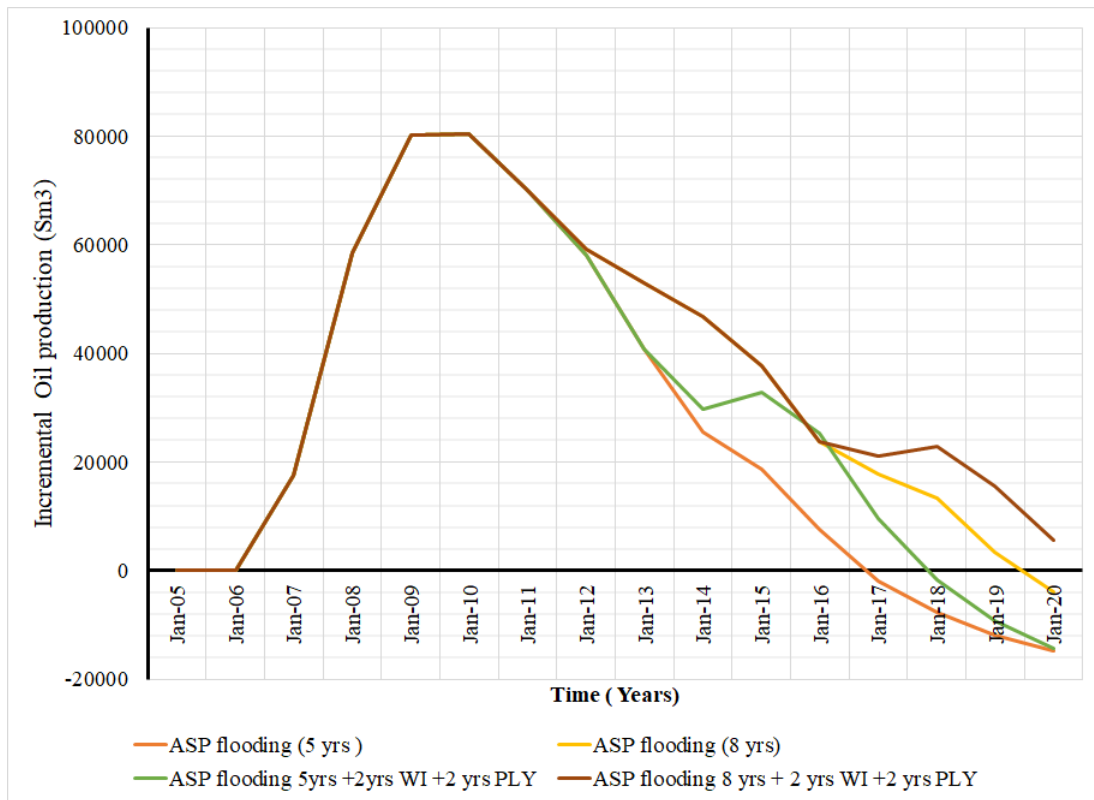


Figure 6.15: Annual Incremental Oil Production for different cases of ASP flooding

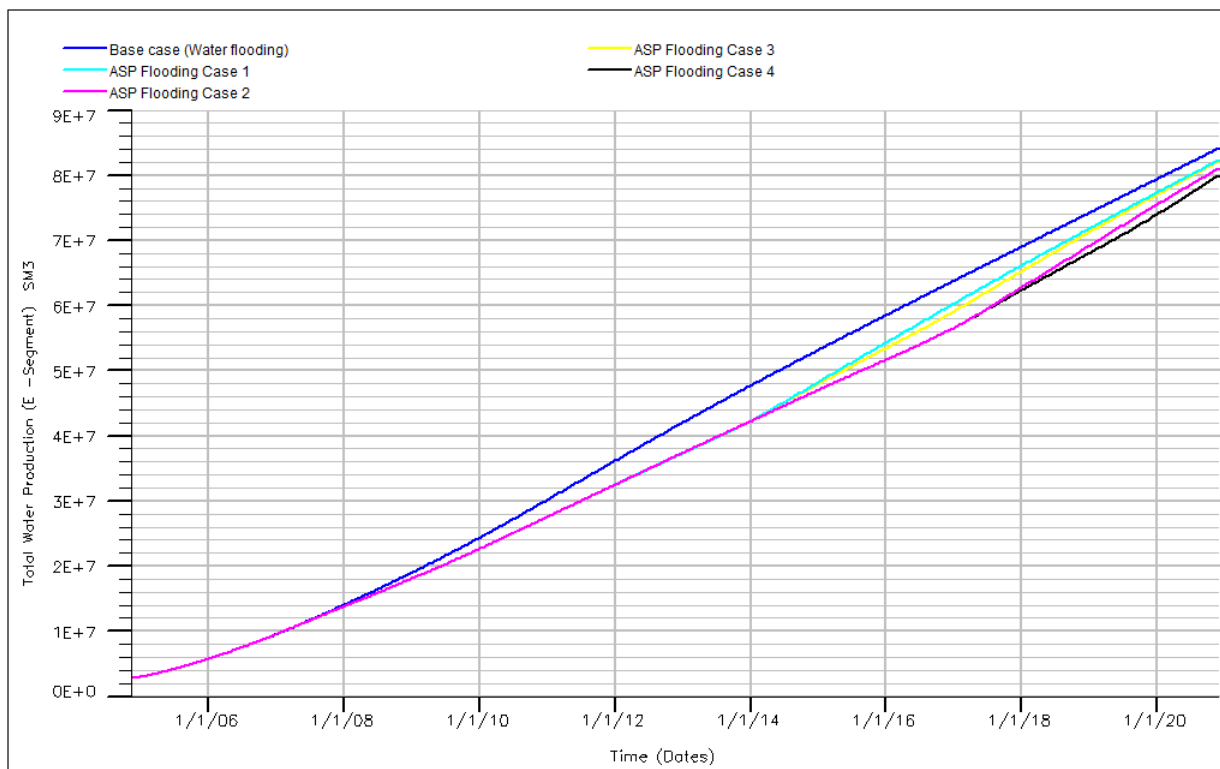


Figure 6.16: Water production total for different cases of ASP flooding

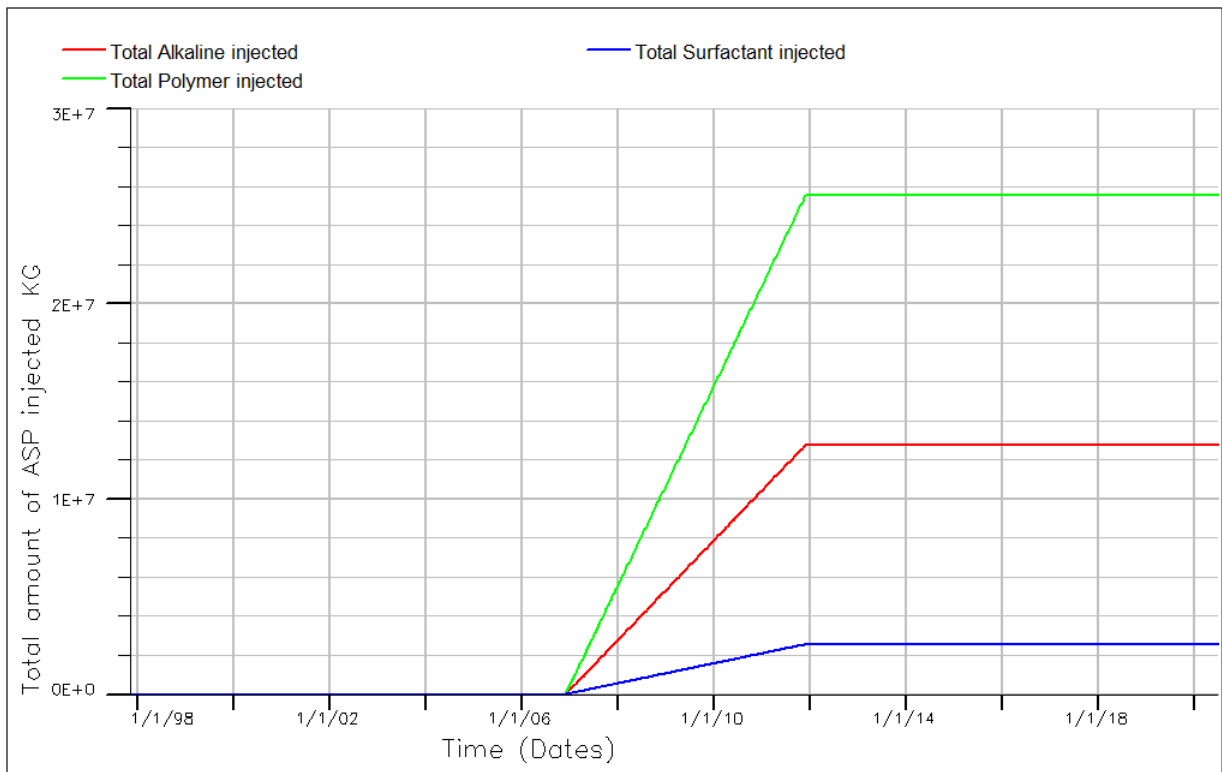


Figure 6.17: Total amount of chemicals injected in ASP Case 1

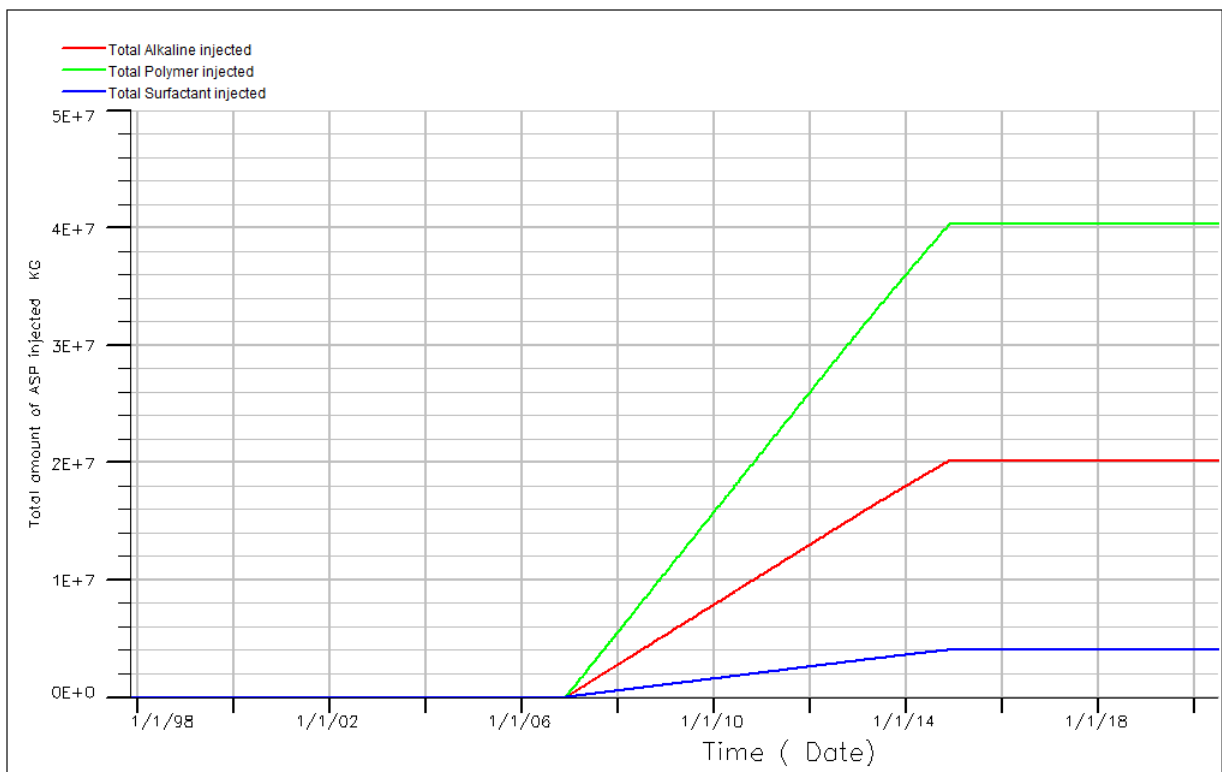


Figure 6.18: Total amount of chemicals injected in ASP Case 2

6.6 Comparison of different cases of chemical flooding in terms of incremental oil production and incremental NPV

NPV calculation was done in order to find the most appropriate chemical EOR method for the Norne E-segment. NPV may be explained as the tool that gives the present value of all payments and provides a platform of comparison for a projects with different payment schedules but similar lifetimes. In choosing between the projects, the larger the Net Present Value the more favorable the project is. The formula in equation (6.1) gives a summarized definition for NPV. Therefore in our case, the chemical method that gave the larges Net Present Value over water flooding was considered as the most appropriate recovery method for Norne E-segment.

$$NPV = \sum_{t=0}^n \frac{C_t}{(1+r)^t} \quad (6.1)$$

Where r is the discount rate, t is the time, C_t cash flow in year t , and n is time period of the project/investment

In calculating the incremental NPV for different chemical EOR cases the economical parameters in table (6.1) were used. The NPV calculation did not include expenses like pump costs neither any extra operational expenditures needed for both chemicals. Again no capital expenditure has been included in NPV calculation as it is assumed to be the same as for water flooding.

Table 6.1: Economical input parameters for NPV calculation

Economical parameter	Value/unit
Oil price [\$/ <i>bbl</i>]	65
Polymer cost [\$/ <i>kg</i>]	- 3
Alkaline cost[\$/ <i>kg</i>]	- 1
Surfactant [\$/ <i>kg</i>]	- 3.5
Discount factor [-]	0.07

The incremental oil production was obtained by comparing different cases of chemical flooding (Alkaline, Surfactant, Polymer and their combination) with the base case that involved water flooding only. This difference in production between the base case and chemical case was used in calculation of incremental NPV for different chemical cases.

Appendix D to H give a summary of incremental NPV calculation for different chemical methods obtained basing on incremental oil production over water flooding. Figure (6.19) shows highest incremental NPV in each plan of chemical flooding. The Case 1 for polymer flooding at concentration of $1.5 \text{ kg}/\text{m}^3$ had the largest incremental NPV than all other cases of chemical flooding. The incremental NPV for this case was + 68.7 million USD.

The use of surfactant and Alkaline-surfactant gave a small incremental oil production. However, the NPV value for these cases became negative as large amount of expensive chemicals were used to facilitate little increment in oil production. The appendix D and E give a summary of the calculated NPV for these cases.

The Surfactant-Polymer (SP) flooding at different concentrations gave higher incremental oil production than pure polymer injection. Despite this fact the NPV for Polymer flooding was still higher as the incremental oil produced following the fact that the injection of additional surfactant in Polymer could not compensate the expenses for surfactant cost. This was also the case for ASP flooding as its incremental oil production was quite high but ended up getting less NPV when compared to Polymer flooding. The summary for NPV calculation for SP and ASP cases are given in appendix G and H respectively.

The Norne E-segment is having good reservoir characteristics and off-cause one of the fields having the highest recovery factor. Injection of polymer at the appropriate dose decreased the mobility ratio and enabled the production of more oil. The application of polymer is not limited for viscous only but also helps a lot for the heterogeneous reservoir.

Basing on this discussion, it can now be confirmed that, injection of polymer to Norne E-segment under the same dosage and reservoir condition would be the best choice over other chemical methods. The finding will probably be improved after the lab work to evaluate and find the accurate chemicals properties for Norne E-segment is accomplished.

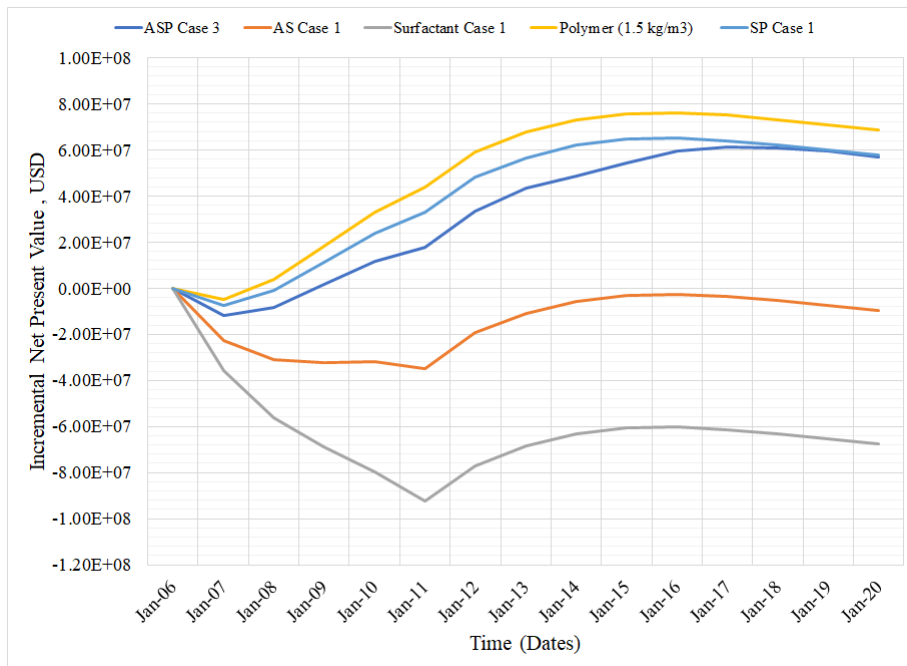


Figure 6.19: Incremental NPV for different cases of chemical flooding

6.7 NPV sensitivity analysis for Polymer flooding using spider chart

The used input parameter in calculating the Net Present Value are subjected to changes something which can affect the final output. Parameters like oil price, polymer price and even discount rate may change and their changes will have impact on the calculated NPV figure. It is common to perform sensitivity analysis in order to evaluate the influence of the economic input data to the economy of the project. The common way of doing this is by use of spider chart which gives the most influenced economic input to the economic indicator of the project (Net Present Value). In sensitivity analysis the effect of changes in values of one variable (at a time) on NPV is studied while keeping the rest parameters constant. All parameters (oil price, polymer price and discount rate) were either increased by 50% or decreased by 50% and the effect on the NPV was analysed. Table (6.2) shows a summary of the NPV for the low case, base case and high case.

Figure (6.20) shows a spider diagram which is a visual tool to display the effect of varying different input parameters on NPV. The effect from the curve is indicated by the steepness of the slope of the curve. The curve with steep slope whether positive or negative indicate that those parameters have great influence on NPV while horizontal or nearly horizontal curves tell the parameters to have little or no effect on NPV figure. The slope of the curve indicates also whether the positive change in parameters have negative or positive effect on the NPV calculated. From figure (6.20) polymer price and discount rate have negative relationship with the NPV for this project. On the other side, there is positive relationship between oil price and NPV.

From figure (6.20) it can be seen that oil price is the parameter with great impact on NPV. Increasing in oil price for 50% caused an increase in NPV to 126.67 million USD which is equal to 45.75% increase. Again, lowering oil price by 50% made NPV figure to drop to 10.7 million USD which is equal to 84.32% decrease in NPV. Other parameters also affected the results whereby the increase in polymer price for 50% lowered the NPV for 52.25% and the decrease of 50% made the NPV to increase by 34.32%. For the case of discount rate, the effect was lower compared to oil and polymer price. An increase Of 50% on discount rate made NPV figure to decrease by 15.11% while decreasing the discount rate by 50% resulted to an increase of 15.17% of NPV.

From this analysis, it is clear that oil price has the greatest influence on NPV of this project when compared to Polymer price and discount rate.

Table 6.2: Single parameter sensitivity analysis for the best case of polymer flooding

OIL PRICE			
	Low Case	Base Case	High Case
Oil Price (USD/bbl)	33	65	98
Change (%)	-50%	0.0%	50 %
NPV (million USD)	10.78	68.73	126.67
Change (%)	-84.32%	0.0%	45.75%
POLYMER PRICE			
	Low Case	Base Case	High Case
Polymer Price (USD/Kg)	1.5	3	4.5
Change (%)	-50%	0.0%	50 %
NPV (million USD)	92.31	68.73	45.14
Change (%)	34.32	0.0%	-52.25%
DISCOUNT RATE			
	Low Case	Base Case	High Case
Discount Rate	0.04	0.07	0.11
Change (%)	50%	0.0%	-50 %
NPV (million USD)	79.15	68.73	59.70
Change (%)	15.17%	0.0%	-15.11%

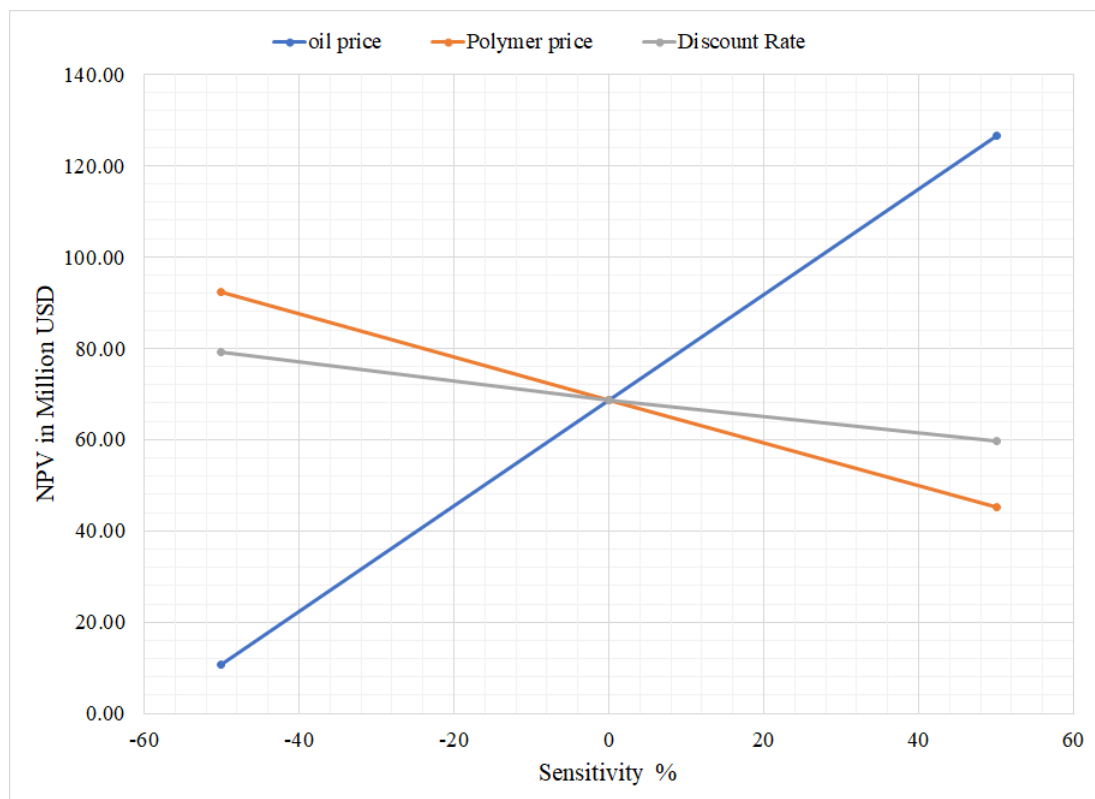


Figure 6.20: Single parameter sensitivity analysis (spider plot) for best case of polymer flooding

Chapter 7

Uncertainty in Chemical EOR flooding

This study main aim was to confirm the suitability of chemical EOR method to the Norne E-segment compared to water flooding. The finding was great and polymer injection was found to be the most appropriate method for this segment of the Norne field. However, the research involved only simulation study of the chemical EOR (Alkaline, Surfactant, Polymer and their blend). Many of optimization parameters were not considered full and hence the work is suspected to a number of uncertainties. Therefore, the application of chemical EOR in this field will still face a lot of challenges due to different uncertainties that can affect the effectiveness of the project. There is a need to do quantitative investigation and assessment of the impact that may be caused by the uncertainties that cling to the Chemical EOR techniques.

The performance of chemical EOR becomes uncertain since no laboratory experiment has been done to assess the application of Chemical EOR Methods at Norne E-segment. The used chemical properties have been gathered from previous work and hence carrying error forward for every simulation work that have been done since then. The compatibility of the used chemical properties with fluid and rock properties in Norne E-segment is very uncertain.

Another uncertainty in this study is the reservoir model itself. The used model for Norne E-segment was obtained by coarsening the grids in other segments and maintaining the grids in E-segment. This does not mean full separation of the E-segment from the rest of the field. The production and output data have been collected by well grouping in the E-segment. Given that there is communication between E-segment with other segments, still no effects of chemical flooding on other segments has been quantified.

Also the performance of chemical in real field remain uncertain. Many parameters affect the performance of the chemicals in real field. Just to mention few, polymer flooding is subjected to adsorption on the rock surface depending on clay content in the reservoir, mineralogy and surface area of the medium. The situation can be estimated by doing a static test on the crushed core or dynamic test by core flooding. Unfortunately no laboratory work for Norne E-segment has been done so far. The injection of polymer has a potential to reduce permeability especially for the low permeability zones. To quantify this also needs experiment on core sample to be done. Again no any lab findings was included in this research. Surfactant like polymer is also subjected to adsorption and hence reduce its efficiency.

On the other hand, the reservoir environment is not uniform and homogeneous, the reservoir geology is full of heterogeneity and this would make the performance of chemical EOR on real field uncertain. The results may be quite different from what has been reported from simulation study.

Chapter 8

Conclusion and Recommendation

8.1 Conclusion

Basing on the simulation findings, Norne E-segment is a good candidate of chemical EOR methods as mentioned before in screening process. However, Norne reservoir characteristics and oil properties favour the use of Polymer flooding than Alkaline and Surfactant alone. This is due to the fact that the use of surfactant and alkaline could not reduce residual oil saturation at economical quantity and ended up getting negative incremental NPV. This results from poor mobility control which makes them to get ride off by fast moving water before having enough interaction with the reservoir oil. If alkaline and surfactant are to be used they need to be mixed with some polymer to ensure favourable mobility ratio to yield better recovery.

The use of ASP had higher incremental oil production than all cases of chemical flooding as it combines the synergy of all the three chemicals (Alkaline, Surfactant and Polymer) However, the incremental NPV for this case became lower than that one for polymer flooding due to excess use of chemicals. This does not nullify the use ASP as the use of different concentrations will probably give different results as it has already been reported by other scholars in previous studies.

The injection time for chemicals used in EOR process has significant effect on the effectiveness of the method. One should know the most appropriate time to shift from water flooding method to EOR method. For example, the start of polymer injection from different years had quite different results on total oil production. Early polymer injection was found to be the best option as it gives high incremental oil production over water flooding.

The location of the injection well also affect the efficiency of chemical EOR process. For this case chemical injection in well F-3H which is in oil zone was much better than the use of injection well F-1H located in water zone.

The price for different chemicals as well as the oil price has great impact on the economic feasibility of chemical EOR methods. Change in technology would probably come with the cheapest chemicals that will justify their use in the industry. Although chemical EOR techniques may be taken as the reserve technology due to the current price of oil, later on once the price for oil changes it may save a lot in assuring the production of extra oil.

The obtained results may not be realistic hundred percent as they were obtained by grouping the wells in E-segment. This means the effect of injected chemicals might have spread to the other segments as they are not totally separated.

8.2 Recommendation

It is very important to do laboratory evaluation for the Norne E-segment to confirm chemical EOR potential in this field. Doing this will find the physical input data for chemical properties and stop using the properties from the analogue fields.

It is recommended to do economic analyses of EOR methods at all stages of reservoir evaluation in order to avoid unnecessary delay that could nullify the suitability of a particular method.

Consideration on environmental issues should be given priority provided that chemical EOR process has potential effect on environmental pollution.

Drilling of new well and use different well location will probably bring more light on the applicability of chemical EOR method in this field.

The chemical EOR need to be tested for the whole field as right now the used segment was not completely separated from other segments rather than coarsening the grids in other segments.

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Appendices

Appendix A

Grouping of the E - segment

Groups and information added to GRUPTREE and GRUPNET respectively in order to get production data of the E-segment.

GRUPTREE

```
-- child    parent
'INJE'  'FIELD' /
'PROD'  'FIELD' /
'MANI-B2' 'PROD' /
'MANI-B1' 'PROD' /
'MANI-D1' 'PROD' /
'MANI-D2' 'PROD' /
'MANI-E1' 'PROD' /
'MANI-E2' 'PROD' /
'MANI-K1' 'MANI-B1' /
'MANI-K2' 'MANI-D2' /
'MANI-C'  'INJE' /
'MANI-F'  'INJE' /
'WI-GSEG' 'INJE' /
'B1-DUMMY' 'MANI-B1' /
'D2-DUMMY' 'MANI-D2' /
-- added groups
'E-SEG'      'PROD' /
'MANI-E1_ESEG' 'E-SEG' /
'MANI-E2_ESEG' 'E-SEG' /
/
```

GRUPNET

```
'FIELD'  20.000 5* /
'PROD'   20.000 5* /
'MANI-B2' 1* 8 1*   'NO' 2* /
'MANI-B1' 1* 8 1*   'NO' 2* /
'MANI-K1' 1* 9999 4* /
'B1-DUMMY' 1* 9999 4* /
'MANI-D1' 1* 8 1*   'NO' 2* /
'MANI-D2' 1* 8 1*   'NO' 2* /
'MANI-K2' 1* 9999 4* /
```

'D2-DUMMY' 1* 9999 4* /
'MANI-E1' 1* 9 1* 'NO' 2* /
'MANI-E2' 1* 9 4* /
- - added information
'E-SEG' 1* 9999 4* /
'MANI-E1_ESEG' 1* 9 1* 'NO' 2* /
'MANI-E2_ESEG' 1* 9 4* /
/

Appendix B

Fundamental chemical EOR keywords used in Eclipse 100

Table B.1: Some fundamental Surfactant keywords used in Eclipse 100

Keyword	Description	Remarks
SURFST	Water-oil surface tension in the presence of surfactant (and salts).	Required
SURFVISC	Modified water viscosity.	Required
SURFCAPD	Capillary de-saturation data.	Required
SURFADS	Adsorption isotherm.	Optional
SURFROCK	Rock properties and adsorption model indicator.	If SURFADS is present
SURFNUM	For specifying miscible relative permeability curves	
WSURFACT	Describe the surfactant concentration of a water injector	Required

Table B.2: Some fundamental Polymer keywords used in Eclipse 100 (Schlumberger, 2014)

Keyword	Description	Remarks
PLMIXPAR	Todd-Longstaff mixing data for the Polymer Model.	Required
PLYADS	Polymer adsorption functions (tabulated).	Required
PLYMAX	Polymer/salt concentrations for mixing calculations.	Required
PLYSHEAR	Polymer shear thinning/thickening data.	Optional
PLYROCK	Polymer-rock properties.	Required
PLYVISC	Polymer solution viscosity function	Required
WPOLYMER	This keyword is used to specify the concentration of polymer	Required

Table B.3: Some fundamental Alkaline keywords used in Eclipse 100

Keyword	Description	Remarks
ALSURFST	Table of oil/water surface tension as a function of alkaline concentration.	Obligatory if the Surfactant Flood Model is active
ALPOLADS	Table of polymer adsorption as a function of alkaline concentration.	Obligatory if the Polymer Flood Model is active.
ALSURFAD	Table of surfactant adsorption as a function of alkaline concentration	Obligatory if the SURFADS keyword is used
ALKADS	Tables of adsorption functions.	Optional
ALKROCK	Specifies alkaline-rock properties	Obligatory if ALKADS is used
WALKALIN	For specifying the concentration of the injected alkaline in a water injector	

Appendix C

Important data for the chemical used (Alkaline, Polymer and Surfactant)

C.1 Alkaline Input file

-- ALKALINE KEYWORDS

-- Water/oil surface tension multipliers as a function of alkaline –concentration

ALSURFST

--Alkaline Water/oil Surface

-- conc Tension Multiplier

-- Kg/m3

0.0 1.0

6.0 0.5

15.0 0.3

20.0 0.1

30.0 0.0 /

-- Alkaline multipliers for polymer adsorption

ALPOLADS

-- Alkaline Adsorption

-- conc Multiplier

-- Kg/m3

0.0 1.0

3.0 0.7

6.0 0.5

9.0 0.3 /

-- Alkaline adsorption

ALKADS

-- Alkaline Alkaline Adsorbed

-- conc 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

2/

C.2 Surfactant Input file

SURFVISC

-- Surf conc Water Viscosity

-- Kg/m³ Centipose

0.0 0.318

5.0 0.449

10.0 0.503

15.0 0.540

20.0 0.630/

SURFST

-- Surfactant Water/Oil Srface

-- conc., kg/m³ 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

3.0 0.006E-03

5.0 0.004E-03

10.0 0.006E-03

20.0 0.01E-03/

SURFADS

-- Surfactant Adsorption by rock

-- Surf conc Adsorbed mass

-- Kg/m³ (kg/kg) = kg surf /kg rock

0.0 0.00000

1.0 0.00017

5.0 0.00017

10.0 0.00017/

SURFCAPD

-- Capillary De-saturation curve
 -- Log10 (capillary Miscibility
 -- number) function 0 = immiscible, 1 = miscible

-8	0.0
-7	0.0
-6	0.0
-5	0.0
-2.5	1.0
0	1.0
5	1.0
10	1.0/

SURFROCK

-- No desorption
 2 2650/

C.3 Polymer Input file

PLYSHEAR

-- Polymer shear thinning data
 -- Wat. Velocity Visc reduction
 -- m/day CP
 0.0 1.0
 2.0 1.0 /
 -- Polymer solution Viscosity Function

PLYVISC

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

-- Polymer Adsorption Function

PLYADS

-- Ply conc. Ply conc.

-- Adsorbed by rock
-- kg/m3 kg/kg
0.0 0.0
0.5 0.0000017
1.0 0.0000017 /

-- Todd-Longstaff Mixing Parameters

PLMIXPAR

1 1* /

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

PLYMAX

-- Ply conc. Salt conc.

-- kg/m3 kg/m3

1.0 0.0 / - -Polymer-Rock Properties

PLYROCK

-- dead residual mass Ads. max.

-- pore resistance density Index Polymer

-- space factor adsorption

0.16 1.0 2650.0 2 0.000017 /

Appendix D

NPV for different surfactant cases

Table D.1: Incremental NPV for Surfactant (5 kg/m³) injection

Time		Annual Oil Production		Annual Oil Increment		Revenue	Surfactant Used	Total Cost	Cash Flow	Discount	Discounted Cash Flow
		Base Case	With Surfactant			USD	KG	USD	USD	factor	USD
Year	Year	Sm3	Sm3	Sm3	bbl						
Dec-06	0	730295.9	730295.9	0	0	0.00E+00	0.00		0.00E+00	1.00	0.00E+00
Dec-07	1	625774	641625.0	15851	98276.2	6.39E+06	1.3E+07	4.47E+07	-3.83E+07	0.93	-3.58E+07
Dec-08	2	542351	595094.0	52743	327006.6	2.13E+07	1.3E+07	4.48E+07	-2.36E+07	0.87	-2.06E+07
Dec-09	3	477553	550085.0	72532	449698.4	2.92E+07	1.3E+07	4.47E+07	-1.55E+07	0.82	-1.26E+07
Dec-10	4	435652	512387.0	76735	475757	3.09E+07	1.3E+07	4.47E+07	-1.38E+07	0.76	-1.05E+07
Dec-11	5	388675	455043.0	66368	411481.6	2.67E+07	1.3E+07	4.47E+07	-1.80E+07	0.71	-1.28E+07
Dec-12	6	339030	395961.0	56931	352972.2	2.29E+07	0.00		2.29E+07	0.67	1.53E+07
Dec-13	7	293308	327227.0	33919	210297.8	1.37E+07	0.00		1.37E+07	0.62	8.51E+06
Dec-14	8	256967	279354.0	22387	138799.4	9.02E+06	0.00		9.02E+06	0.58	5.25E+06
Dec-15	9	229378	241483.0	12105	75051	4.88E+06	0.00		4.88E+06	0.54	2.65E+06
Dec-16	10	208595	210244.0	1649	10223.8	6.65E+05	0.00		6.65E+05	0.51	3.38E+05
Dec-17	11	190732	185658.0	-5074	-31458.8	-2.04E+06	0.00		-2.04E+06	0.48	-9.71E+05
Dec-18	12	176166	166226.0	-9940	-61628	-4.01E+06	0.00		-4.01E+06	0.44	-1.78E+06
Dec-19	13	163550	150465.0	-13085	-81127	-5.27E+06	0.00		-5.27E+06	0.41	-2.19E+06
Dec-20	14	152947	138058.0	-14889	-92311.8	-6.00E+06	0.00		-6.00E+06	0.39	-2.33E+06
NPV for Surfactant flooding case 1 [USD]											-6.76E+07

Table D.2: Incremental NPV for Surfactant (10 kg/m³) injection

Time		Annual Oil Production		Annual Oil Increment		Revenue	Surfactant Used	Total Cost	Cash Flow	Discount	Discounted Cash Flow
		Base Case	With Surfactant			USD	KG	USD	USD	factor	USD
Year	Year	Sm3	Sm3	Sm3	bbl						
Dec-06	0	730,296	730,296	0	0	0.00E+00	0.00		0.00E+00	1.00	0.00E+00
Dec-07	1	625,774	643,286	17512	108574.4	7.06E+06	2.6E+07	8.94E+07	-8.24E+07	0.93	-7.70E+07
Dec-08	2	542,351	600,768	58417	362185.4	2.35E+07	2.6E+07	8.97E+07	-6.61E+07	0.87	-5.78E+07
Dec-09	3	477,553	557,688	80135	496837	3.23E+07	2.6E+07	8.94E+07	-5.71E+07	0.82	-4.66E+07
Dec-10	4	435,652	515,938	80286	497773.2	3.24E+07	2.6E+07	8.94E+07	-5.71E+07	0.76	-4.35E+07
Dec-11	5	388,675	458,697	70022	434136.4	2.82E+07	2.6E+07	8.94E+07	-6.12E+07	0.71	-4.36E+07
Dec-12	6	339,030	396,917	57887	358899.4	2.33E+07	0.00		2.33E+07	0.67	1.55E+07
Dec-13	7	293,308	334,012	40704	252364.8	1.64E+07	0.00		1.64E+07	0.62	1.02E+07
Dec-14	8	256,967	282,412	25445	157759	1.03E+07	0.00		1.03E+07	0.58	5.97E+06
Dec-15	9	229,378	248,094	18716	116039.2	7.54E+06	0.00		7.54E+06	0.54	4.10E+06
Dec-16	10	208,595	216,110	7515	46593	3.03E+06	0.00		3.03E+06	0.51	1.54E+06
Dec-17	11	190,732	188,765	-1967	-12195.4	-7.93E+05	0.00		-7.93E+05	0.48	-3.77E+05
Dec-18	12	176,166	168,557	-7609	-47175.8	-3.07E+06	0.00		-3.07E+06	0.44	-1.36E+06
Dec-19	13	163,550	151,701	-11849	-73463.8	-4.78E+06	0.00		-4.78E+06	0.41	-1.98E+06
Dec-20	14	152,947	138,085	-14862	-92144.4	-5.99E+06	0.00		-5.99E+06	0.39	-2.32E+06
NPV for Surfactant flooding case 2 [USD]											-2.37E+08

Table D.3: Incremental NPV for Surfactant (20 kg/m³) injection

Time		Annual Oil Production		Annual Oil Increment		Revenue	Surfactant Used	Total Cost	Cash Flow	Discount	Discounted Cash Flow
Year	Year	Base Case Sm3	With Surfactant Sm3	Sm3	bbl	USD	KG	USD	USD	factor	USD
Dec-06	0	730295.9	730295.9	0	0	0.00E+00	0.00		0.00E+00	1.00	0.00E+00
Dec-07	1	625774	644716.0	18942	117440.4	7.63E+06	5.1E+07	1.79E+08	-1.71E+08	0.93	-1.60E+08
Dec-08	2	542351	605615.0	63264	392236.8	2.55E+07	5.1E+07	1.79E+08	-1.54E+08	0.87	-1.34E+08
Dec-09	3	477553	562569.0	85016	527099.2	3.43E+07	5.1E+07	1.79E+08	-1.45E+08	0.82	-1.18E+08
Dec-10	4	435652	518506.0	82854	513694.8	3.34E+07	5.1E+07	1.79E+08	-1.45E+08	0.76	-1.11E+08
Dec-11	5	388675	458948.0	70273	435692.6	2.83E+07	5.1E+07	1.79E+08	-1.51E+08	0.71	-1.07E+08
Dec-12	6	339030	392686.0	53656	332667.2	2.16E+07	0.00		2.16E+07	0.67	1.44E+07
Dec-13	7	293308	330819.0	37511	232568.2	1.51E+07	0.00		1.51E+07	0.62	9.41E+06
Dec-14	8	256967	283166.0	26199	162433.8	1.06E+07	0.00		1.06E+07	0.58	6.14E+06
Dec-15	9	229378	250828.0	21450	132990	8.64E+06	0.00		8.64E+06	0.54	4.70E+06
Dec-16	10	208595	222525.0	13930	86366	5.61E+06	0.00		5.61E+06	0.51	2.85E+06
Dec-17	11	190732	193551.0	2819	17477.8	1.14E+06	0.00		1.14E+06	0.48	5.40E+05
Dec-18	12	176166	171953.0	-4213	-26120.6	-1.70E+06	0.00		-1.70E+06	0.44	-7.54E+05
Dec-19	13	163550	154716.0	-8834	-54770.8	-3.56E+06	0.00		-3.56E+06	0.41	-1.48E+06
Dec-20	14	152947	140779.0	-12168	-75441.6	-4.90E+06	0.00		-4.90E+06	0.39	-1.90E+06
NPV for Surfactant flooding case 3 [USD]											-5.97E+08

Appendix E

NPV for different Alkaline - Surfactant cases

Table E.1: Incremental NPV for Alkaline-Surfactant (5 kg/m³ and 2kg/m³) injection for 5 years

Time		Annual Oil Production		Annual Oil Increment	Revenue	Surfactant Used	Alkaline Used	Total Cost	Cash Flow	Discount	Discounted Cash Flow	
Year	Year	Base Case Sm3	With AS Sm3	Sm3	bbl	USD	KG	KG	USD	USD	factor	USD
Dec-06	0	730295.9	730295.9	0	0	0.00E+00				0.00E+00	1.00	0.00E+00
Dec-07	1	625774	641606.0	15832	98158.4	6.38E+06	5.11E+06	1.3E+07	3.07E+07	-2.43E+07	0.93	-2.27E+07
Dec-08	2	542351	595111.0	52760	327112	2.13E+07	5.12E+06	1.3E+07	3.07E+07	-9.48E+06	0.87	-8.28E+06
Dec-09	3	477553	550204.0	72651	450436.2	2.93E+07	5.11E+06	1.3E+07	3.07E+07	-1.38E+06	0.82	-1.13E+06
Dec-10	4	435652	512122.0	76470	474114	3.08E+07	5.11E+06	1.3E+07	3.07E+07	1.57E+05	0.76	1.20E+05
Dec-11	5	388675	455112.0	66437	411909.4	2.68E+07	5.11E+06	1.3E+07	3.07E+07	-3.89E+06	0.71	-2.77E+06
Dec-12	6	339030	396037.0	57007	353443.4	2.30E+07				2.30E+07	0.67	1.53E+07
Dec-13	7	293308	327349.0	34041	211054.2	1.37E+07				1.37E+07	0.62	8.54E+06
Dec-14	8	256967	279433.0	22466	139289.2	9.05E+06				9.05E+06	0.58	5.27E+06
Dec-15	9	229378	241554.0	12176	75491.2	4.91E+06				4.91E+06	0.54	2.67E+06
Dec-16	10	208595	210269.0	1674	10378.8	6.75E+05				6.75E+05	0.51	3.43E+05
Dec-17	11	190732	185665.0	-5067	-31415.4	-2.04E+06				-2.04E+06	0.48	-9.70E+05
Dec-18	12	176166	166238.0	-9928	-61553.6	-4.00E+06				-4.00E+06	0.44	-1.78E+06
Dec-19	13	163550	150489.0	-13061	-80978.2	-5.26E+06				-5.26E+06	0.41	-2.18E+06
Dec-20	14	152947	138105.0	-14842	-92020.4	-5.98E+06				-5.98E+06	0.39	-2.32E+06
NPV for AS Case 1											NPV [USD]	-9.87E+06

Table E.2: Incremental NPV for Alkaline-Surfactant (10 kg/m³ and 2kg/m³) injection for 5 years

Time		Annual Oil Production		Annual Oil Increment	Revenue	Surfactant Used	Alkaline Used	Total Cost	Cash Flow	Discount	Discounted Cash Flow	
Year	Year	Base Case Sm3	With AS Sm3	Sm3	bbl	USD	KG	KG	USD	USD	factor	USD
Dec-06	0	730295.9	730295.9	0	0	0.00E+00	0E+00	0.00		0.00E+00	1.00	0.00E+00
Dec-07	1	625774	643261.0	17487	108419.4	7.05E+06	5.11E+06	2.6E+07	4.34E+07	-3.64E+07	0.93	-3.40E+07
Dec-08	2	542351	600778.0	58427	362247.4	2.35E+07	5.12E+06	2.6E+07	4.36E+07	-2.00E+07	0.87	-1.75E+07
Dec-09	3	477553	557741.0	80188	497165.6	3.23E+07	5.11E+06	2.6E+07	4.34E+07	-1.11E+07	0.82	-9.08E+06
Dec-10	4	435652	515983.0	80331	498052.2	3.24E+07	5.11E+06	2.6E+07	4.34E+07	-1.11E+07	0.76	-8.44E+06
Dec-11	5	388675	458746.0	70071	434440.2	2.82E+07	5.11E+06	2.6E+07	4.34E+07	-1.52E+07	0.71	-1.08E+07
Dec-12	6	339030	397056.0	58026	359761.2	2.34E+07	0.00E+00			2.34E+07	0.67	1.56E+07
Dec-13	7	293308	334046.0	40738	252575.6	1.64E+07	0.00E+00			1.64E+07	0.62	1.02E+07
Dec-14	8	256967	282468.0	25501	158106.2	1.03E+07	0.00E+00			1.03E+07	0.58	5.98E+06
Dec-15	9	229378	248106.0	18728	116113.6	7.55E+06	0.00E+00			7.55E+06	0.54	4.11E+06
Dec-16	10	208595	216156.0	7561	46878.2	3.05E+06	0.00E+00			3.05E+06	0.51	1.55E+06
Dec-17	11	190732	188781.0	-1951	-12096.2	-7.86E+05	0.00E+00			-7.86E+05	0.48	-3.74E+05
Dec-18	12	176166	168554.0	-7612	-47194.4	-3.07E+06	0.00E+00			-3.07E+06	0.44	-1.36E+06
Dec-19	13	163550	151700.0	-11850	-73470	-4.78E+06	0.00E+00			-4.78E+06	0.41	-1.98E+06
Dec-20	14	152947	138096.0	-14851	-92076.2	-5.98E+06	0.00E+00			-5.98E+06	0.39	-2.32E+06
NPV for AS Case 2											NPV [USD]	-4.84E+07

Table E.3: Incremental NPV for Alkaline-Surfactant (15 kg/m³ and 2kg/m³) injection for 5 years

Time		Annual Oil Production		Annual Oil Increment		Revenue	Surfactant Used	Alkaline Used	Total Cost	Cash Flow	Discount	Discounted Cash Flow
Year	Year	Base Case Sm3	With AS Sm3	Sm3	bbl	USD	KG	KG	USD	USD	factor	USD
Dec-06	0	730295.9	730295.9	0	0	0.00E+00	0E+00	0.00		0.00E+00	1.00	0.00E+00
Dec-07	1	625774	644716.0	18942	117440.4	7.63E+06	5.11E+06	3.8E+07	5.62E+07	-4.86E+07	0.93	-4.54E+07
Dec-08	2	542351	605615.0	63264	392236.8	2.55E+07	5.12E+06	3.8E+07	5.64E+07	-3.09E+07	0.87	-2.70E+07
Dec-09	3	477553	562569.0	85016	527099.2	3.43E+07	5.11E+06	3.8E+07	5.62E+07	-2.19E+07	0.82	-1.79E+07
Dec-10	4	435652	518506.0	82854	513694.8	3.34E+07	5.11E+06	3.8E+07	5.62E+07	-2.28E+07	0.76	-1.74E+07
Dec-11	5	388675	458948.0	70273	435692.6	2.83E+07	5.11E+06	3.8E+07	5.62E+07	-2.79E+07	0.71	-1.99E+07
Dec-12	6	339030	392686.0	53656	332667.2	2.16E+07	0.00E+00			2.16E+07	0.67	1.44E+07
Dec-13	7	293308	330819.0	37511	232568.2	1.51E+07	0.00E+00			1.51E+07	0.62	9.41E+06
Dec-14	8	256967	283166.0	26199	162433.8	1.06E+07	0.00E+00			1.06E+07	0.58	6.14E+06
Dec-15	9	229378	250828.0	21450	132990	8.64E+06	0.00E+00			8.64E+06	0.54	4.70E+06
Dec-16	10	208595	222525.0	13930	86366	5.61E+06	0.00E+00			5.61E+06	0.51	2.85E+06
Dec-17	11	190732	193551.0	2819	17477.8	1.14E+06	0.00E+00			1.14E+06	0.48	5.40E+05
Dec-18	12	176166	171953.0	-4213	-26120.6	-1.70E+06	0.00E+00			-1.70E+06	0.44	-7.54E+05
Dec-19	13	163550	154716.0	-8834	-54770.8	-3.56E+06	0.00E+00			-3.56E+06	0.41	-1.48E+06
Dec-20	14	152947	140779.0	-12168	-75441.6	-4.90E+06	0.00E+00			-4.90E+06	0.39	-1.90E+06
NPV for AS Case 3											NPV [USD]	-9.36E+07

Appendix F

Incremental NPV for different cases of Polymer (P) flooding (Norne E - Segment)

F.1 Incremental NPV for different concentrations of Polymer flooding

Table F.1: Incremental NPV for Polymer flooding at concentration of 0.2 Kg/m3

Time		Annual Oil Production		Annual Oil Increment		Revenue	Polymer Used	Total Cost	Cash Flow	discount	Discounted Cash Flow
Year	Year	Base Case Sm3	With Polymer Sm3	Sm3	bbl	USD	KG	USD	USD	factor	USD
Dec-06	0	730295.9	730295.9	0	0	0.00E+00	0.00		0.00E+00	1.00	0.00E+00
Dec-07	1	625774	631427.0	5653	35048.6	2.28E+06	5.1E+05	1.53E+06	7.45E+05	0.93	6.96E+05
Dec-08	2	542351	559456.0	17105	106051	6.89E+06	5.1E+05	1.54E+06	5.36E+06	0.87	4.68E+06
Dec-09	3	477553	499282.0	21729	134719.8	8.76E+06	5.1E+05	1.53E+06	7.22E+06	0.82	5.90E+06
Dec-10	4	435652	457142.0	21490	133238	8.66E+06	5.1E+05	1.53E+06	7.13E+06	0.76	5.44E+06
Dec-11	5	388675	406784.0	18109	112275.8	7.30E+06	5.1E+05	1.53E+06	5.76E+06	0.71	4.11E+06
Dec-12	6	339030	352974.0	13944	86452.8	5.62E+06	0.00		5.62E+06	0.67	3.74E+06
Dec-13	7	293308	297943.0	4635	28737	1.87E+06	0.00		1.87E+06	0.62	1.16E+06
Dec-14	8	256967	256152.0	-815	-5053	-3.28E+05	0.00		-3.28E+05	0.58	-1.91E+05
Dec-15	9	229378	225395.0	-3983	-24694.6	-1.61E+06	0.00		-1.61E+06	0.54	-8.73E+05
Dec-16	10	208595	202779.0	-5816	-36059.2	-2.34E+06	0.00		-2.34E+06	0.51	-1.19E+06
Dec-17	11	190732	184027.0	-6705	-41571	-2.70E+06	0.00		-2.70E+06	0.48	-1.28E+06
Dec-18	12	176166	169422.0	-6744	-41812.8	-2.72E+06	0.00		-2.72E+06	0.44	-1.21E+06
Dec-19	13	163550	157169.0	-6381	-39562.2	-2.57E+06	0.00		-2.57E+06	0.41	-1.07E+06
Dec-20	14	152947	147075.0	-5872	-36406.4	-2.37E+06			-2.37E+06	0.39	-9.18E+05
NPV for Polymer flooding case 1[USD]											1.90E+07

Table F.2: Incremental NPV for Polymer flooding at concentration of 0.8 Kg/m3

Time		Annual Oil Production		Annual Oil Increment		Revenue	Polymer Used	Total Cost	Cash Flow	discount	Discounted Cash Flow
		Base Case	With Polymer			USD	KG	USD	USD	factor	USD
Year	Year	Sm3	Sm3	Sm3	bbl						
Dec-06	0	730,296	730,296	0	0	0.00E+00	0.00		0.00E+00	1.00	0.00E+00
Dec-07	1	625,774	637,892	12118	75131.6	4.88E+06	2.0E+06	6.13E+06	-1.25E+06	0.93	-1.17E+06
Dec-08	2	542,351	581,398	39047	242091.4	1.57E+07	2.0E+06	6.15E+06	9.59E+06	0.87	8.37E+06
Dec-09	3	477,553	530,287	52734	326950.8	2.13E+07	2.0E+06	6.13E+06	1.51E+07	0.82	1.23E+07
Dec-10	4	435,652	491,411	55759	345705.8	2.25E+07	2.0E+06	6.13E+06	1.63E+07	0.76	1.25E+07
Dec-11	5	388,675	438,504	49829	308939.8	2.01E+07	2.0E+06	6.13E+06	1.39E+07	0.71	9.95E+06
Dec-12	6	339,030	379,319	40289	249791.8	1.62E+07	0.00		1.62E+07	0.67	1.08E+07
Dec-13	7	293,308	314,344	21036	130423.2	8.48E+06	0.00		8.48E+06	0.62	5.28E+06
Dec-14	8	256,967	266,996	10029	62179.8	4.04E+06	0.00		4.04E+06	0.58	2.35E+06
Dec-15	9	229,378	231,932	2554	15834.8	1.03E+06	0.00		1.03E+06	0.54	5.60E+05
Dec-16	10	208,595	205,149	-3446	-21365.2	-1.39E+06	0.00		-1.39E+06	0.51	-7.06E+05
Dec-17	11	190,732	182,840	-7892	-48930.4	-3.18E+06	0.00		-3.18E+06	0.48	-1.51E+06
Dec-18	12	176,166	165,405	-10761	-66718.2	-4.34E+06	0.00		-4.34E+06	0.44	-1.93E+06
Dec-19	13	163,550	151,009	-12541	-77754.2	-5.05E+06	0.00		-5.05E+06	0.41	-2.10E+06
Dec-20	14	152,947	139,440	-13507	-83743.4	-5.44E+06			-5.44E+06	0.39	-2.11E+06
NPV for Polymer flooding case 2 [USD]											5.26E+07

Table F.3: Incremental NPV for Polymer flooding at concentration of 1.5 Kg/m3

Time		Annual Oil Production		Annual Oil Increment		Revenue	Polymer Used	Total Cost	Cash Flow	discount	Discounted Cash Flow
		Base Case	With Polymer			USD	KG	USD	USD	factor	USD
Year	Year	Sm3	Sm3	Sm3	bbl						
Dec-06	0	730295.9	730295.9	0	0	0.00E+00	0.00		0.00E+00	1.00	0.00E+00
Dec-07	1	625774	641616.0	15842	98220.4	6.38E+06	3.8E+06	1.15E+07	-5.11E+06	0.93	-4.78E+06
Dec-08	2	542351	595036.0	52685	326647	2.12E+07	3.8E+06	1.15E+07	9.70E+06	0.87	8.48E+06
Dec-09	3	477553	550082.0	72529	449679.8	2.92E+07	3.8E+06	1.15E+07	1.77E+07	0.82	1.45E+07
Dec-10	4	435652	512509.0	76857	476513.4	3.10E+07	3.8E+06	1.15E+07	1.95E+07	0.76	1.49E+07
Dec-11	5	388675	455633.0	66958	415139.6	2.70E+07	3.8E+06	1.15E+07	1.55E+07	0.71	1.10E+07
Dec-12	6	339030	395763.0	56733	351744.6	2.29E+07	0.00		2.29E+07	0.67	1.52E+07
Dec-13	7	293308	327111.0	33803	209578.6	1.36E+07	0.00		1.36E+07	0.62	8.48E+06
Dec-14	8	256967	279233.0	22266	138049.2	8.97E+06	0.00		8.97E+06	0.58	5.22E+06
Dec-15	9	229378	241421.0	12043	74666.6	4.85E+06	0.00		4.85E+06	0.54	2.64E+06
Dec-16	10	208595	210226.0	1631	10112.2	6.57E+05	0.00		6.57E+05	0.51	3.34E+05
Dec-17	11	190732	185669.0	-5063	-31390.6	-2.04E+06	0.00		-2.04E+06	0.48	-9.69E+05
Dec-18	12	176166	166240.0	-9926	-61541.2	-4.00E+06	0.00		-4.00E+06	0.44	-1.78E+06
Dec-19	13	163550	150473.0	-13077	-81077.4	-5.27E+06	0.00		-5.27E+06	0.41	-2.19E+06
Dec-20	14	152947	138059.0	-14888	-92305.6	-6.00E+06			-6.00E+06	0.39	-2.33E+06
NPV for Polymer flooding case 3 [USD]											6.87E+07

Table F.4: Incremental NPV for Polymer flooding at concentration of 2.0 Kg/m3

Time		Annual Oil Production		Annual Oil Increment	Revenue	Polymer Used	Total Cost	Cash Flow	discount	Discounted Cash Flow	
Year	Year	Base Case Sm3	With Polymer Sm3	Sm3	bbl	USD	KG	USD	USD	factor	USD
Dec-06	0	730295.9	730295.9	0	0	0.00E+00	0.00		0.00E+00	1.00	0.00E+00
Dec-07	1	625774	643215.0	17441	108134.2	7.03E+06	5.1E+06	1.53E+07	-8.30E+06	0.93	-7.76E+06
Dec-08	2	542351	600740.0	58389	362011.8	2.35E+07	5.1E+06	1.54E+07	8.16E+06	0.87	7.13E+06
Dec-09	3	477553	557666.0	80113	496700.6	3.23E+07	5.1E+06	1.53E+07	1.70E+07	0.82	1.38E+07
Dec-10	4	435652	515794.0	80142	496880.4	3.23E+07	5.1E+06	1.53E+07	1.70E+07	0.76	1.29E+07
Dec-11	5	388675	458624.0	69949	433683.8	2.82E+07	5.1E+06	1.53E+07	1.29E+07	0.71	9.17E+06
Dec-12	6	339030	396903.0	57873	358812.6	2.33E+07	0.00		2.33E+07	0.67	1.55E+07
Dec-13	7	293308	334063.0	40755	252681	1.64E+07	0.00		1.64E+07	0.62	1.02E+07
Dec-14	8	256967	282399.0	25432	157678.4	1.02E+07	0.00		1.02E+07	0.58	5.97E+06
Dec-15	9	229378	248085.0	18707	115983.4	7.54E+06	0.00		7.54E+06	0.54	4.10E+06
Dec-16	10	208595	216096.0	7501	46506.2	3.02E+06	0.00		3.02E+06	0.51	1.54E+06
Dec-17	11	190732	188739.0	-1993	-12356.6	-8.03E+05	0.00		-8.03E+05	0.48	-3.82E+05
Dec-18	12	176166	168524.0	-7642	-47380.4	-3.08E+06	0.00		-3.08E+06	0.44	-1.37E+06
Dec-19	13	163550	151671.0	-11879	-73649.8	-4.79E+06	0.00		-4.79E+06	0.41	-1.99E+06
Dec-20	14	152947	138067.0	-14880	-92256	-6.00E+06			-6.00E+06	0.39	-2.33E+06
NPV for Polymer flooding case 4 [USD]											6.66E+07

Table F.5: Incremental NPV for Polymer flooding at concentration of 4.0 Kg/m3

Time		Annual Oil Production		Annual Oil Increment	Revenue	Polymer Used	Total Cost	Cash Flow	discount	Discounted Cash Flow	
Year	Year	Base Case Sm3	With Polymer Sm3	Sm3	bbl	USD	KG	USD	USD	factor	USD
Dec-06	0	730295.9	730295.9	0	0	0.00E+00	0.00		0.00E+00	1.00	0.00E+00
Dec-07	1	625774	647981.0	22207	137683.4	8.95E+06	1.0E+07	3.07E+07	-2.17E+07	0.93	-2.03E+07
Dec-08	2	542351	616018.0	73667	456735.4	2.97E+07	1.0E+07	3.07E+07	-1.06E+06	0.87	-9.23E+05
Dec-09	3	477553	568560.0	91007	564243.4	3.67E+07	1.0E+07	3.07E+07	6.02E+06	0.82	4.91E+06
Dec-10	4	435652	520460.0	84808	525809.6	3.42E+07	1.0E+07	3.06E+07	3.53E+06	0.76	2.69E+06
Dec-11	5	388675	446681.0	58006	359637.2	2.34E+07	9.7E+06	2.90E+07	-5.64E+06	0.71	-4.02E+06
Dec-12	6	339030	370508.0	31478	195163.6	1.27E+07	0.00		1.27E+07	0.67	8.45E+06
Dec-13	7	293308	313919.0	20611	127788.2	8.31E+06	0.00		8.31E+06	0.62	5.17E+06
Dec-14	8	256967	267065.0	10098	62607.6	4.07E+06	0.00		4.07E+06	0.58	2.37E+06
Dec-15	9	229378	239662.0	10284	63760.8	4.14E+06	0.00		4.14E+06	0.54	2.25E+06
Dec-16	10	208595	224602.0	16007	99243.4	6.45E+06	0.00		6.45E+06	0.51	3.28E+06
Dec-17	11	190732	205426.0	14694	91102.8	5.92E+06	0.00		5.92E+06	0.48	2.81E+06
Dec-18	12	176166	183542.0	7376	45731.2	2.97E+06	0.00		2.97E+06	0.44	1.32E+06
Dec-19	13	163550	162915.0	-635	-3937	-2.56E+05	0.00		-2.56E+05	0.41	-1.06E+05
Dec-20	14	152947	147615.0	-5332	-33058.4	-2.15E+06			-2.15E+06	0.39	-8.33E+05
NPV for Polymer flooding case 5 [USD]											7.09E+06

F.2 Incremental NPV for different starting points of Polymer (P) flooding (1.5 kg/m3)

Table F.6: Incremental NPV for Polymer (1.5 kg/m3) flooding starting 2006

Time		Annual Oil Production		Annual Oil Increment		Revenue	Polymer Used	Total Cost	Cash Flow	Discount	Discounted Cash Flow
		Base Case	With Polymer			USD	KG	USD	USD	factor	USD
Year	Year	Sm3	Sm3	Sm3	bbl						
Dec-06	0	730295.9	730295.9	0	0	0.00E+00			0.00E+00	1.00	0.00E+00
Dec-07	1	625774	641616.0	15842	98220.4	6.38E+06	3.8E+06	1.15E+07	-5.11E+06	0.93	-4.78E+06
Dec-08	2	542351	595036.0	52685	326647	2.12E+07	3.8E+06	1.15E+07	9.70E+06	0.87	8.48E+06
Dec-09	3	477553	550082.0	72529	449679.8	2.92E+07	3.8E+06	1.15E+07	1.77E+07	0.82	1.45E+07
Dec-10	4	435652	512509.0	76857	476513.4	3.10E+07	3.8E+06	1.15E+07	1.95E+07	0.76	1.49E+07
Dec-11	5	388675	455633.0	66958	415139.6	2.70E+07	3.8E+06	1.15E+07	1.55E+07	0.71	1.10E+07
Dec-12	6	339030	395763.0	56733	351744.6	2.29E+07			2.29E+07	0.67	1.52E+07
Dec-13	7	293308	327111.0	33803	209578.6	1.36E+07			1.36E+07	0.62	8.48E+06
Dec-14	8	256967	279233.0	22266	138049.2	8.97E+06			8.97E+06	0.58	5.22E+06
Dec-15	9	229378	241421.0	12043	74666.6	4.85E+06			4.85E+06	0.54	2.64E+06
Dec-16	10	208595	210226.0	1631	10112.2	6.57E+05			6.57E+05	0.51	3.34E+05
Dec-17	11	190732	185669.0	-5063	-31390.6	-2.04E+06			-2.04E+06	0.48	-9.69E+05
Dec-18	12	176166	166240.0	-9926	-61541.2	-4.00E+06			-4.00E+06	0.44	-1.78E+06
Dec-19	13	163550	150473.0	-13077	-81077.4	-5.27E+06			-5.27E+06	0.41	-2.19E+06
Dec-20	14	152947	138059.0	-14888	-92305.6	-6.00E+06			-6.00E+06	0.39	-2.33E+06
NPV for Polymer flooding (2006) [USD]											6.87E+07

Table F.7: Incremental NPV for Polymer (1.5 kg/m3) flooding starting 2008

Time		Annual Oil Production		Annual Oil Increment		Revenue	Polymer Used	Total Cost	Cash Flow	Discount	Discounted Cash Flow
		Base Case	With Polymer			USD	KG	USD	USD	factor	USD
Year	Year	Sm3	Sm3	Sm3	bbl						
Dec-06	0	730,296	730,296	0	0	0.00E+00			0.00E+00	1.00	0.00E+00
Dec-07	1	625,774	625,774	0	0	0.00E+00			0.00E+00	0.93	0.00E+00
Dec-08	2	542,351	542,351	0	0	0.00E+00			0.00E+00	0.87	0.00E+00
Dec-09	3	477,553	488,609	11056	68547.2	4.46E+06	3.8E+06	1.15E+07	-7.04E+06	0.82	-5.75E+06
Dec-10	4	435,652	478,879	43227	268007.4	1.74E+07	3.8E+06	1.15E+07	5.92E+06	0.76	4.52E+06
Dec-11	5	388,675	450,203	61528	381473.6	2.48E+07	3.8E+06	1.15E+07	1.33E+07	0.71	9.48E+06
Dec-12	6	339,030	404,108	65078	403483.6	2.62E+07	3.8E+06	1.15E+07	1.47E+07	0.67	9.79E+06
Dec-13	7	293,308	356,129	62821	389490.2	2.53E+07	3.8E+06	1.15E+07	1.38E+07	0.62	8.61E+06
Dec-14	8	256,967	319,240	62273	386092.6	2.51E+07			2.51E+07	0.58	1.46E+07
Dec-15	9	229,378	273,280	43902	272192.4	1.77E+07			1.77E+07	0.54	9.62E+06
Dec-16	10	208,595	236,650	28055	173941	1.13E+07			1.13E+07	0.51	5.75E+06
Dec-17	11	190,732	206,451	15719	97457.8	6.33E+06			6.33E+06	0.48	3.01E+06
Dec-18	12	176,166	180,857	4691	29084.2	1.89E+06			1.89E+06	0.44	8.39E+05
Dec-19	13	163,550	161,303	-2247	-13931.4	-9.06E+05			-9.06E+05	0.41	-3.76E+05
Dec-20	14	152,947	146,097	-6850	-42470	-2.76E+06			-2.76E+06	0.39	-1.07E+06
NPV for Polymer flooding (2008) [USD]											5.90E+07

Table F.8: Incremental NPV for Polymer (1.5 kg/m³) flooding starting 2010

Time		Annual Oil Production		Annual Oil Increment	Revenue	Polymer Used	Total Cost	Cash Flow	Discount	Discounted Cash Flow	
Year	Year	Base Case Sm ³	With Polymer Sm ³	Sm ³	bbl	USD	KG	USD	USD	factor	USD
Dec-06	0	730295.9	730295.9	0	0	0.00E+00			0.00E+00	1.00	0.00E+00
Dec-07	1	625774	625774.0	0	0	0.00E+00			0.00E+00	0.93	0.00E+00
Dec-08	2	542351	542351.0	0	0	0.00E+00			0.00E+00	0.87	0.00E+00
Dec-09	3	477553	477553.0	0	0	0.00E+00			0.00E+00	0.82	0.00E+00
Dec-10	4	435652	435652.0	0	0	0.00E+00			0.00E+00	0.76	0.00E+00
Dec-11	5	388675	397326.0	8651	53636.2	3.49E+06	3.8E+06	1.15E+07	-8.01E+06	0.71	-5.71E+06
Dec-12	6	339030	372740.0	33710	209002	1.36E+07	3.8E+06	1.15E+07	2.06E+06	0.67	1.37E+06
Dec-13	7	293308	344456.0	51148	317117.6	2.06E+07	3.8E+06	1.15E+07	9.12E+06	0.62	5.68E+06
Dec-14	8	256967	317007.0	60040	372248	2.42E+07	3.8E+06	1.15E+07	1.27E+07	0.58	7.39E+06
Dec-15	9	229378	291544.0	62166	385429.2	2.51E+07	3.8E+06	1.15E+07	1.36E+07	0.54	7.37E+06
Dec-16	10	208595	269719.0	61124	378968.8	2.46E+07			2.46E+07	0.51	1.25E+07
Dec-17	11	190732	235266.0	44534	276110.8	1.79E+07			1.79E+07	0.48	8.53E+06
Dec-18	12	176166	204686.0	28520	176824	1.15E+07			1.15E+07	0.44	5.10E+06
Dec-19	13	163550	180506.0	16956	105127.2	6.83E+06			6.83E+06	0.41	2.84E+06
Dec-20	14	152947	159745.0	6798	42147.6	2.74E+06			2.74E+06	0.39	1.06E+06
NPV for Polymer flooding (2010) [USD]											4.61E+07

Table F.9: Incremental NPV for Polymer (1.5 kg/m³) flooding starting 2012

Time		Annual Oil Production		Annual Oil Increment	Revenue	Polymer Used	Total Cost	Cash Flow	Discount	Discounted Cash Flow	
Year	Year	Base Case Sm ³	With Polymer Sm ³	Sm ³	bbl	USD	KG	USD	USD	factor	USD
Dec-06	0	730295.9	730295.9	0	0	0.00E+00			0.00E+00	1.00	0.00E+00
Dec-07	1	625774	625774.0	0	0	0.00E+00			0.00E+00	0.93	0.00E+00
Dec-08	2	542351	542351.0	0	0	0.00E+00			0.00E+00	0.87	0.00E+00
Dec-09	3	477553	477553.0	0	0	0.00E+00			0.00E+00	0.82	0.00E+00
Dec-10	4	435652	435652.0	0	0	0.00E+00			0.00E+00	0.76	0.00E+00
Dec-11	5	388675	388675.0	0	0	0.00E+00			0.00E+00	0.71	0.00E+00
Dec-12	6	339030	339030.0	0	0	0.00E+00			0.00E+00	0.67	0.00E+00
Dec-13	7	293308	299091.0	5783	35854.6	2.33E+06	3832500.30	1.15E+07	-9.17E+06	0.62	-5.71E+06
Dec-14	8	256967	282878.0	25911	160648.2	1.04E+07	3832499.90	1.15E+07	-1.06E+06	0.58	-6.14E+05
Dec-15	9	229378	273786.0	44408	275329.6	1.79E+07	3832498.80	1.15E+07	6.40E+06	0.54	3.48E+06
Dec-16	10	208595	263497.0	54902	340392.4	2.21E+07	3842999.00	1.15E+07	1.06E+07	0.51	5.39E+06
Dec-17	11	190732	247710.0	56978	353263.6	2.30E+07	3832501.00	1.15E+07	1.15E+07	0.48	5.45E+06
Dec-18	12	176166	232706.0	56540	350548	2.28E+07			2.28E+07	0.44	1.01E+07
Dec-19	13	163550	207168.0	43618	270431.6	1.76E+07			1.76E+07	0.41	7.29E+06
Dec-20	14	152947	181751.0	28804	178584.8	1.16E+07			1.16E+07	0.39	4.50E+06
NPV for Polymer flooding (2012) [USD]											2.99E+07

F.3 Incremental NPV for different Polymer (P) flooding length

Table F.10: Incremental NPV for Polymer (1.5 kg/m³) flooding for 3 years

Time		Annual Oil Production		Annual Oil Increment		Revenue	Polymer Used	Total Cost	Cash Flow	Discount	Discounted Cash Flow
		Base Case	With Polymer			USD	KG	USD	USD	factor	USD
Year	Year	Sm3	Sm3	Sm3	bbl						
Dec-06	0	730295.9	730295.9	0	0	0.00E+00	0.00		0.00E+00	1.00	0.00E+00
Dec-07	1	625774	641616.0	15842	98220.4	6.38E+06	3.8E+06	1.15E+07	-5.11E+06	0.93	-4.78E+06
Dec-08	2	542351	595036.0	52685	326647	2.12E+07	3.8E+06	1.15E+07	9.70E+06	0.87	8.48E+06
Dec-09	3	477553	550082.0	72529	449679.8	2.92E+07	3.8E+06	1.15E+07	1.77E+07	0.82	1.45E+07
Dec-10	4	435652	505889.0	70237	435469.4	2.83E+07			2.83E+07	0.76	2.16E+07
Dec-11	5	388675	428795.0	40120	248744	1.62E+07			1.62E+07	0.71	1.15E+07
Dec-12	6	339030	357174.0	18144	112492.8	7.31E+06			7.31E+06	0.67	4.87E+06
Dec-13	7	293308	299168.0	5860	36332	2.36E+06			2.36E+06	0.62	1.47E+06
Dec-14	8	256967	258211.0	1244	7712.8	5.01E+05			5.01E+05	0.58	2.92E+05
Dec-15	9	229378	226937.0	-2441	-15134.2	-9.84E+05			-9.84E+05	0.54	-5.35E+05
Dec-16	10	208595	202733.0	-5862	-36344.4	-2.36E+06			-2.36E+06	0.51	-1.20E+06
Dec-17	11	190732	182063.0	-8669	-53747.8	-3.49E+06			-3.49E+06	0.48	-1.66E+06
Dec-18	12	176166	165484.0	-10682	-66228.4	-4.30E+06			-4.30E+06	0.44	-1.91E+06
Dec-19	13	163550	151663.0	-11887	-73699.4	-4.79E+06			-4.79E+06	0.41	-1.99E+06
Dec-20	14	152947	140416.0	-12531	-77692.2	-5.05E+06			-5.05E+06	0.39	-1.96E+06
NPV for Polymer flooding for 3 yrs [USD]											4.87E+07

Table F.11: Incremental NPV for Polymer (1.5 kg/m³) flooding for 5 years

Time		Annual Oil Production		Annual Oil Increment		Revenue	Polymer Used	Total Cost	Cash Flow	Discount	Discounted Cash Flow
		Base Case	With Polymer			USD	KG	USD	USD	factor	USD
Year	Year	Sm3	Sm3	Sm3	bbl						
Dec-06	0	730,296	730,296	0	0	0.00E+00	0.00		0.00E+00	1.00	0.00E+00
Dec-07	1	625,774	641,616	15842	98220.4	6.38E+06	3.8E+06	1.15E+07	-5.11E+06	0.93	-4.78E+06
Dec-08	2	542,351	595,036	52685	326647	2.12E+07	3.8E+06	1.15E+07	9.70E+06	0.87	8.48E+06
Dec-09	3	477,553	550,082	72529	449679.8	2.92E+07	3.8E+06	1.15E+07	1.77E+07	0.82	1.45E+07
Dec-10	4	435,652	512,509	76857	476513.4	3.10E+07	3.8E+06	1.15E+07	1.95E+07	0.76	1.49E+07
Dec-11	5	388,675	455,633	66958	415139.6	2.70E+07	3.8E+06	1.15E+07	1.55E+07	0.71	1.10E+07
Dec-12	6	339,030	395,763	56733	351744.6	2.29E+07			2.29E+07	0.67	1.52E+07
Dec-13	7	293,308	327,111	33803	209578.6	1.36E+07			1.36E+07	0.62	8.48E+06
Dec-14	8	256,967	279,233	22266	138049.2	8.97E+06			8.97E+06	0.58	5.22E+06
Dec-15	9	229,378	241,421	12043	74666.6	4.85E+06			4.85E+06	0.54	2.64E+06
Dec-16	10	208,595	210,226	1631	10112.2	6.57E+05			6.57E+05	0.51	3.34E+05
Dec-17	11	190,732	185,669	-5063	-31390.6	-2.04E+06			-2.04E+06	0.48	-9.69E+05
Dec-18	12	176,166	166,240	-9926	-61541.2	-4.00E+06			-4.00E+06	0.44	-1.78E+06
Dec-19	13	163,550	150,473	-13077	-81077.4	-5.27E+06			-5.27E+06	0.41	-2.19E+06
Dec-20	14	152,947	138,059	-14888	-92305.6	-6.00E+06			-6.00E+06	0.39	-2.33E+06
NPV for Polymer flooding for 5 yrs [USD]											6.87E+07

Appendix G

Incremental NPV for different cases of Surfactant-Polymer (SP) flooding (Norne E - Segment)

Table G.1: Incremental NPV for Surfactant-Polymer (0.3 kg/m³ and 1.5 kg/m³) injection for 5 years

Time		Annual Oil Production		Annual Oil Increment		Revenue	Surfactant Used	Polymer Used	Total Cost	Cash Flow	Discount	Discounted Cash Flow
		Base Case	With SP			USD	KG	KG	USD	USD	factor	USD
Year	Year	Sm3	Sm3	Sm3	bbl							
Dec-06	0	730295.9	730295.9	0	0	0.00E+00				0.00E+00	1.00	0.00E+00
Dec-07	1	625774	641606.0	15832	98158.4	6.38E+06	7.66E+05	3.8E+06	1.42E+07	-7.80E+06	0.93	-7.29E+06
Dec-08	2	542351	595111.0	52760	327112	2.13E+07	7.69E+05	3.8E+06	1.42E+07	7.04E+06	0.87	6.15E+06
Dec-09	3	477553	550204.0	72651	450436.2	2.93E+07	7.66E+05	3.8E+06	1.42E+07	1.51E+07	0.82	1.23E+07
Dec-10	4	435652	512122.0	76470	474114	3.08E+07	7.67E+05	3.8E+06	1.42E+07	1.66E+07	0.76	1.27E+07
Dec-11	5	388675	455112.0	66437	411909.4	2.68E+07	7.67E+05	3.8E+06	1.42E+07	1.26E+07	0.71	8.98E+06
Dec-12	6	339030	396037.0	57007	353443.4	2.30E+07				2.30E+07	0.67	1.53E+07
Dec-13	7	293308	327349.0	34041	211054.2	1.37E+07				1.37E+07	0.62	8.54E+06
Dec-14	8	256967	279433.0	22466	139289.2	9.05E+06				9.05E+06	0.58	5.27E+06
Dec-15	9	229378	241554.0	12176	75491.2	4.91E+06				4.91E+06	0.54	2.67E+06
Dec-16	10	208595	210269.0	1674	10378.8	6.75E+05				6.75E+05	0.51	3.43E+05
Dec-17	11	190732	185665.0	-5067	-31415.4	-2.04E+06				-2.04E+06	0.48	-9.70E+05
Dec-18	12	176166	166238.0	-9928	-61553.6	-4.00E+06				-4.00E+06	0.44	-1.78E+06
Dec-19	13	163550	150489.0	-13061	-80978.2	-5.26E+06				-5.26E+06	0.41	-2.18E+06
Dec-20	14	152947	138105.0	-14842	-92020.4	-5.98E+06				-5.98E+06	0.39	-2.32E+06
NPV for SP Case 1											NPV [USD]	5.77E+07

Table G.2: Incremental NPV for Surfactant-Polymer (0.3 kg/m³ and 2.0 kg/m³) injection for 5 years

Time		Annual Oil Production		Annual Oil Increment		Revenue	Surfactant Used	Polymer Used	Total Cost	Cash Flow	Discount	Discounted Cash Flow
		Base Case	With SP			USD	KG	KG	USD	USD	factor	USD
Year	Year	Sm3	Sm3	Sm3	bbl							
Dec-06	0	730295.9	730295.9	0	0	0.00E+00				0.00E+00	1.00	0.00E+00
Dec-07	1	625774	643261.0	17487	108419.4	7.05E+06	7.67E+05	5.1E+06	1.80E+07	-1.10E+07	0.93	-1.02E+07
Dec-08	2	542351	600778.0	58427	362247.4	2.35E+07	7.69E+05	5.1E+06	1.81E+07	5.48E+06	0.87	4.79E+06
Dec-09	3	477553	557741.0	80188	497165.6	3.23E+07	7.67E+05	5.1E+06	1.80E+07	1.43E+07	0.82	1.17E+07
Dec-10	4	435652	515983.0	80331	498052.2	3.24E+07	7.66E+05	5.1E+06	1.80E+07	1.44E+07	0.76	1.10E+07
Dec-11	5	388675	458746.0	70071	434440.2	2.82E+07	7.67E+05	5.1E+06	1.80E+07	1.02E+07	0.71	7.29E+06
Dec-12	6	339030	397056.0	58026	359761.2	2.34E+07				2.34E+07	0.67	1.56E+07
Dec-13	7	293308	334046.0	40738	252575.6	1.64E+07				1.64E+07	0.62	1.02E+07
Dec-14	8	256967	282468.0	25501	158106.2	1.03E+07				1.03E+07	0.58	5.98E+06
Dec-15	9	229378	248106.0	18728	116113.6	7.55E+06				7.55E+06	0.54	4.11E+06
Dec-16	10	208595	216156.0	7561	46878.2	3.05E+06				3.05E+06	0.51	1.55E+06
Dec-17	11	190732	188781.0	-1951	-12096.2	-7.86E+05				-7.86E+05	0.48	-3.74E+05
Dec-18	12	176166	168554.0	-7612	-47194.4	-3.07E+06				-3.07E+06	0.44	-1.36E+06
Dec-19	13	163550	151700.0	-11850	-73470	-4.78E+06				-4.78E+06	0.41	-1.98E+06
Dec-20	14	152947	138096.0	-14851	-92076.2	-5.98E+06				-5.98E+06	0.39	-2.32E+06
NPV for SP Case 2											NPV [USD]	5.59E+07

Table G.3: Incremental NPV for Surfactant-Polymer (0.3 kg/m³ and 2.5 kg/m³) injection for 5 years

Time		Annual Oil Production		Annual Oil Increment		Revenue	Surfactant Used	Polymer Used	Total Cost	Cash Flow	Discount	Discounted Cash Flow
Year	Year	Base Case	With SP			USD	KG	KG	USD	USD	factor	USD
		Sm3	Sm3	Sm3	bbl							
Dec-06	0	730295.9	730295.9	0	0	0.00E+00				0.00E+00	1.00	0.00E+00
Dec-07	1	625774	644716.0	18942	117440.4	7.63E+06	7.66E+05	6.4E+06	2.18E+07	-1.42E+07	0.93	-1.33E+07
Dec-08	2	542351	605615.0	63264	392236.8	2.55E+07	7.69E+05	6.4E+06	2.19E+07	3.59E+06	0.87	3.14E+06
Dec-09	3	477553	562569.0	85016	527099.2	3.43E+07	7.67E+05	6.4E+06	2.18E+07	1.24E+07	0.82	1.01E+07
Dec-10	4	435652	518506.0	82854	513694.8	3.34E+07	7.67E+05	6.4E+06	2.18E+07	1.15E+07	0.76	8.81E+06
Dec-11	5	388675	458948.0	70273	435692.6	2.83E+07	7.63E+05	6.4E+06	2.18E+07	6.56E+06	0.71	4.68E+06
Dec-12	6	339030	392686.0	53656	332667.2	2.16E+07				2.16E+07	0.67	1.44E+07
Dec-13	7	293308	330819.0	37511	232568.2	1.51E+07				1.51E+07	0.62	9.41E+06
Dec-14	8	256967	283166.0	26199	162433.8	1.06E+07				1.06E+07	0.58	6.14E+06
Dec-15	9	229378	250828.0	21450	132990	8.64E+06				8.64E+06	0.54	4.70E+06
Dec-16	10	208595	222525.0	13930	86366	5.61E+06				5.61E+06	0.51	2.85E+06
Dec-17	11	190732	193551.0	2819	17477.8	1.14E+06				1.14E+06	0.48	5.40E+05
Dec-18	12	176166	171953.0	-4213	-26120.6	-1.70E+06				-1.70E+06	0.44	-7.54E+05
Dec-19	13	163550	154716.0	-8834	-54770.8	-3.56E+06				-3.56E+06	0.41	-1.48E+06
Dec-20	14	152947	140779.0	-12168	-75441.6	-4.90E+06				-4.90E+06	0.39	-1.90E+06
NPV for SP Case 3										NPV [USD]		4.74E+07

Appendix H

Incremental NPV for different cases of ASP flooding (Norne E - Segment)

Table H.1: Incremental NPV for ASP (1 kg/m3, 0.2 kg/m3 and 2 kg/m3) injection for 5 years

Time		Annual Oil Production		Annual Oil Increment	Revenue	Polymer Used	Alkaline Used	Surfactant Used	Total Cost	Cash Flow	Discount	Discounted Cash Flow	
Year	Year	Base Case	With ASP		USD	KG	KG	KG	USD	USD	factor	USD	
		Sm3	Sm3	Sm3	bbl								
Dec-06	0	730296	730296	0	0	0.00E+00					1.00	0.00E+00	
Dec-07	1	625774	643281	17507	108543.4	7.06E+06	5.11E+06	2.56E+06	5.1E+05	1.97E+07	-1.26E+07	0.93	-1.18E+07
Dec-08	2	542351	600783	58432	362278.4	2.35E+07	5.12E+06	2.56E+06	5.1E+05	1.97E+07	3.82E+06	0.87	3.34E+06
Dec-09	3	477553	557748	80195	497209	3.23E+07	5.11E+06	2.55E+06	5.1E+05	1.97E+07	1.26E+07	0.82	1.03E+07
Dec-10	4	435652	515957	80305	497891	3.24E+07	5.11E+06	2.56E+06	5.1E+05	1.97E+07	1.27E+07	0.76	9.68E+06
Dec-11	5	388675	458737	70062	434384.4	2.82E+07	5.11E+06	2.56E+06	5.1E+05	1.97E+07	8.56E+06	0.71	6.10E+06
Dec-12	6	339030	397030	58000	359600	2.34E+07					2.34E+07	0.67	1.56E+07
Dec-13	7	293308	334089	40781	252842.2	1.64E+07					1.64E+07	0.62	1.02E+07
Dec-14	8	256967	282444	25477	157957.4	1.03E+07					1.03E+07	0.58	5.98E+06
Dec-15	9	229378	248118	18740	116188	7.55E+06					7.55E+06	0.54	4.11E+06
Dec-16	10	208595	216136	7541	46754.2	3.04E+06					3.04E+06	0.51	1.54E+06
Dec-17	11	190732	188783	-1949	-12083.8	-7.85E+05					-7.85E+05	0.48	-3.73E+05
Dec-18	12	176166	168565	-7601	-47126.2	-3.06E+06					-3.06E+06	0.44	-1.36E+06
Dec-19	13	163550	151707	-11843	-73426.6	-4.77E+06					-4.77E+06	0.41	-1.98E+06
Dec-20	14	152947	138091	-14856	-92107.2	-5.99E+06					-5.99E+06	0.39	-2.32E+06
NPV for ASP Case 1											NPV [USD]	4.91E+07	

Table H.2: Incremental NPV for ASP (1 kg/m3, 0.2 kg/m3 and 2 kg/m3) injection for 8 years

Time		Annual Oil Production		Annual Oil Increment	Revenue	Polymer Used	Alkaline Used	Surfactant Used	Total Cost	Cash Flow	Discount	Discounted Cash Flow	
Year	Year	Base Case	With ASP		USD	KG	KG	KG	USD	USD	factor	USD	
		Sm3	Sm3	Sm3	bbl								
Dec-06	0	730296	730296	0	0	0.00E+00					1.00	0.00E+00	
Dec-07	1	625774	643281	17507	108543.4	7.06E+06	5.11E+06	2.56E+06	5.1E+05	1.97E+07	-1.26E+07	0.93	-1.18E+07
Dec-08	2	542351	600783	58432	362278.4	2.35E+07	5.12E+06	2.56E+06	5.1E+05	1.97E+07	3.82E+06	0.87	3.34E+06
Dec-09	3	477553	557748	80195	497209	3.23E+07	5.11E+06	2.55E+06	5.1E+05	1.97E+07	1.26E+07	0.82	1.03E+07
Dec-10	4	435652	515957	80305	497891	3.24E+07	5.11E+06	2.56E+06	5.1E+05	1.97E+07	1.27E+07	0.76	9.68E+06
Dec-11	5	388675	458737	70062	434384.4	2.82E+07	5.11E+06	2.56E+06	5.1E+05	1.97E+07	8.56E+06	0.71	6.10E+06
Dec-12	6	339030	398276	59246	367325.2	2.39E+07	5.11E+06	2.56E+06	511029.50	1.97E+07	4.20E+06	0.67	2.80E+06
Dec-13	7	293308	346292	52984	328500.8	2.14E+07	4.94E+06	2.47E+06	493652.50	1.90E+07	2.35E+06	0.62	1.46E+06
Dec-14	8	256967	303821	46854	290494.8	1.89E+07	4.76E+06	2.38E+06	475688.80	1.83E+07	5.68E+05	0.58	3.31E+05
Dec-15	9	229378	266981	37603	233138.6	1.52E+07					1.52E+07	0.54	8.24E+06
Dec-16	10	208595	232313	23718	147051.6	9.56E+06					9.56E+06	0.51	4.86E+06
Dec-17	11	190732	208433	17701	109746.2	7.13E+06					7.13E+06	0.48	3.39E+06
Dec-18	12	176166	189549	13383	82974.6	5.39E+06					5.39E+06	0.44	2.39E+06
Dec-19	13	163550	167027	3477	21557.4	1.40E+06					1.40E+06	0.41	5.81E+05
Dec-20	14	152947	149033	-3914	-24266.8	-1.58E+06					-1.58E+06	0.39	-6.12E+05
NPV for ASP Case 2											NPV [USD]	4.11E+07	

Table H.3: Incremental NPV for ASP (1 kg/m3, 0.2 kg/m3 and 2 kg/m3) injection for 5 years followed by 2 years of WI and 2 years of Polymer(0.4 kg/m3) injection

Time		Annual Oil Production				Annual Oil Increment	Revenue	Polymer Used	Alkaline Used	Surfactant Used	Total Cost	Cash Flow	Discount	Discounted Cash Flow
Year	Year	Base Case	With ASP			USD	KG	KG	KG	USD	USD	factor	USD	
		Sm3	Sm3	Sm3	bbl									
Dec-06	0	730296	730296	0	0	0.00E+00						1.00	0.00E+00	
Dec-07	1	625774	643281	17507	108543.4	7.06E+06	5.11E+06	2.56E+06	5.1E+05	1.97E+07	-1.26E+07	0.93	-1.18E+07	
Dec-08	2	542351	600783	58432	362278.4	2.35E+07	5.12E+06	2.56E+06	5.1E+05	1.97E+07	3.82E+06	0.87	3.34E+06	
Dec-09	3	477553	557748	80195	497209	3.23E+07	5.11E+06	2.55E+06	5.1E+05	1.97E+07	1.26E+07	0.82	1.03E+07	
Dec-10	4	435652	515957	80305	497891	3.24E+07	5.11E+06	2.56E+06	5.1E+05	1.97E+07	1.27E+07	0.76	9.68E+06	
Dec-11	5	388675	458737	70062	434384.4	2.82E+07	5.11E+06	2.56E+06	5.1E+05	1.97E+07	8.56E+06	0.71	6.10E+06	
Dec-12	6	339030	397030	58000	359600	2.34E+07					2.34E+07	0.67	1.56E+07	
Dec-13	7	293308	334089	40781	252842.2	1.64E+07					1.64E+07	0.62	1.02E+07	
Dec-14	8	256967	286773	29806	184797.2	1.20E+07	1.02E+06	0.00E+00		3.07E+06	8.95E+06	0.58	5.21E+06	
Dec-15	9	229378	262282	32904	204004.8	1.33E+07	1.02E+06	0.00E+00		3.07E+06	1.02E+07	0.54	5.55E+06	
Dec-16	10	208595	233898	25303	156878.6	1.02E+07					1.02E+07	0.51	5.18E+06	
Dec-17	11	190732	200240	9508	58949.6	3.83E+06					3.83E+06	0.48	1.82E+06	
Dec-18	12	176166	174413	-1753	-10868.6	-7.06E+05					-7.06E+05	0.44	-3.14E+05	
Dec-19	13	163550	154367	-9183	-56934.6	-3.70E+06					-3.70E+06	0.41	-1.54E+06	
Dec-20	14	152947	138522	-14425	-89435	-5.81E+06					-5.81E+06	0.39	-2.25E+06	
NPV for ASP Case 3												NPV [USD]	5.71E+07	

Table H.4: Incremental NPV for ASP (1 kg/m3, 0.2 kg/m3 and 2 kg/m3) injection for 8 years followed by 2 years of WI and 2 years of Polymer(0.4 kg/m3) injection

Time		Annual Oil Production				Annual Oil Increment	Revenue	Polymer Used	Alkaline Used	Surfactant Used	Total Cost	Cash Flow	Discount	Discounted Cash Flow
Year	Year	Base Case	With ASP			USD	KG	KG	KG	USD	USD	factor	USD	
		Sm3	Sm3	Sm3	bbl									
Dec-06	0	730296	730296	0	0	0.00E+00						1.00	0.00E+00	
Dec-07	1	625774	643281	17507	108543.4	7.06E+06	5.11E+06	2.56E+06	5.1E+05	1.97E+07	-1.26E+07	0.93	-1.18E+07	
Dec-08	2	542351	600783	58432	362278.4	2.35E+07	5.12E+06	2.56E+06	5.1E+05	1.97E+07	3.82E+06	0.87	3.34E+06	
Dec-09	3	477553	557748	80195	497209	3.23E+07	5.11E+06	2.55E+06	5.1E+05	1.97E+07	1.26E+07	0.82	1.03E+07	
Dec-10	4	435652	515957	80305	497891	3.24E+07	5.11E+06	2.56E+06	5.1E+05	1.97E+07	1.27E+07	0.76	9.68E+06	
Dec-11	5	388675	458737	70062	434384.4	2.82E+07	5.11E+06	2.56E+06	5.1E+05	1.97E+07	8.56E+06	0.71	6.10E+06	
Dec-12	6	339030	398276	59246	367325.2	2.39E+07	5.11E+06	2.56E+06	5.1E+05	1.97E+07	4.20E+06	0.67	2.80E+06	
Dec-13	7	293308	346292	52984	328500.8	2.14E+07	4.94E+06	2.47E+06	4.9E+05	1.90E+07	2.35E+06	0.62	1.46E+06	
Dec-14	8	256967	303821	46854	290494.8	1.89E+07	4.76E+06	2.38E+06	4.8E+05	1.83E+07	5.68E+05	0.58	3.31E+05	
Dec-15	9	229378	266981	37603	233138.6	1.52E+07					1.52E+07	0.54	8.24E+06	
Dec-16	10	208595	232313	23718	147051.6	9.56E+06					9.56E+06	0.51	4.86E+06	
Dec-17	11	190732	211805	21073	130652.6	8.49E+06	1.02E+06			3.07E+06	5.43E+06	0.48	2.58E+06	
Dec-18	12	176166	198951	22785	141267	9.18E+06	1.02E+06			3.07E+06	6.12E+06	0.44	2.72E+06	
Dec-19	13	163550	179070	15520	96224	6.25E+06					6.25E+06	0.41	2.60E+06	
Dec-20	14	152947	158550	5603	34738.6	2.26E+06					2.26E+06	0.39	8.76E+05	
NPV for ASP Case 4												NPV [USD]	4.41E+07	

