ABSTRACT

About 60% of oil still lays trapped in the reservoir even after primary and secondary recovery processes have been completed. This trapped oil could be residual or by-passed oil. Residual oil occurs as a result of high capillary action of water that keeps the oil immobile. One way of recovering this capillary trapped oil is by flooding the reservoir with surfactants. Surfactants are surface active agents that act on the interface between oil and water with the aim of reducing the interfacial tension between them thereby causing trapped oil to flow.

In the Norne field E-Segment, pockets of oil are still trapped after water flooding for a number of years, especially in the Ile and Tofte Formations which holds about 80% of oil in the Norne E-Segment. With increasing water cut and reduced oil production, it becomes obvious that water flooding alone cannot recover the oil effectively, thus a need for an enhancing agent, like surfactant.

When flooding the reservoir with surfactants, it is very important to ascertain the right quantity of surfactant that would yield the maximum recovery without unnecessary waste of the surfactant because of the high cost.

In this thesis, a series of screening methods were used in order to come up with the appropriate surfactant quantity and concentration that would yield maximum recovery of trapped oil at a minimal cost.

The first step was modeling of continuous surfactant flooding into the reservoir for a period of 4 years and 7 years respectively. It was discovered that flooding the reservoir for a period of 7 years did not necessarily lead to a better oil recovery than flooding for 4 years. Also, flooding for 7 years led to a high quantity of surfactant injection into the reservoir and a subsequent production of same at the producer well E-2H. A situation like this is not desirable because of the cost of surfactants.

Having established that a 4-year surfactant injection period is preferable to a 7-year period, the second step was to compare between slug injection of surfactants at 2 months intervals and at 6 months intervals respectively. It was discovered that injecting surfactant slug every 2 months (that is 3 times in a year) did not necessarily do better than injecting at every 6 months interval. Also, injecting surfactant every 2 months required very high quantities of surfactants to meet the demand. Also there is a high production of surfactant at the producer well.

Having confirmed through reservoir modeling that surfactant slug injection for a 6-month interval is better than that of a 2-month interval, the next step was to compare between continuous surfactant injection for 4 years and surfactant slug injection for 4 years (at 6-month interval). Continuous surfactant flooding was discarded in favor of the slug injection because of
the high quantity of surfactant needed compared to the quantity needed in case of slug injection. Also, continuous surfactant flooding did not necessarily lead to better oil recovery than slug surfactant flooding.

Having established that the most effective method to inject surfactant into the reservoir is slug injection for 4 years at 6 months interval, the next challenge was to determine the appropriate surfactant concentration that would be needed for optimal recovery of residual oil. Eight (8) different surfactant concentrations were modeled and these include concentrations at 10kg/m³, 20kg/m³, 30kg/m³, 40kg/m³, 50kg/m³, 60kg/m³, 80kg/m³ and 100kg/m³. Net present value (NPV) was used to determine the best concentration that would yield the maximum profit. The concentration of 10kg/m³ gave the best NPV.

Having discovered that the surfactant slug of 10kg/m³ concentration would yield better recovery, the next task was to check the effect of drilling new wells or recompleting already drilled wells on recovery.

Four cases were considered;
1. Original wells without injection of surfactant slug.
2. Original wells with surfactant slug injection.
3. Injecting surfactant slug into original wells in addition to a newly drilled well.
4. Injecting surfactant slug into wells that had been re-completed/extended in addition to a newly drilled well.

From the economic analysis, it was discovered that recompleting the wells in addition to a new well gave the best NPV followed by the case where surfactant was injected to the original well with a newly drilled well. All these options did better than the base-case where surfactant was not injected at all.

The case of re-completion of the wells gave a better recovery because the re-completed wells were made to inject surfactants directly into the Ile and Tofte formations which hold about 80% of oil in the reservoir.

In conclusion, surfactant flooding is a good option for the Norne field E-Segment especially when the Ile and Tofte formations are targeted.

Based on this conclusion, it is recommended that the right surfactant structure that would be suitable for the Norne field E-Segment fluid and rock property be developed in the laboratory (this thesis involved only simulation studies). It is also important that up-scaling the appropriate laboratory identified surfactants to a field-scale usage be done correctly. Studies have shown that the reason why many surfactants that seem to do well in the laboratory but do not do well in the field is due to incorrect up-scaling.
The timing of surfactant injection into the Norne field E-Segment is also recommended to be early in the life of the field. This is because of the heterogeneous nature of the field. Injection of surfactant at a later time might not lead to optimum oil recovery.

Thus, simulation studies show that surfactant injection, at the appropriate time is good for the Norne E-Segment.
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Above all, I worship the Almighty God for giving me the strength and understanding to complete this work. Thank You Lord.
DEDICATION

I say a big thank you to my wonderful husband, Nwabufo and my three lovely children Chidalu, Chiadika and Chidiuso for the love, patience and support they gave to me during the course of this master program. I love you very much.

May God always bless you.
DISCLAIMER

All view expressed in this thesis are mine and does not necessarily reflect the views of Statoil and the Norne license partners.
# TABLE OF CONTENT

1.0 **Introduction**  

1.1 Enhanced Oil Recovery  

1.2 Basic Mechanism of EOR  
   1.2.1 Improving the Mobility Ratio  
   1.2.2 Increasing the Capillary Number  

1.3 Classification of EOR Methods  
   1.3.1 Chemical Flooding  
      1.3.1.1 Polymer  
      1.3.1.2 Surfactant Flooding  
      1.3.1.3 Alkaline Flooding  
      1.3.1.4 Micellar Flooding  
      1.3.1.5 ASP Flooding  
   1.3.2 Miscible Displacement  
      1.3.2.1 Miscible Slug Process  
      1.3.2.2 Vaporizing Gas Drive  
      1.3.2.3 Carbon dioxide Flooding  
      1.3.2.4 Nitrogen & Flue-gas Flooding  
   1.3.3 Thermal Flooding  
      1.3.3.1 Cyclic Steam Stimulation  
      1.3.3.2 Steam Assisted Gravity Drainage  
      1.3.3.3 In Situ Combustion
1.3.3.4 Toe-to-Heel Air Injection 10
1.3.3.5 VAPEX Process 12
1.34 Microbial Enhanced Oil Recovery (MEOR) 12
1.4 Enhanced Oil Recovery (EOR) Screening Criteria 13

2.0 Overview of Surfactants 15
2.1 Structure of a surfactant 16
2.2 Basic Surfactant Classification 17
   2.2.1 Anionic 18
   2.2.2 Cationic 18
   2.2.3 Nonionic 18
   2.2.4 Amphoteric 18
2.3 Application of Surfactants 18
2.4 Surfactants in the Petroleum Industry 19
2.5 Literature Review 21
2.6 Surfactant Flooding in Petroleum Reservoirs 25
   2.61 Process Description 25
   2.62 Capillary Desaturation 26
   2.63 Volumetric Sweep Efficiency 27
   2.64 Effect of Salinity on Surfactant 28
2.7 Surfactant Flooding of the North Sea 31
   2.71 Use of Polymer 31
   2.72 Temperature Variation 31
2.73 Core Floods
2.74 Low Tension Polymer Flood
2.75 Timing

2.8 Factors That Affect the Efficiency of Surfactant
2.81 Adsorption
2.82 Preventing Adsorption

2.9 Modeling Surfactant Flooding in Reservoir Using Eclipse
2.91 Relative Permeability Model
2.92 Capillary Pressure
2.93 Water PVT Properties
2.94 Activating the Surfactant Model in Eclipse

2.10 Limitations of Eclipse Simulator in surfactant Flooding

3.0 Norne Field: General Information

3.1 Reservoir Description
3.2 Reservoir Communication
3.3 Drainage Strategy
3.4 Geology

3.4.1 Garn Formation
3.4.2 Not Formation
3.4.3 Ile Formation
3.4.4 Tofte Formation
3.4.5 Tilje Formation
<table>
<thead>
<tr>
<th>Section</th>
<th>Title</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.46</td>
<td>Ile &amp; Tofte</td>
<td>47</td>
</tr>
<tr>
<td>3.5</td>
<td>Oil and Gas Composition</td>
<td>47</td>
</tr>
<tr>
<td>3.6</td>
<td>Production</td>
<td>48</td>
</tr>
<tr>
<td>3.7</td>
<td>Norne Field E-Segment</td>
<td>51</td>
</tr>
<tr>
<td>3.71</td>
<td>Modeling of Norne E-Segment in Eclipse</td>
<td>51</td>
</tr>
<tr>
<td>3.72</td>
<td>Coarse Model</td>
<td>53</td>
</tr>
<tr>
<td>3.8</td>
<td>Production Profile of the E-Segment</td>
<td>53</td>
</tr>
<tr>
<td>3.9</td>
<td>Pressure Profile</td>
<td>60</td>
</tr>
<tr>
<td>3.10</td>
<td>EOR Potential for the Norne Field E-Segment</td>
<td>60</td>
</tr>
<tr>
<td>3.11</td>
<td>Strategy for Surfactant Flooding in This Thesis</td>
<td>63</td>
</tr>
<tr>
<td>3.12</td>
<td>Testing out Surfactant Flooding Option on a Synthetic Model</td>
<td>63</td>
</tr>
<tr>
<td>3.12.1</td>
<td>Results of Synthetic Simulation</td>
<td>64</td>
</tr>
<tr>
<td>4.0</td>
<td>Results of Surfactant Simulation &amp; Discussion</td>
<td>67</td>
</tr>
<tr>
<td>4.1</td>
<td>Continuous Surfactant Injection</td>
<td>67</td>
</tr>
<tr>
<td>4.2</td>
<td>Surfactant Slug Injection</td>
<td>67</td>
</tr>
<tr>
<td>4.3</td>
<td>Appropriate Surfactant Concentration</td>
<td>75</td>
</tr>
<tr>
<td>4.4</td>
<td>Injecting Surfactant into the Norne E-Segment (Modified Wells)</td>
<td>78</td>
</tr>
<tr>
<td>4.41</td>
<td>Injecting Surfactant with Original Well Configuration</td>
<td>78</td>
</tr>
<tr>
<td>4.42</td>
<td>Injecting Surfactants into Re-completed &amp; New Wells</td>
<td>79</td>
</tr>
<tr>
<td>4.43</td>
<td>Injecting Surfactants with Original wells &amp; New Wells</td>
<td>80</td>
</tr>
<tr>
<td>4.44</td>
<td>Well Configuration</td>
<td>81</td>
</tr>
<tr>
<td>4.45</td>
<td>Effect of Surfactant Injection into all well configuration</td>
<td>82</td>
</tr>
</tbody>
</table>
# LIST OF FIGURES

<table>
<thead>
<tr>
<th>Figure</th>
<th>Description</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Figure 1</td>
<td>World Petroleum Consumption</td>
<td>1</td>
</tr>
<tr>
<td>Figure 2</td>
<td>Water Fingering into Oil Bank</td>
<td>5</td>
</tr>
<tr>
<td>Figure 3</td>
<td>Classification of EOR Processes</td>
<td>6</td>
</tr>
<tr>
<td>Figure 4</td>
<td>Micellar Flooding Process</td>
<td>7</td>
</tr>
<tr>
<td>Figure 5</td>
<td>Cyclic Steam Stimulation</td>
<td>11</td>
</tr>
<tr>
<td>Figure 6</td>
<td>Steam Assisted Gravity Drainage</td>
<td>11</td>
</tr>
<tr>
<td>Figure 7</td>
<td>Toe-To Heel Air Injection</td>
<td>12</td>
</tr>
<tr>
<td>Figure 8</td>
<td>Critical Micelle Concentration</td>
<td>16</td>
</tr>
<tr>
<td>Figure 9</td>
<td>Structure of Molecular Surfactant</td>
<td>17</td>
</tr>
<tr>
<td>Figure 10</td>
<td>Effect of Pore-size Distribution on CDC</td>
<td>26</td>
</tr>
<tr>
<td>Figure 11</td>
<td>Effect of Wettability on Residual Oil Saturation</td>
<td>27</td>
</tr>
<tr>
<td>Figure 12</td>
<td>Schematic Representation of Type II (-)</td>
<td>29</td>
</tr>
<tr>
<td>Figure 13</td>
<td>Schematic Representation of Type II (+)</td>
<td>29</td>
</tr>
<tr>
<td>Figure 14</td>
<td>Schematic Representation of Type III</td>
<td>30</td>
</tr>
<tr>
<td>Figure 15</td>
<td>Phase Behavior Representation</td>
<td>30</td>
</tr>
<tr>
<td>Figure 16</td>
<td>Schematic S-shaped Adsorption Isotherm</td>
<td>34</td>
</tr>
<tr>
<td>Figure 17</td>
<td>Relative Permeability Calculation in Eclipse</td>
<td>37</td>
</tr>
<tr>
<td>Figure 18</td>
<td>Eclipse Data File</td>
<td>39</td>
</tr>
<tr>
<td>Figure 19</td>
<td>Norne Field Position</td>
<td>41</td>
</tr>
<tr>
<td>Figure 20</td>
<td>Norne Field Segment &amp; Wells</td>
<td>43</td>
</tr>
<tr>
<td>Figure 21</td>
<td>Schematic Illustration of North-South Structural Profile</td>
<td>44</td>
</tr>
<tr>
<td>Figure 22</td>
<td>NE-SW Cross-Section of fluid Contact &amp; Drainage Strategy</td>
<td>45</td>
</tr>
<tr>
<td>Figure 23</td>
<td>Drainage Strategy for the Norne Field From date to 2014</td>
<td>45</td>
</tr>
<tr>
<td>Figure 24</td>
<td>Stratigraphic Subdivision of the Norne Reservoir</td>
<td>48</td>
</tr>
<tr>
<td>Figure 25</td>
<td>Oil production from Norne Field within 24 months</td>
<td>49</td>
</tr>
<tr>
<td>Figure 26</td>
<td>Gas production from Norne Field within 24 months</td>
<td>50</td>
</tr>
<tr>
<td>Figure 27</td>
<td>Water production from Norne Field within 24 months</td>
<td>50</td>
</tr>
<tr>
<td>Figure 28</td>
<td>Norne Field Showing E-Segment</td>
<td>54</td>
</tr>
<tr>
<td>Figure 29</td>
<td>Water Production Rate in E-Segment</td>
<td>55</td>
</tr>
<tr>
<td>Figure 30</td>
<td>Oil Production Rate in E-Segment</td>
<td>55</td>
</tr>
<tr>
<td>Figure 31</td>
<td>Gas Production Rate in E-Segment</td>
<td>56</td>
</tr>
<tr>
<td>Figure 32</td>
<td>Cumulative Oil Produced in E-Segment</td>
<td>56</td>
</tr>
<tr>
<td>Figure 33</td>
<td>Cumulative Gas Produced in E-Segment</td>
<td>57</td>
</tr>
<tr>
<td>Figure 34</td>
<td>Cumulative Water Produced in E-Segment</td>
<td>57</td>
</tr>
<tr>
<td>Figure 35</td>
<td>Water Cut</td>
<td>58</td>
</tr>
<tr>
<td>Figure 36</td>
<td>Gas Oil Ratio (GOR) in E-Segment</td>
<td>58</td>
</tr>
<tr>
<td>Figure 37</td>
<td>Reservoir Pressure for Norne</td>
<td>59</td>
</tr>
</tbody>
</table>
Figure 38 Formation Volume Factor
Figure 39 Oil Saturation in layer 6
Figure 40 Oil Saturation in layer 9
Figure 41 Oil Saturation in layer 13
Figure 42 Oil Saturation in Block 15, 74 and 7
Figure 43 Oil Saturation in Block 16, 75, and 6
Figure 44 Synthetic Models for Surfactant Flooding
Figure 45 Effect of Surfactant Flooding on Recovery Factor
Figure 46 Effect of Surfactant Flooding on Oil Production Rate
Figure 47 Effect of Surfactant Flooding on Water Production Rate
Figure 48 Oil Rate for Continuous Surfactant Flooding
Figure 49 Total Oil Productions for Continuous Surfactant Flooding
Figure 50 Total Surfactant Injected into E-Segment
Figure 51 Surfactant Production from Well E-2H
Figure 52 Oil Rate for Slug Injection
Figure 53 Total Surfactant Slug Injected into E-Segment
Figure 54 Surfactant Slug Produced from E-2H
Figure 55 Oil Production Rate with Higher Water Injection Surfactant Slug Injection for 6 months Interval Period
Figure 56 Oil Production Rate: Comparison between Slug & Continuous Injection
Figure 57 Total Oil Production: Comparison between Slug & Continuous Injection
Figure 58 Surfactant Production from Well E-2H
Figure 59 Total Surfactant Injected into E-Segment
Figure 60 Production Rates for different Surfactant Concentration
Figure 61 NPV for different Surfactant Concentration
Figure 62 Original Wells in the Norne E-Segment
Figure 63 Recompletions + New Wells
Figure 64 Original Wells + New Wells
Figure 65 Porosity Profile for Norne E-Segment, Ile Formation
Figure 66 Effect of Surfactant Injection into all Well Configuration
Figure 67 Cumulative Oil from E-Segment with New Wells + Surfactant
Figure 68 Oil Production Rate from E-Segment with New Wells + Surfactant
Figure 69 Water Production Rate from E-Segment with New Wells + Surfactant
Figure 70 Total Water Production from E-Segment with New Wells + Surfactant
Figure 71 GOR for E-Segment with New Wells & Surfactant
Figure 72 Pressure Profile for E-Segment with New Wells & Surfactant
Figure 73 Field Oil Efficiency for Norne E-Segment for New Wells Surfactant
Figure 74 Net Present Value for Different Well Configurations
LIST OF TABLES

Table 1  Summary of Screening Criteria for EOR Methods    14
Table 2  Characteristics Properties of Surfactants     19
Table 3  Some Basic Surfactant Keywords in Eclipse Simulator  39
Table 4  NPD Reserves Estimates for 31-12-09     49
Table 5  Well Status in Norne E-Segment      51
Table 6  Characteristics Fluid Parameter for Norne    52
Table 7  Average Values of Porosity & Permeability     53
Table 8  NPV Calculation for Different Surf Concentration  76
Table 9  F-1H Completions Data       81
Table 10 F-3H Completions Data       81
Table 11 CHI-1 Completions Data       81
Table 12 Economics of Surfactant Injection into Different Well Cases  88
1.0 INTRODUCTION

More than two-thirds of oil discovered around the world still remains unrecovered after using the conventional production technique, namely, primary and secondary means of production. Primary recovery utilizes the natural energies in the reservoir like expansion, compaction, gas drive, solution gas drive and natural water drive while secondary recovery stage, involves water injection at designated points in the reservoir to displace oil towards producing wells. However due to oil by-pass and capillary forces, as much as 40 – 70% of the original oil is still left in place (1).

World demand for petroleum has been steadily on the increase (Figure 1) with the International Energy Agency (IEA) projecting that the world petroleum consumption will rise from 3564 MTOE in 2007 to as much 5471 MTOE in 2015 and 6301 MTOE in 2030.

Figure 1: World Petroleum Consumption (2)
Unfortunately, estimates of undiscovered reserves have decreased steadily since 1970\(^{(3)}\). In US for example, projected production from known fields using conventional technology was projected to drop to about 4 million B/D in 1990 and 3 million B/D by 1995. Exploration is expected to add to new reserves but the size of new reserves is in doubt. Historical correlations of drilling and new finds in these mature provinces suggest that little oil remains to be discovered \(^{(4)}\). Even when these reserves are discovered, the environmentally hostile condition makes it very costly and time consuming to produce.

Studies have shown that the volume of ‘unrecoverable’ oil in existing reservoirs after primary and secondary production is about \(5 \times 10^9 \text{ m}^3\) (30 billion bbls) in Canada \(^{(5)}\), about 10 times as much in U.S.A. and about two trillion bbls worldwide.

From the foregoing, it becomes apparent that ways of recovering the capillary trapped oil have to be sought. This forms the basis of Enhanced Oil Recovery (EOR) which usually implies recovery beyond the secondary stage.

In the North Sea, a typical oil field consists of deep sandstone reservoirs of high pressures and temperatures, containing light oil \(^{(6)}\). Productive oil zones are thick and very productive rock results in high well rates. Many fields are supported by water injection since the natural water drive is not sufficient to maintain pressure. In such an environment, with very high cost of drilling and production, most tertiary methods like thermal methods are not considered promising. It was however recognized that some secondary and tertiary recovery methods could succeed. Specifically, waterflooding through polymer addition and a reduction of interfacial tension through surfactant addition were recognized as technically feasible methods of some potential regarding extra oil.\(^{(6)}\)

Some of the Enhanced Oil Recovery technologies that have been conducted in the North Sea from 1975 to 2005 include HC gas injection, Water Alternating Gas injection (WAG), Simultaneous Water Alternating Gas Injection (SWAG), Foam Assisted Water Alternating Gas (FAWAG) and Microbial Enhanced Oil Recovery (MEOR) \(^{(7)}\). Other methods, including surfactant flooding were however planned to be carried out in the future.

This thesis work therefore focuses on possibility of increasing oil recovery in the Norne Field’s E Segment located in the Norwegian Continental Shelf by the use of surfactant flooding, which is a chemical method of Enhanced Oil Recovery (EOR). In very recent times, especially in the year 2010, lots of papers have been published by researchers on ways of improving surfactants quality and reducing the cost. This is needed to make it an even more efficient means of reducing the residual oil saturation in the reservoir. This fact coupled with the rise in oil price makes surfactant flooding a worthwhile venture.
1.1 ENHANCED OIL RECOVERY

Enhanced Oil Recovery (EOR) refers to all processes (other than water flooding) in which energy and chemicals are supplied to the reservoir to establish pressure gradients, modify interfacial tensions and wettability, adjust the mobility of the driving fluid, alter the permeability of selected zones and change fluid properties in such a way that oil flows towards the producing well in a controlled manner \(^{(1)}\). In other words, EOR means that ‘something’ other than plain water or brine is being injected into the reservoir to increase oil recovery\(^{(8)}\).

The term Improved Oil Recovery (IOR) has been used increasingly instead of the traditional EOR or the more restrictive ‘tertiary recovery’. IOR sometimes signifies measures taken during—not after—the primary and secondary stages to increase oil recovery. Even though most petroleum engineers understand the meaning of all these phrases, the technical communications are improved if the terms with their intended technical meanings are used. Tertiary recovery should not be used as a synonym for EOR because some EOR methods work quite well as either secondary or tertiary methods like CO\(_2\) flooding while others, such as steam, or polymer flooding are more effective as enhanced secondary operations.

One big attraction of EOR is that there is over one-half of oil still remaining in reservoirs, where wells and facilities already exist. In Saskatchewan, Canada, the Department of Energy and Mines estimated that development of enhanced oil recovery processes applicable to thin, unconsolidated sand reservoirs could mean the recovery of about 635 million\(M^3\) (4 Billion bbls) of heavy oil\(^{(9)}\). Also applying EOR to conventional oilfields could add about 95 million\(M^3\) (600Mbbls) to Saskatchewan’s established reserve of 70 million\(M^3\). Oil production from EOR projects continues to supply an increasing percentage of the world’s oil. About 3% of the worldwide production comes from EOR. Thus the potential for the development of EOR is clear and very compelling.

1.2 BASIC MECHANISMS OF ENHANCED OIL RECOVERY

For an EOR to be effective, the two important parameters that must be taken into consideration are the mobility ratio and the capillary number.

1.2.1 IMPROVING THE MOBILITY RATIO

Mobility of a fluid is defined as the ratio of the effective permeability to the viscosity of the fluid

\[
\lambda = \frac{K_i}{\mu_i}
\]  

[EQ 1.0]

Where
\( \lambda \) = Mobility

\( k \) = Effective Permeability

\( \mu \) = Fluid Viscosity

\( i = \) oil, water or gas

While mobility ratio, \( M \), is defined as the mobility of the displacing fluid divided by the mobility of the displaced fluid.

\[
M = \frac{\frac{K_{rw}}{\mu_w}}{\frac{K_{ro}}{\mu_o}}
\]  \([\text{EQ 1.1}]\)

For maximum displacement efficiency, \( M \) should be \( \leq 1 \) for favorable mobility ratio. If \( M > 1 \), then it means that the displacing fluid, for example, water in a waterflood moves more easily than the displaced fluid, for example, oil. This is unfavorable because the displacing fluid will flow past the displaced fluid given rise to a phenomenon called ‘viscous fingering’ where most of the oil is by-passed (Figure 2). However, if \( M > 1 \) and there is no viscous fingering, it means that more fluid will be injected to attain a given residual oil saturation in the pores. Thus, for effective displacement of fluid, the mobility ratio is very important.

In case of enhanced oil recovery, mobility ratio can be made smaller, in order words, ‘improved’ by one of the following ways;

- Lowering the viscosity of the displaced fluid, for example, oil
- Increasing the viscosity of displaced fluid
- Increasing the effective permeability to oil
- Decreasing the effective permeability to the displacing fluid.

### 1.2.2 INCREASING THE CAPILLARY NUMBER

Capillary number is defined as the dimensionless ratio between the viscous and the capillary forces \( ^{(6)} \) given by

\[
N_c = \frac{\mu V}{\sigma} \quad \text{or} \quad \frac{\kappa \Delta p}{\sigma L}
\]  \([\text{EQ 1.2}]\)

Where

\( N_c \) = Capillary Number
$\mu = \text{Displaced fluid viscosity}$

$V = \text{Pore velocity}$

$\sigma = \text{Interfacial tension between the displaced and displacing fluids}$

$\Delta P/L = \text{Pressure gradient across a distance L}$

$K = \text{Effective Permeability to the displaced fluid}$

When the capillary number is increased, the residual oil saturation is decreased by either a reduction in oil viscosity or an increase in pressure gradient but of more importance is a decrease in the interfacial tension (IFT). However, for a meaningful residual oil to be produced, the critical value of $\Delta P/L\sigma$ has to be exceeded by an increase in water flooding rate $^{(11)}$.

![Figure 2: Fingering of water into the oil bank for mobility ratios greater than 1 $^{(19)}$](image)

### 1.3 CLASSIFICATION OF ENHANCED OIL RECOVERY METHODS

There are various classifications of enhanced oil recovery and the method used depends on reservoir geology and fluid properties. Miscible displacement is the dominant recovery method in Canada; with steam injection growing fast as heavier oil/bitumen resources are exploited $^{(10)}$. In United States of America, steam injection is the principal recovery method with miscible carbon dioxide flooding coming next.

Several EOR process have been described by different authors $^{(12)}$ but the one given by Farouk and Thomas is more encompassing. (Figure 3)

A broad classification is basically thermal and non-thermal where thermal methods are applied to heavy oil reservoirs and non-thermal applied to light oils.
1.3.1 CHEMICAL FLOODING

Chemical flooding methods are targeted at recovering of residual oil left in the reservoir after water flooding. It involves the use of a polymer or surfactant to improve mobility ratio and capillary number. Chemical flooding is further subdivided into polymer flooding, surfactant flooding, miscellar flooding, alkaline flooding, miscellar-surfactant-polymer (ASP) flooding.

1.3.1.1 POLYMER FLOODING

This involves the addition of a very small amount of water-soluble, high molecular weight polymer to the displacing water in order to increase the apparent viscosity of the water and lower the mobility ratio. Thus polymer flooding is primarily used when displacing high viscosity oils. However because the viscosity of heavy oil is high and there is a limit to polymer concentration due to cost and mechanical consideration for injection pressures, polymers are likely to be of little benefit for heavy oil with viscosity of more than 100 mPa.S.
1.3.1.2 SURFACTANT FLOODING

Mobilization of residual oil trapped by capillary forces in the porous medium is the main mechanism with surfactant flooding characterized by a reduction in IFT and residual oil saturation. A suitable surfactant should lower the oil-water IFT sufficiently and adsorbs little on the rock matrix. The main problem with surfactant is loss to the rock matrix through several mechanisms like adsorption, precipitation and phase behavior changes.

1.3.1.3 ALKALINE FLOODING

Alkaline flooding is a very complex process. The aim of flooding the reservoir with alkaline is to form a surfactant in situ, which arises as a result of reactions between the injected alkali and the acid components of the crude oil. A problem with this method is that alkaline consumption is very high due to reactions with clay. Alkaline flooding began with the injection of sodium carbonate solution in Bradford area of Pennsylvania in 1925\(^{21}\) and since then, work on this process has continued.

1.3.1.4 MICELLAR FLOODING

A Micellar solution is defined as a dispersion of oil in water (or water in oil), containing a large proportion of surfactants (5-10%) as well as co-surfactants and salt \(^{14}\). The ability of a micellar solution to make oil soluble would depend on the surfactant and hydrocarbon characteristics. The Micellar solution creates a miscible zone by dissolving oil and water ahead of it thus sweeping the fluids ahead like a piston in miscible displacement. The capillary number is greatly increased in this mixing. (Figure 4)

The Micellar flooding process has shown to be successful in the field for recovering oil from water flooded reservoir \(^{15}\).

![Figure 4: Micellar Flooding Process; complete displacement of oil is assumed \(^{15}\)](image-url)
1.3.1.5 ALKALINE-SURFACTANT-POLYMER (ASP) FLOODING

This process, as the name suggests, is a combination of the three processes namely alkaline, surfactant and polymer flooding in which the three slugs are used in sequence. Alternatively, the three fluids could be mixed together and injected as a single slug. The objective of the ASP flooding process is to reduce the amount of chemical consumed per unit volume of oil required and invariably a reduction in cost.

1.3.2 MISCIBLE DISPLACEMENT

In miscible floods, the displacing fluid is soluble in oil so that there will be no interfacial force between oil and solvent and the theoretical residual oil saturation will be zero. Two types of miscible flooding, usually used in Canada, were distinguished by Asgarpour. They include vertical miscible floods which are implemented in pinnacle reefs or reservoirs with high relief angles where solvents are injected as a blanket at the top of the reservoir to take advantage of a gravity stabilized displacement while horizontal miscible floods is that in which solvent and water are injected alternatively to mobilize residual oil and push it to the producers. Other classifications of miscible floods are; miscible slug or first-contact miscible flooding, condensing gas drive, vaporizing gas drive and carbon dioxide flooding.

1.3.2.1 MISCIBLE SLUG PROCESS

Propane or LPG slug [about 5% hydrocarbon pore volume (HCPV)] is used as miscible slug and is driven by a cheaper lean gas, like methane. Water is often injected with the drive gas in small alternating quantity (WAG). This has the effect of improving the mobility ratio at the gas-slug interface. The pressure should be such that there is miscibility at the front edge of the slug and the oil in place, as well as between the trailing edge and the driving gas, otherwise, miscibility will not occur.

1.3.2.2 VAPOURIZING GAS DRIVE

This is a multiple contact process employing lean gas in which ethane to hexane fractions are transferred from oil to the gas, until miscibility is achieved. The operating pressure in the process is usually higher, above 20MPa. A problem inherent in all miscible processes is that of viscous fingering of the less viscous material, causing slug dissipation. Two conditions must be met for the vaporizing gas drive process to operate; first, the pressure at the gas-oil interface must be high and second, the reservoir must contain a high concentration of C2-C6. Lean gas, nitrogen gas and flue gas are common gases used for vaporizing gas drive.
1.3.2.3 CARBON DIOXIDE FLOODING

Carbon dioxide flooding cuts across as both a miscible and an immiscible gas displacement technique. A significant difference between the two methods lies in the pressure with which Carbon dioxide is injected into the reservoir. For miscible carbon dioxide injection, the pressure has to be higher than the minimum miscibility pressure (MMP) for miscibility to occur. This can be compared to that of the lean gas process, even though CO₂ will extract heavier component from the oil of up to C₃₀ unlike lean gas process that vaporizes only C₂-C₆ thus making it more effective. In the immiscible gas displacement, the injection pressure of CO₂ is not so high, but the characteristics of CO₂ like promotion of oil swelling and reduction of viscosity makes it to displace oil, especially in heavy crudes.

1.3.2.4 NITROGEN AND FLUE-GAS FLOODING

Apart from compressed air, nitrogen and flue gas are the cheapest gases that can be injected into the reservoir. They are usually considered together because the pressures required (MMP) for good displacements are similar. However, flue gas has a limitation of corrosion, so nitrogen is preferably used. Nitrogen injection is however possible in deep reservoirs with light oils because of it very high MMP.

1.3.3 THERMAL FLOODING

Thermal oil recovery utilizes heat to aid in oil recovery and this is typical for oil reservoirs with very high viscosities and low API gravities, otherwise known as heavy oil reservoirs. These heavy oil reservoirs are typical in Indonesia, Canada, Venezuela and USA. Thermal recovery is subdivided into the following;

- Steam-based thermal recovery process
  - Cyclic Steam Stimulation (CSS)
  - Steam Assisted Gravity Drainage (SAGD)
- In Situ Combustion
  - Toe-to-Heel Air Injection (THAI)
- Solvent-based Tertiary Resources
  - VAPEX
  - Thermal Solvent
- Hybrid (Steam-solvent) and co-injection processes

Steam injection is one principal enhanced oil recovery method for heavy oil reservoirs accounting for 90% of all oil produced by such methods. As at 1995, it was reported that total
oil production by steam in North America was 530,000B/D (84,200 M³/day) (17), Canada accounts for 110,000 B/D. Most of this production is by steam. In situ combustion accounts for 2,520 B/D in the US and 5,200 B/D in Canada. The largest steam injection projects is in Indonesia with production of 250,000 B/D. In Venezuela, production is 277,000 B/D.

1.3.3.1 CYCLIC STEAM STIMULATION (CSS)

This is also known as the Huff and Puff method and consists of 3 steps - injection, soaking and production. Steam is first injected into a well for a certain amount of time to heat the oil in the surrounding reservoir to a temperature at which it flows. After it is decided that enough steam has been injected, the steam is usually left to ‘soak’ for some time. Then, oil is produced out of the same well, at first, by natural flow and then by artificial lift. Production will decrease as the oil cools down, and once production reaches an economically determined level, the steps are repeated again. The process can be quite effective, especially in the first few cycles. However, it is typically only able to recover 20% of the original oil in place (OOIP), compared to steam flooding which has been reported to recover over 50% of OOIP (18). There are some challenges involved in using the CSS, for example in thin zones, it cannot be used effectively and also in reservoirs without fluid communication. The resultant effect is that there will be heat loss, less production and steam breakthrough at the surface (Figure 5).

1.3.3.2 STEAM ASSISTED GRAVITY DRAINAGE (SAGD)

Steam Assisted Gravity Drainage (SAGD) is an enhanced oil recovery technology for producing heavy crude oil and bitumen. It is an advanced form of steam stimulation in which a pair of horizontal wells is drilled into the reservoir, one a few meters above the other. Low pressure steam is continuously injected into the upper wellbore to heat the oil and reduce its viscosity, causing the heated oil to drain into the lower wellbore, where it is pumped out (Figure 6).

1.3.3.3 IN SITU COMBUSTION

This method ignites the oil while in the reservoir. The idea is to burn some of the oil in place which causes heat emission enough to mobilize the rest of the oil. It is cost efficient and reduces CO2 emission and waste.

1.3.3.4 TOE-TO-HEEL AIR INJECTION (THAI)

This method ensures a higher recovery with 70-80% of oil in place recovered. Feasible over a broader range of reservoirs (including low pressure, thinner; previously steamed, deeper; gas over bitumen and bottom water). It is cheaper with 30% lower capital cost since it requires only one horizontal well with no steam and water handling facilities required. It also has a lower environmental impact with less water use and 50% lower greenhouse gas emissions (Figure 7).
Enhanced Oil Recovery for Norne Field’s E-Segment Using Surfactant Flooding
1.3.3.5 VAPEX PROCESS

Vapour extraction process (VAPEX) is an energy-efficient method of recovering high viscosity heavy oil and bitumen from reservoirs. The process uses a solvent in the miscible displacement of bitumen or heavy crude. It is a non-thermal method and has lower energy requirements and GHG emissions than Cyclic Steam Stimulation (CSS) or Steam Assisted Gravity Drainage (SAGD). VAPEX is applied in Dover project in Canada.

1.3.4 MICROBIAL ENHANCED OIL RECOVERY (MEOR)

In situ MEOR process involves injection of micro organism and suitable nutrients into the reservoir. The micro-organism represents a replenishable in-situ source of surfactant and other beneficial metabolites as acid, gas, biopolymer or solvent that can be supported and manipulated by addition of inexpensive nutrients such as molasses. In an experiment to improve the oil recovery from UAE reservoirs using bacteria flooding, Abdulrazag et al. (20)
noted that there was significant increase in oil recovery through the production of bio-
surfactant, bio-gas and bio-mass.

1.4 EOR SCREENING CRITERIA

From the foregoing, it is evident that there are various types of EOR, thus the choice of which
method to apply to a particular reservoir becomes challenging. Taber et al. (8) came up with a
set of screening criteria that should guide petroleum engineers on the particular choice of EOR
method to use. The major considerations for the EOR processes are both the fluid properties
and the reservoir characteristics.

The Table 1 below gives a set of criteria to consider in choosing an EOR method.

The API gravity of Norne oil is 33° so the surfactant flooding can be used (With reference to
Table 1).
<table>
<thead>
<tr>
<th>Oil Properties</th>
<th>Reservoir Characteristics</th>
</tr>
</thead>
<tbody>
<tr>
<td>EOR Method</td>
<td>Gravity (API)</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas Injection Methods (Miscible)</td>
<td></td>
</tr>
<tr>
<td>Nitrogen &amp; flue gas</td>
<td>&gt;35 &gt;48</td>
</tr>
<tr>
<td>Hydrocarbon</td>
<td>&gt;23 &gt;41</td>
</tr>
<tr>
<td>CO₂</td>
<td>&gt;22 &gt;36</td>
</tr>
<tr>
<td>Immiscible gases</td>
<td>&gt;12</td>
</tr>
<tr>
<td>Enhanced Waterflooding</td>
<td></td>
</tr>
<tr>
<td>Micellar Polymer, ASP/Alkaline</td>
<td>&gt;20 &gt;35</td>
</tr>
<tr>
<td>Polymer Flooding</td>
<td>&gt;15</td>
</tr>
<tr>
<td>Thermal/Mechanic</td>
<td></td>
</tr>
<tr>
<td>Combustion</td>
<td>&gt;35 &gt;48</td>
</tr>
<tr>
<td>Steam</td>
<td>&gt;8 to 13.5</td>
</tr>
<tr>
<td>Surface Mining</td>
<td>7 to 10</td>
</tr>
</tbody>
</table>

Table 1: Summary of Screening Criteria for EOR Methods (8)
2.0 OVERVIEW OF SURFACTANTS

Surfactants or surface active agents are soaps or soap-like substances that have the ability to change the surface or interfacial properties of their solutions to a very marked degree even if they are present in minute amounts.

In order to explain the characteristics of surfactants, some terms need to be defined;

- **Hydrophilic**: A water loving term indicating the tendency of specie to interact strongly with water.
- **Hydrophobic**: (water hating) opposite of hydrophilic, having little energetically favorable interaction with water.
- **Lipophilic** (Fat loving): A general term used to describe materials that have a high affinity for fatty or organic solvents, essentially the opposite of hydrophilic.
- **Lipophobic** (Fat hating). The opposite of lipophilic that is, materials preferring to be in more polar or aqueous media.
- **Lyophilic**: (Solvent loving) A general term applied to a specific solute-solvent system indicating the solubility relationship between the two. A highly water-soluble material such as acetone would be termed lyophilic in an aqueous context. \(^{(22)}\)
- **Lyophobic**: (Solvent hating). The opposite of lyophilic. A hydrocarbon, for example will be lyophilic in relation to water. If the given solvent is changed to octane, then the hydrocarbon will become lyophilic.
- **Micelles**: Aggregated units composed of a number of molecules of surface-active materials formed as a result of the thermodynamics between the solvents.
- **Solubilization**: The process of making a normally insoluble material soluble in a given medium. Solubilization could be a hydrocarbon chain in water by chemical modification involving the addition of a head group and the micellar Solubilization of an oil phase in water or vice versa.
- **Microemulsion**: A thermodynamically stable phase formed when oil, water and surfactant are mixed, usually surfactant rich.
- **CMC**: This stands for Critical Micelle Concentration. It occurs when anionic surfactant is dissolved in aqueous solution, the surfactant dissociates into a cation and a monomer. If the surfactant concentration is increased, the lipophilic halves of the surfactant begin to associate among themselves to form aggregates or micelles containing so many monomers. A plot of surfactant monomer concentration versus total surfactant concentration is a curve at begins at the origin and levels off at the critical micelle concentration (CMC).\(^{(22)}\)
2.1 STRUCTURE OF A SURFACTANT

A surfactant molecule consists of a hydrophilic head group and a lipophilic tail. The head refers to the solubilizing group – the lyophilic or hydrophilic group in aqueous systems and the tail refers to the lyophobic or hydrophobic group in water. The entire molecule is sometimes called an amphiphile signifying a dual-nature which makes the surfactant reside at the interface between the aqueous and organic phases, lowering the interfacial tension. (Figure 9)

In water, the hydrophobic group maybe a hydrocarbon or siloxane chain of sufficient size that will produce the desired solubility characteristics when bound to a suitable hydrophilic group. In aqueous systems, the hydrophilic group (the ‘head’) will be ionic or highly polar, so that it can act as a solubilizing functionality. In a non polar solvent such as hexane, the same groups will function in the opposite sense.

As the temperature, pressure or solvent environment of a surfactant varies significant alterations in the solution and interfacial properties of the surfactant may occur. Hence, modifications in the chemical structure of the surfactant maybe needed to maintain a desired degree of surface activity. A given surfactant effect will be intimately tied to the
specific solvent environment in use. Any change in that environment may significantly alter the effectiveness of a surfactant and require major structural changes to retain the desired surface effects. Thus, for surface activity in a given system, the prospective surfactant molecule must possess a chemical structure that is amphiphilic in the desired solvent under the proposed condition of use.

![Figure 9: Structure of molecular surfactant](image)

### 2.2 BASIC SURFACTANT CLASSIFICATION

In aqueous systems, the hydrophobic group is generally a long-chain hydrocarbon group. The hydrophilic or head will be an ionic or highly polar group that can impact some water solubility to the molecule. The nature of the hydrophile forms the most useful chemical classification of the surface-active agent while the hydrophobe or tail forms the sub-groups.

The four basic classes of surfactants are defined as follows:
2.2.1 ANIONIC

The hydrophile is a negatively charged group such as carboxyl (RCOO⁻M⁺), sulfonate (RSO₃⁻M⁺), or phosphate (ROPO₃⁻M⁺). Anion surfactants are commonly used in micellar polymer flooding because they are stable, relatively resistant to retention and are generally good. R stands for hydrocarbon groups.

2.2.2 CATIONIC

The hydrophile bears a positive charge, like the quaternary ammonium halides (R₄N⁺X⁻), where the four R-groups may or may not be the same but will usually have the same generic family. The surfactant molecule contains an inorganic anion to balance the charge. Cationic surfactants are used little in micellar polymer flooding because they are highly absorbed by the anionic surfaces of interstitial clays.

2.2.3 NONIONIC

The hydrophile has no charge but derives its water solubility from highly polar groups such as polyoxyethylene (POE or OCH₂CH₂O⁻) or R-polyol groups including sugar. These surfactants do not form bonds, but when dissolved in aqueous solutions, exhibit surfactant properties by electronegativity contrasts between their constituents. Nonionic surfactants are however more tolerant than anionic in high salinity environment.

2.2.4 AMPHOTERICS

This surfactant class contains two or more of the other classes. In order words, an amphoteric surfactant may contain both an ionic group and a non-polar group.

2.3 APPLICATION OF SURFACTANTS

The balance between the lyophilic (solvent loving) and lyophobic (solvent hating) portions of the surfactant molecule determine its properties and applications. In other words, such characteristics as wetting control and foaming capacity, detergency power, surface tension reducing capacity and critical Micelle concentration are dependent on the balance between the lyophilic and lyophobic parts of the surfactants, in other words, the surfactant structure. As a result, some surfactants would perform better in some applications and less in others.

Industry and laboratory experiments are yet to come up with a surfactant that satisfies all the various needs of surfactant-application. Basically, a surfactant’s specific utility in
a given system is dependent on the surfactant’s characteristics. Table 2 gives some basic characteristics that must be inherent in a particular surfactant for it to perform some specific functions.

<table>
<thead>
<tr>
<th>APPLICATION</th>
<th>CHARACTERISTICS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mineral Flotation</td>
<td>Favorable price and proper adsorption characteristics on the ores of interest</td>
</tr>
<tr>
<td>Petroleum Recovery</td>
<td>Proper wetting of oil-bearing formations, micro-emulsion formation and properties such as Solubilization, breaking up of emulsion easily after oil recovery.</td>
</tr>
<tr>
<td>Lubrication</td>
<td>Chemical stability and ability to absorb at surfaces</td>
</tr>
<tr>
<td>Pharmaceuticals</td>
<td>Requires proper emulsifying properties, low toxicity, biocompatibility</td>
</tr>
<tr>
<td>Detergency</td>
<td>Desirable foaming properties, good salt and PH stability, biodegradability, low Critical Micelles Concentration requirement</td>
</tr>
</tbody>
</table>

Table 2: Characteristic properties of surfactant

Surfactants are used in various aspects of our lives and these include:

- Detergents and cleaners
- Cosmetics and personal care products
- Textiles and fibers
- Paints
- Leathers and furs
- Plastics and composite
- Medicine and biochemical
- Oilfield chemicals and Petroleum Production
- Pharmaceuticals
- Food and Packaging of food
- Pest control and plant protection

### 2.4 SURFACTANT IN THE PETROLEUM INDUSTRY

Surfactants are used as enhanced oil recovery agents during oil recovery. After a reservoir is water-flooded, globules of oil are left trapped in the reservoir due to a high capillary pressure. Surfactant flooding is a process in which surfactants are introduced into the reservoir to increase oil recovery by lowering the interfacial tension between oil and water, thereby making the discontinuous residual oil globules trapped in the pores
of the rock by capillary forces to flow. The surfactant should be able to develop an ultra low interfacial tension to give a capillary number that is large enough to overcome capillary forces and allow the oil to flow \cite{23}

A surfactant system should have the ability to lower the oil-water interfacial tension as this is very important in the mobilization of residual oil. It should also be able to propagate through the reservoir without losing this important ability \cite{24}. Contrary to these requirements, the surfactant slug usually breaks down under very high temperatures. Adsorption of the surfactants on the rock surfaces and high salinity of reservoir brines also leads to the precipitation of surfactants. These are few of the problems encountered by surfactants as they move through the reservoir.

The most common primary surfactant used in the petroleum industry is petroleum sulfonates produced by sulfonating a pure organic chemical, an intermediate molecular weight refinery stream or crude oil. \cite{32}

\[
R - C = C - H
\]

If the structure above represents the molecular structure of the feedstock, then sulfonation reaction produces

\[
R - C = C - H + SO_3^- \rightarrow R - C = C - SO_3^- + H^+
\]  
(α-olefin sulfonate)

The carbon-carbon double bond can also be saturated to give

\[
R - C = C - SO_3^- + H_2 \rightarrow R - CH - CH - SO_3^- 
\]  
(alkyl sulfonate)

If the feedstock is aromatic, then

\[
R - \oplus + SO_3^- \rightarrow R - \oplus - SO_3^- + H^+
\]  
(Alkylbenzenesulfonate)
2.5 LITERATURE REVIEW

A lot of research has been ongoing to determine ways of improving on the existing qualities of surfactants.

Barnes et al. (23) carried out experiments to develop surfactants for chemical flooding at difficult reservoir conditions. They realized that a particular surfactant’s ability depended so much on reservoir characteristics like crude oil type, temperature and water composition. Thus, in order to achieve an ultra low IFT during flooding, the structure of the surfactant has to be tailored to these conditions. Evaluations were carried out on two surfactant families, both produced by Shell, namely: Internal olefin sulfonates (IOS) which are part of ENORDET\textsuperscript{TM} O series and proprietry and the branched C\textsubscript{16}, C\textsubscript{17} alcohol-based anionic surfactants which are part of the ENORDET\textsuperscript{TM} A series. Both families are suitable for EOR since they have reduced tendency to form ordered structures/liquid crystals that are undesirable in reservoirs. The two families have the promise to be used in flooding reservoirs at difficult higher temperature and high salinity reservoirs. They could also be tailored to work under a range of conditions. They were able to prove, through experiments, that internal olefin sulfonates (IOS) can be used over a range of salinities and give high oil Solubilization at their optimal salinities, especially for longer chains. These properties and their chemical stability at higher temperatures make them very versatile surfactants for EOR and promising for reservoirs with temperatures up to 150\textdegree C. They also confirmed that a family of anionic surfactants based on a branched C\textsubscript{16}/C\textsubscript{17} alcohol looks promising for reservoir conditions of higher salinity and hard water content. For future work, they plan to investigate the effect of the presence of divalent ions on performance of the IOS and branched C\textsubscript{16}, C\textsubscript{17} alcohol based surfactants and also the effect of the blend of these two surfactant types in a reservoir.

Ping Zhao et al. (25) in their paper titled ‘Development of High-performance Surfactants for Difficult Oils’ focused on EOR recovery of crude oils that are characterized as difficult due to high carbon number, high asphaltene, paraffin and/or wax content and in some cases high viscosity. They observed that one of the most important characteristics of a good EOR surfactant is the degree of branching of the hydrophobes which tends to minimize undesirable behavior in the reservoir like gel formation. In their study, they used phase behavior experiments for screening surfactants instead of measuring IFT or proceeding directly to corefloods because they observed that numerous surfactants and chemical formulations can be tested rapidly and with little effort. They observed that a class of surfactants known as internal olefin sulfonates (IOS) has great success by themselves or when combined with other surfactants. The one-step synthesis through
sulfonation of olefins keeps the cost of these high performance surfactants in competitive range. The carbon number of IOS surfactants can be tailored to apply to difficult oils or reservoir conditions. In a final word, the high performance and low consumption of these surfactants when properly formulated can make them more economically competitive than the conventional surfactants.

For application of Internal Olefin sulfonates and other surfactants to EOR based on structure-performance relationships required at different reservoir conditions, Barnes et al.\(^{(26)}\) mentioned that before a surfactant or surfactant family can be produced for commercial use it must be screened so that a particular surfactant structure can be selected for certain reservoir characteristics. Also, a surfactant development program would be required to establish that the selected surfactant can be manufactured cost-effectively on a large scale with consistent quality. In their work, the authors observed that the 4 carbon cuts of the IOS family \((C_{15-18}, C_{19-23}, C_{20-24} \text{ and } C_{24-28})\) cover a wide range of reservoir salinities while IOS 19-23 has a moderate optimal salinity combined with a high Solubilization parameter making it a promising surfactant for moderate salinity environment. An IOS 24-28 based surfactant gives excellent performance with several regionally different crude oils. They concluded that the commercially available IOS and alcohol-alkoxy-sulfate families cover most of the reservoir conditions expected while for high temperature and high salinity reservoirs, alcohol based sulfonates will be required.

In their paper titled ‘An integrated Workflow for Chemical EOR Pilot Design’ Moreau et al.\(^{(27)}\) reported an integrated workflow for designing optimal conditions for chemical EOR operations. They based their workflow on identifying the best chemicals suitable for a given field using robotized techniques. The robotized technique enables fast and accurate solubility screening, phase diagram and interfacial tension screening for optimum design. Another factor on which they based their workflow was on core flood experiments basically for adsorption measurement and oil recovery determination. The aim of this study was to establish a workflow for the optimization and validation of surfactant-polymer (SP) and Alkali-Surfactant-Polymer (ASP) mixtures in a chemical EOR.

It is important that when a surfactant is injected into the reservoir, it should achieve a low interfacial tension while maintaining its integrity. However, this is not usually the case as surfactants are usually broken down by some adverse effects in the reservoir. Thus, Pope et al.\(^{(28)}\) studied the role of Co-Solvents and Co-Surfactants in making chemical floods more effective. They carried out a lot of experiments before concluding that the addition of a co-solvent or co-surfactant helps to achieve aqueous phase stability that ensures that injected mixture will transport in the reservoir over long...
distances with low retention. Two core floods experiment they carried out showed that the performance of the chemical formulation was improved by the addition of a low concentration of co-surfactant to achieve a clear ASP slug. It is important that the aqueous surfactant solution (slug) injected must be clear, stable, single phase in order to achieve the required characteristics of deep transport into the reservoir. They also observed that Alcohol ethoxylates show excellent solvent-surfactant properties better than glycol ethers and alcohols.

In their paper titled ‘Low-Cost, High-Performance Chemicals for Enhanced Oil Recovery’ Pope et al. (29) made some interesting discoveries. They observed that using phase behavior to screen surfactants and other chemicals was more advantageous for viscous oil and other difficult conditions than it was for more conventional conditions. Also performance and prediction of surfactant behavior is dependent on understanding of surfactant structure while viscous oils which tend to have high acid numbers are found in reservoirs with high porosity and permeability making them more attractive for chemical EOR than many light oil reservoirs. In conclusion of their work, they observed that recent advances with surfactants and introduction of new EOR chemicals have shown an increasing potential for low cost and high efficiency chemical EOR. The branched Guerbet alkoxy sulfates surfactants showed excellent attributes for EOR. They also discovered why oil cut increase as oil viscosity increase using the fractional flow theory.

In their study Ben Shiau et al. (30) investigated the possibility of designing an alcohol-free surfactant for chemical oil recovery. To achieve this goal, they selected a binary anionic surfactant mixture made up of a branched-tail primary surfactant (dioctyl sulfoisuccinate) and a high performance and low sorption surfactant (sodium linear alkyl diphenyloxide disulfonates). This combination is supposed to achieve the middle phase microemulsion with fast coalescent rate and ultra-low interfacial tension. Binary and ternary anionic surfactant mixtures were tested on some crude from Wyoming with the following conclusions; two alcohol-free surfactants suitable for chemical EOR at the field (Wyoming) were formulated.

Flaaten et al. (31) in their paper titled ‘ASP Chemical Flooding without Need for Soft Water’ showed that a form of borax known as metaborax could be used with hard brines since they prevent precipitation unlike sodium carbonate which will precipitate in the presence of divalent cations. A surfactant formulation in hard brine with metaborate included showed good oil recovery in a core flood.

Ping Zhao et al. (33) reported that the reason why most field-scale surfactant flooding does not seem to do well when compared to the laboratory scale flooding is because
high-quality surfactant that is easily produced at lab-scale is not properly scaled-up for field use. An example of a case of under-performing surfactant is in the Bell Creek where the petroleum-sulfonate blends used for the pilot test contained far more polysulfonates than the products used in the laboratory test. This led to highly water-soluble and fast-moving polysulfonates breaking through early causing severe emulsions in the field. Too often chemical EOR deployed in field trials was based entirely on laboratory without proper consideration if the same surfactant would work well in the field. They concluded that to ensure delivery of high-performance and repeatable surfactant product in the field, a comprehensive, time-consuming but necessary program for commercial surfactant manufacturing must be developed. Also, blending, transportation, logistics for field delivery and storage must be carefully evaluated with a detailed QA/QC plans developed ahead of time to ensure that the field surfactant-blend performs as well as the small-scale product used in the design.

Puerto et al. (34) in their work observed that many reservoirs suitable for surfactant EOR have high temperatures and salinities ranging from 70 – 120°C and total dissolved solids (TDS) content up to 200,000mg/L respectively. These conditions could lead to precipitation of injected surfactant or other undesirable phase separation. Through experiments, they concluded that blends of AGS (Alkoxylated glycidyl sulfonates) and IOS (Internal Olefin Sulfonates) have promise of providing ultra low IFT required to displace oil as well as being appropriate for high temperature reservoirs and optimal salinities.

Kumar et al. (35) in their work tried to develop alkaline-surfactant methods in order to improve recovery from a heavy oil field in north of Alaska. They noted that the key problem in heavy oil reservoir is inefficient sweep due to low mobility of the oil not the residual oil in swept region. They thus proposed to identify chemicals for forming oil-in-water emulsions and also conduct corefloods to understand the recovery of viscous oils. After laboratory work, amongst their discovery is the fact that low viscosity oil-in-water emulsions can be obtained at salinity up to 20,000ppm with acidic crudes by using hydrophilic surfactants along with an alkali. Alkaline forms soap on reacting with acidic components of the crude thus reducing the cost of surfactants to be used.

Gao et al. (36) in their paper titled ‘Integrated Evaluation of Surfactant-Polymer Floods’ proposed that surfactant-polymer flood would be more profitable if a set of guidelines are followed strictly. These guidelines were developed to combat the complexity of chemical flooding which includes precipitation, surfactant adsorption on rocks, phase separation and a host of others. The guidelines include screening of the reservoir, chemical optimization, detailed chemical laboratory design, reservoir modeling,
economic evaluation, pilot testing, application re-evaluation and commercialization. If all these guidelines are followed accordingly, then a more robust chemical formula for flooding will be achieved.

Stoll et al. \(^{(37)}\) examined the possibility of developing a robust Alkaline-Surfactant-Polymer system to be used in oil recovery for some sandstone and carbonate reservoirs in Petroleum Development Oman. The study was done with support from Shell Technology Oman. They observed that taking ASP from the laboratory to the field is very complex with lots of trials and errors involved. They however came up with a suitable formulation for the sandstone field in Petroleum Development Oman, after rigorous laboratory works.

Wang et al. \(^{(38)}\) propose a mechanism to attain ultra – low IFT without addition of alkali, salts, alcohol, co-surfactants and solvents in the system. They recognize that some kind of amphoteric surfactants like the betaine surfactant attain an ultra-low IFT at very low concentrations even in high salt-concentrated and high temperature environment.

### 2.6 SURFACTANT FLOODING IN PETROLEUM RESERVOIRS

As mentioned previously, the aim of surfactant flooding is to recover residual oil held back by capillary forces after waterflooding. Injection of surfactant solution leads to a reduction in this interfacial tension between oil and water thereby leading to a mobilization of the residual oil. If the efficiency of surfactant is very good, then the reduction in Interfacial tension (IFT) could be as much as \(10^4\) which corresponds to a value in the neighborhood of \(1\mu N/m\) \(^{(6)}\).

#### 2.61 PROCESS DESCRIPTION

Trapped oil droplets or ganglions are mobilized due to a reduction in interfacial tension between oil and water after surfactant solution has been injected. The coalescence of these drops leads to a local increase in oil saturation. An oil bank will start to flow, mobilizing any residual oil in front. Behind the oil bank, the surfactant helps to prevent the mobilized oil from being re-trapped. The ultimate residual oil will be determined by interfacial tension between oil and surfactant solution behind the oil bank.

The high cost of surfactant leads to the injection of only a small portion of the pore volume in most cases. The surfactant slug thus has to be displaced by water, in some cases containing polymer which through its ability to increase viscosity prevents fingering and breakdown down of slug.

The main aspects of surfactant flooding are discussed below;
2.62 CAPILLARY DESATURATION

The pressure drop across trapped oil has to overcome the capillary forces that trap oil in order for residual oil saturation in water flooded zones to be reduced. This represents what happens when IFT between oil and water is reduced by surfactants. The residual oil saturation corresponds to the capillary number, the dimensionless ratio between the viscous and capillary forces. Typical plots of residual saturation as function of capillary number is illustrated with the Capillary Desaturation Curve which varies with pore-size distribution and wettability (Figure 10 & 11). The oil saturation starts to drop as pore size becomes narrower at high capillary number (N_c). The CDC for the wetting phase is shifted to the right of the CDC of the non-wetting phase by two orders of magnitude. A surfactant flood should perform best in a water-wet reservoir. A reservoir with narrow pore-size distribution will give the lowest residual oil saturation.

Figure 10: Effect of pore-size distribution on the CDC

![Diagram showing the effect of pore-size distribution on the CDC](image-url)
2.63 VOLUMETRIC SWEEP EFFICIENCY

For efficient displacement of the oil bank towards the producing wells, the mobility ratio has to be as low as possible. Low mobility ratio prevents fingering of the surfactant slug into the oil bank and also reduces large-scale dispersion caused by permeability contrasts, gravity segregation and well pattern. The volumetric sweep efficiency is improved upon by low mobility ratio because a lot of the injected fluids are forced into areas far from the line between injector and producer wells. Simulation studies have been used to further confirm that low mobility ratio is of very high importance in oil recovery \(^{(6)}\)
2.64 EFFECT OF SALINITY ON SURFACTANT

The purpose of surfactant flooding is to reduce the interfacial tension (IFT) between oil and water and in some cases, depending on the kind of surfactant deployed, change wettability towards more water wet, thereby mobilizing residual oil and improving recovery. The effectiveness of surfactants floods depends, among other parameters, on the brine salinity and amount of surfactant lost to the formation due to adsorption \(^{39}\). Based on the brine salinity and surfactant’s concentration, different phase regime may exist in the surfactant-water-oil system. The surfactant-brine-oil behavior is conventionally illustrated on a ternary diagram with the top apex representing the surfactant \(i=3\), the lower left represents brine \((i=1)\) and the lower right represents oil \((i=2)\).

At low salinity, the surfactant is predominantly in the aqueous phase (Type II-) where there is good aqueous-phase stability and poor oil-phase solubility. Thus an overall composition near the brine-oil boundary of the ternary will split into two phases: an excess oil phase that is essentially pure oil and a micro-emulsion phase that contains brine, surfactant and some solubilized oil. Type II means no more than two phases can form and (-) means the tie lines have a negative slope. (Figure 12)

At high salinity, the surfactant goes into prefentially oleic phase (Type II+). This system is formed at the front. The surfactant can mobilize residual oil by swelling which is an effective mechanism that does not require low interfacial tension \(^{6}\). (Figure 13)

At Intermediate salinities, an additional phase (Type III) (Figure 14) results in the lowest IFTs and can therefore presents in principle the optimal conditions for a surfactant flood. However, the micro-emulsion generated in the Type III regime may have a high viscosity which could be difficult transporting thereby increasing the cost if polymer is used.

Core-flood experiments have shown that highest recovery is at optimal salinities. This surfactant-water-oil phase behavior was studied in details by Nelson et al.
Enhanced Oil Recovery for Norne Field’s E-Segment Using Surfactant Flooding

**Figure 12:** Schematic representation of type II (-) System \(^{32}\)

**Figure 13:** Schematics of Type II (+) System \(^{32}\)
A prism diagram showing how the phase changes from a Type II- to a Type III then a Type II+ due to changes in salinity is seen in Figure 15.
2.7 SURFACTANT FLOODING OF THE NORTH SEA

Kleppe et al (6) in the SPOR MONOGRAPH reported that the use of surfactants to improve recovery in the North Sea reservoirs has been studied with main candidates being the forties field like the Oseberg and Gullfaks field. The possibility of injecting surfactant in the North Sea looks very optimistic because from studies, surfactants can be injected before the reservoir is completely waterflooded thereby improving the process economy by earlier production of the extra oil. A recent study estimated the Improved Oil potential for surfactant flooding on the Norwegian continental shelf to be 100 million Sm³ (6). This potential is reduced to 70 million Sm³ if an efficiency corresponding to a volume ratio of 40 between produced extra oil and injected surfactant is required. This is however still a considerable amount of oil corresponding to total recoverable reserves in fields like Ula or Draugen. This potential could however drop to 50% if there is a delay of 10 years.

Some reservoir conditions like offshore location requires new ways of designing a surfactant flood.

2.71 USE OF POLYMER

Polymers that are compatible with the North Sea reservoirs are difficult to find (6). The use of polymers has been avoided and in its place, a large, low-concentration slug has been used with great advantages – high injectivity and faster production have been achieved. One polymer that could be considered is scleroglucan but it cannot be produced in large quantity while Xanthan is a promising candidate for temperatures below 80°C.

2.72 TEMPERATURE VARIATION

Injecting cold seawater into the reservoir in the North Sea during a surfactant flood would affect the phase behavior due to temperature variations. This results in unfavorable phase gradients from a Type II (+) towards Type II (-), the possibility of phase trapping is therefore increased. A phase behavior change towards Type III has been observed with an increase in pressure.

2.73 CORE FLOODS

Two surfactant systems with promising behaviors have been identified for the North Sea (6). They include; a branched ethoxylated alcohol designed for the Gullfaks field and an ethoxylated sulfonate mixed with alkyl-aryl-sulfonate, alpha-olefin sulfonate and an alcohol designed for the Oseberg field. For the Gullfaks field, injecting a 0.5 PV of a 2%
surfactant in seawater reduced the residual oil from 44% to 5% while same injection recovered 90% of residual oil for the Berea core displacements at reservoir conditions.

2.74  LOW TENSION POLYMER FLOOD

Injecting biopolymer with surfactant at low concentration can recover oil very efficiently in the North Sea. The polymer scleroglucan or Xanthan improves the performance of the surfactant by reducing the adsorption levels down to 0.1 mg surfactant per gram rock, in some cases. It also helps in the reduction of interfacial tension even in the vicinity of wider ranges of salinity and surfactant concentration and reduces also the possibility of phase trapping.

2.75  TIMING

This involves checking the appropriate time for surfactant injection to achieve optimal oil recovery. A black oil simulator used on the Oseberg field showed that for a homogenous reservoir, the optimal injection time was after some water had been injected. In a heterogeneous case, however, it was discovered that it would be more favorable for the surfactant to be injected as early as possible.

2.8  FACTORS THAT AFFECT THE EFFICIENCY OF SURFACTANT DURING A FLOOD

It is important that when a surfactant is injected into the reservoir, it should achieve a low interfacial tension while maintaining its integrity. However this is not usually the case as the surfactant gets broken down. Some of the factors leading to the surfactant losing its integrity include;

2.81  ADSORPTION

Precipitation, phase trapping and adsorption are various mechanisms by which surfactants are trapped by the reservoir rock. A lot of research in the past and recent times has produced ways to technically prevent loss of surfactant through precipitation and phase trapping. This is achieved by using salt tolerant surfactants while changes in parameters like salt, hardness, pressure, temperature, co-surfactant responsible for phase behavior only take place within acceptable limits.

However, adsorption of surfactants at the solid-liquid interface will always take place and most times, instantaneously. Adsorption of surfactants at the solid/liquid interface comes into play by electrostatic interaction between the solid (adsorbent) and the surfactant (adsorbate). Ion exchange, ion pairing and hydrophobic bonding are some of the mechanisms by which surfactants adsorb onto mineral surfaces of the rock. A lot of the reservoir minerals like kaolinite, quartz show a negative charge at natural pH of the
brine, however, some of the clay minerals have positively charged edges. Negatively charged surfactants are usually considered as the main surfactant specie in a slug in order to lower the adsorption.

The quantity of surfactants adsorbed on the rock is given by:

\[ EQ \ 2.0 \]

\[
\frac{PORV}{\phi} \cdot MD \cdot CA(C_{surf})
\]

Where

- \( PORV \) is the Pore volume of the cell
- \( \phi \) is the porosity
- \( MD \) is the mass density of the rock
- \( CA(C_{surf}) \) is the adsorption isotherm as a function of local surfactant concentration in solution.

An example of an isotherm for the adsorption of a negatively charged surfactant onto an adsorbent with positively charged sites is S-shaped. There are four regions reflecting distinct modes of adsorption (Figure 16)

**REGION 1**

Anionic exchange is the main means of surfactant adsorption. It shows as a linear relationship between adsorbed material and equilibrium concentration.

**REGION 2**

An interaction between the hydrophobic chains of the oncoming surfactants and the surfactants already adsorbed naturally leads to a marked increase in adsorption. This takes place above the CMC of the surface.

**REGION 3**

The electrostatic repulsion between the surfactant and similarly charged solid has to be overcome by adsorption, this leads to a decrease in adsorption of the surfactants.
Above the Critical Micelle Concentration, CMC, a plateau adsorption is obtained. The concentration of monomers is constant above the CMC and the micelles do not adsorb onto the solid.

**2.82 PREVENTING/MITIGATING ADSORPTION**

One of the ways of reducing adsorption in chemical flooding is by doing a ‘pre-flush’. A pre-flush involves injecting some chemicals and this could be;

- Injection of sodium chloride in order to reduce hardness.
- Injection of alkaline additives like sodium hydroxide, carbonates, phosphates and silicates to render the reservoir rock more negatively charged and reduce hardness.
- In order to block active sites on the rock that could encourage adsorption, sacrificial chemicals like lignosulfonates, polyethylene oxide, and polybasic carboxylic acids \(^\text{6}\) are injected before a surfactant.
2.9 MODELING SURFACTANT FLOODING IN RESERVOIRS USING THE ECLIPSE SIMULATOR.

Surfactant flooding through the reservoir can be modeled using the Eclipse 100 simulator. The Eclipse 100 is a fully–implicit, three-phase, three dimensional general purpose black oil simulators with gas condensate option. The program is written in FORTRAN77 and operates on any computer with an ANSI-standard FORTRAN77 compiler and with sufficient memory \(^{[41]}\). Two phase options (oil/water, oil/gas, and gas/water) are solved as two components systems, Eclipse 100 may also be used to model oil vaporizing in gas.

The modeling of injected surfactant is done by solving a conservation equation for surfactant within the water phase \(^{[46]}\). The surfactants are updated at the end of each time-step fully-implicitly after the oil, water and gas flows have been computed. The surfactant is assumed to exist only in the water phase, and the input to the reservoir is specified as a concentration at water injector.

An important factor in the modeling of surfactant flooding is the capillary number. The capillary number is the measure of the ratio of the viscous forces to the capillary forces. In eclipse, the capillary number is given by;

\[
N_c = \frac{K \cdot \text{grad}P}{ST \cdot C_{\text{unit}}} \quad \text{[EQ 2.1]}
\]

Where

- \(K\) = Is the permeability
- \(P\) = Is the potential
- \(ST\) = Is the interfacial tension
- \(C_{\text{unit}}\) = Is the conversion factor depending on the unit used
- \(K \cdot \text{grad}P\) = Is calculated as

\[
K \cdot \text{grad}P = \sqrt{(K_x \cdot \text{grad}P_x)^2 + (K_y \cdot \text{grad}P_y)^2 + (K_z \cdot \text{grad}P_z)^2} \quad \text{[EQ 2.2]}
\]

Where for cell \(i\)

\[
K_x \cdot \text{grad}P_x = 0.5 \left[ \frac{K_x}{D_x} \left( P_i - P_{i-1} \right) + \frac{K_x}{D_x} \left( P_{i+1} - P_i \right) \right] \quad \text{[EQ 2.3]}
\]

Similar for the Y and Z direction.
The importance of the relative permeability cannot also be over-emphasized because in the reduction of interfacial tension between water and oil the important factor that changes is the relative permeability.

2.91 RELATIVE PERMEABILITY MODEL

The concept of relative permeability is fundamental to the study of the simultaneous flow of immiscible fluids in porous media.

Permeability refers to 100% saturation of single–phase fluid. It is usually designated by the symbol K. In petroleum reservoirs however, the rocks are usually saturated with two or more fluids, such as water, gas and oil. Effective permeability describes the simultaneous flow of more than one fluid; it is the ability of a porous material to conduct a fluid when its saturation is less than 100% of the pore space. Relative permeability is the ratio of the effective permeability of a given phase, say oil (K_o) in the presence of other phases (water and/or gas), to the absolute permeability K.

Relative permeabilities are influenced by the following factors; saturation, saturation history, wettability, temperature, viscous, capillary and gravitational forces.

In Eclipse simulator relative permeability model is very important for the transition of immiscible relative permeability curves at low capillary number to miscible relative permeability curves at high capillary number. A table is supplied by the user that would describe this transition as a function of log_{10} (capillary number).

There are two steps in the calculation of the relative permeability used in the miscibility function between two extremes; first the end points of the curves are interpolated and both the immiscible and miscible curves are scaled to conform to these points. The relative permeability values are looked up on both curves and the final relative permeability is taken as an interpolation between these two values. This procedure is shown in Figure 17 for the oil to water curve.
2.92 CAPILLARY PRESSURE

When two immiscible fluids are in contact in the interstices of a porous medium, a discontinuity in pressure exists across the interface separating them. The difference in pressure $P_C$ is called capillary, which is pressure in the non-wetting phase minus the pressure in the pressure.

Thus the capillary pressure may have either positive or negative values.

Water oil capillary pressure will reduce as the concentration of surfactant increases. It is actually the reduction in oil water capillary pressure that gives rise to the reduction in the residual oil saturation. The oil water capillary pressure is taken as:

$$P_{c_{ow}} = P_{c_{ow}}(S_w) \frac{ST(C_{surf})}{ST(C_{surf} = 0)}$$  \[EQ 2.4\]
Where

ST(C_{surf}) \quad \text{Represents the surface tension at the present surfactant concentration}

ST(C_{surf} = 0) \quad \text{Represents the surface tension at zero concentration}

P_{cow}(S_w) \quad \text{Represents the capillary pressure from the immiscible curves initially scaled to the interpolated end-points calculated in the relative permeability model.}

2.93 WATER PVT PROPERTIES

The surfactant modifies the viscosity of the pure or salted water input using the PVTW or PVTWSALT keyword respectively. The SURFVISC keyword is used to represent the surfactant viscosity as a function of surfactant concentration and is used to calculate the water-surfactant solution viscosity as follows;

\[ \mu_{ws}(C_{surf}, P) = \mu_w(P) \frac{\mu_s(C_{surf})}{\mu_w(P_{ref})} \]  \hspace{1cm} \text{[EQ 2.5]}

Where

\( \mu_s \) \quad \text{Is the viscosity from SURFVISC keyword.}

\( \mu_w \) \quad \text{Is the viscosity from the PVTW or PVTWSALT keyword.}

\( \mu_{ws} \) \quad \text{Is the viscosity of the water-surfactant mixture.}

\( P_{ref} \) \quad \text{Is the reference pressure in the PVTW or PVTWSALT keywords.}

\( C_{sref} \) \quad \text{Is the reference salt concentration in the PVTWSALT keywords.}

2.94 ACTIVATING THE SURFACTANT MODEL IN ECLIPSE

The model is activated by specifying the keyword SURFACT in the RUNSPEC section (Figure 18). The output of the geometric data used by the surfactant model can be reported by setting ‘KOVERD’ mnemonic in RPTGRID. In the PROPS section, three obligatory keywords must be used while two optional keywords could be used in cases in which adsorption takes place. Table 3 gives a summary of the surfactant keywords and their descriptions.
<table>
<thead>
<tr>
<th>Keyword</th>
<th>Description</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>SURFST</td>
<td>Water-oil Surface tension in the presence of surfactant</td>
<td>Obligatory</td>
</tr>
<tr>
<td>SURFVISC</td>
<td>Modified water viscosity</td>
<td>Obligatory</td>
</tr>
<tr>
<td>SURFCAPD</td>
<td>Capillary de-saturation data</td>
<td>Obligatory</td>
</tr>
<tr>
<td>SURFADS</td>
<td>Adsorption isotherm</td>
<td>Optional</td>
</tr>
<tr>
<td>SURFROCK</td>
<td>Rock properties and adsorption model indicator</td>
<td>If SURFADS is present</td>
</tr>
<tr>
<td>SURFNUM</td>
<td>For specifying miscible relative permeability curves</td>
<td></td>
</tr>
<tr>
<td>WSURFACT</td>
<td>Injected surfactant concentration of water injector</td>
<td>Obligatory</td>
</tr>
</tbody>
</table>

Table 3: Some basic surfactant keywords used in the Eclipse simulator

---

**RUNSPEC**

```plaintext
RUNSPEC
TITLE
Example Surfactant Flood Case.
DIMENS 5 5 1 /
NONNC
OIL
WATER
SURFACT
FIELD
TRACERS 0 1 0 0 'DIFF' /
TABDIMS
```

Figure 18: An excerpt from an Eclipse data file showing the SURFACT keyword
2.10 LIMITATIONS OF THE ECLIPSE SIMULATOR

The Eclipse simulator does not model the detailed chemistry of a surfactant process. It does not provide options as to what type of surfactant to use for given reservoir structures or certain fluid characteristics. It just presents the surfactant option as a blanket over all types of reservoir and fluid characteristics. In recent times lots of research has led to the discovery of various kinds of surfactant, which because of their structure can lead to better oil recovery through an ultra-low interfacial tension achievement. However, because the Eclipse simulator does not have the ability of modeling detailed chemistry of a surfactant; it becomes difficult to test out different characteristics of surfactants on different reservoir types.

Studies have shown that the performance of surfactants can be improved upon by tailoring it to reservoir characteristics and fluid properties. These features cannot be modeled by Eclipse.
3.0 **NORNE FIELD; GENERAL FIELD INFORMATION**

The Norne field is situated in the southern part of the Nordland II area in the Norwegian Sea precisely on blocks 6608/10 and 6508/1. Its location, relative to other fields is shown in Figure 19. The field is located 200km of the Norwegian shore and 85km northeast of the Heidrun Field. The water depth is approximately 380m.

![Figure 19: Shows Norne field relative to other fields](image)

Figure 19: Shows Norne field relative to other fields [45]
3.1 RESERVOIR DESCRIPTION

The Norne field was discovered in 1991 by well 6608/10-2 and further appraisal was done in 1993 with well 6608/10-3.

The Norne field consists of two separate oil compartments;

- The main structure discovered in December 1991 and includes 98% of the oil in place consists of the Norne C, D and E segments; 60% of the STOIIP is in the C-segment
- The Northeast Segment (Norne G-Segment) (Figure 20)

The Norne main structure is relatively flat and consists of an equally 110 meter thick oil leg primarily in the reservoir formations of Ile and Tofte. The overlying gas cap is mostly in the Garn formation above the Not formation shale. The underlying water zone is generally in the heterogeneous Tilje formation. There is no much evidence for aquifer support. The gas oil contact is in general close to the Not formation shale which acts as a barrier throughout the field. This was actually shown after production and injection start-up showed a pressure increase in Garn formation and a pressure decline in Ile/Tofte, showing that there is no communication across the Not shale. (Figure 21)

Pressure tests show very good communication between Ile/Tofte and Garn across the main structure while there is limited communication between Norne Main Structure and the Northeast segment. (42)

Vertical communication between Tofte and Tilje is limited, thus perforation is usually higher up, that is, in the oil zone to aid injection of water.

The total proven in-place hydrocarbon volumes on the Norne Main structure are $155.4 \times 10^6$ Sm$^3$ oil with $17.3 \times 10^9$Sm$^3$ associated gas and $11.0 \times 10^9$Sm$^3$ free gas with $0.6 \times 10^6$ Sm$^3$ associated condensate.

The Norne G-Segment (Northeast Segment) is assumed to contain no free gas and total proven in-place hydrocarbon has been calculated to be $3.8 \times 10^6$ Sm$^3$ (42).

3.2 RESERVOIR COMMUNICATION

The Norne field reservoir contains both faults and Stratigraphic barriers/layers which act as restrictions to vertical and lateral flow. Stratigraphic barriers have been identified and
their lateral extent and thickness variation assessed using cores and logs. Some of the continuous barriers in the Norne field include:

- Garn3/Garn2 – carbonate cemented layer at the top Garn 2
- Not formation – claystone
- Ile3/Ile 3 – carbonate cementations and increased clay content at base 3
- Ile2/Ile1 – carbonate cemented layers at base Ile 2
- Ile 1/Tofte 4 – Carbonate cemented layers at top Tofte 4
- Tofte 2/Tofte 1 – significant grain size contrast
- Tilje 3/Tilje 2 – claystone formation

Figure 20: Norne Field Segments and Wells (45)
3.3 DRAINAGE STRATEGY

The Norne main structure is developed with horizontal wells completed at depths that make the gas and water front arrive simultaneously. The reservoir pressure was initially planned to be maintained by re-injecting all the produced gas into the gas cap and water injection into the water zone. The non-communication between the Garn and Ile formations made that plan to be revised. The gas was instead re-injected into the water zone with proper monitoring to prevent early gas breakthrough and increase in GOR. (Figure 22 & Figure 23)

The development of the field is with five templates at the seabed connected to a floating production vessel. Development drilling started in August 1996 while oil production started on November 6, 1997. There has been gas injection on the Norne Field from the same date. Water injection started in July 1998.
Enhanced Oil Recovery for Norne Field’s E-Segment Using Surfactant Flooding

Figure 22: NE-SW Cross-section of Fluid Contacts and Drainage Strategy

Figure 23: Drainage Strategy for the Norne Field from Pre-start to 2014
3.4 GEOLOGY

The Norne field is characterized by sandstones that are fine-grained, basically well sorted sub-arkosic arenites. The depth of burial of the sandstones is between 2500m to 2700m thus undergoing diagenesis which leads to a reduction in the reservoir quality due to mechanical compaction. The porosities of the sandstones are however good, in the range of 25-30% and the permeability values are in the range of 20-2500mD. The N/G values are in the range of 0.7-1 and water saturations ranges from 12-43% for the hydrocarbon zones. Some of the formation encountered in the Norne field are in two major categories, the FANGST which consists of the Garn, Not and Ile Formations and the BÅT which includes the Tofte, Tilje and Åre Formations (Fig 24)

3.41 GARN FORMATION

The garn formation is 35m thick sandstone units deposited during the late Aalenian and early Bajocian. It is divided into three reservoir zones, Garn 1, Garn 2 and Garn 3.\(^{(43)}\) There is generally and increase in reservoir quality in the upward direction. Garn 1 is generally coarsening upward with a bioturbated, muddy and very fine sandstones in the lower part. Garn 2 consists of an interbedded laminated and bioturbated fine grained sandstone unit deposited during transgression in a lower shore-face environment. The upper part of Garn 3 consists of low angled cross bedded fine grained sandstones.

3.42 NOT FORMATION

The Not Formation is a dark grey to black claystone unit containing siltstone lamina that was deposited during Aalenian time. The Not formation is 7.5m thick. The sedimentology of the Not formation indicates deposition in a relatively quiet marine depositional environment. The Not Formation consists of only organic shale and the N/G is zero.\(^{(43)}\)

3.43 ILE FORMATION

Ile formation is 32-40m thick sandstone unit deposited during the Aalenian. The Ile is subdivided into three reservoirs; Ile 1, Ile 2 and Ile 3.\(^{(43)}\) The Ror formation and Ile 1 and Ile 2 are separated by calcareous cemented layers. These calcareous layers might form barriers to vertical fluid flow and is thus important in the reservoir modeling. The calcareous cemented units at the top of the Ror formation and at the top of Ile 1 are probably results of minor flooding events in a general regressive period. The regressive parts of the Ile formation – Ile 1 and Ile 2 have very good reservoir quality while the transgressive part- Ile 3 has good reservoir quality with gradual decreasing reservoir properties towards the top of the formation.
3.44 TOFTE FORMATION

The Tofte formation is approximately 50m thick sandstone deposited above an unconformity. The Tofte formation is divided into three reservoir zones, a lower coarse to medium grained sandstone unit which represents Tofte 1, a middle very fine grained sandstone unit representing Tofte 2 and an upper fine grained sandstone representing Tofte 3.\(^{(43)}\)

3.45 TILJE FORMATION

The Tilje formation has a heterolithic composition with subhorizontal bedding, deposited during late Pliensbachian. The base of the Tilje formation sits at the uppermost coal of the Åre formation and represents the transition to the more sand-prone rocks of the Tilje formation. The Tilje formation is divided into four reservoir zones, Tilje 1-4, based on the biostratigraphic events and similarities in log pattern. Tilje 1 has two sandstone units separated by shale. The lower unit has a coarsening upward trend. Tilje 2 has a heterolithic composition, sandstone layers with variable thicknesses and extensively bioturbated and laminated shales.\(^{(43)}\) Tilje 3 is the most sand prone part of Tilje formation and is dominated by fine grained sandstones while Tilje 4 has bioturbated muddy sandstone in the lower part.

3.46 ILE & TOFTE FORMATION

In this thesis, a lot of attention will be paid to the Ile and Tofte formations because they are by far the most important reservoir formations, accounting for 36% and 44% of the proven oil respectively. The southern fault block within the Norne field contains 80% of the proven oil in place. 86.4% of the proven gas and associated condensate and 90.6% of the proven oil and associated gas lie within block 6608/10 while for block 6508/1 they are 13.6% and 9.4% respectively.

3.5 OIL AND GAS COMPOSITION

Compositional analysis of the reservoir oil shows a methane content of 46-48 mole % and a C\(_{10}\) plus content of 32-35%. The corresponding values for reservoir gas are approximately 91 mole % for methane and 0.4-0.5% for C\(_{10}\) plus. The content of carbon dioxide is measured to 0.6-1 mole% for the reservoir oil and 1.0-1.3 for the reservoir gas. The hydrogen sulphide content from well-site analysis measured to 0-4ppm\(^{(42)}\)
3.6 PRODUCTION

Table 4 below gives the reserves estimates for Norne Field to December 31, 2009, as reported by Norwegian Petroleum Directorate (NPD). Figures 25, 26 and 27 give the production profile for the Norne field within the last 24 months.

Figure 24: Stratigraphic subdivision of the Norne reservoir. (42)
Recoverable Reserves

<table>
<thead>
<tr>
<th>Recoverable Reserves</th>
<th>Oil (Mill Sm$^3$)</th>
<th>Gas (Bill Sm$^3$)</th>
<th>NGL (Million Tonn)</th>
<th>Condensates (million Sm$^3$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>94.7</td>
<td>10.5</td>
<td>1.6</td>
<td>0.0</td>
<td></td>
</tr>
</tbody>
</table>

Remaining Reserves

<table>
<thead>
<tr>
<th>Remaining Reserves</th>
<th>Oil (Mill Sm$^3$)</th>
<th>Gas (Bill Sm$^3$)</th>
<th>NGL (Million Tonn)</th>
<th>Condensates (million Sm$^3$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>12</td>
<td>4.5</td>
<td>0.9</td>
<td>0.0</td>
<td></td>
</tr>
</tbody>
</table>

Table 4: NPD Reserves Estimate as at 31.12.2009

Figure 25: Oil Production from Norne Field within the last 24 months

Enhanced Oil Recovery for Norne Field’s E-Segment Using Surfactant Flooding
Figure 26: Gas Production from Norne Field within the last 24 months \(^{(46)}\)

Figure 27: Water Production from Norne Field within the last 24 months \(^{(46)}\)
3.7 NORNE FIELD E-SEGMENT

The E segment of the Norne field is part of the Norne main structure which also comprise of the C and D segments. The Ile and the Tofte formations are the most important in this segment because about 80% oil in the Norne field is contained in these formations. From the Eclipse model of the Norne field, The E-segment had five (5) wells as at 2004. Table 5 below gives a summary of these wells;

<table>
<thead>
<tr>
<th>WELL</th>
<th>TYPE</th>
<th>STATUS</th>
</tr>
</thead>
<tbody>
<tr>
<td>F-1H</td>
<td>Water Injector</td>
<td>Active</td>
</tr>
<tr>
<td>E-3H</td>
<td>Oil Producer</td>
<td>Shut</td>
</tr>
<tr>
<td>E-3AH</td>
<td>Oil Producer</td>
<td>Active</td>
</tr>
<tr>
<td>E-2H</td>
<td>Oil Producer</td>
<td>Active</td>
</tr>
<tr>
<td>F-3H</td>
<td>Water Injector</td>
<td>Active</td>
</tr>
</tbody>
</table>

Table 5: Well Status in the Norne Field E-Segment

3.71 MODELING OF NORNE FIELD IN ECLIPSE SIMULATOR

The Norne field was modeled with non-vertical faults to follow the fault pattern (47). For a better description of transmissibility across faults and a more correct match to geological model, point geometry was used instead of an orthogonal grid. The reservoir model has 46 grids in the X-direction, 112 in the Y direction and 22 layers. Each geological layer (reservoir zone) is in general represented by one layer, for example, the Ile and the Tofte formations are represented by layers 5-11 and 12-18 respectively.

The reservoir parameters used in the simulation model are based on results from two wells namely 6608/10-2 and 6608/10-3. The fluid analyses from both wells indicate one common fluid system over the main structure in the field. Water compressibility used in the eclipse model was $4.67 \times 10^{-5}$/bar at 277 bars while the formation volume factor used was $1.038 \text{m}^3/\text{Sm}^3$. The rock compressibility of $4.84 \times 10^{-5}$/bar was used in the entire reservoir while the water viscosity is 0.318 cp. (47)

The pressure and temperature used in the simulation model is 273.2 bar and 98.3°C respectively at 2639m. It is assumed that three different equilibrium regions exist in the reservoir (including the Northeast segment).
The porosities used in the reservoir simulation model are sampled from the porosity maps. The calculation of porosity is based on density log where the total porosity has been estimated from the equation

\[
\phi = \alpha + \beta \rho_b \quad \text{[EQ 3.0]}
\]

Where \( \alpha \) and \( \beta \) are found from cross-plots of the overburden corrected core porosity against the density log. The porosity is modeled as a constant average value for each reservoir zone.

For the permeability, the value used for each layer was constant in the simulation model. The permeability figures used were obtained as an average from the two wells mentioned previously. These permeability figures were obtained from logs based on the relationship between core porosity and core permeability. There is a reasonable agreement between the permeability calculated from the well test and the permeability calculated from log.

For water saturation, the maps of the initial water saturation used in the geological model have been sampled to give the initial water saturation in the reservoir model. The calculation of the initial water saturation is based on Archie’s equation and calibrated in the oil-water transition zone against/towards capillary pressure measurements.

Table 6 gives some Norne’s fluid properties while Table 7 gives some of the porosity and permeability values used in reservoir modeling of the 2000 Eclipse reservoir model.

<table>
<thead>
<tr>
<th></th>
<th>Units</th>
<th>Norne Structure</th>
<th>Norne Segment</th>
<th>G-Segment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bubble point</td>
<td>bar</td>
<td>251</td>
<td>216</td>
<td></td>
</tr>
<tr>
<td>Gas Oil Ratio</td>
<td>Sm(^3)/Sm(^3)</td>
<td>111</td>
<td>96</td>
<td></td>
</tr>
<tr>
<td>Oil Formation Volume Factor</td>
<td>Rm(^3)/Rm(^3)</td>
<td>1.347</td>
<td>1.3</td>
<td></td>
</tr>
<tr>
<td>At bubble point</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil density at bubble point</td>
<td>g/cm(^3)</td>
<td>0.712</td>
<td>0.729</td>
<td></td>
</tr>
<tr>
<td>Oil Viscosity at bubble point</td>
<td>cp</td>
<td>0.58</td>
<td>0.695</td>
<td></td>
</tr>
<tr>
<td>Oil formation Volume factor at</td>
<td>Rm(^3)/Sm(^3)</td>
<td>1.3185</td>
<td></td>
<td></td>
</tr>
<tr>
<td>initial conditions</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Formation volume factor for gas</td>
<td>Rm(^3)/Rm(^3)</td>
<td>4.74 \times 10^{-3}</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Table 6: Characteristic Fluid Parameter for Norne Field* (47)
### Table 7: Average values of porosity and permeability in modeling\(^{(47)}\)

<table>
<thead>
<tr>
<th>Formation</th>
<th>Net/Gross (Fraction)</th>
<th>Depth M TVD/MSL</th>
<th>Porosity Fraction</th>
<th>Permeability mD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Garn 3</td>
<td>0.94</td>
<td>2553</td>
<td>0.29</td>
<td>813.9</td>
</tr>
<tr>
<td>Garn 2</td>
<td>0.86</td>
<td>2562</td>
<td>0.23</td>
<td>518.6</td>
</tr>
<tr>
<td>Garn 1</td>
<td>0.78</td>
<td>2570</td>
<td>0.18</td>
<td>44.5</td>
</tr>
<tr>
<td>Not</td>
<td></td>
<td>2581</td>
<td>0.12</td>
<td>0</td>
</tr>
<tr>
<td>Ile 3.2</td>
<td>0.89</td>
<td>2591</td>
<td>0.23</td>
<td>137.6</td>
</tr>
<tr>
<td>Ile 3.1</td>
<td>0.92</td>
<td>2601</td>
<td>0.23</td>
<td>87.6</td>
</tr>
<tr>
<td>Ile 2.2.2</td>
<td>0.99</td>
<td>2614</td>
<td>0.26</td>
<td>723.9</td>
</tr>
<tr>
<td>Ile 2.1</td>
<td>0.8</td>
<td>2622</td>
<td>0.22</td>
<td>508.1</td>
</tr>
<tr>
<td>Ile 1</td>
<td>0.97</td>
<td>2630</td>
<td>0.27</td>
<td>793.5</td>
</tr>
<tr>
<td>Tofte 4</td>
<td>0.93</td>
<td>2628</td>
<td>0.23</td>
<td>108.8</td>
</tr>
<tr>
<td>Tofte 3.4.2</td>
<td>1</td>
<td>2637</td>
<td>0.31</td>
<td>1348.2</td>
</tr>
<tr>
<td>Tofte 3.4.1</td>
<td>1</td>
<td>2641</td>
<td>0.3</td>
<td>1063.7</td>
</tr>
<tr>
<td>Tofte 3.3.2</td>
<td>1</td>
<td>2645</td>
<td>0.28</td>
<td>590.7</td>
</tr>
<tr>
<td>Tofte 3.3.1</td>
<td>1</td>
<td>2649</td>
<td>0.27</td>
<td>375.3</td>
</tr>
<tr>
<td>Tofte 3.2</td>
<td>1</td>
<td>2653</td>
<td>0.26</td>
<td>255.9</td>
</tr>
<tr>
<td>Tofte 3.1</td>
<td>1</td>
<td>2663</td>
<td>0.26</td>
<td>166.7</td>
</tr>
<tr>
<td>Tofte 2</td>
<td>0.97</td>
<td>2666</td>
<td>0.22</td>
<td>58.5</td>
</tr>
<tr>
<td>Tofte 1.2</td>
<td>0.9</td>
<td>2679</td>
<td>0.24</td>
<td>971.6</td>
</tr>
<tr>
<td>Tofte 1.1</td>
<td>0.89</td>
<td>2686</td>
<td>0.23</td>
<td>819.6</td>
</tr>
<tr>
<td>Tilje 4</td>
<td>0.83</td>
<td>2694</td>
<td>0.19</td>
<td>308.7</td>
</tr>
<tr>
<td>Tilje 3</td>
<td>0.87</td>
<td>2709</td>
<td>0.24</td>
<td>555.4</td>
</tr>
<tr>
<td>Tilje 2</td>
<td>0.72</td>
<td>2731</td>
<td>0.16</td>
<td>212.4</td>
</tr>
<tr>
<td>Tilje 1</td>
<td>0.9</td>
<td>2771</td>
<td>0.25</td>
<td>1614</td>
</tr>
</tbody>
</table>

#### 3.72 COARSE MODEL

The Eclipse model used in this study is a coarse model which means that cells that are in regions of the reservoir where accuracy is unimportant are amalgamated. Figure 28 shows an Eclipse model of the coarse Norne field where only the E-segment is fine gridded.

#### 3.8 PRODUCTION PROFILE OF THE E-SEGMENT

The production rate for water, oil and gas for the E-segment are given in the following Figures 29, 30 and 31 respectively. The water production rate peaked at 3700 Sm\(^3\)/day in 2004. The oil production rate for the Norne field peaked in 2001 at 9000Sm\(^3\)/day.
while at 2004 it declines to 1800Sm$^3$. Gas production rate peaked to $2 \times 10^6$ Sm$^3$/day in 1999 while in 2004 it declined to $5 \times 10^5$Sm$^3$. The high gas production rate could be attributed to the injection of gas into the Garn formation. Unfortunately there is no connection between the Garn and the Ile formation so the injection of gas leads to a build up in the pressure in the Garn formation and an increase in the gas production rate. From Figure 31, total oil produced is $8.9 \times 10^6$ Sm$^3$ as at 2004 while total gas produced is $1.4 \times 10^6$Sm$^3$ also at 2004, Figure 32. Figure 33 shows that total water produced is $2.8 \times 10^5$Sm$^3$ at 2004.

![Figure 28: Norne Field showing E-Segment with the other segments being coarse.](image)
Figure 29: Water Production Rate from E-Segment (History & Simulated)

Figure 30: Oil Production Rate from E-Segment (History & Simulated)
Figure 31: Gas Production Rate from E-Segment (History & Simulated)

Figure 32: Total Oil Produced from the Norne E-Segment (History & Simulated)
Enhanced Oil Recovery for Norne Field’s E-Segment Using Surfactant Flooding
Figure 35: Water Cut for the Norne E-Segment (History & Simulated)

Figure 36: GOR for the Norne E-Segment (History & Simulated)
Figure 37: Reservoir Pressure for the Norne Field

Figure 38: Formation Volume Factor (Bo) vs. Pressure
Figure 35 shows the water cut which peaked at 0.78 in 2004. Figure 36 shows the Gas Oil Ratio (GOR) which peaked at 3500 Sm$^3$/Sm$^3$ in 1999 and in 2004 was 2700 Sm$^3$/Sm$^3$. This could also be attributed to the gas injection in the Garn formation that could not be transmitted to the Ile formation because of the sealing Not formation.

3.9 PRESSURE PROFILE

The pressure profile for the Norne field is shown in Figure 37. The initial reservoir pressure was 277 bars. Production of oil and gas led to a decline of pressure; however, this was put in check by injection of gas into the Garn formation and injection of water into the Tilje formation. However, the injection of gas into the Garn formation had to be discontinued because there was no communication between the Garn and the Ile since the Not formation between them is sealing. The gas was thereafter injected into the Tilje formation.

The bubble point pressure for the Norne Main Structure is 251 bars while for the Norne-G Segment are 216 bars.

The plot of Formation volume factor and reservoir pressure in Figure 38 show that the Norne reservoir is still in the undersaturated region. This is because the reservoir pressure is above the bubble point pressure.

3.10 EOR POTENTIAL FOR THE NORNE FIELD E-SEGMENT

Petrophysical and geological data shows that about 80% of the oil in the Norne E-segment is contained in the Ile and Tofte formation. From the Eclipse model, the Ile and Tofte formation is represented by layers 5-18 and after production has gone on for seven years, (1997 – 2004) the saturation of oil is still very high. This is evident from the eclipse model (Figures 39 and 40). Figure 41 shows the oil saturation in the Tofte layer. The oil saturation is not as high as the Ile formation though.

Also, a plot of block oil saturation for block I=15, J=74 and K=7 and also for I=16, J=75 and k=6 shows that the oil saturation is still very high. These are shown in Figures 42 and 43 respectively.
Enhanced Oil Recovery for Norne Field’s E-Segment Using Surfactant Flooding

Figure 39: Shows Oil saturation for the Ile formation (layer 6) in 2004

Figure 40: Shows Oil saturation for the Ile formation (layer 9) in 2004 (7 years of production)
Figure 41: Shows Oil Saturation in Tofte Formation (layer 13) in 2004

Figure 42: Oil Saturation for block I=15, J=74 and K=7
3.11 STRATEGY FOR SURFACTANT FLOODING IN THIS THESIS

From the foregoing, it is evident that the oil saturation after seven (7) years of production is still high, especially in the Ile formation, about 70-80%. However, surfactant is supposed to attack the interfacial tension between oil and water and release the residual oil trapped by capillary forces. Thus, the strategy that would be used in this thesis is to allow the E-segment to produce until the reservoir gets to the residual oil before the start of surfactant injection.

3.12 TESTING OUT SURFACTANT FLOODING OPTION ON A SYNTHETIC MODEL IN ECLIPSE

In order to ascertain if the surfactant model in the Eclipse simulator could be used to model increase in oil recovery by reduction of interfacial tension between oil and water, an earlier work that was done using a synthetic model proved the effectiveness.

The synthetic model was of dimension 10, 10, 3 in I, J and K directions. Two wells, one producer and an injector were placed in grids 10, 10, 3 and 1, 1, 3 respectively. The model is homogeneous and flat and the Norne fluid and rock properties were used to populate it. (Figure 44)
The following cases were simulated:

- Base case with only water flooding
- Continuous surfactant flooding. After water flooding for 150 days, surfactant was introduced at the injector well.
- Effect of high interfacial tension is tested with continuous surfactant flooding.
- Effect of zero capillary pressure is tested with continuous surfactant flooding.
- Effect of injecting surfactant slug then water.
- Horizontal well is used instead of vertical well to test the time used to get to zero residual oil.

### 3.12.1 RESULTS OF SYNTHETIC SIMULATION

The Figure 45 shows the effect of injecting surfactant into the synthetic model. The blue line represents the recovery factor for the base case without surfactant flooding while the green line represents recovery factor with surfactant flooding. The base case and the surfactant case have recovery factors of 75% and 97% respectively.
Thus, from the fore-going, it is obvious that the eclipse surfactant option works in recovery of residual oil. Thus this model will be applied to the Norne E segment.

![Image: Effect of Surfactant flooding on Recovery Factor for Synthetic Case](image1)

**Figure 45:** Effect of Surfactant flooding on Recovery Factor for Synthetic Case

![Image: Effect of Surfactant Flooding on Oil Production Rate for Synthetic Case](image2)

**Figure 46:** Effect of Surfactant Flooding on Oil Production Rate for Synthetic Case
 Figures 46 & 47 show the oil production rate and water production rate respectively.
4.0 RESULTS OF SIMULATIONS AND DISCUSSION.
Modeling the injection of surfactants into an oil reservoir should be a systematic process. This is because surfactants are expensive and it is pertinent to ensure that unnecessary waste is prevented during the course of injection. For example, if slug injection of surfactant could give the same increased oil recovery as continuous injection, then the latter becomes unnecessary as this will give rise to increased expenditure while also resulting to excess production of surfactants at the producer wells. In this thesis, there is a step by step modeling of what method of surfactant injection to use. Several cases were examined ranging from continuous surfactant injection with different periods of injection to slug injection with different intervals. Also, the appropriate surfactant concentration was determined and the most profitable well configurations were examined.

4.1 CONTINUOUS SURFACTANT INJECTION
In continuous surfactant injection, two cases were considered; injection of surfactant continuously for four (4) years starting from 2005 and injection of surfactants continuously for seven (7) years also starting at 2005. The aim was to ascertain which would give a better recovery. Figure 48 and 49 show the oil production rate and total oil produced for the two cases respectively. From figure 48, it can be seen that oil production rate for continuous injection for 4 years is about 50 Sm^3/day less that the oil rate for continuous injection for 7 years. The next concern is to find out if this increment is worth the injection of surfactant for 7 years. This is shown in Figures 50 and 51. From Figure 50, the total surfactant injected into the E-Segment is shown to be about 770 million kg for 7 years and about 380 million kg for 4 years. Figure 51 shows that the production of surfactant from the producer well E-2H is 92,000kg/day for continuous surfactant injection for 7 years while for continuous injection for four years it is about 85,000 kg/day.
From this analysis, it can be seen that it is rather wasteful to inject surfactant for 7 years because the incremental oil anticipated is not encouraging. Thus injecting surfactant for four years is better. However, the volume and therefore the cost of surfactant needed for four years is still a considerable amount because surfactants are expensive. The next step will be to model surfactant slug injection and compare it to continuous surfactant injection. The better one in terms of economics will be selected.

4.2 SURFACTANT SLUG INJECTION
Surfactant slug injection involves injecting a certain volume of surfactant for a period of time followed by water. Two cases were modeled; injecting at 2 months interval and injecting at 6 months interval (Figures 52-55)
Enhanced Oil Recovery for Norne Field’s E-Segment Using Surfactant Flooding

Figure 48: Oil Rate for Continuous Surfactant flooding for 4 years and 7 years

Figure 49: Total Oil Produced for Continuous Surfactant flooding for 4 & 7 Years
Figure 50: Total Surfactant Injected into the E-Segment for Continuous Case

Figure 51: Surfactant Production from Well E-2H for Continuous Surfactant Injection
Figure 52: Oil Rate at Surfactant slug Injection for 2-Month & 6-Month Period

Figure 53: Total Surfactant Slug Injected into Norne E-Segment for Slug Injection
Figure 54: Surfactant Production Rate at Well E-2H in E-Segment for Slug Injection

Figure 55: Oil Production Rate with Higher Water Injection for the 6 Months Interval (Slug)
Figure 52 shows oil production rate for surfactant slug injection at 2 months and 6 months intervals compared to the base case. After injection of surfactants in 2005, there was significant increase in oil production rate until 2010 when the rates went down below the base case. The water injection rate could be increase to increase the production rate from 2010, however, it is important to find out which is better – injection of surfactant at 2 months interval or injection at 6 months interval.

Figure 53 and 54 is used to ascertain this. Looking at the total mass of surfactant needed for both 2 months injection period and 6 months injection period, it can be seen that about 150 million kg is required for two months while about only 122 million kg is required for 6 months intervals.

In figure 54, the production of surfactant from well E-2H is over 35,000 kg/day for the 2 months injection period while for 6 months injection period it is 26,000kg/day. Thus it is obvious that injection for a 6 months period is better since less surfactant are used and thus, produced at the well E-2H.

Figure 55 shows the oil production rate with an increased water injection for the 6 months surfactant injection period since it performed better. From the graph, it is can be seen that the oil production rate after 2010 has increased for the slug injection of 6 months interval.

Thus for the surfactant slug injection, a period of 6 months interval will likely be more profitable than a 2 months period.

The Next step is to compare the continuous surfactant injection of 4 years with the slug injection of 6 months interval over a period of 4 years.

Figures 56 – 59 show comparison between surfactant slug and continuous surfactant injection over a four year period. Figure 56 shows the production rate for the base case to be 2000Sm³/day in 2006 while for continuous surfactant flooding the production rate is 3,000Sm³/day at the same period. For surfactant slug flooding, the production rate is 4000 Sm³/day for the same time under consideration. For total oil produced (Figure 57) cumulative are 17 million, 15 million and 14 million for Surfactant slug flooding, continuous surfactant flooding and base cases respectively. Figure 58 shows the surfactant production from well E-2H while figure 59 shows the total surfactant injected into the E-Segment. Both show that surfactant slug injection is more favorable than continuous surfactant injection.

From the above analysis, the option of surfactant slug for injection into the reservoir for a four year period at intervals of 6 months is the most appropriate.
Figure 56: Oil Production Rate: Comparison between Slug and Continuous Injection

Figure 57: Total Oil Production: Comparison between Slug and Continuous Injection
Figure 58: Surfactant Production from Well E-2H from the E-Segment (Continuous & Slug)

Figure 59: Total Surfactant Injected into the E-Segment (Continuous & Slug)
4.3 APPROPRIATE SURFACTANT CONCENTRATION.

From modeling in the previous sections, it was discovered that flooding pattern should be for 6 months Interval for 4 years. The surfactant concentration used during the modeling was 10kg/m³. However, it is not certain if this is the best surfactant concentration that would reduce residual oil to the barest minimum while ensuring that maximum profit is obtained.

Eight (8) different surfactant concentrations were modeled to see which would return the highest production rate and net present value. The surfactant concentrations used were 10kg/m³, 20kg/m³, 30kg/m³, 40kg/m³, 50kg/m³, 60kg/m³, 80kg/m³ and 100kg/m³.

Figure 60 shows the oil production rate for the different surfactant concentrations mentioned above.

![Figure 60: Production Rates for different Surfactant Concentrations in kg/m³](image)
From figure 60, it can be seen that increasing surfactant concentrations led to increase in the production rate. From the figure, the base production (that is without surfactant injection) has a rate of 2,000 Sm$^3$/day in year 2006. Surfactant was injected into the reservoir in 2005 and this shot up the production rate of the concentration of 10 kg/m$^3$ to 4,500 Sm$^3$/day. A surfactant concentration of 20 kg/m$^3$ gave a production rate of 6,000 Sm$^3$/day. Surfactant concentration of 30 kg/m$^3$ increased the production rate to 6,300 Sm$^3$/day while a concentration of 40 kg/m$^3$ increased the production rate to 6,500 Sm$^3$. Surfactant concentration of 80 kg/m$^3$ and 100 kg/m$^3$ gave production rates of 7,000 Sm$^3$/day and 7,200 Sm$^3$/day respectively. Even though the production rate increases with each increasing concentration, the increment might not really be very substantial.

In order to determine the most effective surfactant concentration, net present value method is used. Net Present Value (NPV) is a central tool in discounted cash flow (DCF) analysis and is a standard method for using the time value of money to appraise long term projects. It is defined by the formula;

\[
NPV = \frac{\text{Revenue} - \text{Expense}}{(1+r)^t}
\]

Where r is the discount rate and t represents time.

A detailed calculation of the NPV for the different surfactant concentration is presented in excel sheet (Econs1Final.xlsx) in the appendix while the summary is presented in Table 8 below;

<table>
<thead>
<tr>
<th>Period</th>
<th>Surfactant Concentration Kg/m$^3$</th>
<th>Oil Production (bbls)</th>
<th>Surfactant Consumed (Thousand Kg)</th>
<th>NPV (MUSD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2004-2014</td>
<td>0</td>
<td>37593571.05</td>
<td>0</td>
<td>2201</td>
</tr>
<tr>
<td>2004-2014</td>
<td>10</td>
<td>53272457.91</td>
<td>122659.64</td>
<td>2901</td>
</tr>
<tr>
<td>2004-2014</td>
<td>20</td>
<td>57085578.9</td>
<td>254209.4</td>
<td>2860</td>
</tr>
<tr>
<td>2004-2014</td>
<td>30</td>
<td>59967804.96</td>
<td>381295.7</td>
<td>2765</td>
</tr>
<tr>
<td>2004-2014</td>
<td>40</td>
<td>62342195.58</td>
<td>510945.5</td>
<td>2634</td>
</tr>
<tr>
<td>2004-2014</td>
<td>50</td>
<td>63985741.47</td>
<td>641706.6</td>
<td>2468</td>
</tr>
<tr>
<td>2004-2014</td>
<td>60</td>
<td>64972901.07</td>
<td>772169.7</td>
<td>2272</td>
</tr>
<tr>
<td>2004-2014</td>
<td>80</td>
<td>66456061.56</td>
<td>1034821.8</td>
<td>1849</td>
</tr>
<tr>
<td>2004-2014</td>
<td>100</td>
<td>675334343.01</td>
<td>1297760.1</td>
<td>1402</td>
</tr>
</tbody>
</table>

Table 8: NPV Calculations for Different Surfactant Concentrations

The following assumptions were used in the calculation of the Net Present Value (NPV)
Surfactant Cost is 2.33 USD/Kg  
Oil Price is 80 USD/bbl  
Discount rate of 8% was used.  
Surfactant cost is the major expense

Comparing different NPVs for different concentrations, it can be seen that the NPV for the surfactant concentration at 10kg/m\(^3\) is 2901 MUSD and this value is very much higher than the base case which is only 2201 MUSD. Also, from the table it can be seen that the oil production increases with increase in surfactant concentration. However, there is also a corresponding increase in surfactants consumed and this raises the expense so that the NPV does not necessarily increase. Figure 61 shows the plot of the NPV of the various surfactant concentrations with respect to different surfactant concentrations and time.

![Net Present Value (NPV) for Different Surfactant Concentrations](image)

**Figure 61: NPV for Different Surfactant Concentrations**
From the figure it is evident that the highest NPV is from surfactant concentration of 10kg/m³. Also, it is interesting to see that surfactant concentrations of 20kg/m³ and 30kg/m³ also did better than the base case where no surfactant was injected.

In a nutshell, to get the maximum recovery of residual oil from the Norne E-Segment, surfactant slug should be injected at six (6) months interval and 10kg/Sm³ concentration.

4.4 INJECTING SURFACTANT INTO THE NORNE E-SEGMENT – MODIFIED WELLS

This involves deciding on the well configuration that would yield the greatest oil recovery. These cases will be considered:

- Original wells; injecting surfactants into the reservoirs and producing using the original wells.
- Additional well and re-completion of the water injectors; the water injectors were modified in order to target the Ile and Tofte formation, where most of the oil reside. Also, a producer was added in order to recover more of the oil in Ile and Tofte.
- Additional well; the injectors and producers remain as they are but a new well is added in the Ile formation to aid in the production of more oil.

4.41 INJECTING SURFACTANTS INTO ORIGINAL WELL CONFIGURATION

Figure 62: Original Wells in the Norne Field E-Segment.
4.42 INJECTING SURFACTANT INTO RE-COMPLETED WELLS AND A NEW WELL CALLED ‘CHI-1’

In figure 63, well F-1H which is a water injector was re-entered and drilled as horizontal well passing through the Ile formation. This was done in order to have more of the surfactants attack the residual oil in the Ile and Tofte formations. Also a new well, CHI-1 was placed at the point of high oil concentration to produce the capillary trapped oil that would be released by the action of injected surfactants through the now horizontal water injector well F-1H. Water injector well F-3H was also re-entered and made a horizontal well going through the Ile and Tofte formation. The aim is to release the capillary trapped oil in these formations and push the oil towards the producer well E-2H. The producer well E-2H was also extended horizontally to have more areas open to flow.

Figure 64 shows the original well configuration in addition to a new well called ‘CHI-1’. The well was drilled into the Ile formation since about 80% of the oil in the Norne field resides in the Ile and Tofte formation.

Comparison will be made amongst the three well configurations to ascertain which would give the most recovery but emphasis will be on the Net Present Value. The Well configuration that returns the greatest NPV will be recommended. Surfactant of concentration 10kg/m3 is
injected into the water injectors in each case at an interval of six (6) months for a period of 4 years. The analysis follows below;

4.43 INJECTING SURFACTANT INTO ORIGINAL WELLS AND A NEW WELL CALLED ‘CHI-1’

Figure 64: Shows Original Wells in Addition to a New well called CHI-1

Figure 65: Shows the porosity for the Norne E-Segment for the Ile Formation
4.44 WELL CONFIGURATIONS

Tables 9 and 10 show a comparison between the original completions and the modified completions. The modified completions were targeted at the Ile and the Tofte formations which contain about 80% of the oil in Norne E-Segment. Table 11 shows the completions data for the new well, CHI-1.

<table>
<thead>
<tr>
<th>WELL – F-1H</th>
<th>Original Wells</th>
<th>Re-completed Wells</th>
</tr>
</thead>
<tbody>
<tr>
<td>I</td>
<td>J</td>
<td>K1</td>
</tr>
<tr>
<td>12</td>
<td>85</td>
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</tr>
<tr>
<td>12</td>
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<td>85</td>
<td>15</td>
</tr>
<tr>
<td>12</td>
<td>85</td>
<td>16</td>
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</tbody>
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Table 9: F-1H Completions Data

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<th>J</th>
<th>K1</th>
<th>K2</th>
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<tr>
<td>14</td>
<td>67</td>
<td>9</td>
<td>9</td>
<td></td>
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<tr>
<td>14</td>
<td>68</td>
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<tr>
<td>15</td>
<td>71</td>
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<td>10</td>
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</table>

Table 10: CHI-1 Completions Data

<table>
<thead>
<tr>
<th>WELL-F-3H</th>
<th>Original Wells</th>
<th>Recompleted Wells</th>
</tr>
</thead>
<tbody>
<tr>
<td>I</td>
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<td>7</td>
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<td>5</td>
</tr>
<tr>
<td>7</td>
<td>56</td>
<td>12</td>
</tr>
</tbody>
</table>

Table 110: F-3H Completions Data
4.45 EFFECT OF SURFACTANT INJECTION INTO ALL THE WELL CONFIGURATIONS

With addition of new wells to the original wells, it becomes natural for production to increase. It now becomes important to ascertain if injecting surfactants into the field at this point would make a significant difference.

Six cases were modeled;

- Original Wells With no surfactant injection.
- Original Wells with surfactant injections.
- Original Wells + new wells with no surfactant injection.
- Original wells + new wells with surfactant injection.
- Re-completed wells + new wells with no surfactant injection.
- Re-completed wells + new wells with surfactant injection.

Figure 66 gives a summary of the results;
From Figure 66, it can be seen that even with new wells added, the cumulative production was still not as much as the cases where surfactants were added. In other words, surfactant injection led to better oil production.

In subsequent discussions, the cases where new wells were added without surfactant injection will not be discussed.

4.46 PRODUCTION

Figure 67 shows the cumulative oil produced for the E-Segment for the three cases mentioned above. The cases with new wells have more cumulative oil than the case with just the original wells. The case with recompleted wells and an additional well can be referred to as case A while that with original wells and an additional well will be referred to as case B. The one with only original wells without new wells will be known as case C. Case A and B have cumulative production of 19 million Sm$^3$ while case C has a cumulative of 1.43 million Sm$^3$. Fig 68 shows oil production rate. In 2006, production rate for case A is 35,280 Sm$^3$/day, for case B, it is 21,266 Sm$^3$/day. Figure 69 shows water production rate which is high for all three cases. This number forms a cumulative of production from the wells from E-Segment. The increase could be attributed to that fact that more water is injected to aid the effectiveness of the surfactants to perform better. Figure 70 also shows cumulative water produced. The gas oil ratio is same, about 5,000sm$^3$/sm$^3$ for the three cases with peaks in 2006 (Figure 71).

4.47 RESERVOIR PRESSURE AND RECOVERY FACTOR

The pressure profile is stable for the field (Figure 72). The pressure profile is a representation of the drainage pattern of each model. Some models show an increase in pressure because of the higher water injection rate. However, the reservoir pressure is higher than the bubble point pressure of 251 bars, therefore making it stable.

The Field Oil Recovery (FOE) represents for the whole field and not just the E-segment. The increment does not seem noticeable in this case (Figure 73). However, the other parameters, apart from FOE, represent the Norne E-Segment.
Figure 67: Cumulative Oil Produced from E-Segment with New Wells and Surfactant

Figure 68: Oil Production Rate from E-Segment with New Wells and Surfactant
Figure 69: Water Production Rate for E-Segment with New Wells and Surfactant

Figure 70: Cumulative Water Produced for E-Segment with New Wells and Surfactant
Figure 71: Gas Oil Ratio for E-Segment with New Wells and Surfactant

Figure 72: Pressure Profile for E-Segment with New Wells and Surfactants
Figure 73: Field Oil Efficiency for Norne E-Segment for New Wells and Surfactant
4.5 ECONOMIC ANALYSIS

It is very important to check the economic viability of a project before sanctioning it. When there are so many options and it is required to make a choice of which project to carry out, then an economic tool is needed. The Net Present Value is normally used and any project that has the highest NPV is favoured.

In any petroleum project, the price of crude oil is very important as high oil prices encourage project sanctioning. In the case of surfactant flooding, the high cost of surfactant had usually discouraged surfactant flooding projects in the past. However, in recent times, the surge in oil price has re-opened the consideration of many projects that otherwise would not have been embarked upon.

In this thesis, there are four options that were considered. These include;
- Using the base case (Original wells without surfactant flooding).
- Using Original well with injection of surfactants.
- Using original wells + New Well with injection of surfactants.
- Using re-completed wells + New Well with surfactant injection.

A detailed economic analysis is carried out in excel sheet (attached at the appendix), (Econs1Final.xlsx) while the summary is presented in Table 12.

<table>
<thead>
<tr>
<th>Oil Prices USD/bbl</th>
<th>Base Case (Original Well, No Surfactant) NPV (MUSD)</th>
<th>Original Wells + Surfactant Injection NPV(MUSD)</th>
<th>Original Wells + New Well + Surfactant Injected NPV (MUSD)</th>
<th>Extended Wells + New Well+ Injected Surfactant NPV (MUSD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>40</td>
<td>1100</td>
<td>1332</td>
<td>1835</td>
<td>1861</td>
</tr>
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<td>60</td>
<td>1651</td>
<td>2117</td>
<td>2881</td>
<td>2930</td>
</tr>
<tr>
<td>80</td>
<td>2200</td>
<td>2901</td>
<td>3927</td>
<td>3999</td>
</tr>
</tbody>
</table>

Table 12: Economics of Surfactant Injection into different well cases

In carrying out this analysis, a number of assumptions were made. These are given below;

Assumptions

- The major expense for original wells without new wells is the cost of surfactant. Other operational costs were not taken into consideration
- Drilling a new well is assumed to cost 20 million USD.
• Recompleting a well is assumed to cost 10 million USD.

From Table 12, it can be seen that revenue increased even at oil price of 40USD/bbl which can be considered low. Also it is noticed that the case of re-completed wells gave the best NPV. This is attributed to the fact that surfactant, through the re-completed wells, was injected directly to the Ile and Tofte formation which contains about 80% of the field’s oil. This explains the high recovery rate obtained from this method compared to others. The case with original wells and an additional well also did well. The least is the base case, that is, original wells without surfactant flooding (Figure 74).

![Net Present Value for Different Well Configurations (10kg/m3 Surf Conc)](image)

*Figure 74: Net Present Value for Different Well Configurations*
5.0 SUMMARY

About 60% of oil is still trapped in the reservoir after primary and secondary recovery has been completed. This trapped oil is known as residual oil and it occurs as a result of high capillary action of water that keeps this oil immobile. One way of recovering this capillary trapped oil is by flooding the reservoir with surfactants. Surfactants are surface active agents that act on the interface between oil and water thereby reducing the interfacial tension between them thus causing the trapped oil to flow.

In this Norne field E-Segment, pockets of residual oil were still trapped after production for a period of 7 years, especially in the Ile and Tofte formations which holds about 80% of oil in the reservoir. With increasing water cut and low oil production, it becomes obvious that water flooding alone cannot recover the oil effectively, thus a need for an enhancing agent, like surfactants.

In flooding the reservoir with surfactants it becomes very important to ascertain the right quantity of surfactant that would yield the maximum recovery without necessarily wasting the surfactant because surfactants are expensive.

A series of screening methods were used in order to come up with the right quantity of surfactant that would yield maximum recovery of residual trapped oil. First was modeling continuous surfactant flooding into the reservoir for a period of 4 years and 7 years respectively. It was discovered that flooding the reservoir continuously for seven years did not necessarily lead to better recovery of oil than flooding for 4 years. Also, flooding for 7 years led to a high quantity of surfactant injected into the reservoir which resulted in the producer well E-2H producing very high quantities of surfactant at the surface. Surfactants are expensive and there is no point wasting them.

The second step was to compare between slug injection at 2 months interval and 6 months interval. After modeling, it was discovered that injecting surfactant every 2 months (that is 6 times in a year) did not necessarily do better than injecting at every 6 months (twice a year). Also, injecting surfactant every two months required very high quantities of surfactant to be injected into the reservoir which also leads to its high production at the surface.
The third step was modeling between continuous surfactant injection for 4 years and slug injection for 4 years (at intervals of every 6 months). Continuous surfactant flooding was discarded because of the high quantity of surfactant needed compared to slug injection.

Having established the most effective method to inject surfactant into the reservoir, the next challenge was the appropriate concentration of surfactants that would be needed for optimal recovery of residual oil. Eight (8) different surfactant concentrations were modeled and these include concentrations at 10kg/m$^3$, 20kg/m$^3$, 30kg/m$^3$, 40 kg/m$^3$, 50kg/m$^3$, 60kg/m$^3$, 80kg/m$^3$ and 100kg/m$^3$. Net Present Value (NPV) was used to determine the best surfactant concentration that would yield the maximum profit. The concentration of 10kg/m$^3$ gave the best NPV.

Having discovered that surfactant slug of 10kg/m$^3$ would yield better recovery the next task was to see if there were ways of recovering more oil by drilling new wells or recompleting already drilled wells.

Four cases were studied;

1. Original wells without injection of surfactant slug;
2. Original wells with surfactant slug injection;
3. Injecting surfactant slug into original wells in addition to a newly drilled well;
4. Injecting surfactant slug into wells that had been re-completed/extended in addition to a newly drilled well.

From the economic analysis, it was discovered that recompleting the wells in addition to a new well gave the best NPV followed by the case where surfactant was injected to the original well with a newly drilled well. All these options did better than the base-case where surfactant was not injected at all.

The case of re-completion of the wells gave a better recovery because the re-completed wells were made to inject surfactants directly into the Ile and Tofte formations which hold about 80% of oil in the reservoir.

In conclusion, surfactant flooding is a good option for the Norne field E-Segment especially when the Ile and Tofte formations are targeted.
5.2 CONCLUSION

1. Continuous injection of surfactant over a 4-year period was economically more viable than injection for a 7-year period.
2. Surfactant slug injection at six-month interval gave better recovery than injection at two-month interval.
3. Surfactant slug injection for a four year period (at 6 months interval) gave better recovery than a continuous injection for a four-year period.
4. Surfactant concentration of 10kg/m$^3$ gave a better recovery than concentrations of 20kg/m$^3$, 30kg/m$^3$, 40kg/m$^3$, 50kg/m$^3$, 60kg/m$^3$, 80kg/m$^3$ and 100kg/m$^3$.
5. Surfactant slug at concentration of 10kg/m$^3$ was injected into different well configurations. The first case was injection into the original well configuration in the Norne E-Segment. The second case was injection of surfactant slug into Original wells + new well while the third case was injection of surfactants into re-completed wells + new wells.
6. The injection of surfactants into recompleted wells + new well gave the best oil recovery and highest revenue. This is because the re-completion of the water injector wells channeled the surfactant slug into the Ile and Tofte formations where most of the oil in the Norne Field E-Segment is located.
7. The Norne-field E-Segment is a very good candidate for surfactant flooding.
6.0 RECOMMENDATION

- Detailed laboratory work could be carried out to determine the exact type of surfactant that would be suitable for the Norne fluid and rock properties. It is also important that after the appropriate surfactants have been determined from laboratory test that a proper up-scale to the field condition is done. It has been discovered through studies that the reason why many field cases don’t seem to do well like the laboratory tested cases is poor up-scaling. The bell-creek case is a good example of this.

- The appropriate time for surfactant injection is very important for a heterogeneous reservoir like the Norne field, E-Segment. It is recommended that surfactant flooding be started earlier in the life of the field. Waiting for the reservoir to be completely waterflooded before injection of surfactants might not lead to good economic outcome.

- The addition of co-solvents and co-surfactants could also be tried out on the selected surfactants to see if it would make the flooding more effective.

- Norne Field E-Segment is a good candidate for surfactant flooding because of the high recovery of oil, also corresponding to high NPV. This becomes even more profitable especially when the surfactant is targeted at the Ile and Tofte formations.
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APPENDIX
-- water injection rate of F-1, F-2, and F-3 by 50

-- Ny model July 2004 build by marsp/oddhu
-- New grid with sloping faults based on geomodel xxx

-------------------------------------
RUNSPEC
--LICENSES
--'NETWORKS' /
--/
DIMENS
46 112 22 /
--NOSIM
--
-- Allow for multregf, etc. Maximum number of regions 20.
--
GRIDOPTS
YES 0 /
WATER
GAS
DISGAS
SURFACT
VAPOIL
METRIC
-- use either hysteresis or not hysteresis
--NOHYST
HYST
START
06 'NOV' 1997 /
EQLDIMS
5 100 20 /
EQLDPT
'THRPRES' / no fine equilibration if swatinit is being used
REGDIMS
-- ntfip  nmfipr  nrfreg  ntfreg
22      3      1*      20    /
TRACERS
--  oil  water  gas  env
1*    10    1*    1*   /
WELLDIMS
--ML  40  36  15  15 /
130  36  15  84 /
--WSEGDIMS
-- 3  10 3 /
LOR
-- manlp maxis.mca.sme mumalg modalat interp
4 2000 318 1 4 20 TNTRP /
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--interm mitsmas.mca.mca rnitt椿mtr mtr
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-- Table no.
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-- Eln.VFP = 2
-- AlmostVertNew.VFP = 3
-- GasProd.VFP = 4
-- NEW_OIL_GAS_G000021.VFP = 5
-- GAS_PDE_VFP = 6
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-- ps2.VFP = 9 (flowline north)
-- PBI.PIPE.Ecl = 31
-- PD1.PIPE.Ecl = 33
-- PE1.PIPE.Ecl = 35
-- PBI.PIPE.Edl = 36
-- BHH.Ecl = 37
-- B2H.Edl = 38
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-- B4H.Edl = 40
-- D1H.Edl = 41
-- D2H.Edl = 42
-- D3H.Edl = 43
-- D4H.Edl = 45
-- E1H.Edl = 47
-- E3H.Edl = 48
VFPDIMNS
10 10 10 10 50 /
FAULTDIMS
10000 /
PAMTDIMS
1 11 /
NTACE
30 /
UNWIN
UNEFOUT
--INITRUNSPEC
OPTIONS
77* 1 /

---------------------------------------------------------
-- Input of grid geometry
---------------------------------------------------------
GRID
NEWTRAN
GRIDFILE
2 /
-- optional for postprocessing of GRID
Enhanced Oil Recovery for Norne Field’s E-Segment Using Surfactant Flooding
Enhanced Oil Recovery for Norne Field’s E-Segment Using Surfactant Flooding
-- Input of PVT data for the model
-- Total 2 PVT regions (region 1 C,D,E segment, region 2 G-segment)
--
```
INCLUDE 
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TRADEC 
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'WAT' / 
'
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-- initialization and relperm curves: see report blabla
--
-- rel. perm and cap. pressure tables --
--
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SURFST 
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/
```
--Surfactant Adsorption by rock
```
SURFADS 
0 0.0000 0.0001 0.0001 0.0001 0.0001 0.0001 0.0001
/
```
--Constant Water viscosity
```
SURFVISC 
0 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
/
```
-- Surfactant Adsorption by rock
```
SURFADS 
0 0.0000 0.0001 0.0001 0.0001 0.0001 0.0001 0.0001
/
```
-- Initialization and relperm curves: see report blabla
--
-- initialization and relperm curves: see report blabla
--
```
INCLUDE 
'./INCLUDE/PVT/PVT-WET-GAS.DTA' 
TRADEC 
'WAT' / 
'WAT' / 
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-- initialization and relperm curves: see report blabla
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-- rel. perm and cap. pressure tables --
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-- Initialization and relperm curves: see report blabla
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-- Initialization and relperm curves: see report blabla
--
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SURFST 
0 0.02 0.0039 0.0001 0.0001 0.0001 0.0001 0.0001
/
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-- Initialization and relperm curves: see report blabla
--
```
INCLUDE 
'./INCLUDE/RELPERM/HYST/swof_mod4Gseg_aug-2006.inc' 
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Enhanced Oil Recovery for Norne Field’s E-Segment Using Surfactant Flooding
Enhanced Oil Recovery for Norne Field’s E-Segment Using Surfactant Flooding
## Enhanced Oil Recovery for Norne Field’s E-Segment Using Surfactant Flooding

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Enhanced Oil Recovery for Norne Field’s E-Segment Using Surfactant Flooding
<table>
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<tr>
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<th>Change in Oil Saturation - %</th>
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Enhanced Oil Recovery for Norne Field’s E-Segment Using Surfactant Flooding
Enhanced Oil Recovery for Norne Field’s E-Segment Using Surfactant Flooding
No increase in the solution gas-oil ratio?

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

------

--- Production Wells ---

INCLUDE

./INCLUDE/VFP/DevNew.VFP /

INCLUDE

./INCLUDE/VFP/E1h.VFP /

INCLUDE

./INCLUDE/VFP/NEW_D2_GAS_0.00003.VFP /

INCLUDE

./INCLUDE/VFP/GAS_PD2.VFP /

INCLUDE

./INCLUDE/VFP/AlmostVertNew.VFP /

INCLUDE

./INCLUDE/VFP/GasProd.VFP /

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

INCLUDE

./INCLUDE/VFP/B1BH.Ecl /

INCLUDE

./INCLUDE/VFP/B2H.Ecl /

INCLUDE

./INCLUDE/VFP/B3H.Ecl /

INCLUDE

./INCLUDE/VFP/B4DH.Ecl /

INCLUDE

./INCLUDE/VFP/D1CH.Ecl /

INCLUDE

./INCLUDE/VFP/D2H.Ecl /

INCLUDE

./INCLUDE/VFP/D3BH.Ecl /

INCLUDE

./INCLUDE/VFP/E1H.Ecl /

INCLUDE

./INCLUDE/VFP/E3CH.Ecl /

INCLUDE

./INCLUDE/VFP/K3H.Ecl /

------

--- Production Flowlines ---

16.5.02 new VFP curves for southgoing PD1,PD2,PB1,PB2 flowlines -> pd2.VFP

INCLUDE

./INCLUDE/VFP/pd2.VFP /

16.5.02 new VFP curves for northgoing PE1,PE2 flowlines -> pe2.VFP

INCLUDE

./INCLUDE/VFP/pe2.VFP /

24.11.06 new matched VLP curves for PB1 valid from 01.07.06

INCLUDE

./INCLUDE/VFP/PB1.PIPE.Ecl /

24.11.06 new matched VLP curves for PB2 valid from 01.07.06

INCLUDE

./INCLUDE/VFP/PB2.PIPE.Ecl /

24.11.06 new matched VLP curves for PD1 valid from 01.07.06

INCLUDE

./INCLUDE/VFP/PD1.PIPE.Ecl /

24.11.06 new matched VLP curves for PD2 valid from 01.07.06

INCLUDE

./INCLUDE/VFP/PD2.PIPE.Ecl /

24.11.06 new matched VLP curves for PE1 valid from 01.07.06

INCLUDE

./INCLUDE/VFP/PE1.PIPE.Ecl /

24.11.06 new matched VLP curves for PE2 valid from 01.07.06

INCLUDE

./INCLUDE/VFP/PE2.PIPE.Ecl /

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--- Injection Flowlines 08.09.2005 ---

VFP INJ nr. 10 Water injection flowline WIC

INCLUDE

./INCLUDE/VFP/WIC.PIPE.Ecl /
Enhanced Oil Recovery for Norne Field’s E-Segment Using Surfactant Flooding