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Comparison of Improved Oil Recovery Processes on the Norne Field, C-Segment

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Abstract

According to current prognosis, oil production in matured reservoirs is expected to decline and this could create gap between supply and demand of hydrocarbons in various parts of the world. Inspite of the huge volumes in the unconventional hydrocarbons reservoirs, they require intensive high energy to recover oil while developing new fields is becoming complicated and expensive. There is, therefore a growing interest in development of efficient and effective improved oil recovery methods so as to increase oil recovery from ageing resources.

This study compares application of three IOR methods namely polymer flooding, well location optimization and low salinity water flooding to the Norne field C segment. The main objective was to carry out comparative simulation study for the three IOR methods and then comparing their performance in terms of net present value. Sensitivity analysis for polymer flooding and low saline water flooding was carried out to analyse suitable well for injection, appropriate composition of polymer and salt as well as right time for injections. Economic evaluation was done to identify which method is most profitable in terms of net present value.

Well C-3H found to be the best injector to use with polymer flooding in Norne C-segment. Low polymer concentration of 0.2 kg/m^3 gave high oil production with less polymer consumption when injected at 3 months cycle interval in early timing. Low saline water injection found also to improve oil production of this field and significant improvements were observed by continuous early injection of low saline water. Furthermore, sidetracking the wells horizontally in the regions of high oil saturation gave high oil production than sidetracking vertically. Economic evaluation showed that polymer flooding gives the lowest incremental NPV while combination of polymer flooding and well location optimization had the highest incremental NPV at all oil prices tested.

The study recommends further studies to be carried for low saline water injection with the use of real field data for saturation and relative permeability end points.

Acknowledgements

In the course of this work, I have been in-line with many people for guidance. To mention few:

I would like to express my deepest appreciation to my supervisor Professor Richard Rwechungura for his help, advices and academic guidance during my thesis work. Though you were very busy, thanks for the time you had with me. Thanks to Professor Jon Kleppe for helping construction for the title of this thesis.

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Abbreviations

ASP	Alkaline-Surfactant -Polymer
CAPEX	Capital Expenditure
EOR	Enhanced Oil Recovery
FPSO	Floating Production, Storage and Offloading
FOE	Field Oil Efficiency
FOPT	Field Oil Production Total
GOR	Gas Oil Ratio
IOR	Improved Oil Recover
LSWF	Low Salinity Water Flooding
LSWI	Low Salinity Water Injection
NCS	Norwegian Continental Shelf
NPD	Norwegian Petroleum Directorate
NPV	Net Present Value
OIP	Oil In Place
OOIP	Original Oil In Place
OPEX	Operation Expenditure
RF	Recovery Factor
SPE	Society of Petroleum Engineers
SWF	Smart Water Flooding
TDS	Total Dissolved Solids
USD	US Dollar
WOR	Water Oil Ratio

Chapter 1

Introduction

Water flooding is simple and inexpensive secondary recovery method being used widely upon depletion of natural energy resources, largely designed without considering injected brine composition. The method can recover about 10-40% oil depending on geological and reservoir characteristics. However, it is likely to find significant amount of oil still remain trapped in the reservoirs even after water flooding. This is due to inefficient macroscopic sweep and microscopic capillary trapping caused by interfacial and surfaces forces which hold oil within pores. Therefore the oil industry is having a big interest in improved oil recovery (IOR) technologies in order to make the most of ultimate oil recovery or to recover additional oil from the left behind residual oil.

NPD defined IOR as "actual measures resulting in an increased oil recovery factor from a reservoir as compared with the expected value at certain point reference in time" [11]. Schlumberger [14] also defined IOR as a method for recovering additional oil further than primary recovery methods (fluid expansion, rock compressibility, gravitational drainage and natural water flow or gas drive) or any activity that increases oil production and increases recovery factor. This implies that IOR include application of technological advances over life of a field and encompasses all secondary and tertiary recovery methods. Conventional IOR methods include improved reservoir management, cost reduction initiatives and advanced methods often called EOR or tertiary recovery. There is no general IOR method applicable to the complete range of field situations. Therefore, selection of appropriate IOR scheme for a specific reservoir is crucial. The main difference between IOR and EOR is that EOR approach is used to recover mostly immobile oil that remains in the reservoir after application of primary and secondary methods while IOR strategies are used to recover mobile oil and/or immobile oil as well. The study in this report relies on the use of well location optimization which is IOR, polymer injection which is both IOR and EOR and low salinity water injection which is both IOR and a secondary recovery method.

Norne field is an offshore province located in blocks 6608/10 and 6508/1 in southern part of Nordland II in the Norwegian sea. Being operated from Harstad in Norway by Statoil ASA with 39.1% stake in the field, its licence partners Petoro AS with 54% stake and Enil Norge AS with 6.9% stake, the field consists of two separate oil compartments: Norne main structure and Northeast Segment. The Norne main structure was discovered in 1991 with 97% of oil in place and consists of C, D, and E segments while Northeast segment consists of Norne G-segment. The reservoir is found at a depth of about 2,500 m (8,200 ft) below the sea level with hydrocarbons located in the lower to middle Jurassic sandstones occupying about 135 m column, 110 m being for oil and 25 m for gas. It is subdivided into five different formations from top to base: Garn, Not, Ile, Tofte and Tilje. Gas is primary located in Garn formation while about 80% of oil is located in Ile and Tofte formations. The reservoir is good sandstone rock with porosity ranging from 25% to 30% and permeability ranging from 20 mD to 2500 mD.

Initially, the drainage strategy for this field was re-injection of produced gas into the gas cap and water injection into the water zone. Yet, during the first year of production, it was noticed that the Not formation is sealing over the Norne main structure and injecting gas into the gas cap (at Garn formation) could not work. Then the solution to inject gas into water zone and lower part of the oil zone as Figure 1.1 shows. The red, green and blue colour signifies gas, oil and water respectively. While red arrow, green arrow and yellow arrow indicates gas injection/production, oil production and water injection respectively.

Injection fluids have been both gas and water up to 2004. In 2005, the gas injection was stopped and water injection has only been used as pressure maintenance technique for oil production till today. Gas export from the Norne field started in 2001 and about 1 GSm^3 of gas is exported every year.

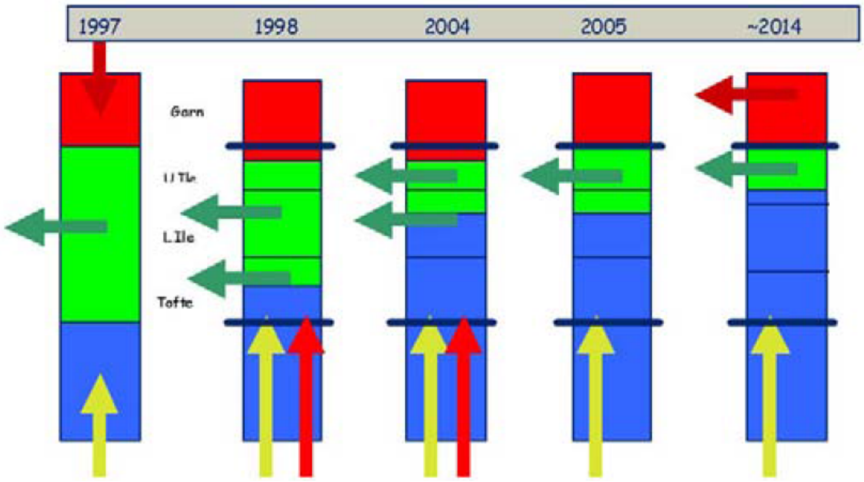


Figure 1.1: Drainage strategy for the Norne field from pre-start and until 2014[26]

The field has in total of 49 wells: 3 exploration (6608/10-2, 6608/10-3 and 6608/10-4), 46 production and injection wells. The discovery in 1991 was with well 6608/10-2 and authentication for existence of hydrocarbons in the discovery well was with well 6608/10-3. Well 6608/10-4 discovered oil in the North-East segment. Development drilling started in August 1996 and oil production started on 06th November 1997. The field was developed with five subsea templates at bottom sea which are connected to a floating production vessel. Today, production is through full fifteen subsea templates.

Several publications have been published about the use of different IOR methods in Norne field C segment. Nielesen (2012), [25] conducted a study in C segment on the use of surfactant flooding and found that the highest increase in oil recovery which can be achieved is only 1.50%. Project profitability could not be achieved due to the highest cost of surfactant. Thus surfactant is not a proper IOR method to be used in C segment. Awolola (2012), [5] used ASP flooding in C segment and found that injecting ASP slug with a concentration of 7 kg/m^3, 2 kg/m^3 and 0.3 kg/m^3

into C-3H (injector well) in a cyclic manner, gave an incremental oil recovery of 2.61%. Abrahamsen (2012), [2] did a comparison between polymer flooding, alkaline flooding and surfactant flooding and found that polymer flooding is the best chemical flooding method for C segment. Surfactant and alkaline were found not to reduce enough residual oil to make the project profitable. Abadli (2012), [1] who also compared alkaline, surfactant and polymer showed that polymer flooding project has a better outcome to Norne C segment compared to water flooding project. He also found that surfactant flooding has a promising effect and is more profitable than polymer flooding in terms of NPV to C segment. However, oil price has significant effect on NPV and NPV is least sensitive to polymer price but high sensitive to surfactant flooding. Thus, polymer flooding might overtake surfactant flooding. All these researches prove that among the chemical EOR methods that can applied to the Norne field C segment, polymer flooding is the best.

This thesis focuses on comparing application of three IOR methods which are Low salinity water injection, well location optimization and polymer injection to Norne field segment C. The purpose is to identify the most beneficial method among these three that can be applied to this field for improving oil recovery. The study has been divided into two phases: phase I and phase II. Phase I was carried out in semester project [24] and involved detailed literature review of the IOR methods under the study and analysed their compatibility with the field. Results for phase I showed that all three IOR methods are good candidates for the Norne field C segment in sense that are compatible with Norne field reservoir properties hence gave credits for extension of the study to phase II. The current work is phase II. It involves numerical simulations study for all three IOR methods.

1.1 Problem Statement

Norne field which came on stream in 1997 was due to shut down in 2014 owing initial development plans. So far, the field has produced about 700 million barrels of oil equivalent that Statoil and its partners have gained considerably from it.

Following a systematic maintenance of Norne FPSO vessel which now is in good technical condition, Statoil plans to extend life of the Norne field to the year 2030 [22]. The remaining resources may total as much as 300 million barrels of oil equivalent. This amount necessitates the need for continuing production.

Globally, average RF is approximately 35% [33]. However, the recovery factor for the Norne field today is about 56.5% with the use of water flooding and this value is considered to be a top result worldwide for production from subsea fields. Even though this RF value is high in comparison with a world wide average, Statoil needs even more. According to Kristine Westvik, a Norne operations Vice president, the ambition is to increase RF to 60% [22]. An increase in recovery rate by 1% will increase income by NOK 300 billion [33]. Thus, increasing from 56.5% to 60% will raise up income by NOK 1.05 trillion. A 60% RF is to be achieved with low cost and high energy production and value creation. The IOR processes are considered to be important and necessary for the Norne field to increase oil recovery and maintaining future production rate. Therefore, for attaining a 60% RF, Statoil is searching for the IOR method(s) which will best suits the Norne field.

Among the IOR methods which are being screened by Statoil for optimizing recovery and NPV from oil fields are water based methods such as polymer flooding and low saline water injection [34] as well as optimizing well location by drilling new wells and maintaining the existing wells.

1.2 Objectives

Among the 4 segments of the Norne field which are C-, D-, E- and G-segment, this work will base on improving oil recovery of the C-segment. The work is phase II of the study and will involve carrying out a comparative simulation study of both low saline water injection, polymer injection and well location optimization to identify which method is most profitable in terms NPV and that will help improving oil recovery in Norne field C-segment at minimum cost. The three methods will be economically analysed individually and when combined. Specific objectives of the study are:

i. Simulation study for polymer flooding, low saline water injection and well location optimization;

ii. Comparing NPV for all simulated cases

1.3 Methodology

Accomplishment of the above objectives will be through the use ECLIPSE 100 simulator. ECLIPSE office, Floviz, S3GRAF and excel will be used for visualization and interpretation of simulation results. Sensitivity analysis will be carried out for polymer injection and low saline water injection as follows

- Polymer injection.
  Sensitivity analysis on injector selection, appropriate polymer concentration and duration time for polymer injection

- Low saline water injection
  Sensitivity analysis on the appropriate brine composition in injected water and proper time for LSWI

In economic analysis, sensitivity investigation on oil price will also be carried out to see its effect on the project.

1.4 Scope

There are several IOR methods which can be investigated before applying them to the field. This work pays attention only on the three IOR methods which are polymer injection, low saline water injection and optimization of well location. Due to time limit, this work will end at comparing performance of the three methods in terms of NPV. The study is also limited to C segment.

Chapter 2

Norne C Segment Review

Norne field C segment is a good candidate for all IOR methods under this study based on the rock and fluid properties [24]. Having 13 wells, 9 producers and 4 injectors, the field is divided into five formations from top to base: Garn, Not, Ile, Tofte and Tilje. Acquired reservoir pressure data from development wells indicate that the Not which is between Garn and Ile acts as sealing layer thus preventing communication between Garn and Ile formations. Hence there is no reservoir communication across the Not formation during production. Each formation has been subdivided into different layers depend on geological model. Present geological model consists 22 reservoir zones (Figure 2.2). Oil in place by the end of 2006 has been investigated in all formations, Figure 2.1, to identify which formation should be targeted mostly during simulation. Based on OIP criterion, Ile and Tilje formations will be the target formation in this study.

Location of C segment wells in all formations is shown in Figures 2.3(a) through 2.3(d).

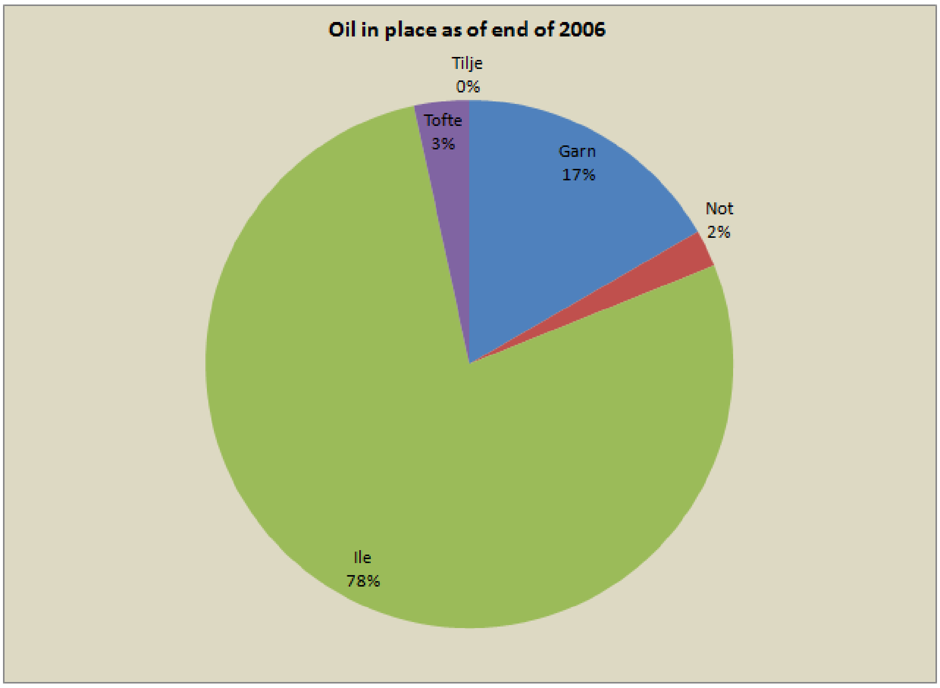


Figure 2.1: Oil in place for all formations at the end of 2006

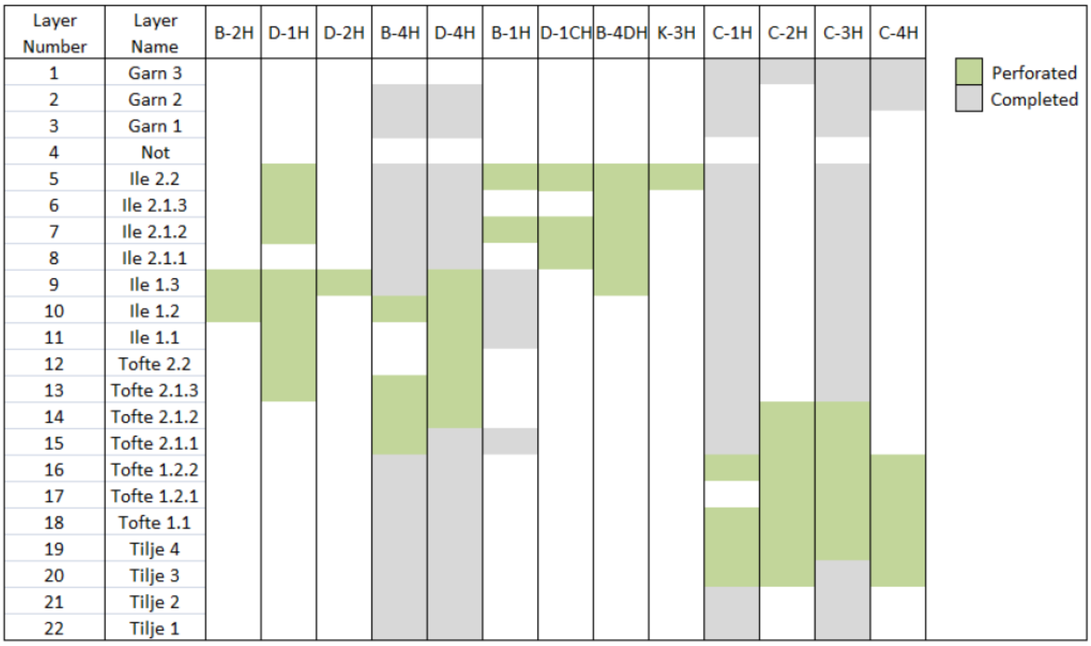
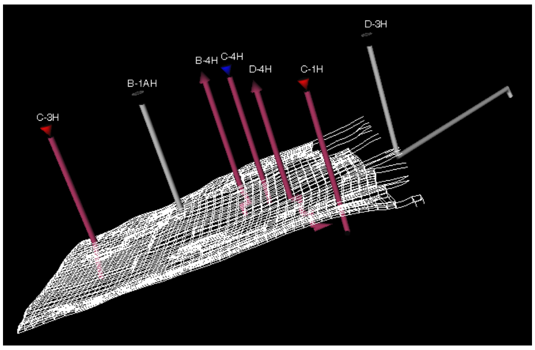
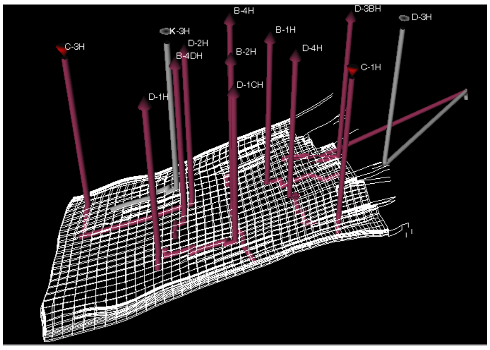


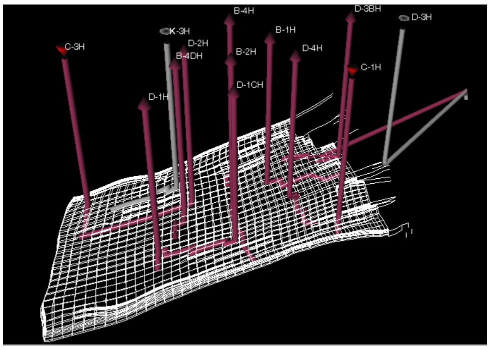
Figure 2.2: Well perforations in Norne C segment



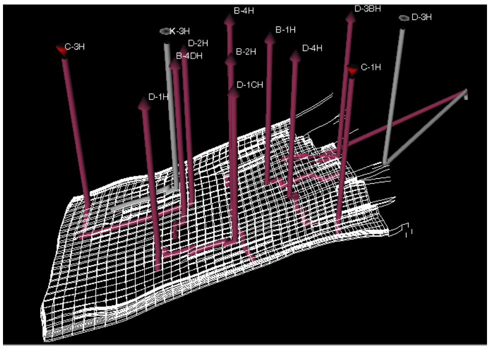
(a) Wells configuration in Garn formation (1^{st} - 3^{rd} layers)



(b) Wells configuration in Ile formation (5^{th} - 11^{th} layers)



(c) Wells configuration in Tofte formation (12^{th} - 18^{th} layers)



(d) Wells configuration in Tilje formation (19^{th} - 22^{nd} layers)

Figure 2.3: Wells distribution in the four formations in C Segment

Vertical and lateral flow in the Norne field are affected by faults and stratigraphic barriers. There are region barriers, field wide barriers and local barriers. Each barrier has been assigned transmissibility multiplier to show the extent which it imposes restriction to fluid flow. The most prominent barriers to fluid flow are the Not formation, carbonate cemented layers which separate Ile 1 and Tofte 4 formations and claystone layer which separate Tilje 3 and Tilje 2 formations [29]. Faults discovered by seismic data have been described using fault planes, divided into sections following reservoir zonation. Each sub-area of the fault planes has been assigned transmissibility multipliers as a function of fault rock permeability, fault zone width, matrix permeability and dimensions of grid blocks in the simulation model. Transmissibility multipliers account for increased or reduced permiability for each fault connection. By assigning unity value means faults do not impose any restrictions to flow, field pressure will be smooth and streamlines will pass through the faults. Conversely, if transmissbility multipliers are non unity, means faults are sealing, the field pressure is discontinous and streamline paths not aligned with the faults. This is the reason for fluid flow restriction.

Field Future Performance Prediction

The field model provided starts from 06 November, 1997 and ends in end of 2006. According to [22], Statoil plans to extend life of the Norne field to the year 2030. Thus, prediction for the future performance of the field will start from 1st Jan, 2007 to 1st Jan, 2022 using the three IOR methods and comparing their performance with the base case.

Among the 9 producers and 4 injectors of C segment, the wells that are still open in the end of 2006 are the production wells B-2H, D-2H, D-1CH, B-4DH, K-3H and injection wells C-1H, C-2H, C-3H. All the shut down wells will be opened so that to carry out prediction will be carried out with all thirteen wells.

Chapter 3

Polymer Flooding

Polymers are molecules formed when a large number of small molecules called monomers are joined together chemically under a process called polymerization. Adding these molecules in water even in minute concentrations, increase solution viscosity. If this mixture is injected into a reservoir, sweeping efficiency is increased resulting to late water breakthrough. Improvement in sweeping efficiency is caused by reduction of water mobility while that for oil remain unaltered. This reduction is due to two main reasons. Firstly, high viscosity of polymer solution than that of pure water. Secondly, reduction of a rock permeability relative to water after the passage of polymer solution. If the mobility ratio is greater than 1, water being more mobile than oil would finger out through the reservoir resulting to poor oil production. But if the mobility ratio is favourable (one or less), the displacement of oil by water occurs in a pistonlike style. The mechanism for polymer flooding is controlled by equation 3.1. The lower the ratio, the more the efficient is the displacement.

$$M = \frac{k_w/\mu_w}{k_o/\mu_o} = \frac{k_w \mu_o}{\mu_w k_o} \tag{3.1}$$

Polymer treatments are effectively applied to prevent early water breakthrough and to obtain better sweep efficiency in water flooding projects. The main impact which polymers have in the reservoir is that they act as blocking agents in flow paths that reduce permeability by filling fractures and high permeability channels at the injector or producing well hence late breakthrough.

For polymer to be useful, it must bring significant reduction in water mobility at low concentrations (low concentrations minimize cost), it must not be adsorbed and must not completely plug up the formation. Before injection, a solution with minimum shear degradation is prepared to ensure stability for polymer solution in the reservoir. Interaction between polymer solution and reservoir has to be monitored continuously and used as a guideline for changing chemical composition and injection rate. Injecting polymer solution at higher rates increases chances for mechanical shear degradation of the polymer. To avoid this tendency, injection equipment and well completions which permit desired injection rates without extensive mechanical degradation are usually used. Nevertheless, polymer solution is usually injected as rapidly as possible at a lower pressure than the reservoir pressure and the increase in oil recovery due to polymer flooding has to be sufficient to pay off polymer expenses and make a profit.

During the modelling process, polymer flood model was activated using the keyword POLYMER and it was assumed that model is not salt-sensitive. Keywords used in the model have been defined in the appendices. Chemical properties for polymer were extracted from different research reports for Norne field including [2], [5] and [23]. The study for polymer flooding was under 3 ways and sensitivity analysis was carried out for each

i. Injector selection

ii. Effect of concentration

iii. Effect of Timing

Assumptions Made

The following assumptions were made during the polymer flooding

i. Constant polymer injection rate of 5800 Kg/m^3 throughout the injection period;

ii. Polymer drive is not salt sensitive;

iii. Temperature is constant throughout the injection period so that polymer is chemically stable;

iv. There is neither polymer degradation nor chemical reaction between polymer and formation;

v. The injected polymer is in the water phase and is specified by its concentration at water injector;

vi. The flow of polymer solution is not affected by the flow of hydrocarbons in the reservoir;

vii. There is no any desorption of polymer throughout the injection period.

3.1 Selection of Injectors

In order to identify which injector/injectors will be the best for injection, fifteen cases were simulated. In each case, water was injected at a constant rate in every month from Jan 2007 to June 2021 while polymer was injected at constant concentration three times per year (after every 4 months). Among the fifteen cases, polymer was injected in single injector, two injectors, three injectors and all four injectors to investigate which injector/injectors will perform better with polymer. Plots of cumulative oil production and recovery factor were used in identifying the best performing injector/injectors as shown in Figures 3.1 to 3.7. For the single injector results, C-3H seems to be a good injector due to higher oil production and recovery factor than other injectors. Figures 3.3, 3.4, 3.5 and 3.6 show that by combining injectors, injecting polymer into C-2H & C-3H and into C-1H, C-2H & C-4H provide good results than other combination. Figures 3.7 and 3.8 compare performance single injector and combined injectors. Combined injectors are performing better with a side effect of too much polymer consumption compared to single injector. Huge polymer consumption requires large capital, thus injecting polymer in more than one injector seems to be wasteful compared to the oil production earned. However, combined injectors can be used if the oil price is good enough to compensate for polymer consumption expenses. Therefore well C-3H seems to be the best injector for polymer injection in C segment.

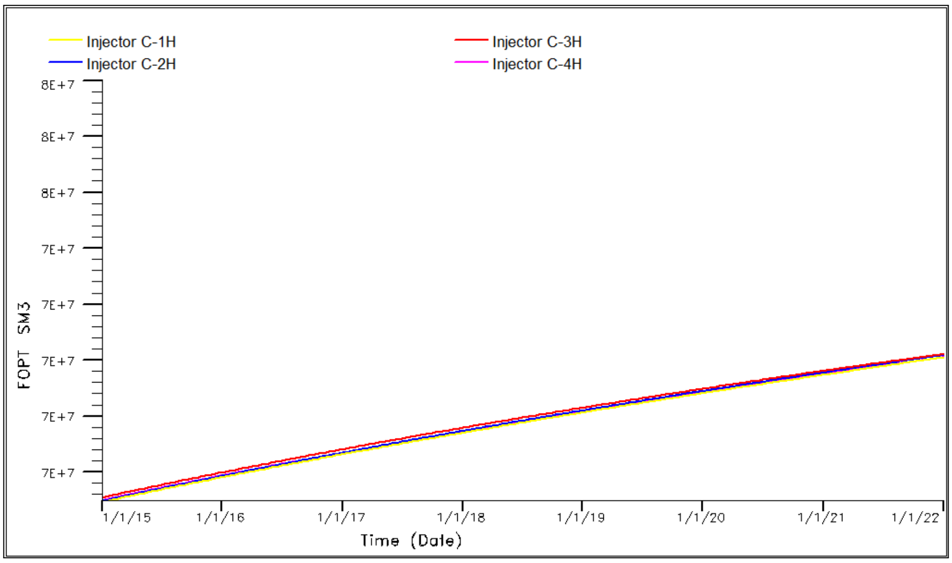


Figure 3.1: Cumulative oil production comparison for polymer injection in single injector

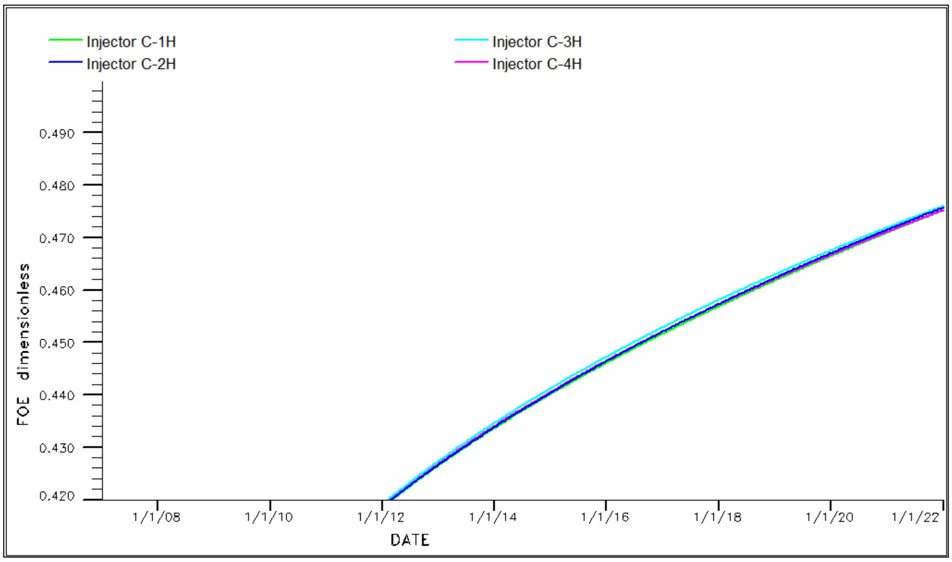


Figure 3.2: Recovery factor comparison for polymer injection in single injector

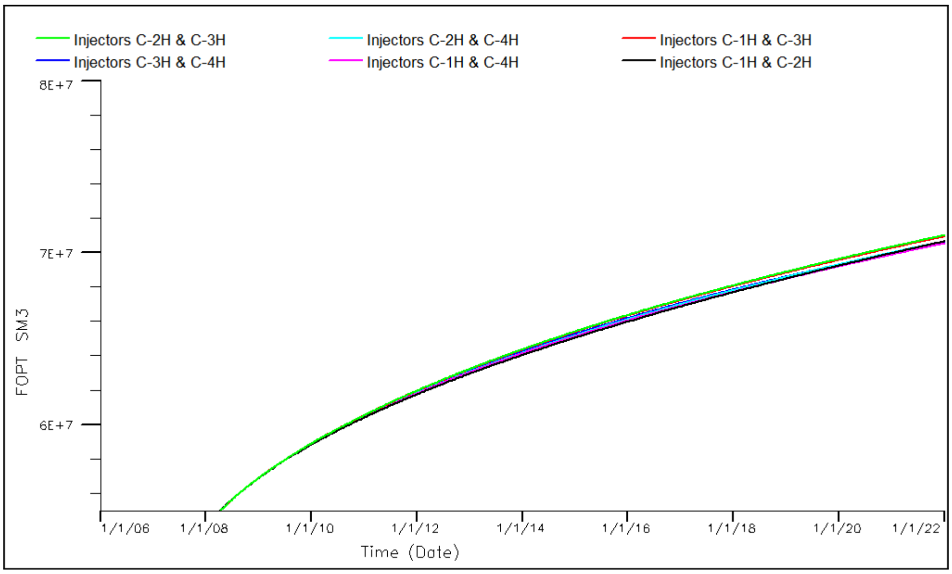


Figure 3.3: Cumulative oil production comparison for polymer injection in two injectors

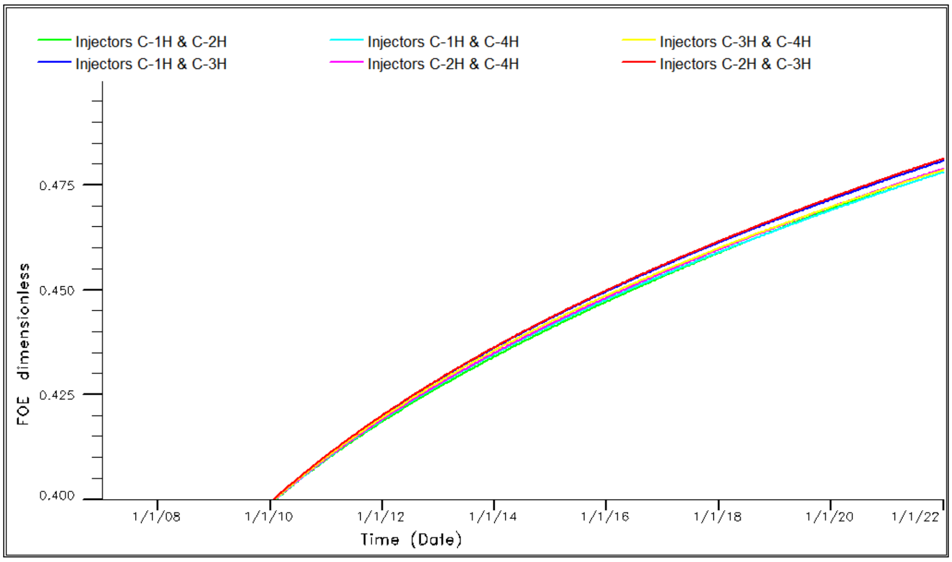


Figure 3.4: Recovery factor comparison for polymer injection in two injectors

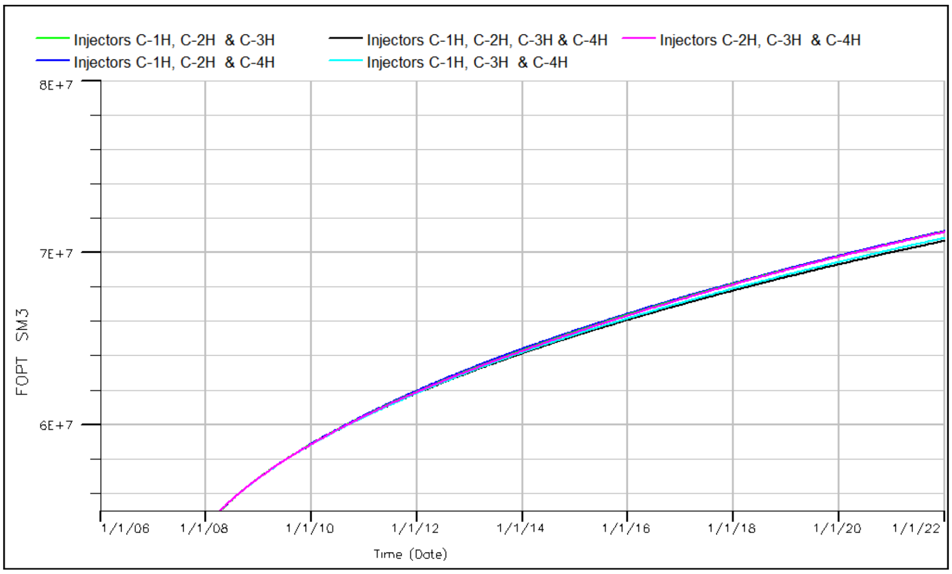


Figure 3.5: Cumulative oil production comparison for polymer injection in three & four injectors

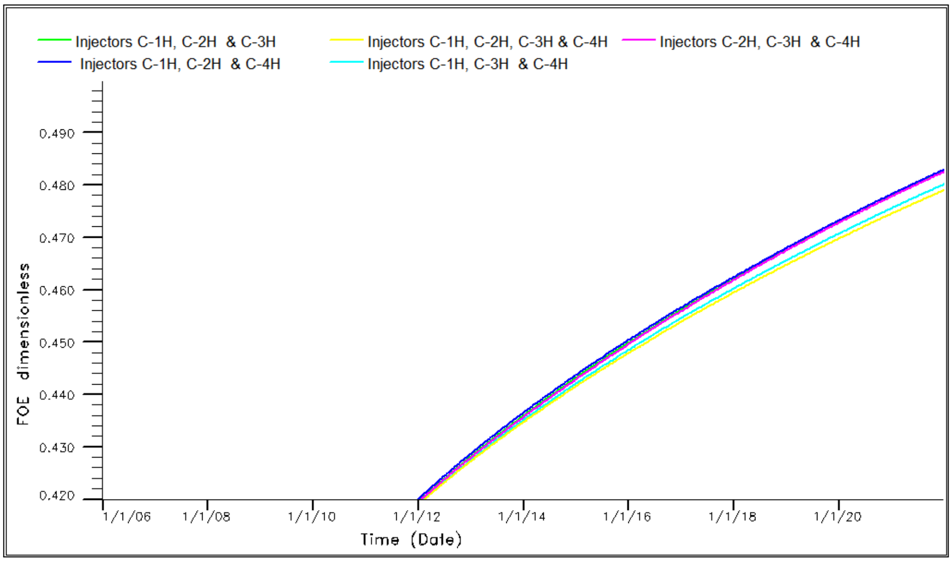


Figure 3.6: Recovery factor comparison for polymer injection in three & four injectors

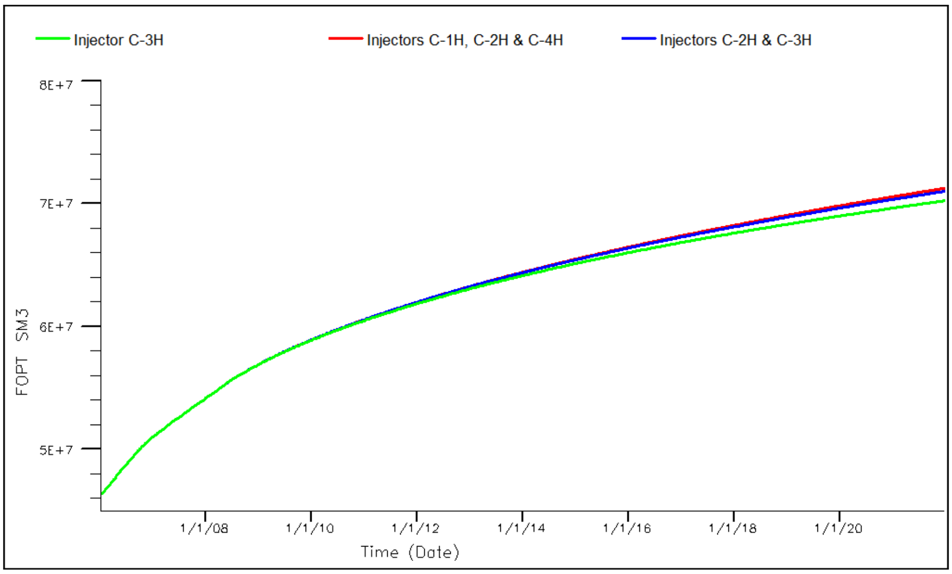


Figure 3.7: Cumulative oil production comparison for injection in single injector and combined injectors

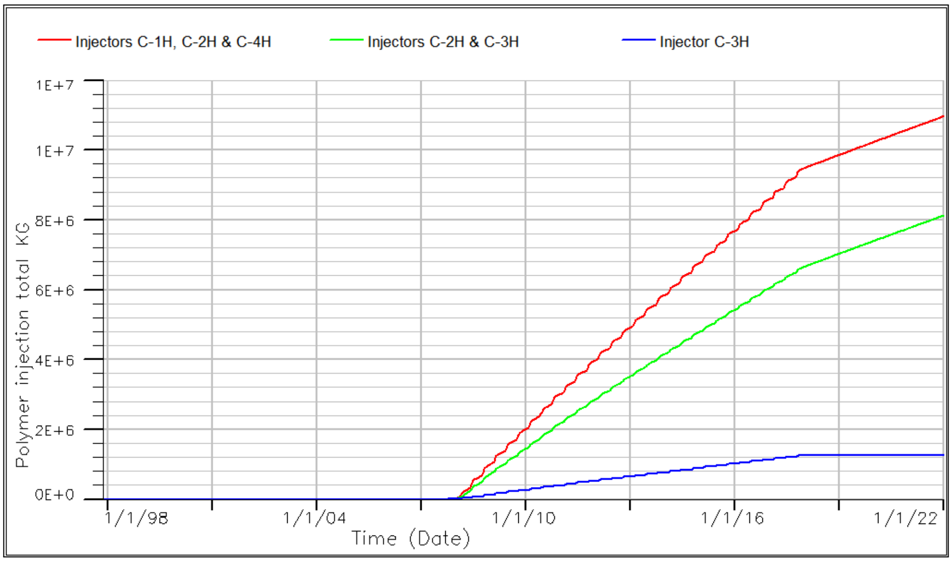


Figure 3.8: Polymer consumption comparison for injection in single injector and combined injectors

3.2 Effect of Polymer Concentration

Usually polymer solutions to be used are formed by dissolving polymer concentration ranging from 250 to 2500 ppm (0.25 to 2.5 kg/m^3) in water to attain desired injection viscosities [6]. But 900 ppm (0.9 kg/m^3) polymer concentration in the polymer slug is considered a good starting value in designing polymer water flooding [10]. Working from this value it can be determined whether optimal polymer concentration is actually higher or lower. It has been proved that as polymer solution concentration increases, its viscosity increases, its mobility ratio decreases and the swept volume increases as well.

Although [10] recommended 900 ppm as a good starting value in polymer flooding, this work investigated also other concentration values below 900 ppm to identify which concentration will be satisfactory. The following concentration values were tested in order to come up with an optimal value that will minimize residual oil saturation.

i. Polymer concentration of 0.2 kg/m^3
ii. Polymer concentration of 0.5 kg/m^3
iii. Polymer concentration of 0.8 kg/m^3
iv. Polymer concentration of 1.0 kg/m^3
v. Polymer concentration of 1.5 kg/m^3
vi. Polymer concentration of 2.5 kg/m^3

During modelling, injector C-3H was used due to its good performance than other injectors as has been revealed in the previous section and polymer injection started from January 2007 to January 2021. An optimal concentration value was determined by analysing plots of cumulative oil production, polymer adsorption, polymer production, recovery factor and cumulative water production.

High concentration yielded highest oil production and higher oil recovery but with a significant amount being adsorbed in the reservoir (Figures 3.9, 3.10 and 3.13). Oil production is higher because of improved mobility ratio which lead to higher water phase viscosity and water permeability reduction hence improved displacement efficiency. Figure 3.12 agrees with the conventional theory that polymer production increases with polymer concentration. As polymer is adsorbed, the injected polymer solution is depleted of its polymer and moves as either water or solution with less polymer concentration than the one injected. Adsorption process also causes reduction in polymer solution relative permeability due to interaction between aqueous solution and polymer retained in the rock. This implies the adsorption process is diminishing polymer effectiveness and due to this lower concentration is favoured because is less adsorbed and less produced. Figure 3.9 and 3.11 show that there is a slightly difference in oil production with a big difference in polymer consumption if different polymer concentrations are used. Because of the slightly difference, it is wasteful to inject higher concentrations of 0.5 kg/m^3, 0.8 kg/m^3, 1.0 kg/m^3, 1.5 kg/m^3 or 2.5 kg/m^3 while low concentration of 0.2 kg/m^3 could give approximately the same results. But if the oil price is competitive, higher polymer concentrations can be used. Therefore 0.2 kg/m^3 is considered as an optimal polymer concentration value to be used with polymer injection.

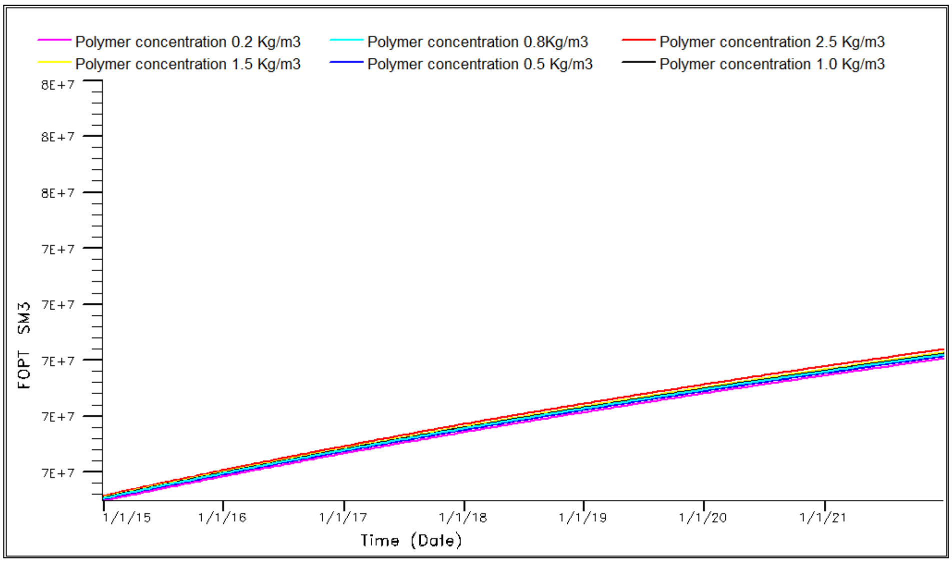


Figure 3.9: Cumulative oil production for polymer flooding at different concentrations

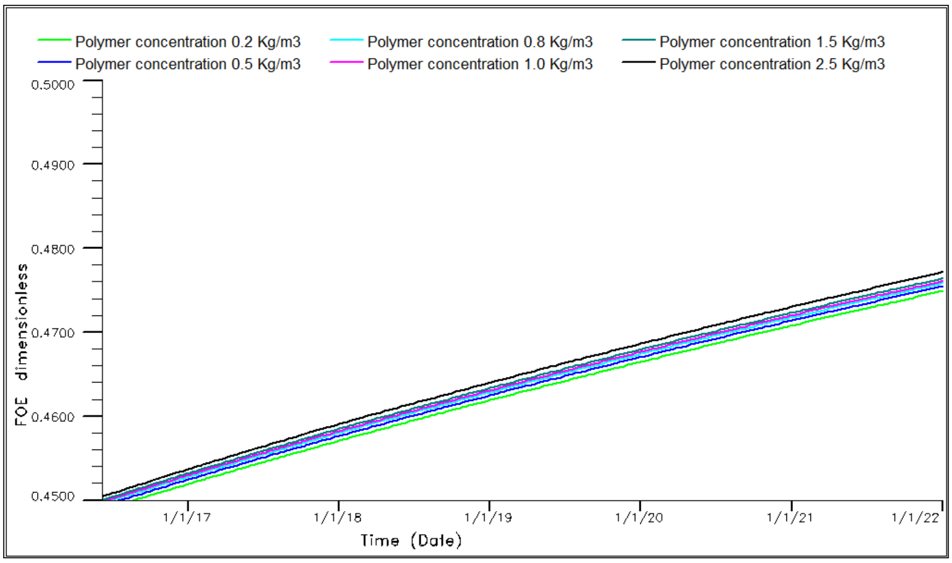


Figure 3.10: Oil recovery factor for polymer flooding at different concentrations

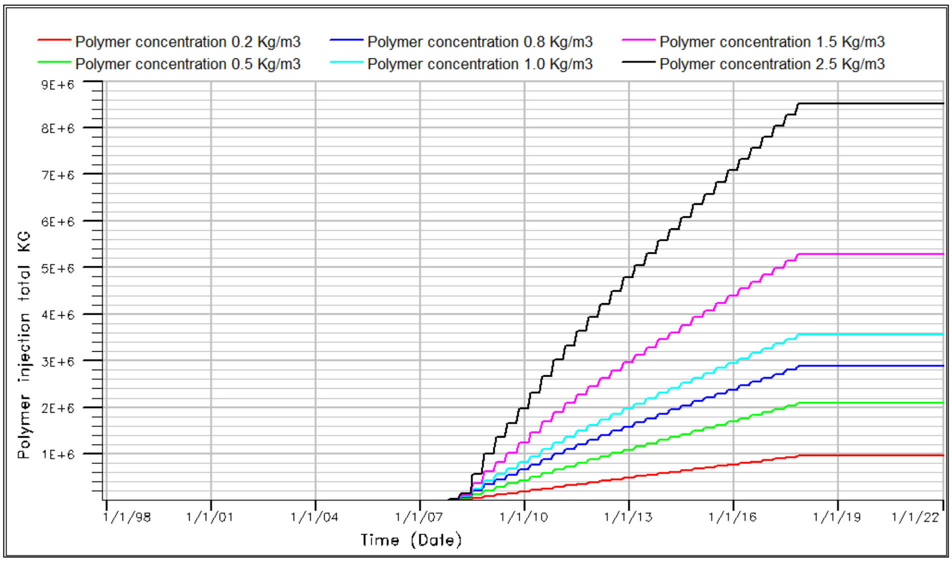


Figure 3.11: Polymer consumption comparison for different concentrations

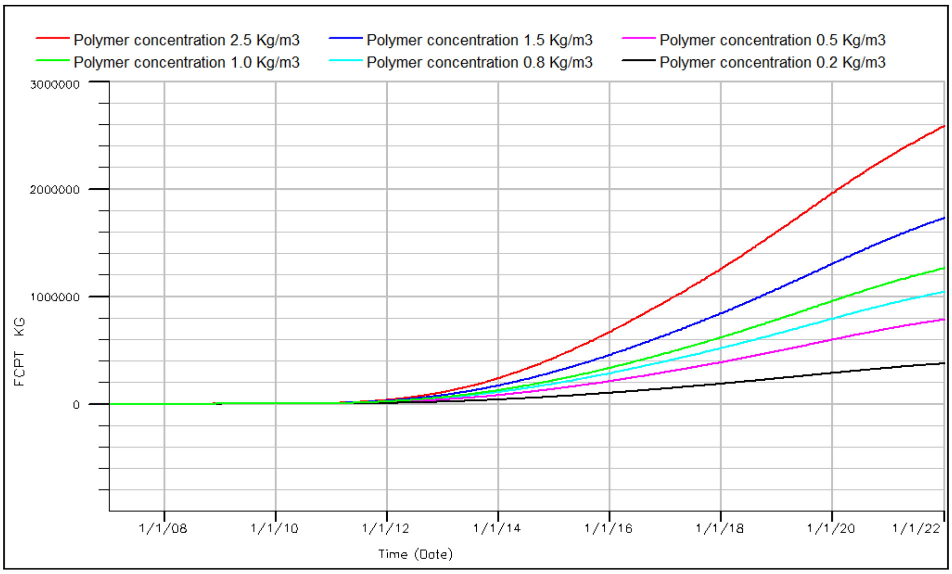


Figure 3.12: Cumulative polymer production at different concentrations

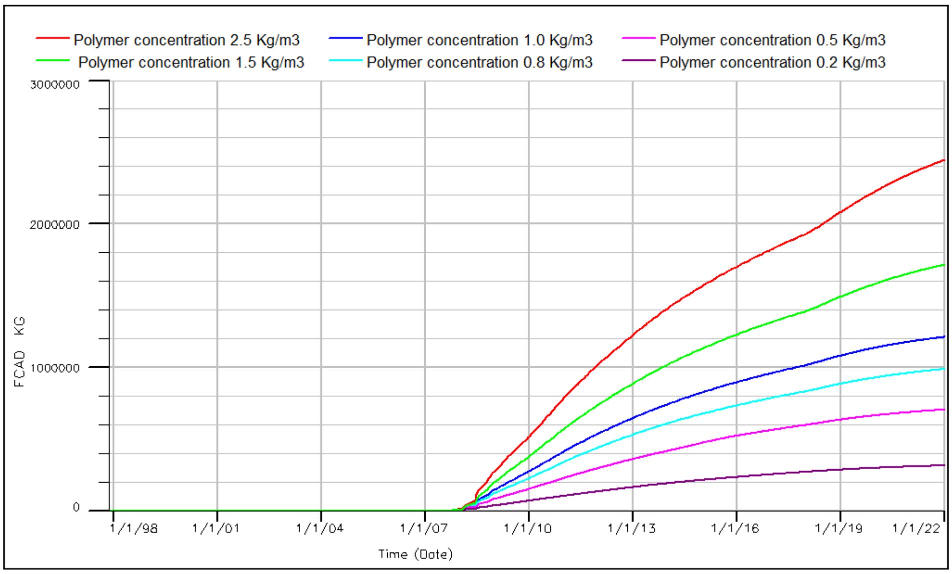


Figure 3.13: Polymer adsorption at different concentrations

3.3 Effect of Timing

After discovering suitable injector for polymer injection and optimal polymer concentration to inject, the next step was to find out the right time to inject, injection duration and mode of injection. Polymer was injected at two different periods, during the start up of the field and in the middle life of the field to identify the right time for polymer injection. Continuous injection at different periods and cyclic injection at different intervals were also examined to identify the injection manner to be used and time length for injection. The following cases were simulated

- Case 1: Injecting polymer from year 2008 to year 2013
    i. Cyclic injection for 3 months (3 months polymer flooding, 3 months water flooding)
    ii. Cyclic injection for 6 months (6 months polymer flooding, 6 months water flooding)
    iii. Continuous injection from January 2008 to January 2013
- Case 2: Injecting polymer from year 2014 to year 2019
    i. Cyclic injection for 3 months (3 months polymer flooding, 3 months water flooding)
    ii. Cyclic injection for 6 months (6 months polymer flooding, 6 months water flooding)
    iii. Continuous injection from January 2014 to January 2016

Figures 3.14 to 3.24 provide description for the simulation results about the timing effect in polymer flooding. Injection from 2008 to 2013 provides high oil production than injection from 2014 to 2019 as shown in Figures 3.14 and 3.16. Recovery factor also follows the same trend as shown by Figures 3.15 and 3.17. This implies in order to gain more oil, early injection of polymer has to be considered.
Comparison between cyclic injection and continuous injection in Figures 3.18, 3.19, 3.20 and 3.21 show that continuous injection of polymer gives higher oil production and higher oil recovery than cyclic injection. The reason behind is, in continuous injection, large quantities of polymer are injected than in cyclic injection, hence high oil production. Figure 3.24 displays polymer consumption for both cyclic injection and continuous injection. Although continuous injection yields high oil production, significant quantity of polymer is consumed too. Continuous injection requires excess polymer of 3.00×10^6 Kg and 3.80×10^6 Kg than 6 months

cyclic injection and 3 months cyclic injection respectively. However, there is a small difference in oil production between continuous and cyclic injection with a big difference in polymer consumption. Thus, a cyclic injection seems to be the suitable manner for injection than continuous injection.

Figure 3.22 compares total oil production for 3 months cyclic injection and 6 months cyclic injection for the right duration of polymer flooding. 6 months interval yields slightly high oil production than 3 months interval. 6 months interval requires excess polymer of 0.8×10^6 Kg than 3 months interval. Due to polymer cost and because the difference in oil production is small while polymer consumption is high, 3 months cyclic injection is a right choice for polymer flooding than 6 months cyclic.

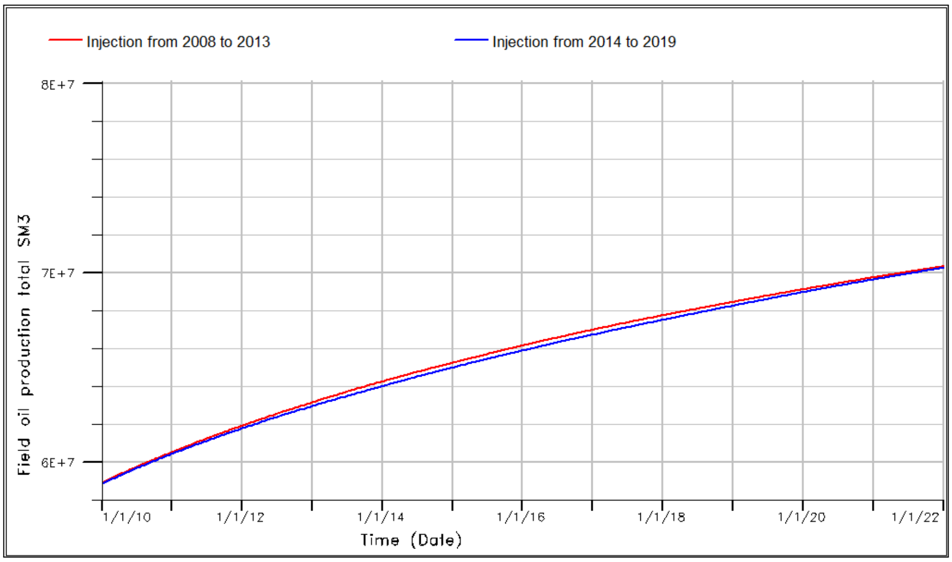


Figure 3.14: Total oil production at different injection periods for 3 months interval

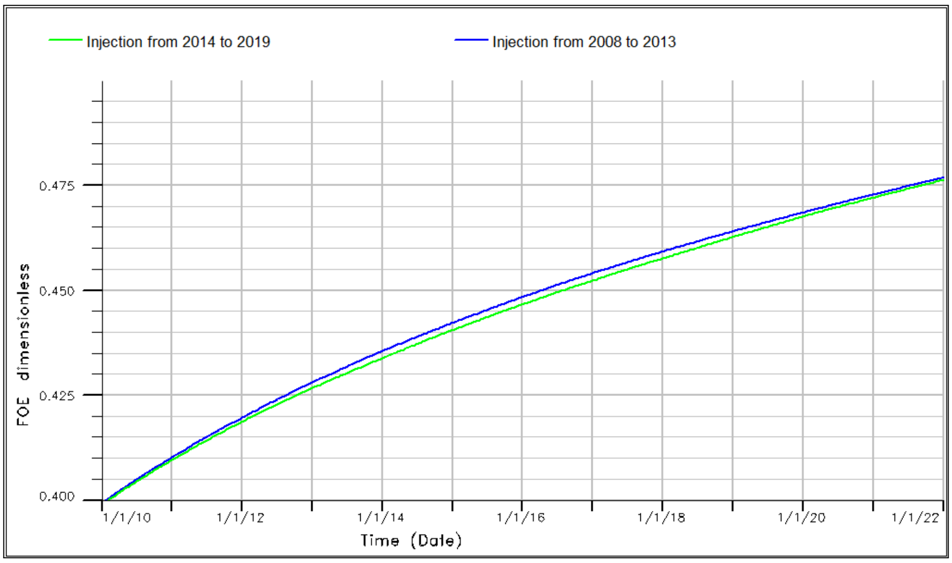


Figure 3.15: Oil recovery factor at different injection periods for 3 months interval

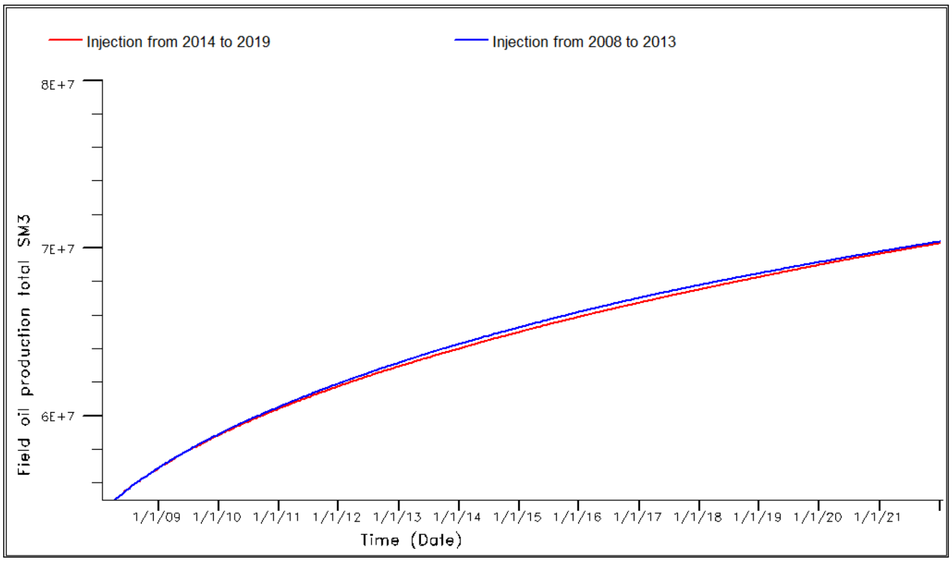


Figure 3.16: Total oil production at different injection periods for 6 months interval

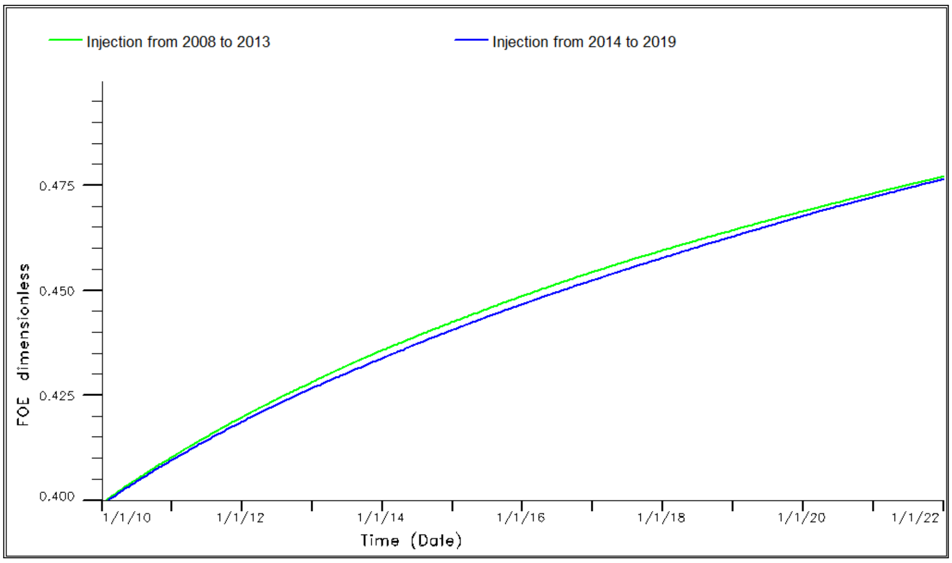


Figure 3.17: Oil recovery factor at different injection periods for 6 months interval

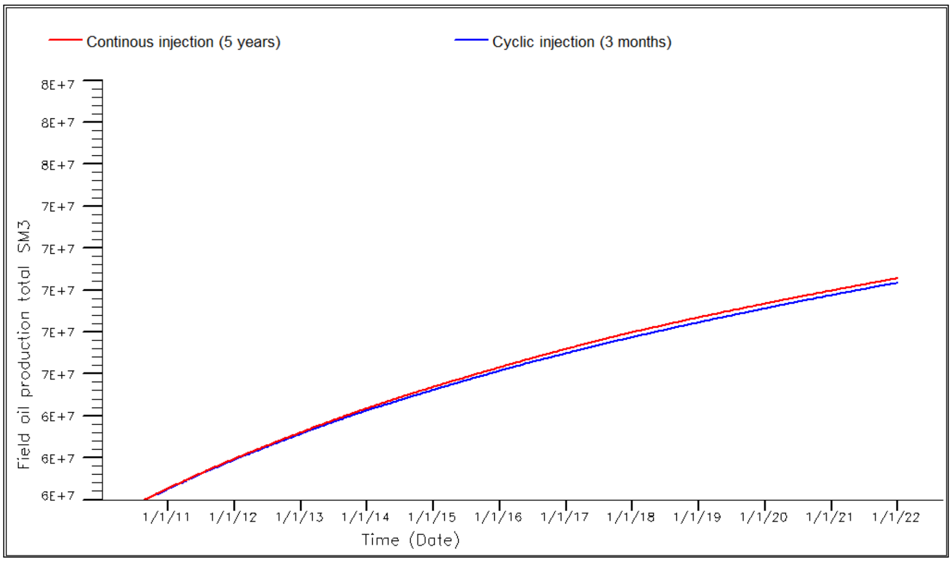


Figure 3.18: Oil production for 3 months cyclic injection and continuous injection

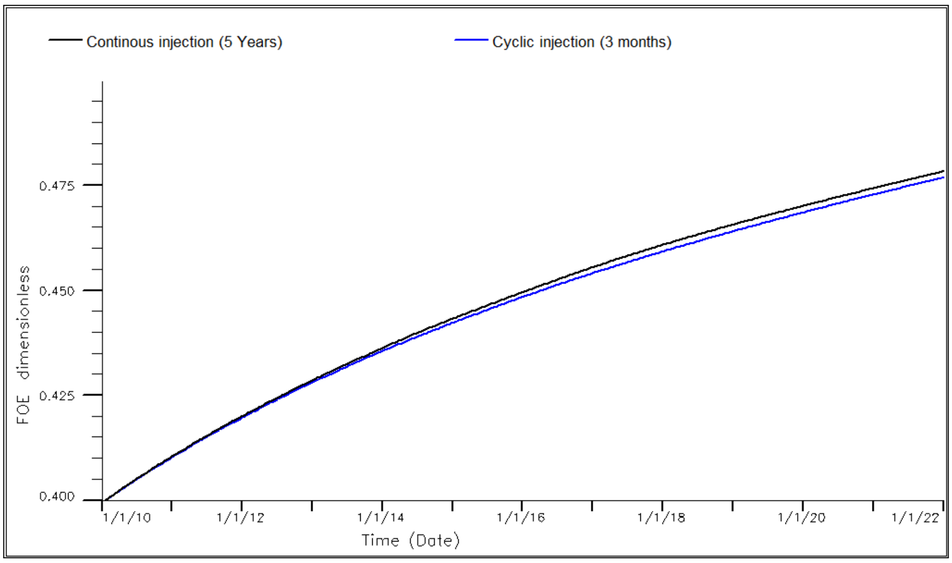


Figure 3.19: Recovery factor for 3 months cyclic injection and continuous injection

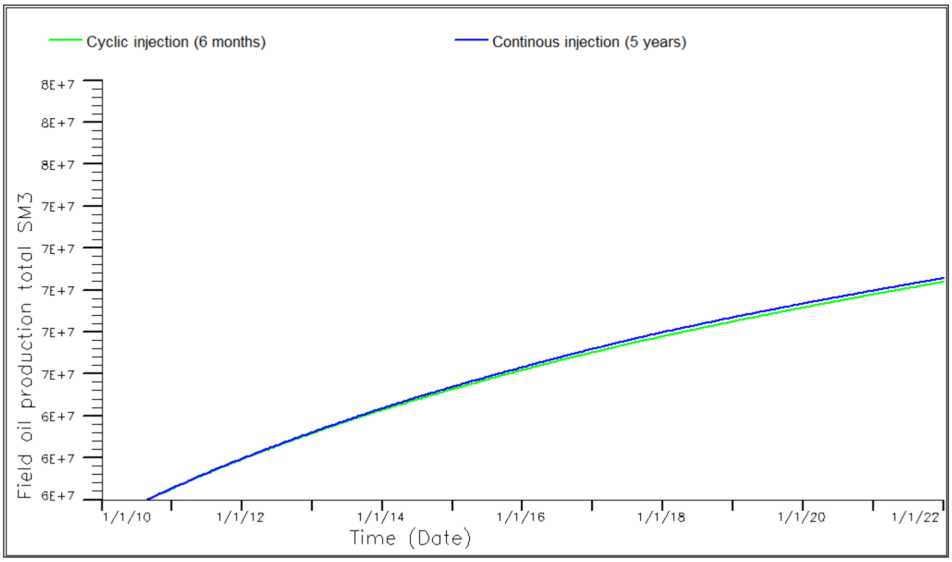


Figure 3.20: Total oil production comparison between 6 months cyclic injection and continuous injection

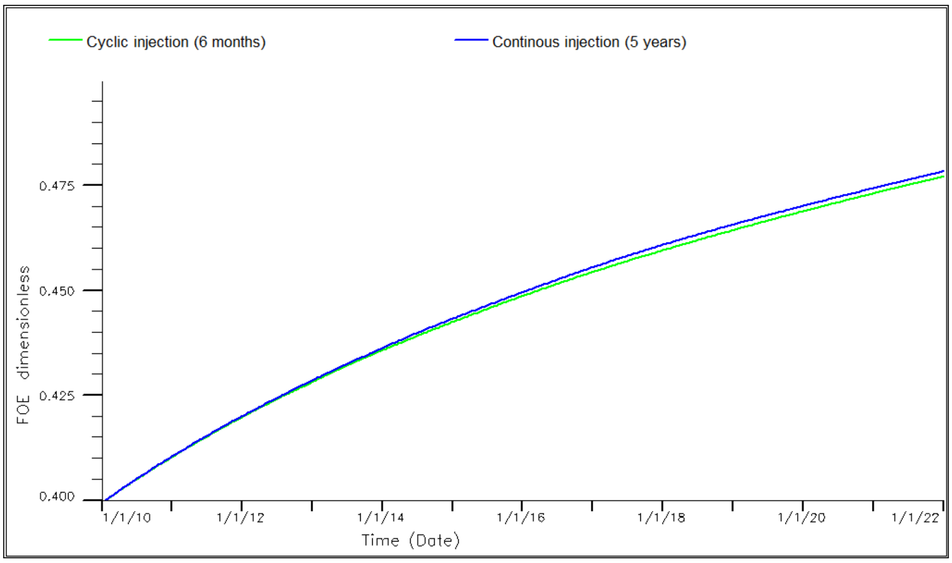


Figure 3.21: Recovery factor comparison for 6 months cyclic injection and continuous injection

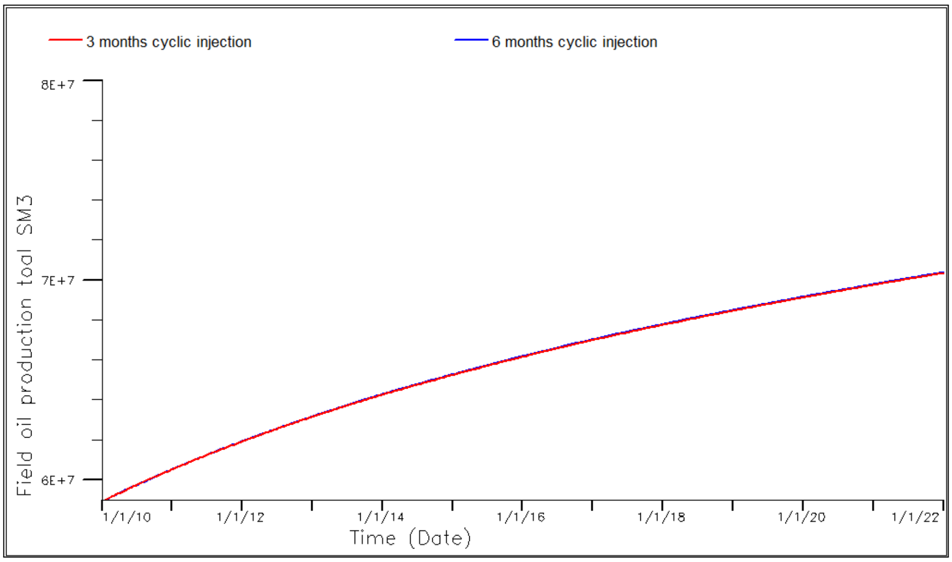


Figure 3.22: Total oil production comparison between 3 months cyclic injection and 6 months cyclic injection

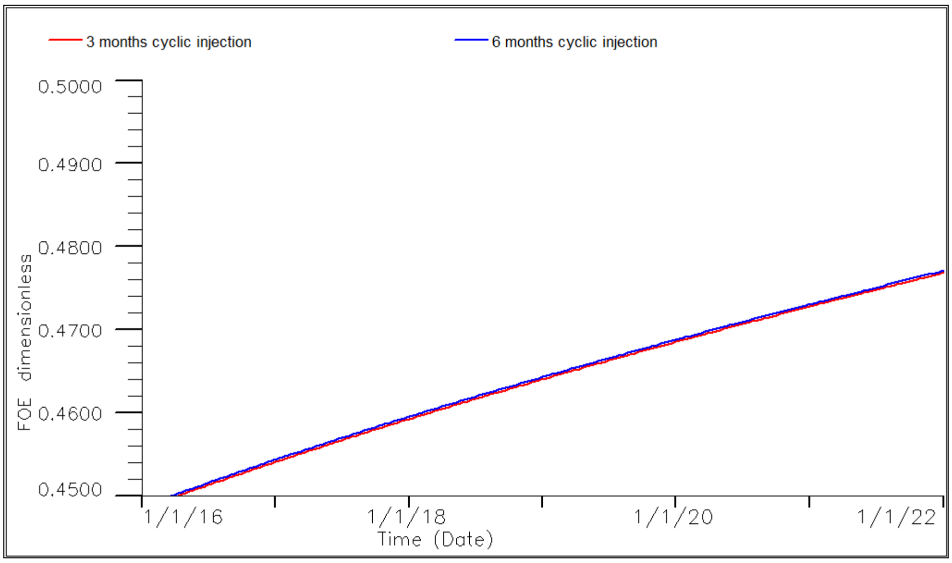


Figure 3.23: Oil recovery factor comparison between 3 months cyclic injection and 6 months cyclic injection

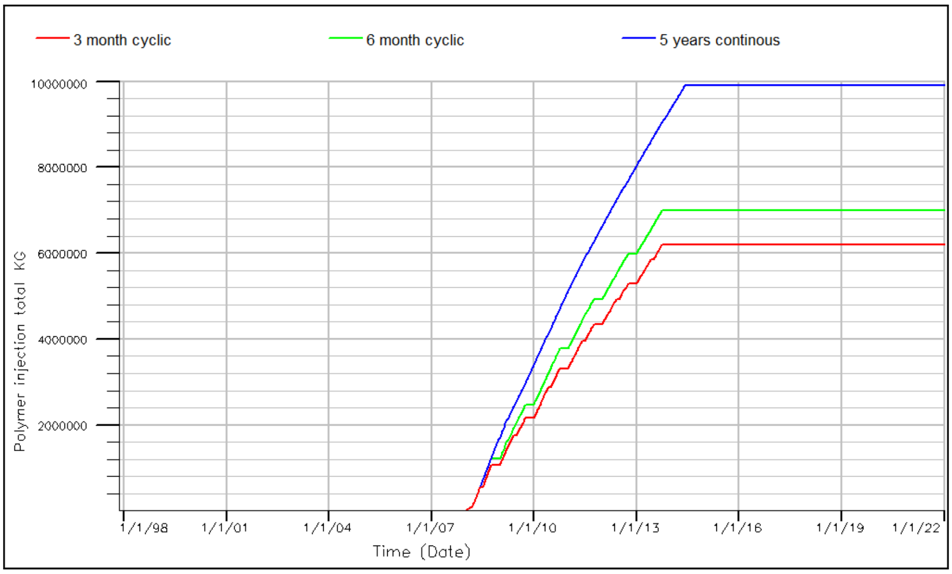


Figure 3.24: Total polymer consumption comparison between cyclic injection and continous injection

Figures 3.25 to 3.28 compares performance of polymer flooding with base case. With polymer flooding, significant improvements in oil production and recovery factor are observed. This is due to modified water phase viscosity making water to spend long time sweeping oil out of the reservoir. Figure 3.27 shows there is a delay in water breakthrough during polymer flooding. This is because increase in water viscosity mobilizes residual oil giving water a room to fill spaces which were holding residual oil hence less water production.

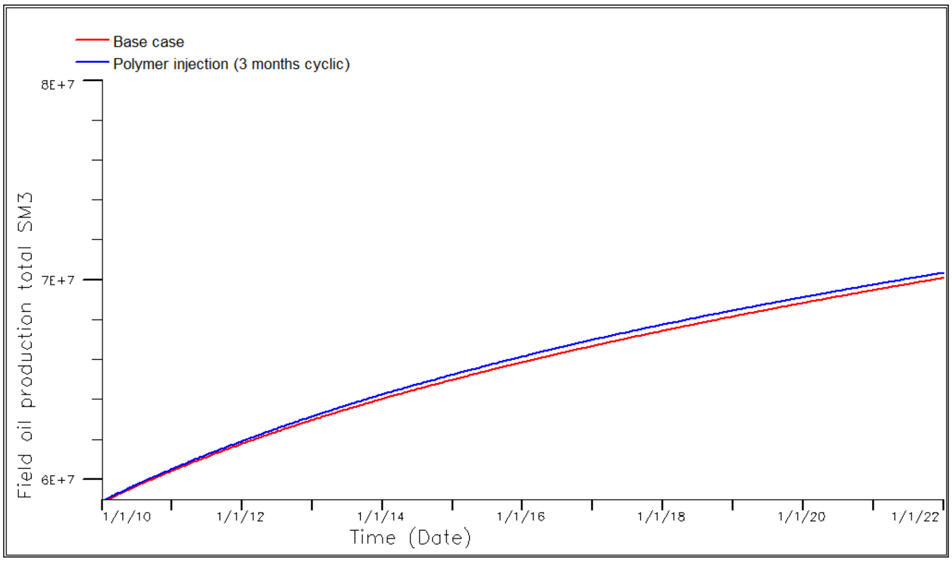


Figure 3.25: Oil production comparison for polymer injection and base case

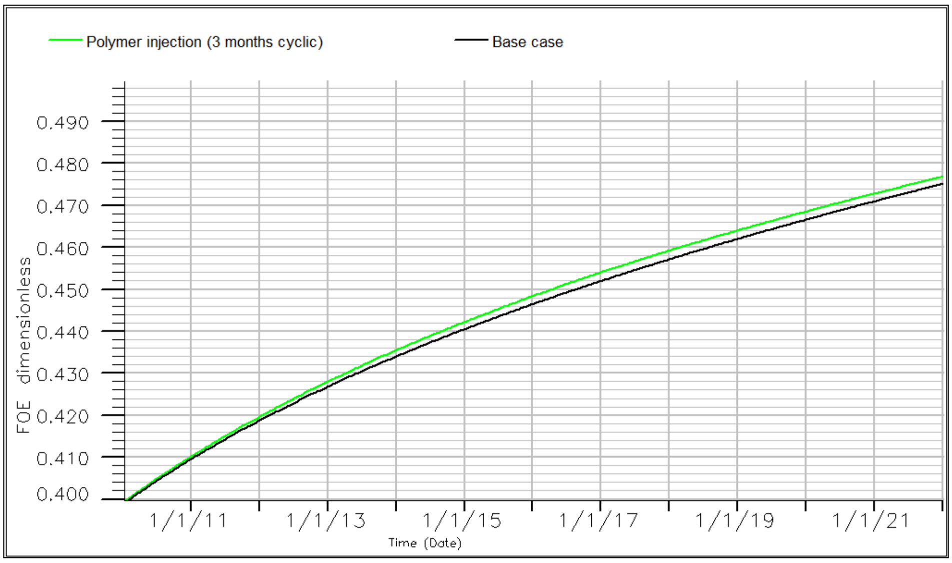


Figure 3.26: Recovery factor comparison for polymer injection and base case

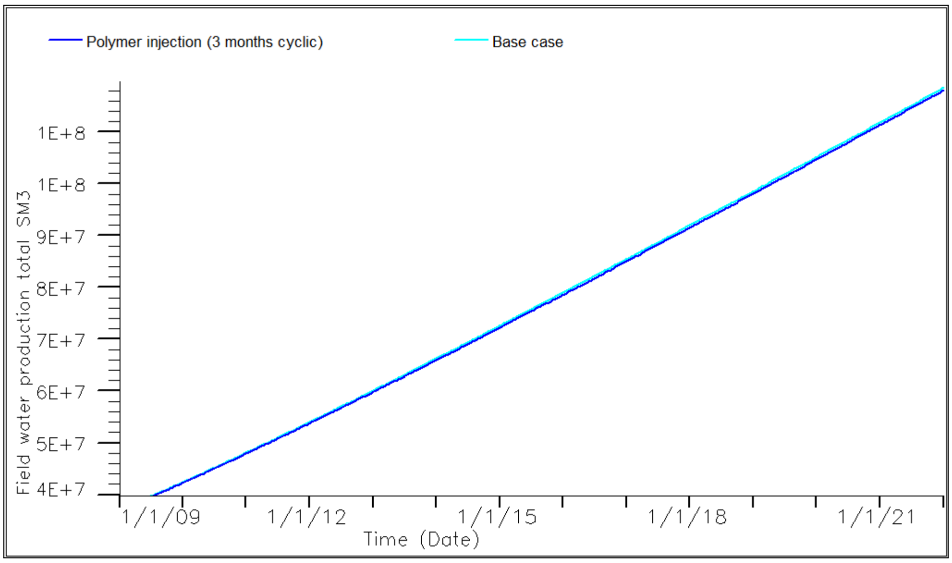


Figure 3.27: Water production comparison for polymer injection and base case

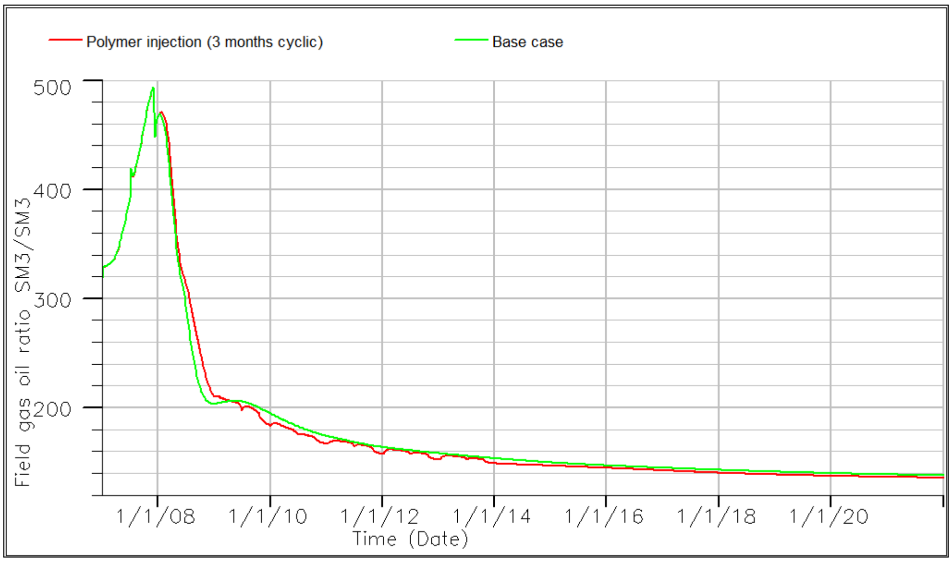


Figure 3.28: Gas oil ratio comparison for polymer injection and base case

Chapter 4

Low Saline Water Flooding

Low saline water flooding (LSWF/LSWI) is an IOR technique that modifies salinity of injection water to improve oil recovery compared to conventional seawater flooding or other higher saline water. It is recommended that in water flooding process, fresh water or at least water with lower dissolved salts than the connate water should be injected for getting good results [19]. Researches involving other water-based EOR methods, such as polymer flooding [9], have also showed that LSWF can improve efficiency of polymer drive oil displacement. Similar, Ayirala and Yousef in their research, [6] proved that lower salinity waters have beneficial effect in polymer to yield better oil recoveries when compared to high salinity waters.

LSWF mechanism relies on the wettability modification from mixed wet or oil wet state to water-wet system, [24] whereby oil wetness is due to presence of clay minerals over the rock surface as well as high saline formation water ($>>$ 10,000 ppm) with high content of bivalent cations. Lowering salinity level increases repulsion forces between clay minerals and oil as a result oil attached to clay minerals is released and floated away. This process leads to reduction of the remaining oil saturation and boosting up of oil recovery.

Injecting low saline water at initial water saturation (S_{wi}) brings much higher oil recovery than with high saline water and on the other hand injecting low saline water at residual oil saturation (S_{or}) requires large volume of water injection to get higher oil recovery [19]. However, the residual oil saturation is expected to decrease as the salinity of the injected water decreases. This study does not involve injection at initial water saturation because the field has been in production since 1997, as a consequence large volume of low saline water injection might be required to get better results.

Sources of Data and Assumptions

In order to model LSWF, keywords BRINE and LOWSALT were activated and the effect of low against high salinity on the reservoir performance was investigated. With use of low salinity option, saturation and relative permeability end points for both oil and water phases as function of salt concentration and water-oil capillary pressure are modified. Water density and viscosity are also changed by adjusting salt concentration in water phase [32]. Other keywords used in the model have been attached in appendices.

The following assumptions were also made during the simulation

i. Saturation and relative permeability end points for both oil and water phases were obtained from [19]. This is a presentation for *Low salinity water flooding* lecture by Chuck Kossack at NTNU. These data are presented by Figures 4.1 and 4.2.

ii. Low saline water was injected at rate of 6000 kg/m^3 and the injection was through well C-3H.

iii. Salt composition of water injected in the base case is 30 kg/m^3.

iv. Weighting factors for the keyword LSALTFNC were assumed using the range from ECLIPSE manuals

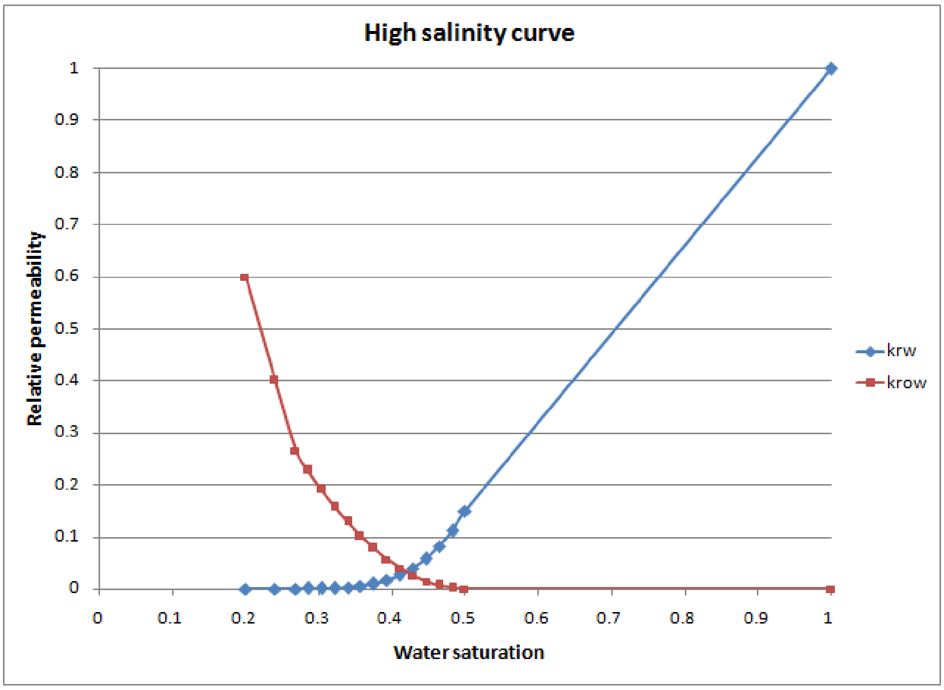


Figure 4.1: High salinity relative permeability curve

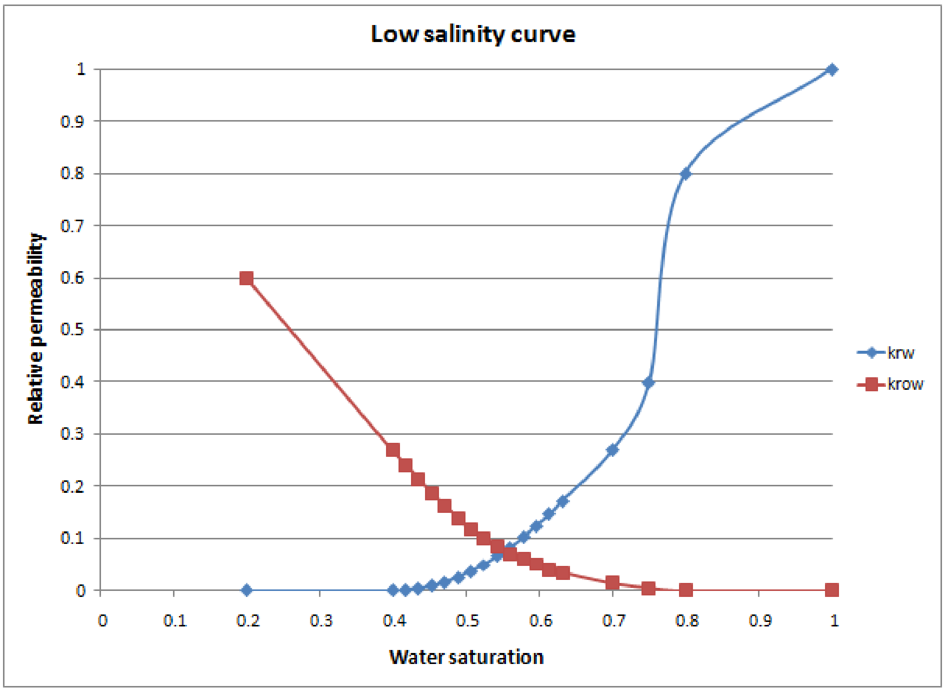


Figure 4.2: Low salinity relative permeability curve

Water salinity can be categorized as: [19]

- Fresh water: < 1 ppm

- Drinking water
    i. Soft: 0-100 ppm
    ii. Moderate: 100-200 ppm
    iii. Hard: 200-300 ppm
    iv. Very hard: 300-500 ppm
    v. Extremely hard: 500-1000 ppm
- Sea water: about 30,000 ppm
- Aquifers/oilfield saturated: 300,000 ppm

Injecting fresh water yields better results but is more costly. However, injecting a slug of fresh water followed by high salinity water is less costly because small volumes of fresh water are used, [19] and [3], and recovers nearly the same percentage of oil as that of fresh water. The study investigated both injection types: fresh water injection, high saline water injection and slug injection to identify which concentration will deliver high oil recovery.

Sensitivity analysis

Due to time constraint, the main sensitivity variables considered were salt concentration in the injection water that will generate high incremental NPV and commencement time for LSWI. Well C-3H that found to perform better with polymer injection as has been pointed out in the previous chapter was used. Results from each analysis were then compared with the base case model to examine the upshot of oil recovery factors, oil produced, water cut and salt production rate for estimating economic worth of LSWI.

4.1 Salt concentration of the injected water

Incremental oil recovery level depends on brine salinity, but this is not simply proportional. Above certain threshold level and below certain level of salinity, recovery does not depend on salinity. Significant low-salinity effects have been seen by [16] for salinities range 1 - 2 kg/m^3, so [16] concluded the thresholds are above and below this range for high and low salinity thresholds. Other findings have shown that injected concentration must be below 25% of the connate water salinity with approximate 3 to 5 kg/m^3 as upper salinity threshold and 0 to 1 kg/m^3 as lower salinity threshold. However, [9] recommended that very low salinity (less than 1 kg/m^3) may cause other complications such as fine migration and clay swelling. According to [30], a successfully low saline water injection can be attained by injecting brine with lower ionic strength typically in the range of 0.5 - 3 kg/m^3 and not more than 5 kg/m^3. In addition, [16] indicated that low saline effect can be achieved by injecting water with less than 25% of the connate water salinity and consistently at 10% of the connate water salinity. Lowering below 10% gave a further improvement in oil recovery.

Based on these findings, concentration values between 0 kg/m^3 to 5 kg/m^3 were analysed (Table 4.1). Although salinity below 1 kg/m^3 was not recommended by [9], in this study it was also included to see its impact in Norne field C segment. Continuous injection of high salinity water, continuous injection of low salinity water together with low saline slug injection at different concentration values were analysed. Assuming that sea water/connate water has salt a composition of 30 kg/m^3 [30], 0.9 kg/m^3 was considered as the lowest saline water and 30 kg/m^3 as high saline water. The other values of salt composition analysed were 1.8 kg/m^3, 3 kg/m^3 and 4.5 kg/m^3 to identify which one will give high oil recovery at reasonable expenses as water treatment for low salinity injection presents significant costs. The three cases simulated are as follows

- **Case 1:** Continuous injection of high saline water (base case)

- **Case 1:** Continuous low salinity water injection at 0.0 kg/m^3, 0.9 kg/m^3, 1.8 kg/m^3, 3 kg/m^3 and 4.5 kg/m^3

- **Case 2:** Low salinity slug injection (low salinity and high salinity injection)

    i. 0.9 kg/m^3 and 30 kg/m^3

    ii. 1.8 kg/m^3 and 30 kg/m^3

    iii. 3.0 kg/m^3 and 30 kg/m^3

    iv. 4.5 kg/m^3 and 30 kg/m^3

Continuous injection was demonstrated by injecting 0.9 kg/m^3 saline water from Jan 2007 to the end of simulation while low salinity slug injection was demonstrated by injecting low saline water, 0.9 kg/m^3, 1.8kg/m^3, 3.0 kg/m^3 and 4.5 kg/m^3 for five years continuously from Jan 2007 to 2011 followed by injecting high saline water, 30 kg/m^3 from Jan 2012 up to the end of simulation.

Table 4.1: Salt composition values below 25% of the connate water composition

Composition in %	Composition in kg/m^3
3	0.9
6	1.8
10	3
15	4.5
100	30

Figures 4.3 to 4.8 report performance of low saline water injection. Considerable improvements in oil production are observed with the use of low saline water compared to high saline water. The difference in oil production between the salt compositions were observed starting from year 2016 to the end as shown by Figures 4.3 and 4.4. The lower the salt composition in the injected water, the higher the improvements in oil production and oil recovery efficiency. Oil recovery increases because low saline water causes floating away of desorbed mobile oil that was previously adsorbed on the rock surface. On the other hand, there is low oil recovery in high saline water due to desorption of more cations to the rock surface.

Low saline slug injection was through injecting low saline water from Jan 2007 to 2011 followed by injecting high saline water from 2012 to the end of simulation. Figure 4.6 shows that slug injection was performing less than injecting low saline water through out the simulation period. Furthermore, injecting 0.9 kg/m^3 with high saline water gave high oil production than other cases as shown in Figures 4.7 and 4.8. This implies that the lower the salt composition in the low salt slug injection, the higher is the improvements in oil production. Low salinity slug injection reduces requirement for low salinity water injection but recovers low oil than continuous low saline water injection. This means, if the oil price is not good, slug injection could be a better option than continuous injection of low saline water.

Furthermore, delayed water production was observed with the use of low saline water as shown by Figures 4.9 through 4.11. There was high water production with the use of high saline water while by reducing salt concentration, water production was low. Also continuous injection of low saline water gave less water production compared to low salinity slug injection as Figure 4.11 shows. However, injection of high saline water produces water volumes approaching those of low salinity slug injection.

Figures 4.13 and 4.12 compare cumulative salt injection at different low salt slug injection. The lower the salt concentration, the lower the salt is in the injection water. This means low salt slug injection requires less treatment hence less costs compared to continuous injection of low salt water.

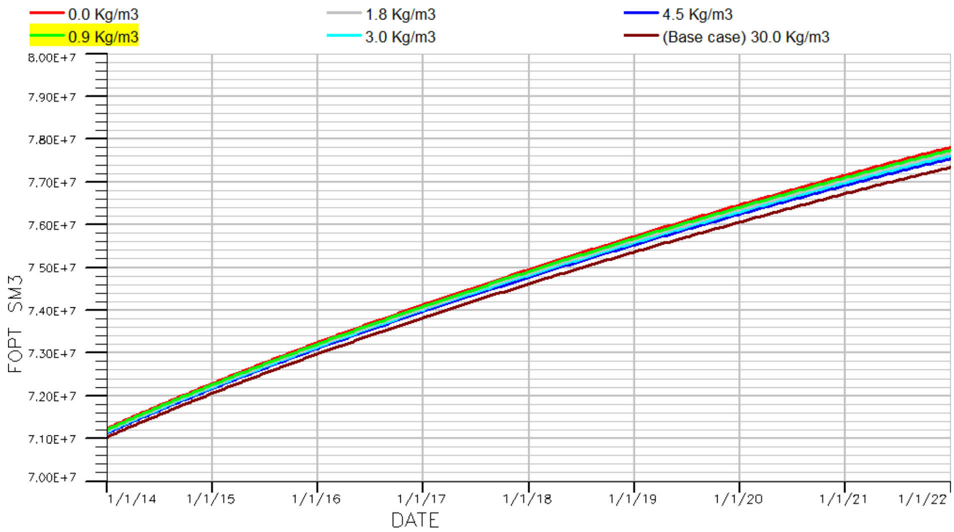


Figure 4.3: Cumulative oil production comparison at different salt composition

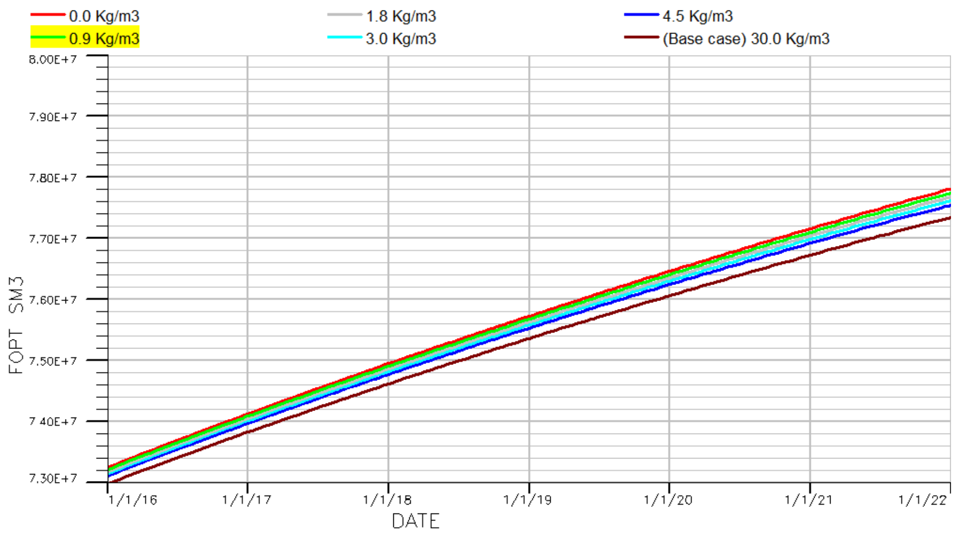


Figure 4.4: Cumulative oil production comparison at different salt composition

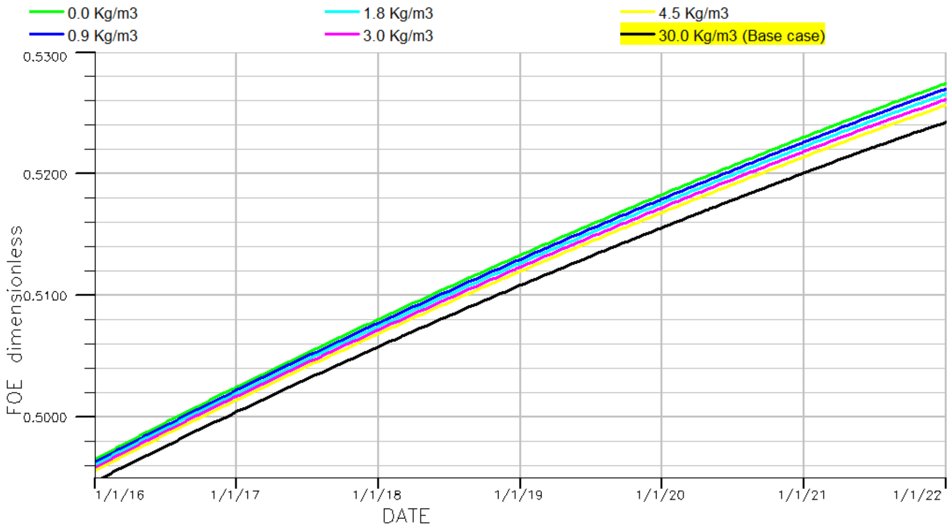


Figure 4.5: Oil recovery factor comparison at different salt composition

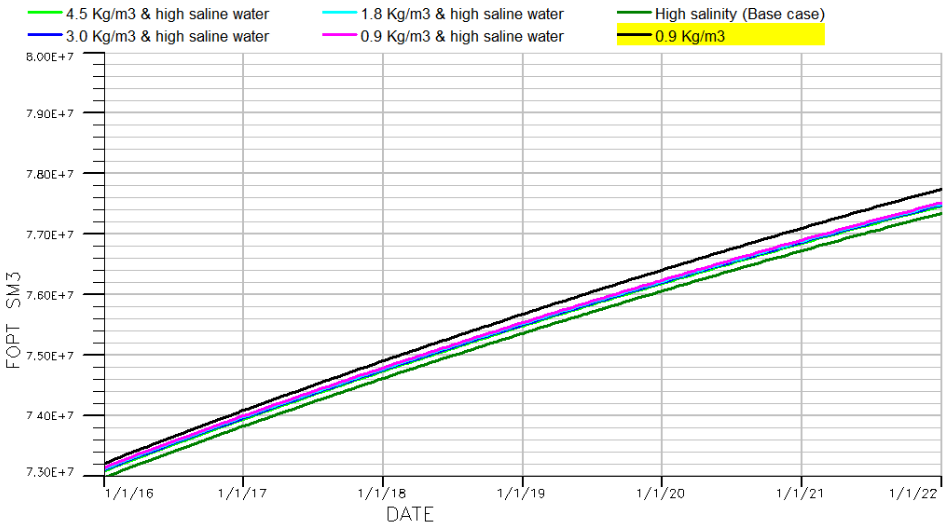


Figure 4.6: Cumulative oil production comparison at different low salt slug injection

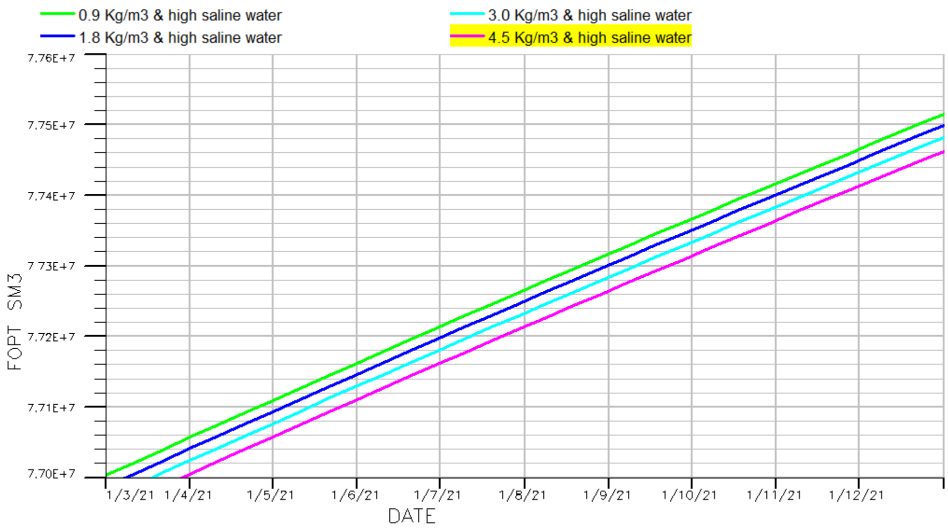


Figure 4.7: Cumulative oil production comparison at different low salt slug injection

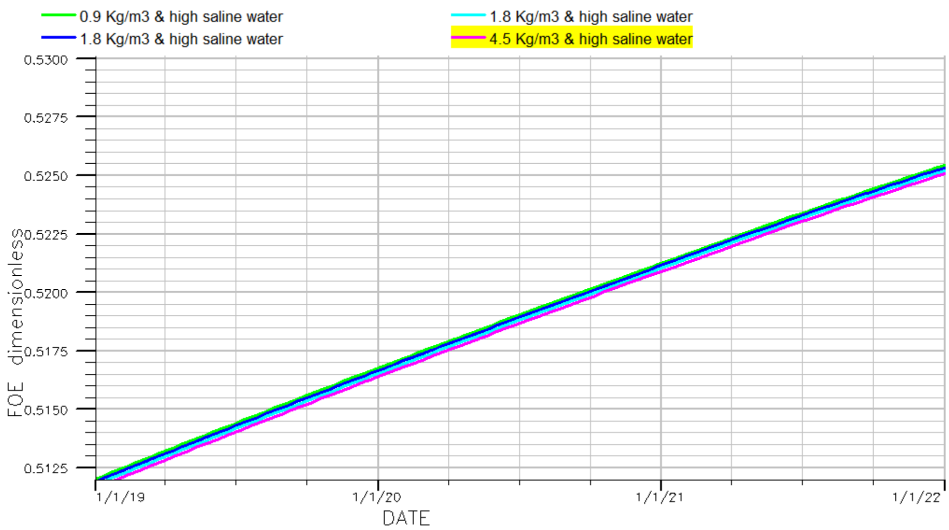


Figure 4.8: Oil recovery factor at different low salt slug injection

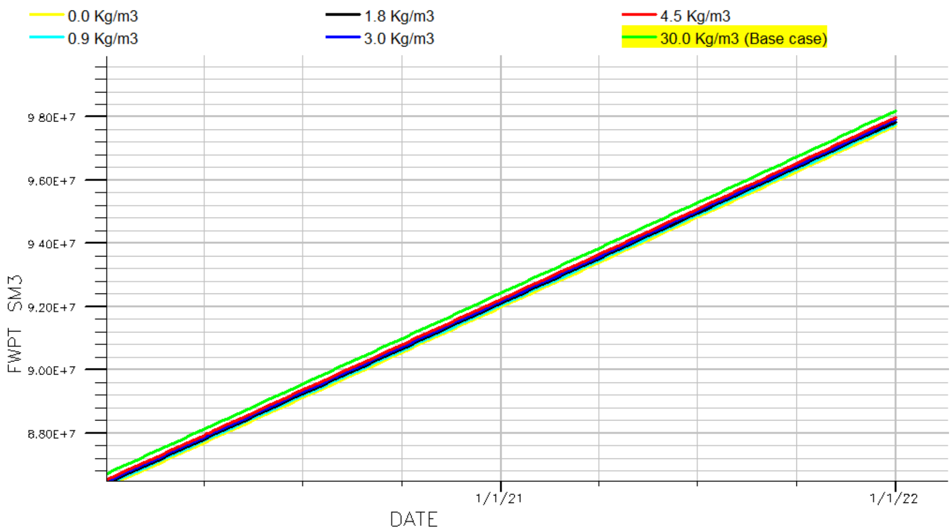


Figure 4.9: High salinity and low salinity comparison of cumulative water produced

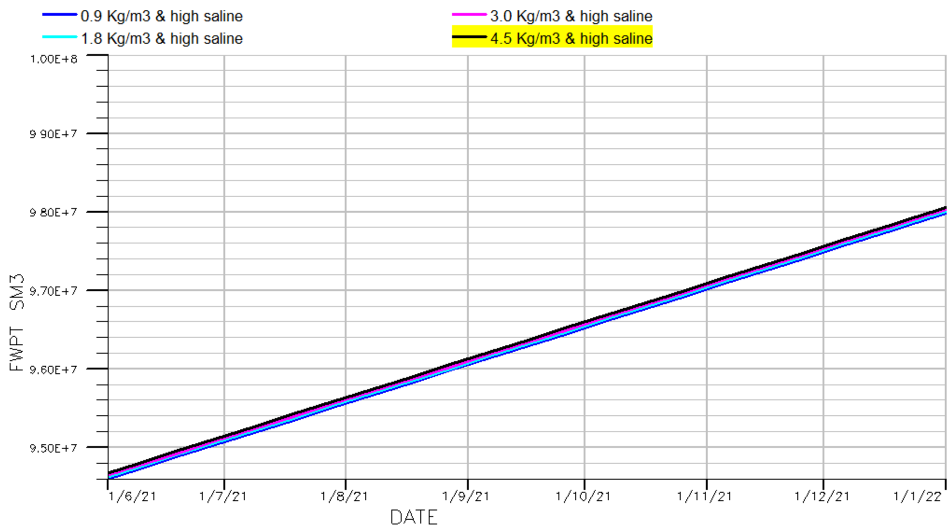


Figure 4.10: Cumulative water production comparison at different low salt slug injection

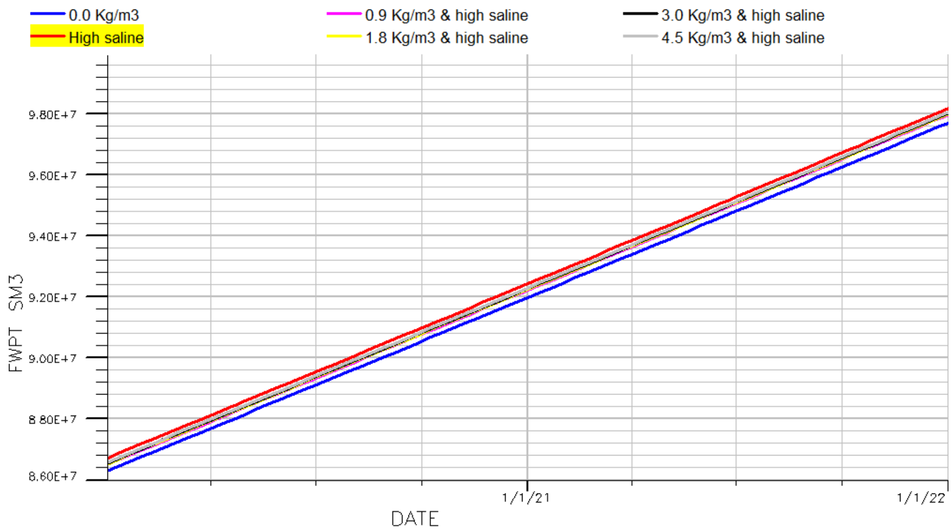


Figure 4.11: Cumulative water production comparison at different low salt slug injection

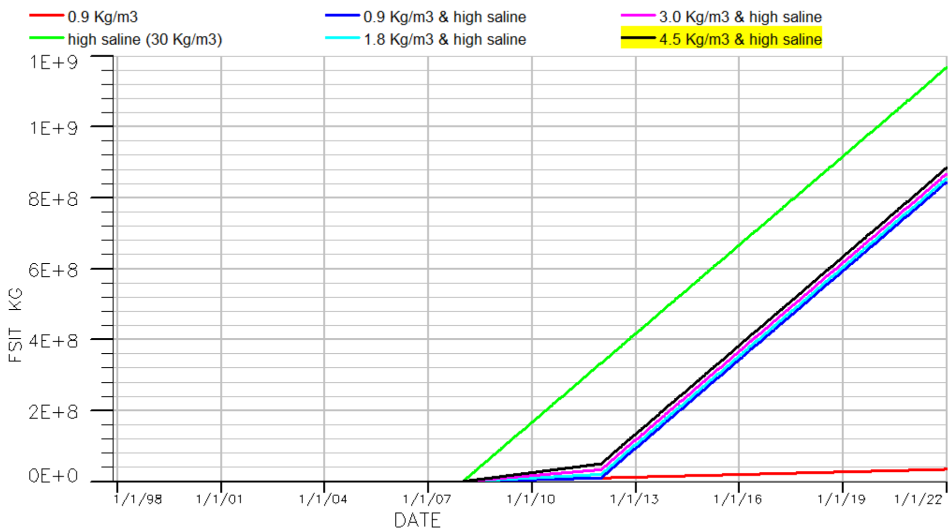


Figure 4.12: Cumulative field salt injection at different low salt slug injection

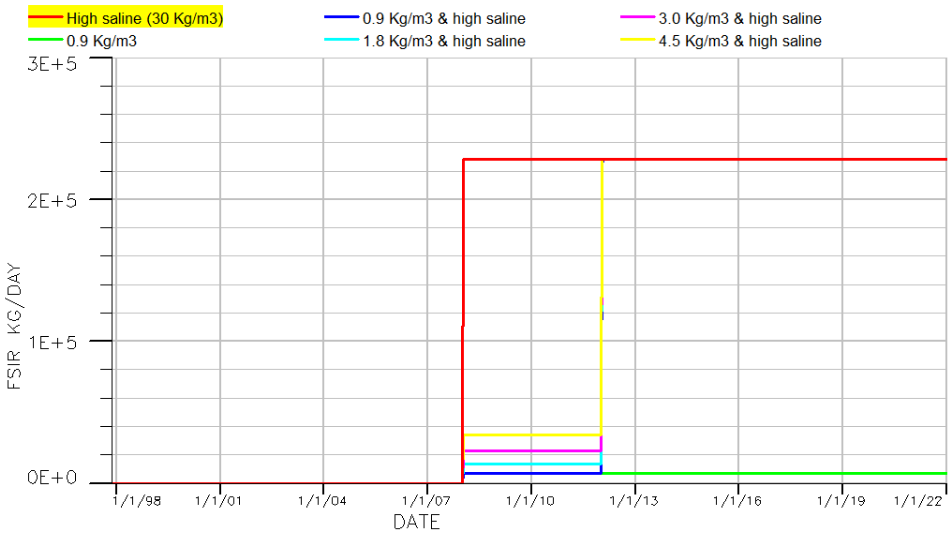


Figure 4.13: field salt injection rate at different low salt slug injection

4.2 Effect of Timing

Although LSWI gives a better recovery than other conventional water flooding methods, literatures insists suitable time for injection also contributes to a better recovery. Sensitivity analysis was run to identify at what time should the injection applied to the field. The following cases were included in the run

- Early injection: Injecting low saline water starting from Jan 2007 to Jan 2014 followed by high saline water from Jan 2015 to the end.
- Late injection: Injecting high saline water starting from Jan 2007 to Jan 2014 followed by low saline water from Jan 2015 to the end.

Figures 4.14 and 4.15 show that early injection of low saline water favours oil production than late injection. Base case and late injection produced exactly the same quantities of oil up to year 2018, from there late injection was producing high than the base case meaning that to benefit more with LSWF, low saline water needs to be injected in early life of the field. There is also a significant delayed in water breakthrough for the case early injection as shown by Figure 4.16. Base case and late injection had approximate the same water production.

The delayed water production is due to replacement of desorbed mobile oil by the injected water, leading to less water production.

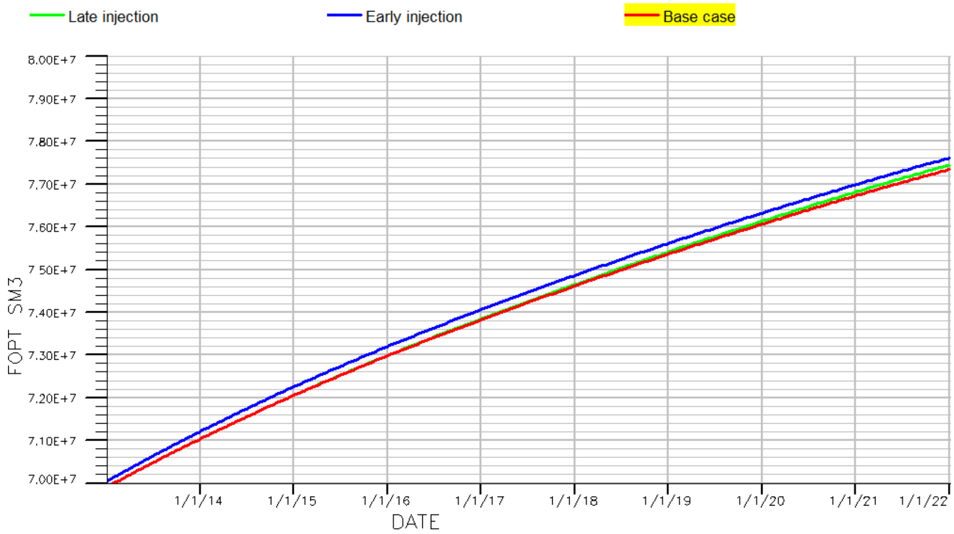


Figure 4.14: Cumulative oil production for early and late injection

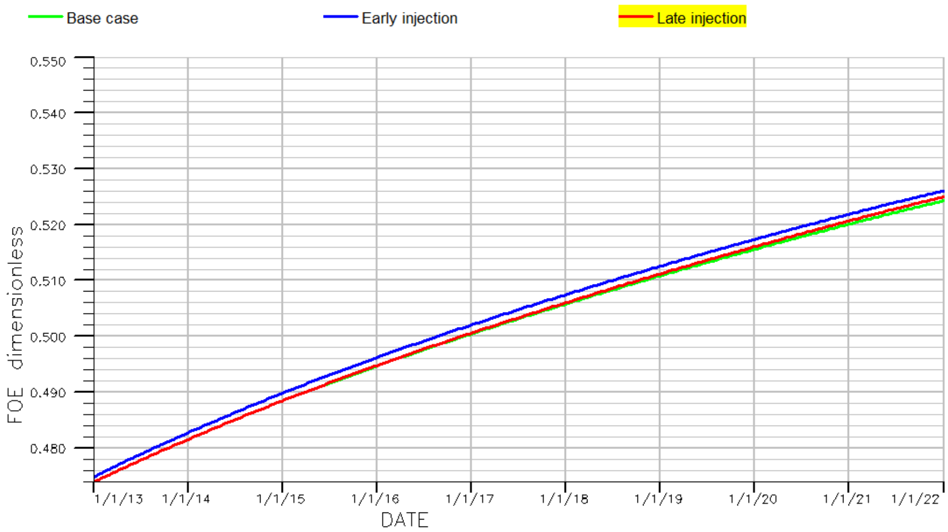


Figure 4.15: Oil recovery factor for early and late injection

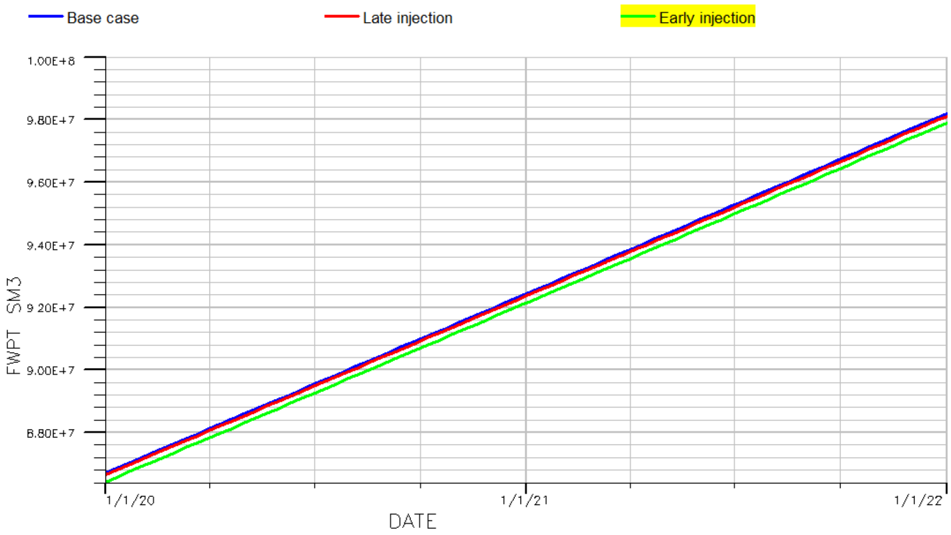


Figure 4.16: Cumulative water production early and late injection

Chapter 5

Well Location Optimization

In the process of reservoir development, the idea is always to drill wells at optimal locations so that more hydrocarbons can be extracted at a lower cost. One of the ultimate purpose for field development is the efficient extraction of hydrocarbons from the reservoir. Therefore, a careful consideration has to be given to the impact of well placement strategy on field recovery efficiency. Optimization procedure does not only provide much better locations to consider within the overall initial field development planning scheme but also is suited for enhancing planning for producing fields for which field extensions are being investigated [8]. Norne field life is thought of being extended, hence optimization of well location is immensely required.

In order to optimize production, wells have to produce longer and better than ever before and dollars in must yield barrels out. A lot of researches have been carried out on the methodologies that can be used in optimizing well location for both initial field development and producing field. Yeten et al., [36] used genetic algorithm in determining optimal type, location and trajectory of nonconventional wells. Xianghong et al., [35] used statistical properties of geology and development data, numerical simulation and fuzzy mathematics to develop an optimization model for determining horizontal well location. Liu and Jalali, [21] converted standard reservoir models to maps of production potential when screening favourable regions for well placement. Their well placement strategy was purely governed by reservoir drainage objectives. Cullick et al., [8] determined optimal subsurface location for injectors and producers by identifying a set of target and well plan locations based on the static reservoir model and then used these locations as initial guess in well placement. Wells were planned using automated well planner followed by optimization using dynamic flow simulation to achieve higher recovery or economic benefits. More recent, the use of genetic algorithm or hybrid genetic algorithm coupled with flow simulations is common in optimizing and configuring well plans.

However, this study involved optimizing well location manually based on both time-invariant reservoir properties such as permeability which is non-uniform and time-varying properties such as oil saturation. Optimization function during the well placement strategy was NPV.

5.1 Review of the Base Case Wells

By the end of 2006, Norne C segment has 3 injectors: C-1H, C-2H and C-3H; and 5 producers: B-2H, D-2H, B-1H, D-1CH and B-4DH still active. 1 injector: C-4H and 4 producers: D-1H, D-4H, B-4H and K-3H were already shut off due to different reasons, one being less productive. However, before starting simulation the 4 producers and 1 injector were reopened to analyse possibility for making them productive because reopening an existing well is less cost than drilling a new well. The optimization procedure paid high attention to the less productive wells aiming at optimizing their location to make them productive.

Both gas and water injection have been injected into the reservoir. However, gas injection stopped in 2005 and was resumed in 2006 to avoid pressure depletion in the gas cap. Based on the model, the injectors are located at the borders of the reservoir while producers are located at the centre of the reservoir, bordered by injectors for ensuring late water and gas breakthrough. Furthermore, the producers are located at some distance from major faults to avoid gas inflow. All injectors can convert between gas and water. Injector C-4H started in November 1997 and was shut in 2003 due to its contribution to high GOR and WC to the nearby producers (B-4H and D-4H). The well was then plugged and sidetracked to well C-4AH to provide pressure support.

Figures 5.1 and 5.2 compares cumulative oil production and water cut for C-segment wells. Wells B-2H and D-2H are good producers for oil with substantial quantities of water cut as well. B-4DH has the highest water cut than all other wells with low oil production. D-1CH has the lowest water cut compared to other wells and its oil production is getting improved with time, implying that it is a good well and should be handled with care. Production for wells D-1CH, B-4DH, K-3H and B-1H is improving with time while for wells D-1H, D-4H and B-4H there is no any improvement in production even after re-opening these wells. Based on these plots, optimization of well location was based on relocation of wells D-1H, D-4H and B-4H to improve productivity of these wells and reducing water production.

Well B-4H started production in 1998 and was shut in 2001. The well perforates vertically through Garn, Ile, Ror, Tofte and Tilje Formations. The model shows that this well is close to three sealing faults (Figure 5.3) and penetrates through one of the faults but it is less productive as shown by Figure 5.1. An attempt was made for perforating the well without penetrating any of the faults to check if the faults have effects on well production. The model also shows there is a possibility of sidetracking this well to southern and northern parts to increase oil production.

Well D-1H started in November 1997 and its production marked the start of life of the field. The well was shut in September 2002 and the plan was to side-track it. However, during the pilot drilling, the drillstring got stuck and the well needed to be redrilled to run the logs. But due to high cost and risk, the well was not redrilled, instead plans for drilling a new well commenced. In this study, the well was sidetracked to check if its production can be improved.

Well D-4H started in June 1998 and was shut in 16th November 2002 because of water breakthrough. This well was also side tracked as an attempt to improve its productivity and reduce water production.

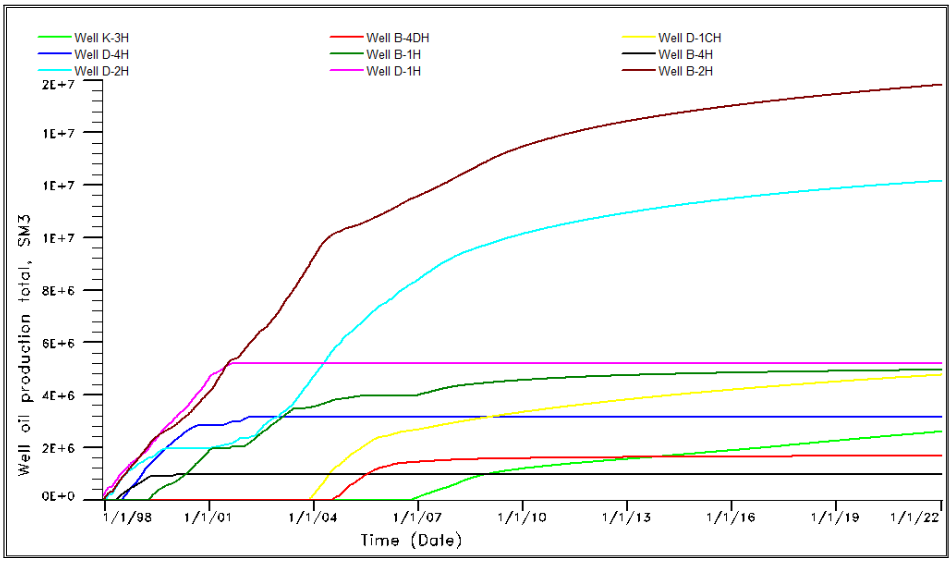


Figure 5.1: Comparison for cumulative oil production for all C segment producers

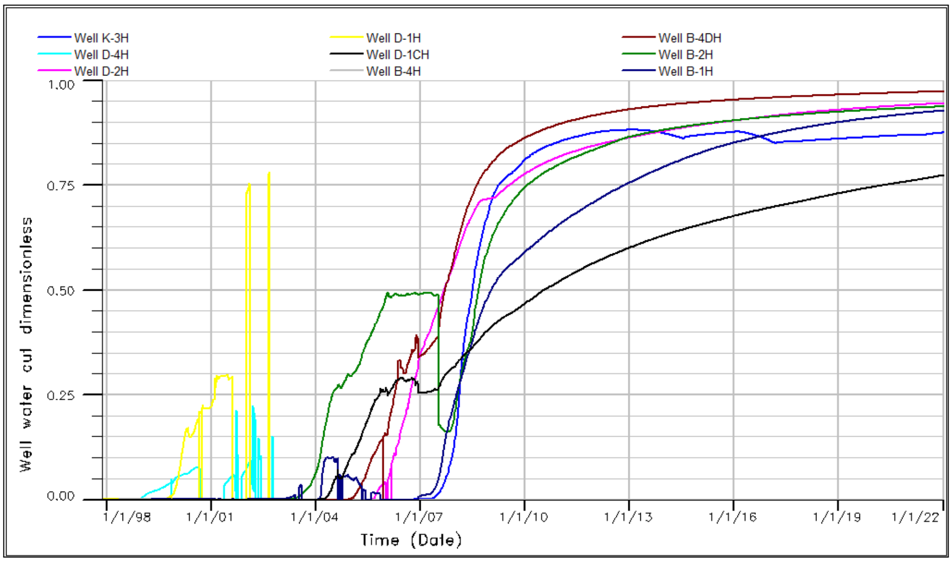


Figure 5.2: Comparison for water cut for all C segment producers

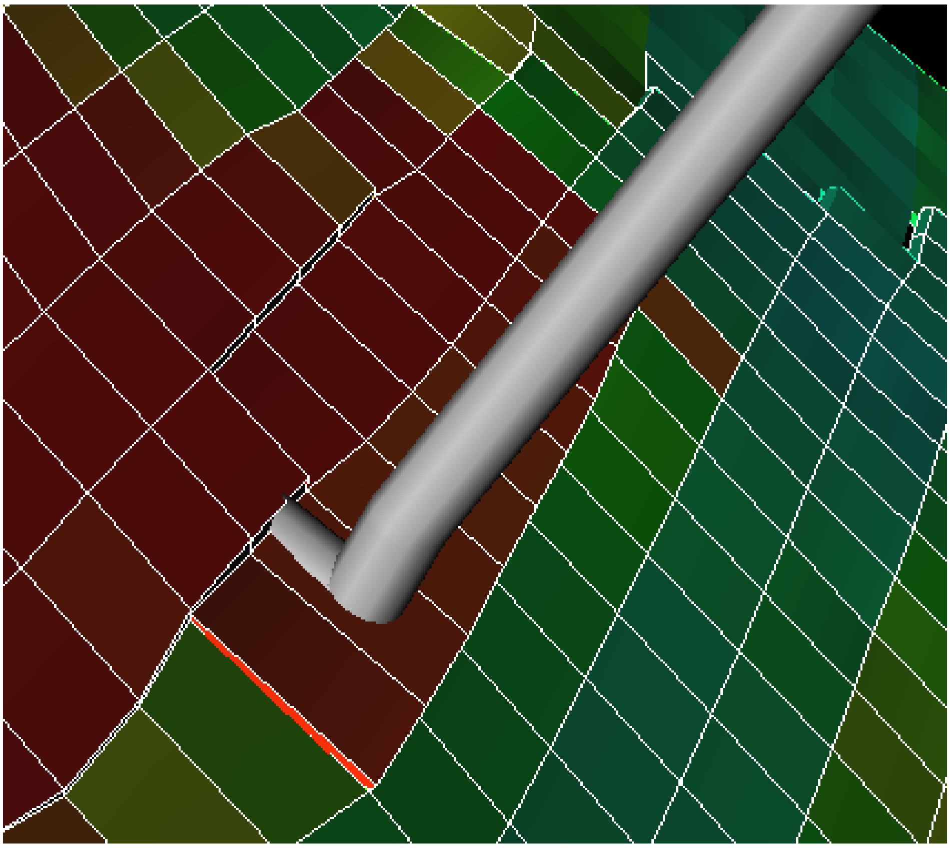


Figure 5.3: Location of well B-4H in the model

5.2 Optimization Procedures

Trial and error method was used for relocation of wells. Optimization process involved determining new wells locations using basic rock properties such as permeability, porosity, oil saturation and faults.

Oil saturation is the percent of total pore volume occupied by oil. This parameter was used in identifying target regions for wells. The intention was to perforate wells in high oil saturation zone to increase oil swept quantities. Since Ile and Tofte contain about 80% of oil, completions were targeted in these two formations.

Fault can be a conduit of, or a barrier to, fluid flow and pressure communication. Understanding fault properties is crucial for accurate well placements and optimal production strategies. Fault zone properties are incorporated in reservoir flow simulators using transmissibility multipliers as function of properties of the fault zone and of the grid block to which they are assigned. The rock properties and stresses that develop within fault zones affect a fault's ability to seal. During optimization procedure, effect of fault in well productivity was analysed. The aim was to check how well productivity is affected by nearby faults by changing well perforations and well configuration. A fault can be sealing in one layer and not sealing in a subsequent layer. If the well is perforating in these two layers in the same grid cells, its productivity must be affected by the sealing fault even if the oil saturation could be high. This is because sealing fault removes communication between grid cells hence imposing fluid flow restriction in the reservoir. Thus well configuration and perforations were both altered to check if production can be raised.

Fluid flow in a reservoir is controlled by how much the rock is open space and how ease the fluid can move through the porous rock. Volume of the pores as well as pore sizes and their connectivity determines rock porosity and permeability. Optimization process was also influenced by porosity and permeability in sense that regions with high porosity and permeability were favoured for wells perforation.

During optmization, all parameters in the keyword COMPDAT were defaulted except the wellbore diameter. This was done both in the base case schedule file and optimization schedule file.

An attempt to sidetrack well D-1H was not successful as the base case was performing more better than optimization case. Initial this well was perforated vertically. During optimization, the well was sidetracked horizontal in a zone of reasonable oil saturation but gave poor results. This is contributed by poor porosity in the well location zone.

Well D-4H which was perforated vertically in the base case, was sidetracked horizontally with a target to high oil saturation zones. Unfortunately it was underperforming too compared to the base case.

Well B-4H was also sidetracked horizontally in different layers. In the base case, this well was perforated vertically and penetrated one of the faults (5.4). In the optimization process, the well was sidetracked horizontally without passing through any of the faults with a target to the high oil saturation zones (5.5). Sidetracking it was success as shown by Figures 5.6 and 5.7. An improved oil production and recovery factor are observed, though the difference is small. Field water cut and gas oil ratio in Figures 5.8 and 5.9 are also reduced in the optimization case compared to the base case. This is because in the base case, this well perforated some parts of water zone. Water production is almost the same for both base case and optimization case as shown by Figure 5.10, meaning that there is no excess costs required for water handling. The same facilities which are used now for water handling can be used even after optimization.

Analysis shows that all horizontal wells in the base case were performing better than vertical wells. The trend is the same even in the optimization process. A horizontal well is drilled parallel to the reservoir bedding plane, while vertical well is drilled perpendicular to the reservoir bedding plane.The good performance of horizontal well is contributed by a good contact area between a well and reservoir compared to a vertical well. This agrees with the study done by [17], which concluded on the use of horizontal wells as proven technology because they offer higher rates compared to vertical wells and provide greater area of communication with the producing formation and good drainage efficiency. Multilateral wells have two or more production holes from a single surface location (Figures **??** and **??** in appendices). Rig capacity determines length of the well [18]; therefore if the rig size is limited, multilateral wells can be a good option to provide a large contact area compared to vertical wells.

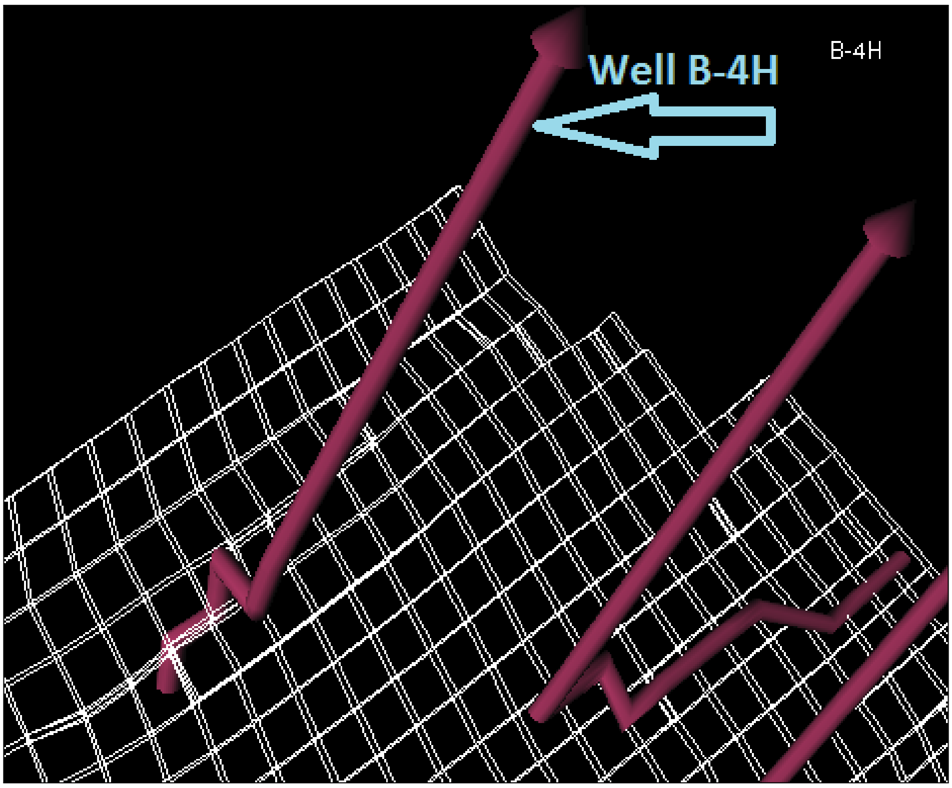


Figure 5.4: Configuration of well B-4H before optimization (in the base case)

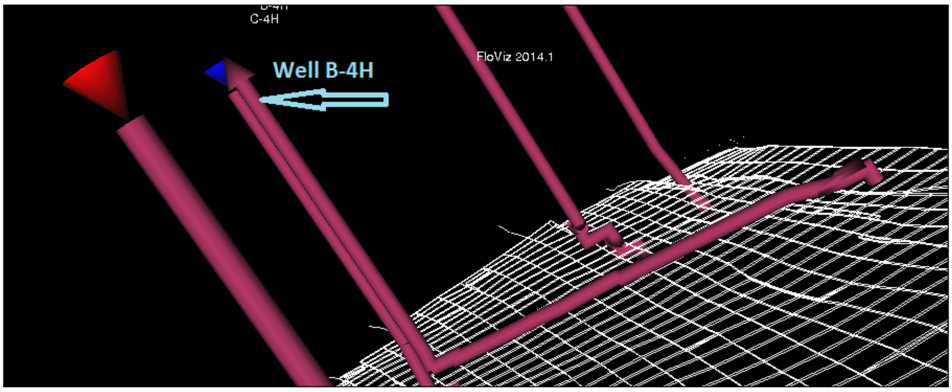


Figure 5.5: Configuration of well B-4H after optimization

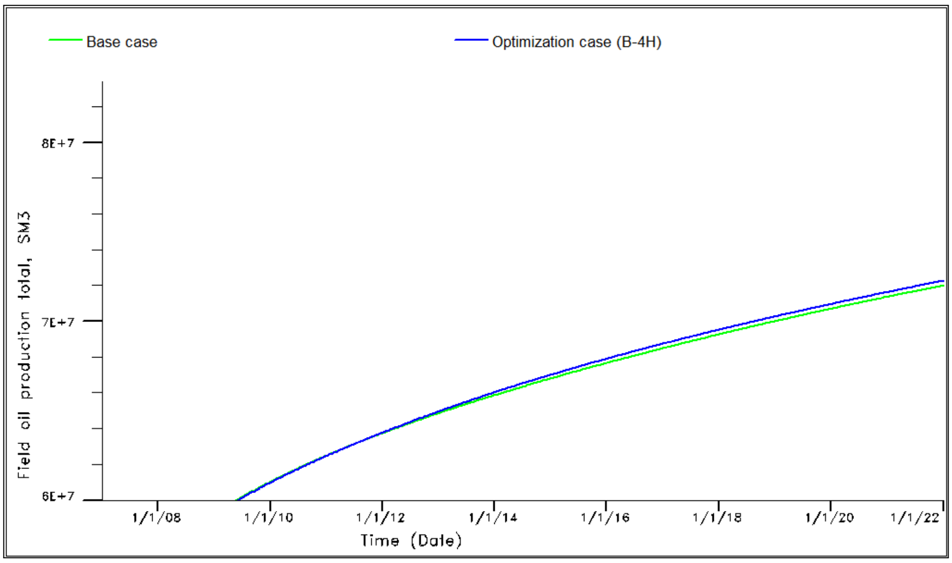


Figure 5.6: Cumulative oil production comparison for base case and optimization case

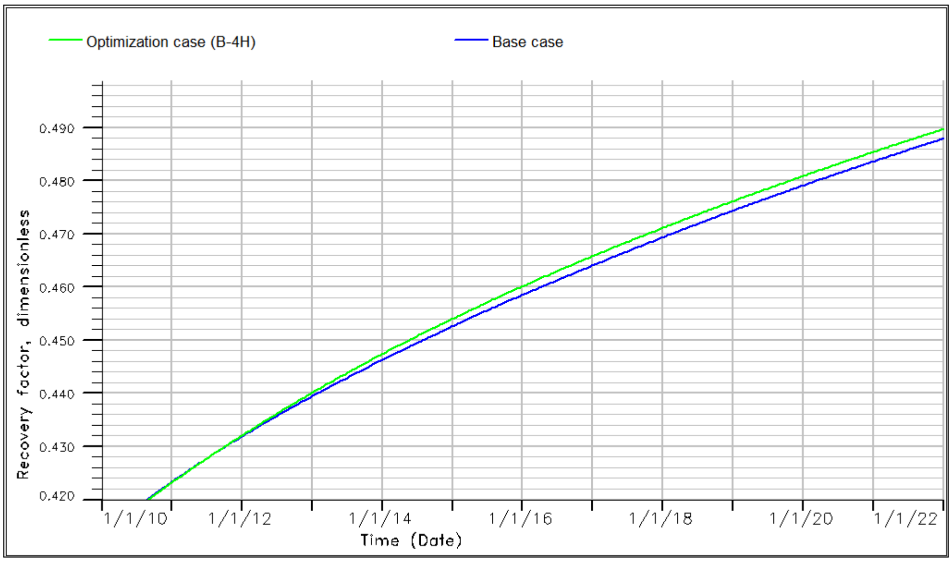


Figure 5.7: Field oil recovery factor for the base case and optimization case

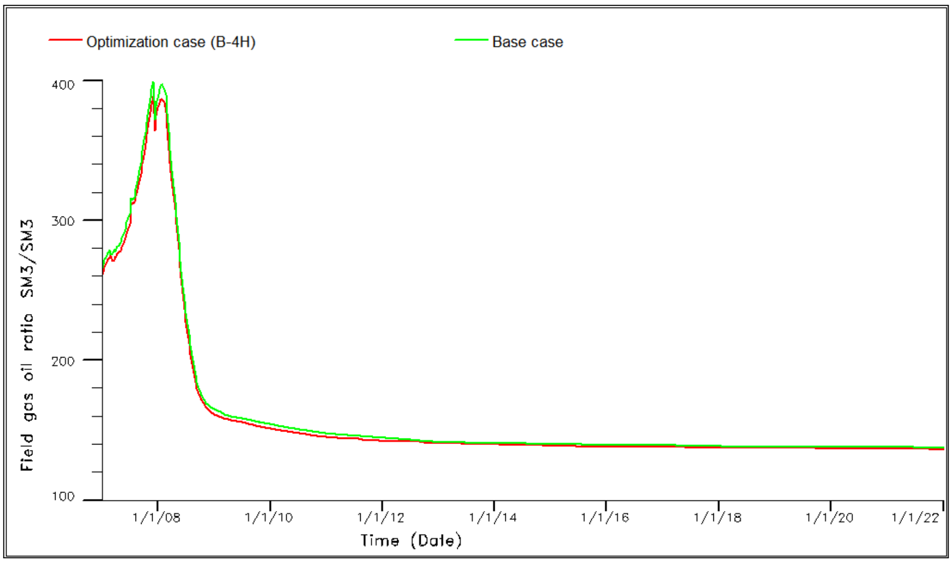


Figure 5.8: Field gas oil ratio for the base case and optimization case

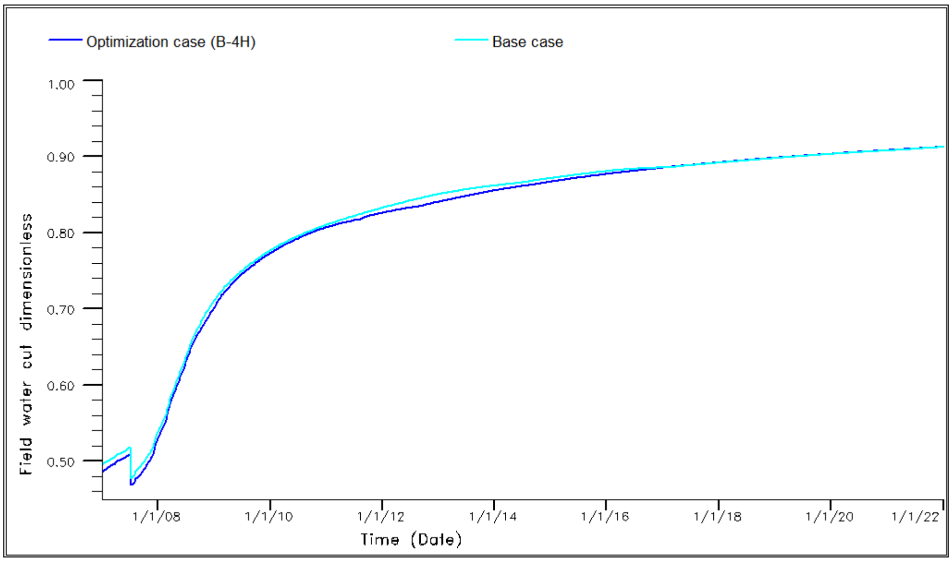


Figure 5.9: Field water cut for the base case and optimization case

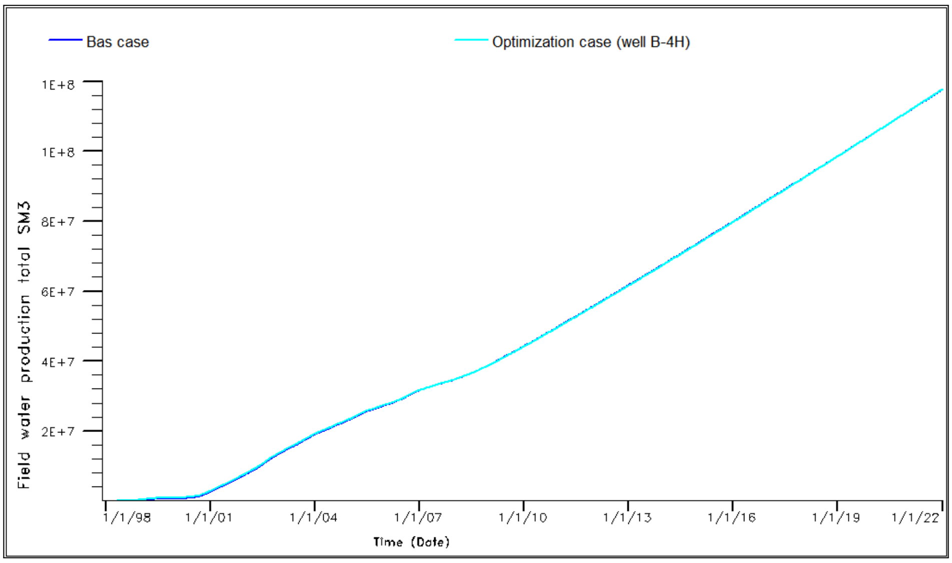


Figure 5.10: Field water production total for the base case and optimization case

Chapter 6

Economic Analysis

The objective of this study was to identify the most promising IOR method(s) among the three to be applied to the Norne field C segment and that will make the project profitable. This was carried out by performing economic evaluation of each IOR methods individually and when combined. However, LSWI was not included in the economic evaluation because i was not able to get water treatment cost. The following scenarios were analysed from year 2007 to year 2022 and then compared with the base case.

i. Scenario 1: Polymer flooding

ii. Scenario 2: Well location optimization

iii. Scenario 3: Polymer flooding and well location optimization

Viability of the options above was determined using incremental NPV. NPV is the difference between present value of cash inflows and present value of cash outflow for a particular of a project. NPV is used in capital budgeting to analyse viability of a new project and is a useful tool to determine whether a project will result in a net profit or loss. Cash inflow include benefits while cash outflows are initial investment cost of a project. Each cash inflow/outflow is discounted back to its present value and then NPV is obtained by summing up all terms as shown in

Equation 6.1. Because time value of a money decreases with time, discount rate in NPV formula accounts for this. A positive NPV signifies that the project is profitable while a negative NPV signifies that project in not profitable and should be rejected. Zero NPV implies there will be neither loose nor gain by pursuing the project and the decision to accept the project should be made with other criteria. Thus for a project to be accepted, it must have positive NPV.

Economic evaluation of the aforementioned options was evaluated using NPV and then comparing their NPV with the base case. NPV calculations was carried out in excel spreadsheet for from year 2007 to 2022 (15 years) and is attached to this report.

$$NPV = \sum_{t=0}^{T} \frac{C_t}{(1+r)^t} - C_0 \tag{6.1}$$

Where

T - Total number of periods, t - Time of the cash flow

C_t - Net cash inflow during the period

C_0 - Initial investment cost

r - Discount rate

Assumptions Made

Sensitivity analysis of oil price was performed to analyse how oil price fluctuation will affect the project. Parameters used in the economic evaluation are the one used in the exercise on *optimal production strategy for the remaining recoverable resources for the future period in Norne field E segment*, [37]. Based on this exercise, the following assumptions were made:

1. Polymer costs 4.4 USD/Kg

2. Discount rate is 10% [37]

3. New side tracked well costs 65 Million USD, [37]

4. Only chemical costs and well sidetracking cost are major expenses.

Two oil prices were included in the analysis: 75 USD/bbl and 100 USD/bbl. 75 USD/bbl oil price is in accordance with the exercise while the 100 USD/bbl was simply assumed to analyse how will the project affected by increasing oil price. Other factors such as discount rate and inflation rate have not been included in sensitivity analysis due to time limitation. In the analysis, only capital expenditure such as chemical cost and well sidetracking cost have been considered as expenditure costs. Other CAPEX costs as well as OPEX have not been included. Table 7 in appendices shows parameters used in the economic evaluation.

Economic analysis results

Based on the assumptions stated above, economic evaluation was carried out to find out the incremental NPV for each scenario. Figures 6.1 and 6.2 displays plots for incremental NPV at oil prices of 75 USD/bbl and 100 USD/bbl respectively. Optimization of well location has high incremental NPV than polymer flooding at concentration of 0.2 kg/m^3 at both oil prices. Combination of Polymer flooding and well location optimization gave the highest incremental NPV than all other scenarios. However, increase NPV is increasing with the increase in oil price.

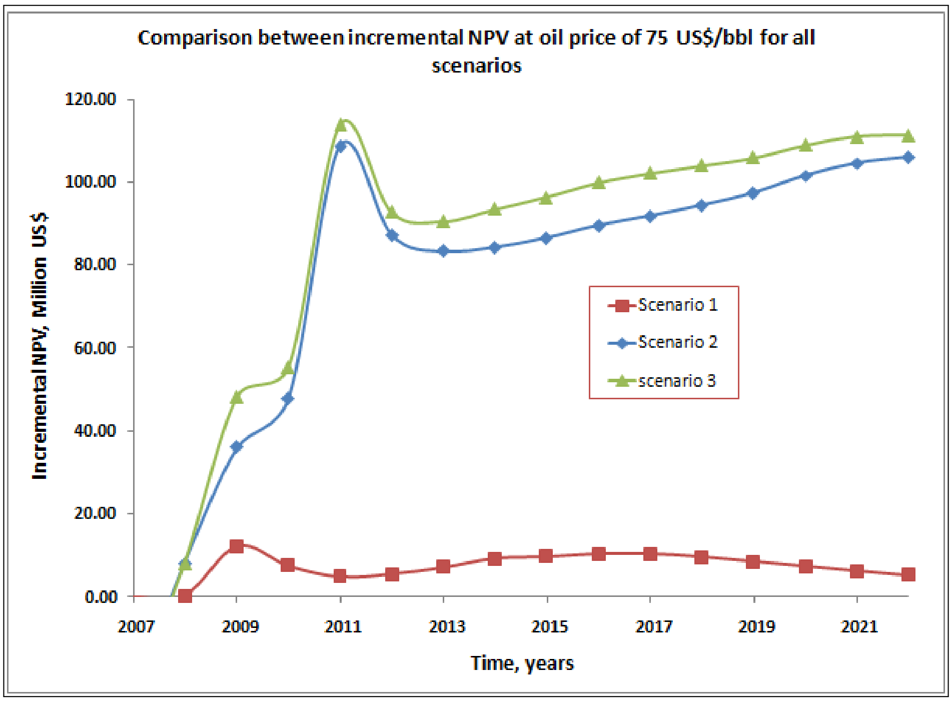


Figure 6.1: Comparison between incremental NPV at oil price of 75 USD/bbl for all scenarios

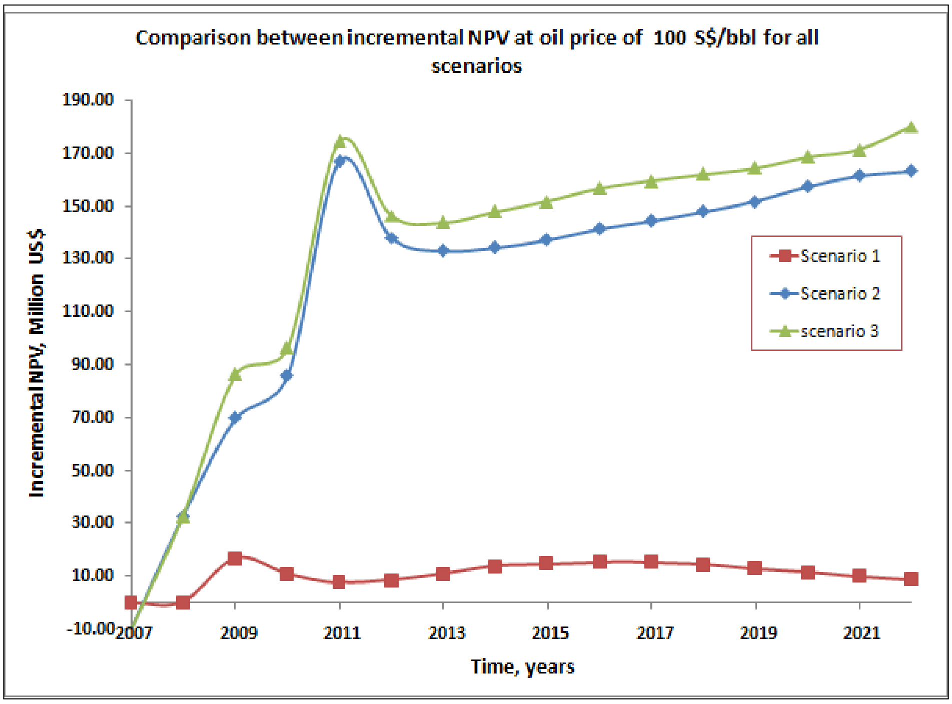


Figure 6.2: Comparison between incremental NPV at oil price of 100 USD/bbl for all scenarios

Chapter 7

Discussion

This thesis is the continuation of my semester project, phase I, in which detailed literature review of the three IOR methods namely, polymer flooding, low saline water flooding and well location optimization was done followed by checking their compatibility with Norne field C segment. It was concluded that all the IOR methods under the study will yield a reasonable increase in recovery factors and this paved the way to thesis, which is phase II of the study. Main objective of this thesis was to carry out comparative simulation study for the three IOR methods and comparing their performance in terms of net present value.

Sensitivity analysis on injector selection, timing and concentration were carried out with polymer flooding. C-3H found to perform better compared to other single injectors and combined injectors. It was also found that the higher the polymer concentration, the higher the oil production. This results from an increase in water phase viscosity, making water to flow slowly and spending longer time in the reservoir. As a result, sweeping efficiency is improved and water breakthrough is delayed. However, the difference in oil production with the use of low polymer concentration and high concentration was small while, the difference in polymer consumption was huge. This means that at the current low oil price, low polymer concentrations are right choice because they consume little polymer. But if the oil price is favourable, high polymer concentrations can be injected. Sensitivity analysis on time showed that early injection of polymer had a better performance than late injection. Comparison between continuous injection and cyclic injection favoured continuous injection. But due to huge polymer consumption in continuous injection and at the current low oil price, cyclic injection at 3 months interval found to be a right manner for polymer injection.

In low saline water flooding, well C-3H was used for injection. It was found that the lower the salt composition in the injected water, the higher the improvements in oil production. Comparison between continuous injection and slug injection of low saline water showed that there is significant improvements in oil production when continuous injection of low saline water is used. In addition, implementing low saline water flooding in the early life of the field gives significant improvement in oil production than late implementation. The observed improvements in oil production are due to alteration of the wetting state of the rock. The rock in study is a mixed wet, the observed improvements implies a change in wettability from mixed wet to water wet state. The wettability alteration is due expansion of the double layer caused by low saline water leading to easier dispersion of clay-oil bond. Clay particle in water consist of double layer of positive ions (divalent ions such as Calcium or Magnesium which joins the oil-clay bond) and negative ions. Injection of high saline water makes the layer more compact while injection of low saline water causes expansion of the layer. When the layer expands, monovalent ions such as sodium that comes with low saline water penetrates the layer, displaces the divalent ions which bind the oil-clay bond. Weakening of the bond between an oil particle and clay release oil hence high oil production with low saline water. In addition, the observed delayed water production with low saline water is due to replacement of mobile oil by low saline injected water.

For the case of optimizing well location, it was found that horizontal wells in this field are performing better than vertical wells. Analysis also shows that sidetracking the wells horizontally in the regions of high oil saturation gives high oil production than sidetracking it vertically. The good performance of horizontal wells is due to the fact that they offer good communication to the reservoir leading to easy sweeping of oil.

Economic evaluation in terms of incremental NPV was done for polymer flooding, well location optimization and for combination of polymer flooding and well location optimization. Low saline water flooding was not included in economic analysis due to uncertainness in the water treatment cost, though it showed considerable improvements in the oil production. Results show that none of scenario had negative incremental NPV, implying that all the IOR methods are profitable and if implemented will give income rise to the owners of the field. Optimization of well location has higher incremental NPV than polymer flooding. Combining well location and polymer flooding gave the highest incremental NPV than all other scenarios.

Generally, objectives of the study were accomplished.

Chapter 8

Conclusion

Based on this study, the following can be concluded for the Norne field C segment relating to the IOR methods under the study.

C-3H is the best injector to use with polymer flooding in Norne C-segment. Low polymer concentration gives significant improvements in oil production with less polymer consumption compared to higher concentration values. Early injection of polymer gives high oil production than late injection. Cyclic injection of polymer at 3 months cycle interval performs better than continuous injection.

With low saline water injection, the lower the salt composition in the injected water, the higher the improvements in oil production. Continuous injection of low saline water performs better than low salinity slug injection. Early injection of low saline water favours oil production than late injection.

In optimizing well location, horizontal wells are performing better than vertical wells. Sidetracking the wells horizontally in the regions of high oil saturation gives high oil production than sidetracking it vertically.

For the economic analysis, all the IOR methods are profitable because they give positive NPV. However, Polymer flooding at a concentration of 0.2 kg/m^3 gave the lowest incremental NPV while combination of polymer flooding and well location optimization had the highest incremental NPV at all oil prices tested.

Chapter 9

Recommendations

Further studies for low saline water flooding is recommended with the use of real data for saturation and relative permeability end points. The data used here were extracted from [19] and in accordance with literature, low saline water flooding is highly affected by relative permeability. Also, to gain high profits, it is recommended to apply these IOR methods when the oil price is favourable.

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Appendices

A Norne field

Table 1: Rock and fluid properties for Norne field

Parameter name	Symbol	Value	SI unit
Porosity	ϕ	25-30	%
Permeability	k	20-2500	mD
Initial reservoir pressure	p_{res}	273	bar @2639TVD
Initial reservoir temperature	T_{res}	98	°C
Bubble point pressure	p_b	250	bara
Oil specific gravity	oil SG	0.7	
API gravity		32.7	^{o}
Oil viscosity	μ	0.5	CP
Oil density at bubble point	ρ_o	0.712	g/cm^3
Initial oil formation volume factor	B_{oi}	1.32	Rm^3/Sm^3
Initial as formation volume factor	B_{gi}	0.0047	Rm^3/Sm^3
Gas oil ratio	GOR	111	Sm^3/Sm^3

Table 2: Wells on C-segment[28]

Producers	Year production started	Total production (sm^3)
B-2H	12.1997	1.14E07
D-1H	11.1997	4.97E06
D-2H	12.1997	7.99E06
B-4H	04.1998	1.01E06
D-4H	06.1998	3.08E06
B-1H	04.1999	3.75E06
D-1CH	11.2003	2.50E06
B-4DH	07.2004	1.47E6
K-3H	10.2006	1.96E4
Injectors	**Total gas injected (sm^3)**	**Total water injected (sm^3)**
C-1H	2.19E+09	1.47E+07
C-2H	0	2.17E+07
C-3H	3.51E+09	5.73E+06
C-4H	2.93E+09	5.47E+06

B Polymer flooding

B.1 Input file for Polymer properties

PLYVISC

Polymer concentration (kg/m3)	*water viscosity multiplier*
0.0	1.0
0.1	1.55
0.3	2.55
0.5	5.125
0.7	8.125
1.0	21.20 /
/	

PLYROCK

Dead pore space	*residual res. factor*	*mass density (kg/rm3)*	*adsorption index*	*Maximum polymer adsorption (kg/kg)*
0.166	1.0	2650	2.0	0.000017

PLYADS

local polymer concentration (kg/sm3)	*polymer concentration adsorbed by rock (kg/kg)*
0.0	0.0
0.5	0.000017
1.0	0.000017 /

PLMIXPAR

1.0 /

PLYMAX

Polymer concentration (kg/sm3)	*Salt conc. (kg/sm3)*
1.0	0.0 /

Table 3: Essential keywords in ECLPSE 100 used for Polymer flooding model [32]

RUNSPEC	
POLYMER	Enables the Polymer Flood Model
PROPS	
PLYVISC	Specifies polymer solution viscosity function
PLYROCK	Specifies rock properties required for polymer flood model
PLYADS	Specifies Polymer adsorption function
PLMIXPAR	Polymer Todd-Longstaff mixing parameter for the viscosity calculation
PLYMAX	Maximum polymer and salt concentrations that are to be used in the mixing parameter calculation of the fluid component viscosities.
SCHEDULE	
WPOLYMER	Specifies concentration of polymer and salt in the injection stream of the well

C Low Saline Water Flooding

C.1 Salt properties used for LSWF mode

PVTWSALT

Reference pressure (Pref) barsa	*Reference salt concentration for stock tank water ($C_{S\ ref}$)kg/sm3*
277.0	0.0 /

Salt conc. (Cs) kg/sm3	*FVF (Bw)*	*Water compressibilty. (Cw) 1/bars*	*Water viscosity (μw) cP*	*Water viscosibil. (Cv) 1/bars*
0.0	1.038	4.67e-5	0.318	0.0
0.9	1.038	4.67e-5	0.318	0.0
1.8	1.038	4.67e-5	0.318	0.0
3.0	1.038	4.67e-5	0.318	0.0
4.5	1.038	4.67e-5	0.318	0.0
30.0	1.038	4.67e-5	0.318	0.0 /

LSALTFNC

Salt concentration Kg/sm³	*Weighting factor F_1*	*Weighting factor F_2*
0	1.0	1*
0.9	0.8	1*
1.8	0.6	1*
3.0	0.4	1*
4.5	0.2	1*
30.0	0.0	1*

SATNUM

113344*52 /

LWSLTNUM

113344*107 /

SALTVD

Depth values m	*The corresponding values of salt concentration (Kg/sm³)*
5000	30
5500	30

Table 4: Essential keywords in ECLPSE 100 used for LSWF model [32]

RUNSPEC	
BRINE	Allows modelling of water with different salinities
LOWSALT	Activates low salinity option. It will automatically turn on the BRINE option if this keyword is not already present
PROPS	
PVTWSALT Specifies water PVT functions with salt present. Used in place of PVTW keyword.	**Record 1** ***Item 1:*** Reference pressure for this table (P_{ref}) ***Item 2:*** The reference salt concentration for stock tank water, ($C_{S\ ref}$), kg/sm^3 **Record 2** ***Column 1***: Salt concentration. Values should increase monotonically down the column C_s kg/sm^3. ***Column 2***: The water formation volume factor at the reference pressure as a function of salt concentration, B_w (Pref, Cs), rm^3/sm^3 . ***Column 3***: The water compressibility as a function of salt concentration, c_w 1/bars ***Column 4***: The water viscosity at the reference pressure as a function of salt concentration, μw (P_{ref}, Cs). ***Column 5***: The water "viscosibility" as a function of salt concentration, $Cv(cs)$, 1/bars
LSALTFNC Specifies low salinity fraction as function of salt concentration in the grid block. Inputs weighting factors F1 and F2 for low salinity saturation functions as function of salt concentration	**Column 1:** Salt concentration. The values should increase monotonically down the column, kg/sm3 **Column 2:** Weighting factor F_1 for the low-salinity saturation endpoints and the relative permeabilities Interpolation. The values should decrease monotonically down the column and should not be greater than 1.0 or less than 0.0. **Column 3:** Weighting factor F_2 for the low-salinity capillary pressure interpolation. The values should decrease monotonically down the column and should not be greater than 1.0 or less than 0.0. This item may be defaulted and is then taken as the value in the second column.
REGIONS	
SATNUM	Specify high salinity table number for each block
LWSLTNUM	Specify low salinity table number for each grid block
SOLUTION	
SALTVD Specify salt concentration vs depth for equilibration	**Column 1:** Depth values, m. The values should increase monotonically down the column. **Column 2:** The corresponding values of salt concentration, kg/sm3
SCHEDULE	
WSALT Set salt concentration in the injection stream of each well	**Record 1:** Well name **Record 2:** The concentration of salt in the injection stream for the well.

Table 5: Data points for high and low salinity curves

Data points for low salinity Curve				Data points for high salinity Curve			
SWAT	**KRW**	**KROW**	**PCOW**	**SWAT**	**KRW**	**KROW**	**PCOW**
0.2	0	0.6	0	0.2	0	0.6	0
0.4	0	0.269	0	0.24	0	0.4	0
0.4179	0.001	0.2407	0	0.2679	0	0.2661	0
0.4357	0.0041	0.2134	0	0.2857	0.0001	0.2268	0
0.4536	0.0092	0.1873	0	0.3036	0.0003	0.1905	0
0.4714	0.0163	0.1624	0	0.3214	0.001	0.1575	0
0.4893	0.0255	0.1386	0	0.3393	0.0024	0.1276	0
0.5071	0.0367	0.1162	0	0.3571	0.0051	0.1008	0
0.525	0.05	0.1	0	0.375	0.0094	0.0772	0
0.5429	0.0653	0.085	0	0.3929	0.016	0.0567	0
0.5607	0.0827	0.07	0	0.4107	0.0256	0.0394	0
0.5786	0.102	0.06	0	0.4286	0.039	0.0252	0
0.5964	0.1235	0.05	0	0.4464	0.0572	0.0142	0
0.6143	0.1469	0.04	0	0.4643	0.081	0.0063	0
0.6321	0.1724	0.034	0	0.4821	0.1115	0.0016	0
0.7	0.27	0.015	0	0.5	0.15	0	0
0.75	0.4	0.005	0	1	1	0	0
0.8	0.8	0	0				
1	1	0	0				

D Well Location Optimization

Table 6: Well B-4H completion for the base case and optimization case

Base case				Optimization			
I	**J**	**K1**	**K2**	**I**	**J**	**K1**	**K2**
10	32	1	1	11	32	5	5
10	32	2	2	12	32	5	5
10	32	3	3	12	32	6	6
10	32	4	4	13	32	6	6
10	32	5	5	14	32	6	6
10	32	6	6	15	32	6	6
10	32	7	7	16	32	7	7
10	32	8	8	17	32	7	7
10	32	9	9	18	32	7	7
10	32	10	10	18	32	8	8
9	32	13	13	19	32	8	8
9	32	14	14	25	32	11	11
9	32	15	15	26	32	11	11
9	32	16	16	26	32	12	12
9	32	17	17	27	32	12	12
9	32	18	18	27	32	13	13
9	32	19	19	28	32	13	13
9	32	20	20	28	32	14	14
9	31	20	20	28	32	15	15
9	31	21	21	28	32	16	16
9	31	22	22	28	32	17	17
				28	32	18	18

E Economic Analysis

Table 7: Parameters used in NPV calculations

Parameter	Value used
Oil price	50.36 USD/bbl and 75 USD/bbl
Discount rate	10%
Cost of new sidetracked well	65 Million USD
Polymer cost	5.5 USD/Kg

Table 8: Scenario 1: Calculation for incremental NPV for polymer flooding (0.2 Kg/m3 Concentration) at oil price of 75 USD/bbl

Timeline		Annual incremental oil production		Annual Revenues	CAPEX			NPV calculations			
Calendar year	Project Year				Polymer consumption	Polymer cost	Total CAPEX	Annual net cash recovery	Discount factor	Discounted NPV	Cumulative NPV
		Sm3	bbl	Million US$	Kg	Million US$	Million US$	Million US$	Million US$	Million US$	Million US$
01-Jan-07	0	-2.80E+02	-1.76E+03	-0.13	0	0	0.00	-0.13	1.000	-0.13	-0.13
01-Jan-08	1	5.56E+02	3.50E+03	0.26	0	0	0.00	0.26	0.909	0.24	0.11
01-Jan-09	2	3.33E+04	2.09E+05	15.69	2.35E+05	1.03	1.03	14.66	0.826	12.11	12.22
01-Jan-10	3	-1.07E+04	-6.74E+04	-5.06	2.63E+05	1.16	1.16	-6.21	0.751	-4.67	7.55
01-Jan-11	4	-5.52E+03	-3.47E+04	-2.61	2.72E+05	1.20	1.20	-3.80	0.683	-2.60	4.96
01-Jan-12	5	3.95E+03	2.49E+04	1.86	2.61E+05	1.15	1.15	0.72	0.621	0.44	5.40
01-Jan-13	6	8.57E+03	5.39E+04	4.04	2.53E+05	1.11	1.11	2.93	0.564	1.65	7.05
01-Jan-14	7	1.14E+04	7.15E+04	5.36	2.50E+05	1.10	1.10	4.26	0.513	2.19	9.24
01-Jan-15	8	2.20E+03	1.38E+04	1.04	0	0.00	0.00	1.04	0.467	0.48	9.73
01-Jan-16	9	2.98E+03	1.88E+04	1.41	0	0.00	0.00	1.41	0.424	0.60	10.32
01-Jan-17	10	-2.08E+02	-1.31E+03	-0.10	0	0.00	0.00	-0.10	0.386	-0.04	10.28
01-Jan-18	11	-4.42E+03	-2.78E+04	-2.09	0	0.00	0.00	-2.09	0.350	-0.73	9.55
01-Jan-19	12	-7.21E+03	-4.53E+04	-3.40	0	0.00	0.00	-3.40	0.319	-1.08	8.47
01-Jan-20	13	-8.34E+03	-5.25E+04	-3.94	0	0.00	0.00	-3.94	0.290	-1.14	7.33
01-Jan-21	14	-8.67E+03	-5.45E+04	-4.09	0	0.00	0.00	-4.09	0.263	-1.08	6.25
01-Jan-22	15	-8.52E+03	-5.36E+04	-4.02	0	0.00	0.00	-4.02	0.239	-0.96	5.29

Table 9: Scenario 2: Calculation for incremental NPV for Well location optimization at oil price of 75 USD/bbl

Timeline		Annual incremental oil production		Annual Revenues	CAPEX			NPV calculations			
Calendar year	Project Year				well sidetracking cost	number of wells sidetracked	Total well sidetracking cost	Annual net cash recovery	Discount factor	Discounted NPV	Cumulative NPV
	t								DF	NPV	CNPV
		Sm3	bbl	Million US$	Million US$		Million US$	Million US$	Million US$	Million US$	Million US$
01-Jan-07	0	8.66E+04	5.45E+05	4.09E+01	65.00	1	65	-24.14	1.000	-24.14	-24.14
01-Jan-08	1	7.49E+04	4.71E+05	3.53E+01				35.34	0.909	32.12	7.99
01-Jan-09	2	7.18E+04	4.52E+05	3.39E+01				33.87	0.826	27.99	35.98
01-Jan-10	3	3.36E+04	2.11E+05	1.58E+01				15.85	0.751	11.90	47.88
01-Jan-11	4	1.89E+05	1.19E+06	8.91E+01				89.13	0.683	60.87	108.76
01-Jan-12	5	-7.34E+04	-4.61E+05	-3.46E+01				-34.61	0.621	-21.49	87.27
01-Jan-13	6	-1.46E+04	-9.17E+04	-6.88E+00				-6.88	0.564	-3.88	83.39
01-Jan-14	7	3.42E+03	2.15E+04	1.62E+00				1.62	0.513	0.83	84.22
01-Jan-15	8	1.06E+04	6.69E+04	5.02E+00				5.02	0.467	2.34	86.56
01-Jan-16	9	1.53E+04	9.63E+04	7.22E+00				7.22	0.424	3.06	89.62
01-Jan-17	10	1.19E+04	7.48E+04	5.61E+00				5.61	0.386	2.16	91.78
01-Jan-18	11	1.62E+04	1.02E+05	7.64E+00				7.64	0.350	2.68	94.46
01-Jan-19	12	1.92E+04	1.21E+05	9.07E+00				9.07	0.319	2.89	97.35
01-Jan-20	13	3.14E+04	1.97E+05	1.48E+01				14.81	0.290	4.29	101.64
01-Jan-21	14	2.43E+04	1.53E+05	1.14E+01				11.45	0.263	3.01	104.65
01-Jan-22	15	1.18E+04	7.41E+04	5.56E+00				5.56	0.239	1.33	105.98

Table 10: Scenario 3: Calculation for incremental NPV for combination of Well location optimization and Polymer flooding (0.2 Kg/m3) at oil price of 75 USD/bbl

Timeline		Annual incremental oil production		Annual Revenues	CAPEX				NPV calculations			
Calendar year	Project Year				Well sidetracking cost	Polymer consumption	Polymer cost	Total costs	Annual net cash recovery	Discount factor	Discounted NPV	Cumulative NPV
	t									DF	NPV	CNPV
		Sm3	bbl	Million US$	Million US$	Kg	Million US$		Million US$	Million US$	Million US$	Million US$
01-Jan-07	0	8.63E+04	5.43E+05	40.73	65.00	0	0.00	65.00	-24.27	1.000	-24.27	-24.27
01-Jan-08	1	7.55E+04	4.75E+05	35.60		0	0.00	0.00	35.60	0.909	32.36	8.09
01-Jan-09	2	1.05E+05	6.61E+05	49.56		2.35E+05	1.03	1.03	48.53	0.826	40.10	48.20
01-Jan-10	3	2.29E+04	1.44E+05	10.79		2.63E+05	1.16	1.16	9.63	0.751	7.24	55.44
01-Jan-11	4	1.83E+05	1.15E+06	86.52		2.72E+05	1.20	1.20	85.32	0.683	58.28	113.71
01-Jan-12	5	-6.94E+04	-4.37E+05	-32.74		2.61E+05	1.15	1.15	-33.89	0.621	-21.04	92.67
01-Jan-13	6	-6.01E+03	-3.78E+04	-2.83		2.53E+05	1.11	1.11	-3.95	0.564	-2.23	90.44
01-Jan-14	7	1.48E+04	9.30E+04	6.98		2.50E+05	1.10	1.10	5.88	0.513	3.02	93.46
01-Jan-15	8	1.28E+04	8.08E+04	6.06		0	0.00	0.00	6.06	0.467	2.83	96.28
01-Jan-16	9	1.83E+04	1.15E+05	8.63		0	0.00	0.00	8.63	0.424	3.66	99.94
01-Jan-17	10	1.17E+04	7.35E+04	5.51		0	0.00	0.00	5.51	0.386	2.13	102.07
01-Jan-18	11	1.18E+04	7.40E+04	5.55		0	0.00	0.00	5.55	0.350	1.95	104.01
01-Jan-19	12	1.20E+04	7.56E+04	5.67		0	0.00	0.00	5.67	0.319	1.81	105.82
01-Jan-20	13	2.30E+04	1.45E+05	10.87		0	0.00	0.00	10.87	0.290	3.15	108.97
01-Jan-21	14	1.56E+04	9.81E+04	7.36		0	0.00	0.00	7.36	0.263	1.94	110.91
01-Jan-22	15	3.26E+03	2.05E+04	1.54		0	0.00	0.00	1.54	0.239	0.37	111.28

Table 11: Scenario 1: Calculation for incremental NPV for polymer flooding (0.2 Kg/m3 Concentration) at oil price of 75 USD/bbl

Timeline		Annual incremental oil production		Annual Revenues	CAPEX			NPV calculations			
Calendar year	Project Year				Polymer consumption	Polymer cost	Total CAPEX	Annual net cash recovery	Discount factor	Discounted NPV	Cumulative NPV
		Sm3	bbl	Million US$	Kg	Million US$	Million US$	Million US$	Million US$	Million US$	Million US$
01-Jan-07	0	-2.80E+02	-1.76E+03	-0.18	0	0	0.00	-0.18	1.000	-0.18	-0.18
01-Jan-08	1	5.56E+02	3.50E+03	0.35	0	0	0.00	0.35	0.909	0.32	0.14
01-Jan-09	2	3.33E+04	2.09E+05	20.92	2.35E+05	1.03	1.03	19.89	0.826	16.44	16.58
01-Jan-10	3	-1.07E+04	-6.74E+04	-6.74	2.63E+05	1.16	1.16	-7.90	0.751	-5.93	10.64
01-Jan-11	4	-5.52E+03	-3.47E+04	-3.47	2.72E+05	1.20	1.20	-4.67	0.683	-3.19	7.45
01-Jan-12	5	3.95E+03	2.49E+04	2.49	2.61E+05	1.15	1.15	1.34	0.621	0.83	8.28
01-Jan-13	6	8.57E+03	5.39E+04	5.39	2.53E+05	1.11	1.11	4.28	0.564	2.41	10.70
01-Jan-14	7	1.14E+04	7.15E+04	7.15	2.50E+05	1.10	1.10	6.05	0.513	3.11	13.80
01-Jan-15	8	2.20E+03	1.38E+04	1.38	0	0.00	0.00	1.38	0.467	0.65	14.45
01-Jan-16	9	2.98E+03	1.88E+04	1.88	0	0.00	0.00	1.88	0.424	0.80	15.25
01-Jan-17	10	-2.08E+02	-1.31E+03	-0.13	0	0.00	0.00	-0.13	0.386	-0.05	15.20
01-Jan-18	11	-4.42E+03	-2.78E+04	-2.78	0	0.00	0.00	-2.78	0.350	-0.97	14.22
01-Jan-19	12	-7.21E+03	-4.53E+04	-4.53	0	0.00	0.00	-4.53	0.319	-1.44	12.78
01-Jan-20	13	-8.34E+03	-5.25E+04	-5.25	0	0.00	0.00	-5.25	0.290	-1.52	11.26
01-Jan-21	14	-8.67E+03	-5.45E+04	-5.45	0	0.00	0.00	-5.45	0.263	-1.44	9.82
01-Jan-22	15	-8.52E+03	-5.36E+04	-5.36	0	0.00	0.00	-5.36	0.239	-1.28	8.54

Table 12: Scenario 2: Calculation for incremental NPV for Well location optimization at oil price of 100 USD/bbl

Timeline		Annual incremental oil production		Annual Revenues	CAPEX			NPV calculations			
Calendar year	Project Year				Well sidetracking cost	Number of wells sidetracked	Total well sidetracking cost	Annual net cash recovery	Discount factor	Discounted NPV	Cumulative NPV
	t								DF	NPV	CNPV
		Sm3	bbl	Million US$	Million US$		Million US$	Million US$	Million US$	Million US$	Million US$
01-Jan-07	0	8.66E+04	5.45E+05	5.45E+01	65.00	1	65	-10.51	1.000	-10.51	-10.51
01-Jan-08	1	7.49E+04	4.71E+05	4.71E+01				47.11	0.909	42.83	32.32
01-Jan-09	2	7.18E+04	4.52E+05	4.52E+01				45.16	0.826	37.32	69.64
01-Jan-10	3	3.36E+04	2.11E+05	2.11E+01				21.13	0.751	15.87	85.51
01-Jan-11	4	1.89E+05	1.19E+06	1.19E+02				118.84	0.683	81.17	166.68
01-Jan-12	5	-7.34E+04	-4.61E+05	-4.61E+01				-46.14	0.621	-28.65	138.03
01-Jan-13	6	-1.46E+04	-9.17E+04	-9.17E+00				-9.17	0.564	-5.18	132.85
01-Jan-14	7	3.42E+03	2.15E+04	2.15E+00				2.15	0.513	1.11	133.95
01-Jan-15	8	1.06E+04	6.69E+04	6.69E+00				6.69	0.467	3.12	137.08
01-Jan-16	9	1.53E+04	9.63E+04	9.63E+00				9.63	0.424	4.08	141.16
01-Jan-17	10	1.19E+04	7.48E+04	7.48E+00				7.48	0.386	2.88	144.04
01-Jan-18	11	1.62E+04	1.02E+05	1.02E+01				10.18	0.350	3.57	147.61
01-Jan-19	12	1.92E+04	1.21E+05	1.21E+01				12.09	0.319	3.85	151.47
01-Jan-20	13	3.14E+04	1.97E+05	1.97E+01				19.74	0.290	5.72	157.19
01-Jan-21	14	2.43E+04	1.53E+05	1.53E+01				15.26	0.263	4.02	161.20
01-Jan-22	15	1.18E+04	7.41E+04	7.41E+00				7.41	0.239	1.77	162.98

Table 13: Scenario 3: Calculation for incremental NPV for combination of Well location optimization and Polymer flooding (0.2 Kg/m3) at oil price of 100 USD/bbl

Timeline		Annual incremental oil production		Annual Revenues	CAPEX				NPV calculations			
Calendar year	Project Year				Well sidetracking cost	Polymer consumption	Polymer cost	Total costs	Annual net cash recovery	Discount factor	Discounted NPV	Cumulative NPV
	t									DF	NPV	CNPV
		Sm3	bbl	Million US$	Million US$	Kg	Million US$		Million US$	Million US$	Million US$	Million US$
01-Jan-07	0	8.63E+04	5.43E+05	54.31	65.00	0	0.00	65.00	-10.69	1.000	-10.69	-10.69
01-Jan-08	1	7.55E+04	4.75E+05	47.46		0	0.00	0.00	47.46	0.909	43.15	32.46
01-Jan-09	2	1.05E+05	6.61E+05	66.08		2.35E+05	1.03	1.03	65.05	0.826	53.76	86.22
01-Jan-10	3	2.29E+04	1.44E+05	14.39		2.63E+05	1.16	1.16	13.23	0.751	9.94	96.15
01-Jan-11	4	1.83E+05	1.15E+06	115.36		2.72E+05	1.20	1.20	114.17	0.683	77.98	174.13
01-Jan-12	5	-6.94E+04	-4.37E+05	-43.66		2.61E+05	1.15	1.15	-44.81	0.621	-27.82	146.31
01-Jan-13	6	-6.01E+03	-3.78E+04	-3.78		2.53E+05	1.11	1.11	-4.89	0.564	-2.76	143.55
01-Jan-14	7	1.48E+04	9.30E+04	9.30		2.50E+05	1.10	1.10	8.21	0.513	4.21	147.76
01-Jan-15	8	1.28E+04	8.08E+04	8.08		0	0.00	0.00	8.08	0.467	3.77	151.53
01-Jan-16	9	1.83E+04	1.15E+05	11.50		0	0.00	0.00	11.50	0.424	4.88	156.40
01-Jan-17	10	1.17E+04	7.35E+04	7.35		0	0.00	0.00	7.35	0.386	2.83	159.24
01-Jan-18	11	1.18E+04	7.40E+04	7.40		0	0.00	0.00	7.40	0.350	2.60	161.83
01-Jan-19	12	1.20E+04	7.56E+04	7.56		0	0.00	0.00	7.56	0.319	2.41	164.24
01-Jan-20	13	2.30E+04	1.45E+05	14.49		0	0.00	0.00	14.49	0.290	4.20	168.44
01-Jan-21	14	1.56E+04	9.81E+04	9.81		0	0.00	0.00	9.81	0.263	2.58	171.02
01-Jan-22	15	3.26E+03	2.05E+04	2.05		0	0.00	0.00	2.05	0.239	0.49	171.52

F Input prediction files

F.1 Low saline water flooding

DATES 1 'JAN' 2007 /

/

WCONINJE

'C-1H' 'WATER' 1* 'RATE' 8000 5* /

'C-2H' 'WATER' 1* 'RATE' 8000 5* /

'C-3H' 'WATER' 1* 'RATE' 6000 5* /

'C-4H' 'WATER' 1* 'RATE' 3000 5* /

/

```
WSALT
'C-3H' 0.9/
/
RPTSCHED
0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /
DATES
1 'JAN' 2008 /
/
WSALT
'C-3H' 0.9 /
/
RPTSCHED
0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /
DATES
1 'JAN' 2009 /
/
WSALT
'C-3H' 0.9 /
/
RPTSCHED
0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /
DATES
1 'JAN' 2010 /
/
WSALT
'C-3H' 0.9 /
/
RPTSCHED
0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /
DATES
1 'JAN' 2011 /
```

```
/
WSALT
'C-3H' 0.9 /
/
RPTSCHED
0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /
DATES
1 'JAN' 2012 /
/
WSALT
'C-3H' 0.9 /
/
RPTSCHED
0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /
DATES
1 'JAN' 2013 /
/
WSALT
'C-3H' 0.9 /
/
RPTSCHED
0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /
DATES
1 'JAN' 2014 /
/
WSALT
'C-3H' 0.9 /
/
RPTSCHED
0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /
DATES
```

1 'JAN' 2015 /

/

WSALT

'C-3H' 0.9 /

/

RPTSCHED

0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /

DATES

1 'JAN' 2016 /

/

WSALT

'C-3H' 0.9 /

/

RPTSCHED

0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /

DATES

1 'JAN' 2017 /

/

WSALT

'C-3H' 0.9 /

/

RPTSCHED

0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /

DATES

1 'JAN' 2018 /

/

WSALT

'C-3H' 0.9 /

/

RPTSCHED

0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /

DATES

1 'JAN' 2019 /

/

WSALT

'C-3H' 0.9 /

/

RPTSCHED 0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /

DATES

1 'JAN' 2020 /

/

WSALT

'C-3H' 0.9 /

/

RPTSCHED

0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /

DATES

1 'JAN' 2021 /

/

WSALT

'C-3H' 0.9 /

/

RPTSCHED

0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /

DATES

1 'JAN' 2022 /

/ WSALT

'C-3H' 0.9 /

/

RPTSCHED 0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /

F.2 Polymer flooding

DATES

1 'JAN' 2007 /

/

WCONINJE

'C-1H' 'WATER' 1* 'RATE' 7800 5* /

'C-2H' 'WATER' 1* 'RATE' 7800 5* /

'C-3H' 'WATER' 1* 'RATE' 5800 5* /

'C-4H' 'WATER' 1* 'RATE' 2900 5* /

/

WPOLYMER

'C-3H' 0.2 0.0 /

/

RPTSCHED 0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /

DATES

1 'JAN' 2008 /

/

WPOLYMER

'C-3H' 0.2 0.0 /

/

RPTSCHED

0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /

DATES

1 'JAN' 2009 /

/

WPOLYMER

'C-3H' 0.2 0.0 /

/

RPTSCHED

0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /

1 'JAN' 2010 /

```
/
WPOLYMER
'C-3H' 0.2 0.0 /
/
RPTSCHED
0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /
DATES
1 'JAN' 2011 /
/
WPOLYMER
'C-3H' 0.2 0.0 /
/
RPTSCHED
0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /
DATES
1 'JAN' 2012 /
/
WPOLYMER
'C-3H' 0.2 0.0 /
/
RPTSCHED
0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /
DATES
1 'JAN' 2013 /
/
WPOLYMER
'C-3H' 0.2 0.0 /
/
RPTSCHED
0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /
DATES
```

```
1 'JAN' 2014 /
/
WPOLYMER
'C-3H' 0.2 0.0 /
/
RPTSCHED
0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /
DATES
1 'JAN' 2015 /
/
WPOLYMER
'C-3H' 0.2 0.0 /
/
RPTSCHED
0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /
DATES
1 'JAN' 2016 /
/
WPOLYMER
'C-3H' 0.2 0.0 /
/
RPTSCHED
0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /
DATES
1 'JAN' 2017 /
/
WPOLYMER
'C-3H' 0.2 0.0 /
/
RPTSCHED
0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /
```

```
DATES
1 'JAN' 2018 /
/
WPOLYMER
'C-3H' 0.2 0.0 /
/
RPTSCHED
0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /
DATES
1 'JAN' 2019 /
/
WPOLYMER
'C-3H' 0.2 0.0 /
/
RPTSCHED
0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /
DATES
1 'JAN' 2020 /
/
WPOLYMER
'C-3H' 0.2 0.0 /
/
RPTSCHED
0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /
DATES
1 'JAN' 2021 /
/
WPOLYMER
'C-3H' 0.2 0.0 /
/
RPTSCHED
```

0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /

DATES

1 'JAN' 2022 /

/

RPTSCHED

0 0 0 0 0 0 2 1 2 0 0 0 0 1 1 0 0 0 0 0 1 /