FAKULTET FOR INGENIØRVITENSKAP OG TEKNOLOGI, NTNU

Simulation of the EOR method "In-depth Profile Control" by transmissibility modification in Eclipse

Study case: Abio Gel Pilot in Segment H1, Gullfaks Main Field

EiT Gullfaks Village 2012, Group 1

Runar Eike Toft
Steven Leonardus Paulus
Marina Salamanca
Sveinung Helle
Jun Zhou
Mohammadreza Rasta

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ABSTRACT

The Gullfaks field is one of the largest oil field on the Norwegian Continental shelf. The oil field has been on production since 1986. In 1994 the peak production was reached, and since then the production has rapidly declined. Already in the early years of the field life, much attention was given to how to get a best possible recovery from the field, and water and gas injection was quickly introduced to keep the reservoir pressure at a high level. Because of the continuous focus on maximizing recovery the expected final recovery has increased from 46.5 % in 1986, through 54.5 % in 2000, and the estimate is now 59 % in 2012. With further developments in recovery strategies and technology it is possible to raise the estimate even higher.

The geology in Gullfaks is complex with numerous fractures and large heterogeneity in the reservoir zones. A recent challenge is to obtain a high recovery from the low permeable rock in heterogeneous reservoir zones. Because of the heterogeneity the injected water has a tendency to sweep predominantly the high permeable zones of the reservoir, leaving oil in areas surrounding these water channels behind. Because of this the average residual oil saturation may still be relatively low in areas with a long history of water injection. To account for this problem it was decided to inject a pilot of a flow diverting chemical called Abio Gel in segment H1 in Gullfaks. Segment H1 is considered a relatively isolated segment and for that reason it is possible to get reliable results regarding the level of success of the pilot. When the injected chemicals get in contact with the formation water they start to form a gel coating on the rock surface. The result is reduced permeability.

To estimate the potential recovery increase by the Abio Gel pilot in segment H1, several Eclipse simulations have been done. An algorithm was made that was used for six simulation scenarios with different degrees of transmissibility reduction in the reservoir. The transmissibility multiplier was applied to a reservoir volume associated with the position of a simulated injected tracer 5 months after the injection. The results of the simulations showed a range from a 40 % production increase to a 2.7 % production decrease from 2 June 2012 to 1 January 2025 compared to the base case. The production change from each well were different, and well A-39 A in Lower Brent showed very good results after the transmissibility modifications. Well B-37 in Upper Brent showed less change, and in most scenarios ended up with a lower production rate in 2025 than in the base case.

An economic analysis of the simulation results indicates that there is potential for a very high value increase by the Abio Gel pilot. However, in the worst case scenario the value of the pilot is negative. The upside of the pilot is nevertheless much higher than the potential loss in the worst case scenario, and implementations of flow diversion with Abio Gel in a few oil fields in China have proved very good results.

PREFACE

This report is part of the final submission in the course TPG4851 – Experts in Teamwork [EiT] Gullfaks Village at NTNU. Experts in Teamwork is a course in which students apply their academic competence in interdisciplinary project work to learn teamwork skills to prepare them for working life. NTNU and Statoil agreed in 2000 to establish EiT Gullfaks Village where student groups are challenged to address current issues related to increasing the oil recovery at the Gullfaks Field. This year the topic was related to an EOR pilot with Abio Gel that was injected in the H1 segment of Gullfaks in 2010. Our challenge was to estimate the potential of increased oil production by doing simulations in Eclipse.

The course is divided in two parts where one part is this project report. The other part is a process report concerning cooperative skills within the team based on reflections on the individuals' behavior in the group.

This project report is divided into two parts where the first part, Part A, gives a presentation of the Gullfaks Main Field and the potential of IOR implementation in this field. In Part B, Eclipse simulations are used to estimate the potential for In Depth Profile Control Technology in Gullfaks segment H1.

We acknowledge the Village Leaders from NTNU, Prof. Jon Kleppe and Jan Ivar Jensen. We also want to thank everyone from Statoil that were involved in this project, and the learning assistants who followed us through this project and gave suggestions to how we could improve the teamwork.

Trondheim, 2 April 2012

Steven Leonardus
Marina Salamanca
Jun Zhou
Mohammadreza Rasta
Sveinung Helle
Runar Eike Toft

TABLE OF CONTENTS

LIST OF FIGURES

Appendix D

LIST OF TABLES

PART A

1 PART A INTRODUCTION

There has been a tremendous development in technology for increased recovery and value on the Norwegian Continental Shelf in the decades following the first oil discovery. The history of the North Sea oil production is a story of a continuous desire to stretch the limits of the technology of exploration and recovery. However, with the current plans the final oil recovery of the North Sea is only 46 %, which means that more than half of the original oil in place will remain in the reservoirs after abandonment. The best way to raise the North Sea oil recovery is believed to be implementation of methods to increase recovery in the largest fields. Gullfaks is among the oil fields in Norway with the largest reserves and most produced oil. The final average oil recovery of Gullfaks is estimated to 59 %, and every percentage increase in the recovery contributes to huge values. A high oil price makes it profitable to invest in measures that will increase the recovery to new levels.

Gullfaks consists of complex formations with numerous faults. A high level of knowledge and continuously improved technology is required to increase the recovery from the field. As technology has developed through times, the expected final recovery has gradually increased from 46.5 % in 1986 to 59 % in 2012. Among the techniques that have led to increased recovery are various types of injection, 4D seismic, smart wells and extensive infill and side-track drilling.

Chapter 2 of this report will give a brief introduction to the geology of Gullfaks Main Field and the challenges that are encountered in the geologically complex formations. Chapter 3 introduces Increased Oil Recovery [IOR], and the focus is on the methods that are implemented in Gullfaks.

2 GULLFAKS MAIN FIELD

The Gullfaks field was discovered in 1978 and was set on production in 1986. The main field lies in block 34/10 in the Tampen-area in the North Sea. Gullfaks is one of the largest producing oil field in Norway, with initial reserves estimated in 2011 to 365.4 million Sm3 (Norwegian Petroleum Directorate [NPD], 2012). Most of the oil is already produced during the 25 years of production, and the remaining reserves is estimated to 14.0 million Sm3 (NPD, 2012). Currently the oil recovery factor of the Gullfaks field is 59 %, but the goal is to increase to 67% (Årlig Statusrapport [ÅSR], 2008). The production peak was reached in 1994, as seen in Figure 2.1, with the highest rate of 90.000 Sm3/day (Talukdar & Instefjord, 2008), followed by an immediate decline which quickly triggered extra focus on Increased Oil Recovery (IOR). Effective reservoir management and a willingness to implement a variety of IOR activities have contributed to a long field life also after the production peak.

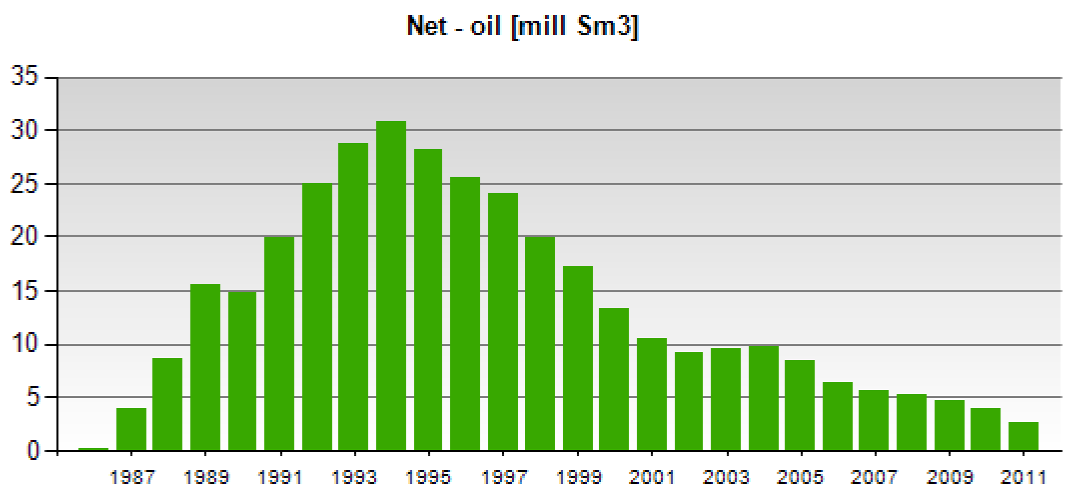

Figure 2.1 Gullfaks Main Field net oil produced (From NPD, 2012)

2.1 RESERVOIR DESCRIPTION

Gullfaks contains reservoirs in Brent Group, Cook Fm, Statfjord Fm and Lunde Fm. The main reservoirs lie in the Brent Group, which contains 73 % of the oil in place in moderate to very good sands (Talukdar & Instefjord, 2008). There are significant variations in lithology and reservoir properties between the different formations, first of all because of the natural deposition during the Early and Middle Jurassic which resulted in layers of varying thickness ranging from very high quality sandstone to impermeable shale. There are also differences in the lithology within each formation because of a large number of faults in the area. The result is a reservoir with a very complex structural geology, which has given difficulties in the development of accurate reservoir models from the seismic data. However, significant improvements in reservoir interpretation have been made in recent years because of advances in seismic surveys and processing techniques. A better understanding of the reservoir helps in reducing the uncertainties involved in the reservoir models and simulations, but challenges introduced by the complexity of the reservoir are still present. A general cross-section from the Gullfaks Main Field can be seen in Figure 2.2.

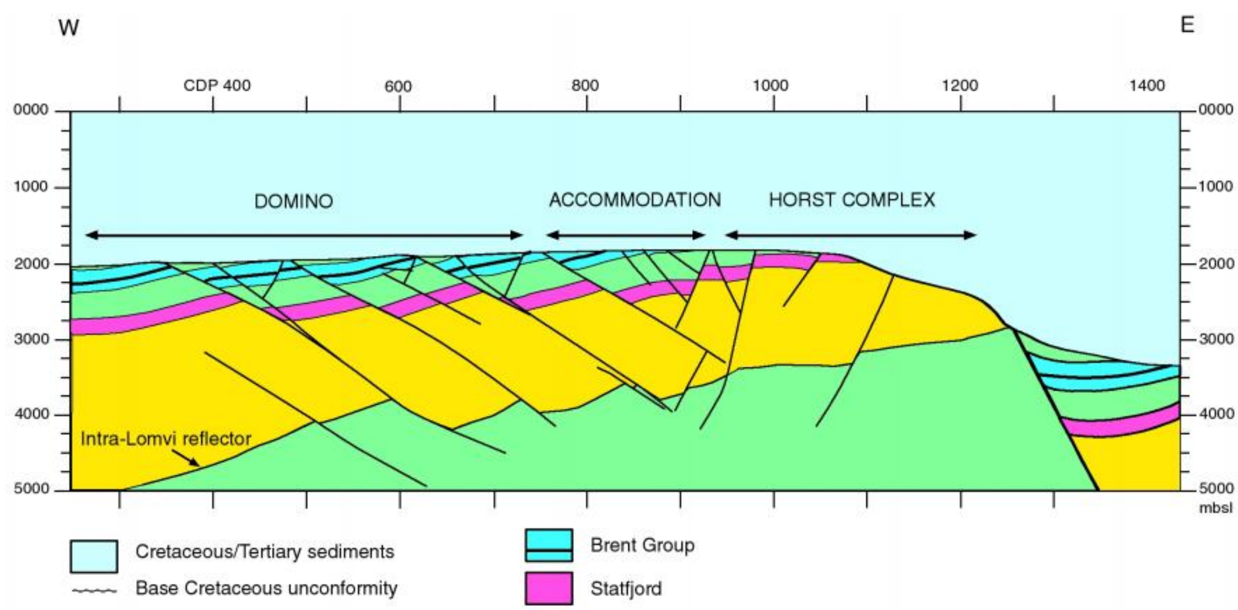

Figure 2.2 General cross-section of Gullfaks Main Field (From: Gullfaks RMP, 2007)

2.2 FORMATION EVALUATION

The formations within Gullfaks Main Field are from the top Tarbert, Ness, Etive, Rannoch and Broom Formations, which are all members of the Brent Group; followed by Cook Fm, Statfjord Fm and Lunde Fm. The general characteristics, drainage methods and challenges in each formation are elaborated below. Much of the following information was found in the Gullfaks Reservoir Management Plan 2007.

2.2.1 Brent Group

The Brent Group is divided into two sub-groups which are called Lower Brent, consisting of Broom, Rannoch and Etive; and Upper Brent, consisting of Ness and Tarbert. These sub-groups are presented in the illustration of stratigraphy column presented in Figure 2.3. The Brent group represents deposits from a northward-building delta system in the mid-Jurassic period. The delta expanded to a position north of the Gullfaks Field before retreating in response to a transgression.

The main challenge in Brent Group is water over-flow due to the contrast of permeability between upper and lower Brent. Injected water will take the most effective way from the injector to the production wells, which means that water highways develop in the reservoir. The result is earlier and higher water production, while large amounts of oil in the lower permeability area remain in the reservoir because of the poor sweep. Another challenge is that water injection allows favorable living conditions for bacteria. The higher bacteria content will cause an increase of H_2S production. H_2S is very corrosive over time and may lead to corrosion in the production system.

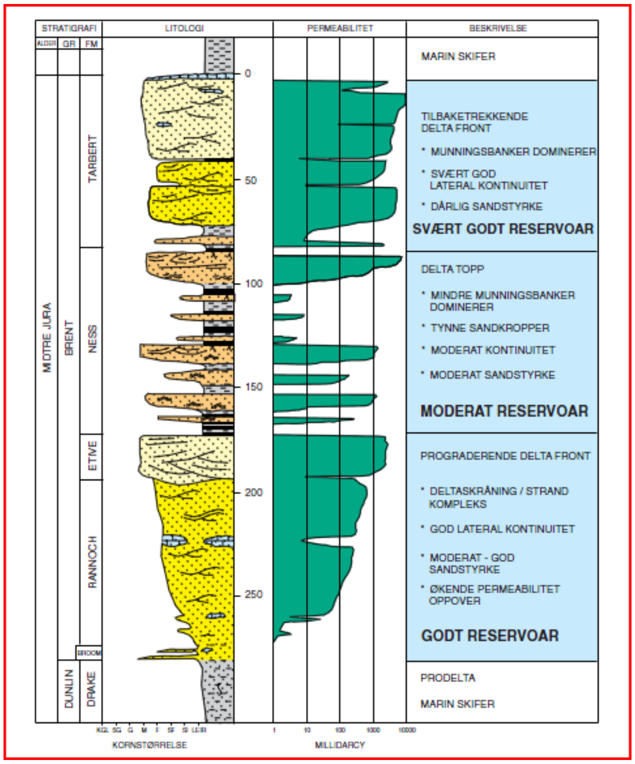

Figure 2.3 Stratigraphy column of Brent Group (From: Gullfaks RMP, 2007)

Tarbert Formation

Tarbert Formation in general can be characterized as massive, homogeneous, highly permeable (3-10 Darcy) reservoir sand. There are areas in Tarbert known as the 'Silky Sand', where the reservoir sand is approximately 50m thick. Shale, coal and carbonate benches are present throughout formations and, to a certain extent, may appear as vertical flooding barriers (Gullfaks RMP, 2007).

This formation is being drained with natural water drive and water injection, that gives the most pressure support to produce while maintaining reservoir pressure above bubble point pressure. In addition to the water injection, gas was injected in well C-17, starting in August 2000, to improve the recovery from the top of the reservoir and to achieve a lighter well column.

The challenge in this formation as it matures is the scattered pockets of oil which needs to be localized and if considered profitable, later produced.

Ness Formation

Ness Formation is characterized by frequent alteration between thin reservoir units (1-20 m thick), and thin shale and coal benches that constitute vertical flooding and pressure barriers. There are also great variations in sand permeability whereas some of the sands have good reservoir properties and large lateral extents. This heterogeneous characteristics and the presence of faults lead to a complex communication pattern internally and with other main reservoirs.

This formation is being drained by maintaining distance between the injection wells and the production wells to allow the displacing phase to have sufficient time and space, via a number of faults, to spread out and provide reasonably good overall pressure support. An alternation of injecting points and a combination of water and gas injection have been a successful strategy for draining the reservoir. Alternation of gas and water injection helps improve recovery by enabling production of attic oil and by providing a lighter fluid column in the production wells.

A challenge in this formation is the poor pressure support to the low permeable sands. Another challenge is early water breakthrough in some of the sand layers which lead to a high water cut on several wells. Sand production, especially after water breakthrough has also been an issue in this formation. Because of low pressure support to some wells, the production rate was also low which gave a reduced capability to lift sands.

Etive, Rannoch, Broom (Lower Brent)

Etive Formation and upper Rannoch Formation generally have very good reservoir properties. Lower parts of Rannoch, including Broom, has moderate to poor quality due to a high degree of calcite cementation and high clay content. This clay content is thought to limit vertical water flow.

These formations are being drained by maintaining pressure above saturation pressure with means of natural water influx and water injection. Occasionally water-alternating-gas injection is conducted to improve recovery from attic oil.

A main challenge in these formations is water overflow due to the difference of permeability between the lower and upper part of lower Brent. The permeability contrast causes the water to flow through the more favorable sands causing poor drainage in the less favorable sand. Another challenge is that water injection induces growth of bacteria leading to H_2S production. This problem was treated by adding nitrate to the injected water to halt the growth of the bacteria. Sand production has also been an issue in some segments where several wells which used to be alternated between injector and producer (e.g. Segment I2A and I2C; well C-5BT2) were no longer available for injection-production alternation because of the sand.

2.2.2 Cook Formation

Cook formation is divided into three parts which are characterized by differences in permeability; Cook 3 has a permeability range from 100 to 5500 mD and Cook 2 has a permeability range from 2 to 100 mD. Cook 1 consists of marine shale with thin, fine-grained sandstone intervals and is considered to be a non-reservoir. Figure 2.4 shows the stratigraphic column of the Cook Formation.

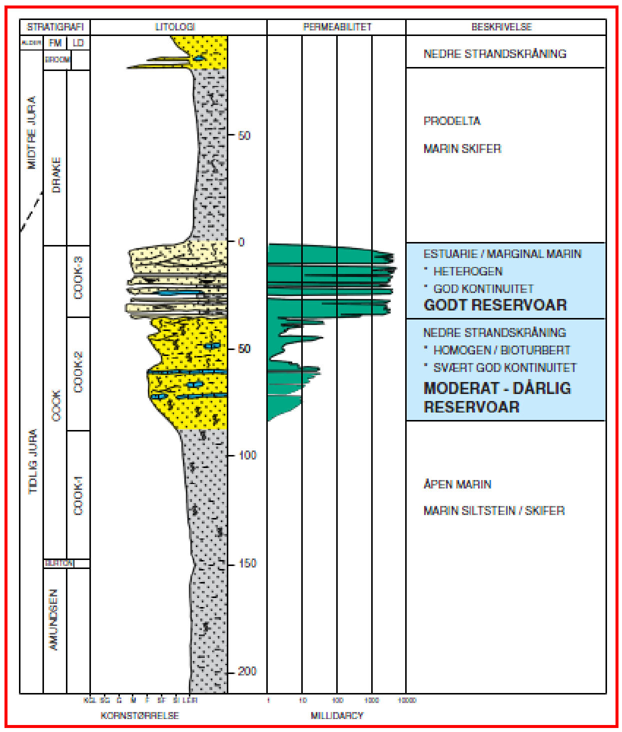

Figure 2.4 Stratigraphic column of Cook Formation (From: Gullfaks RMP, 2007)

The Cook Formation is being drained by water injection. Water is primarily injected in Cook 2 to avoid water overflow in Cook 3 with better reservoir properties. Gas was injected in Cook 2 from October 1997 in well C-18, but the well was recompleted in 2001 to switch to WAG injection. Unfortunately, open fractures to the water-filled Cook 3 made gas injection difficult to do, so only water injection is now conducted and in a limited rate to prevent fracture propagation towards the Shetland formation. The producers in this formation are normally commingled using virtually vertical fractured wells. The wells are perforated in Cook 2 and the fracture designed to reach Cook 3. This method managed to improve drainage of poorer sands in Cook 2, while production from Cook 3 helps in maintaining an acceptable production rate.

One of the challenges in this formation is fracture propagation towards the Shetland Group which must be avoided. Therefore, there is a limitation on the injection pressure and rate. Poor reservoir properties are giving rise to steep pressure gradients between the injectors and producers. This is causing formation of cracks around the injectors and lead to poor sweep in the reservoir. The steep pressure gradient is also posing challenges in the planning of drilling new targets; new wells must be drilled underbalanced to reach the targets in Cook.

2.2.3 Statfjord Formation

Statfjord Formation is zone based primarily on lithographic criteria. The upper part of this formation has lower mica content than the lower part. It is a younger sand formation, which has more favorable reservoir properties. The lower part of Statfjord, which is known as S1-S2, have variations in reservoir thickness and quality. It is also characterized by frequent alternating sand and shale.

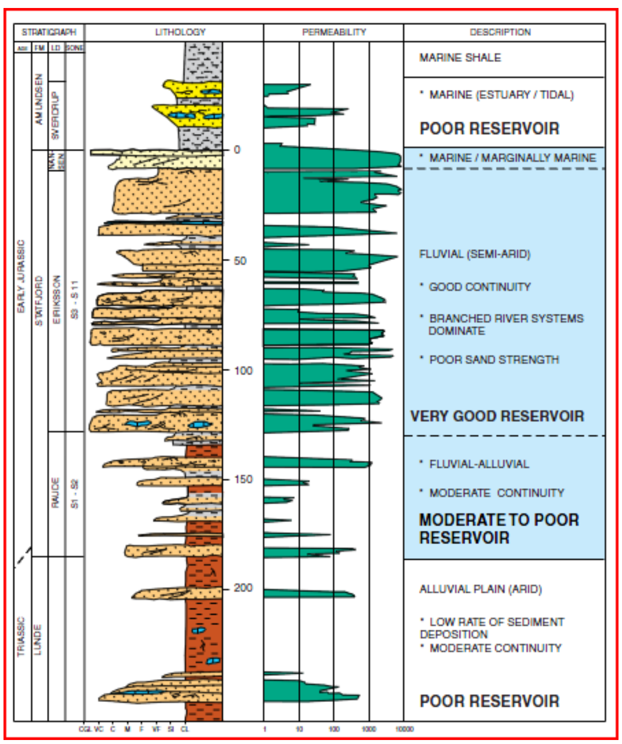

Figure 2.5 Stratigraphy column of Statfjord Formation (From: Gullfaks RMP, 2007)

Statfjord Formation is being drained with water injection to provide pressure support and increase the sweep efficiency. Gas injection is used to drain attic oil and to improve the pressure support in some segments. DIACS (Downhole Instrumentation and Control System) completion in some wells allows the management of commingle operations from reservoirs with different Productivity Index and does also allow shutting off water-producing zones easily. Reversing injector to be producer and vice versa is a method used to increase drainage area and reduce local residual oil saturation.

The challenge in this formation is to maintain the reservoir pressure by means of water injection. Faults that provide seals in some areas and communication paths in other areas give problems. Some areas have sufficient pressure support but some other has minimum or lack of pressure support. Tracers have been injected along with water to check the water-front movement in the reservoir, and thus allowing assessments of areas with pressure support in the reservoir.

2.2.4 Lunde Formation

Lunde Formation is divided into three members: lower, middle and upper Lunde Formation, as shown in Figure 2.6. This formation is characterized by an impermeable 'background facies' (floodplain sediments) that contains a varying number of channel sandstones. The channel system has variation of permeability which ranges around 0 mD for cemented sandstone and around 500mD for the best sandstone. Faults that exist in this formation contribute to increased communication between segments in this formation, and connect Lunde to Statfjord formation.

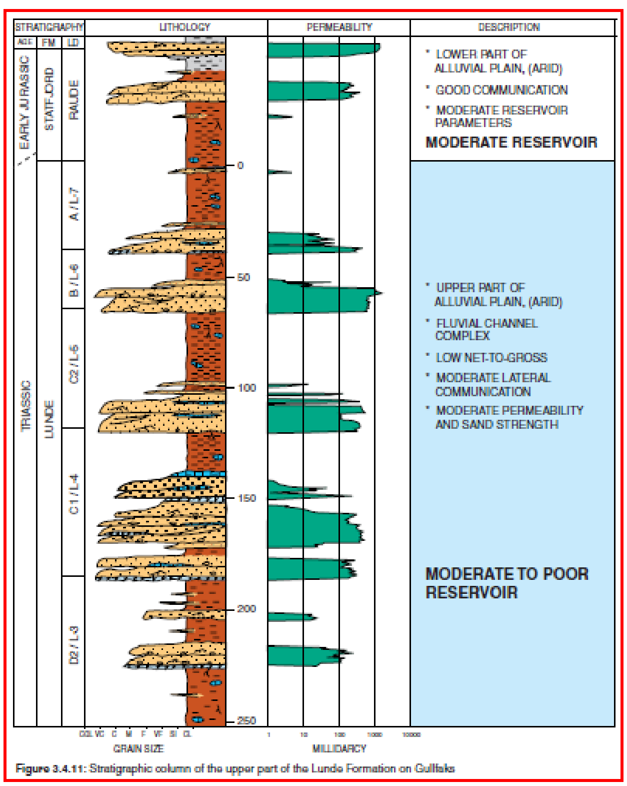

Figure 2.6 Stratigraphy column of Lunde Formation (From: Gullfaks RMP, 2007)

Poor communication with the other parts of the field causes Lunde to be produced slowly. This formation interval had to be shut in periodically to allow indirect pressure support (from water injection) to build up. Inflow control and monitoring (e.g. DIACS) on the wells in Lunde are important to facilitate zone-by-zone production. High deviation or horizontal drilling had proven to be beneficial as it allows more drainage area.

The challenges in producing from Lunde are the uncertainties related to reserve estimates, low production rates and sand productions. Well planning and completion strategy will be a delicate process.

2.3 STUDY OF THE SEGMENTS IN GULLFAKS MAIN FIELD AND RELATED OIL RECOVERY RATES.

The reservoir area of Gullfaks Main Field is divided into several drainage areas, also known as segments, which are primarily separated by faults. Some faults have little impact on the flow of reservoir fluids, while other faults may act as barriers against fluid and pressure communication. A segment that is surrounded by faults that hinder communication with neighbor segments is considered as a fully isolated segment. All fully or partly isolated segments are special cases that need their own custom production strategies. In Gullfaks there are dozens of isolated segments with different reservoir properties because of the stratigraphic complexity of the Gullfaks field, and because of this, each segment requires special attention. Production history has proven pressure communication to some extent between most of the neighboring segments because of non-isolation faults. Figure 2.7 illustrates most of the segments in Gullfaks Main Field.

In this section, estimates of isolated segments in Gullfaks Main Field are presented, based on a literature study from Chapter 4 in Gullfaks Reservoir Management Plan 2007 and a study of structural depth maps for each formation. Since most of the attention in this project is on segment H1, the structural depth maps for the Brent Group around H1 are shown in Figures 2.8 – 2.10.

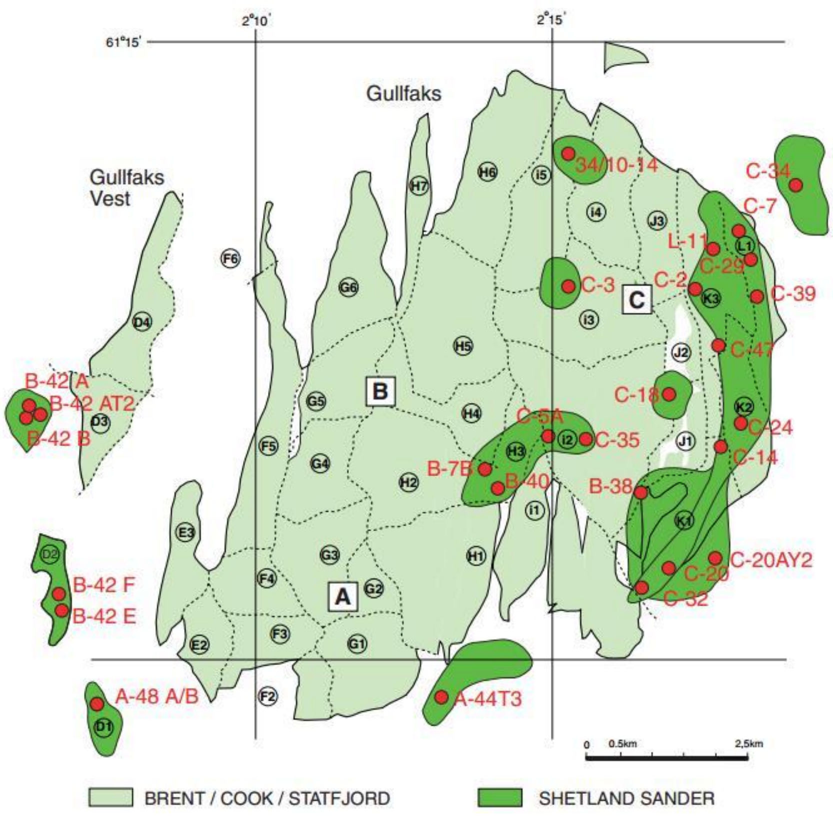

Figure 2.7 Map of segments in Gullfaks Main Field (From: Gullfaks RMP, 2007).

2.3.1 Brent Group

Tarbert Formation

Segment G1 in this formation has no pressure support from the other segments. Therefore, it is considered isolated from the other segments. Segment H1 is considered partially isolated because of internal faults. The faults create complex communication patterns with some of the G-segments as shown by tracers, pressure data and other information that has been collected.

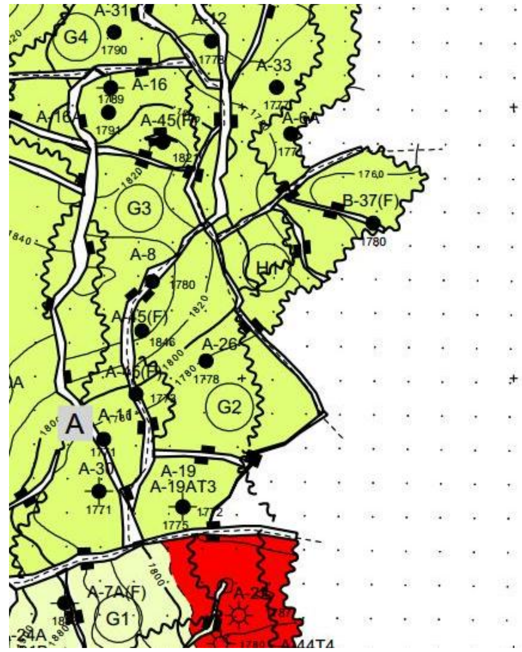

Figure 2.8 Top Tarbert (From: Gullfaks RMP, 2007).

Ness Formation

The communication in this formation has improved with time because the faults, which initially acted as barriers, started making communication. Segment G1 is relatively isolated in relation to the other segments based on the pressure support that it has. The pressure support comes only from injected gas and not from other segments. Segment H1 is partially isolated from the rest of the field.

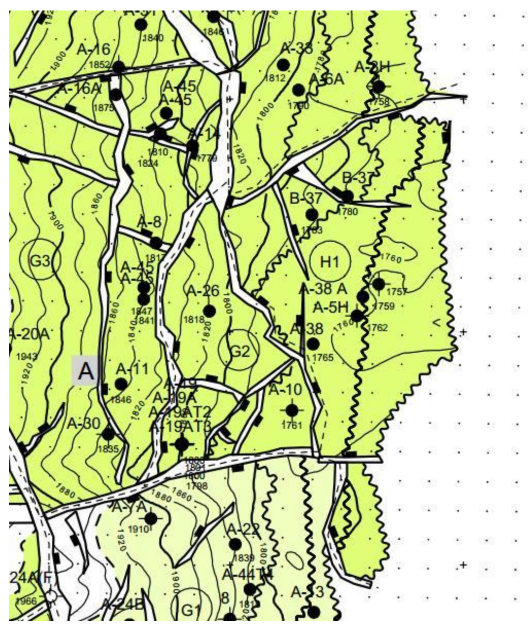

Figure 2.9 Top Ness (From: Gullfaks RMP, 2007).

Lower Brent

In this formation, there is no communication that has been identified between segment I1 and the rest of the I-segments. Segment U1 is an isolated segment and is not in communication with the rest of lower Brent. There have been indications of communication across some segment transition, namely H2/G5, H1/G2 and H4/G5.

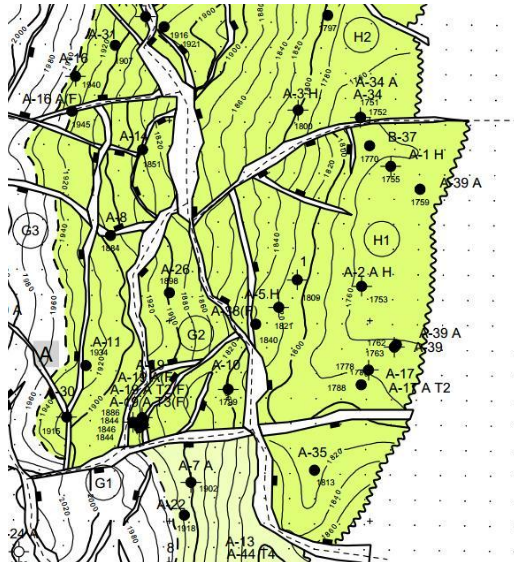

Figure 2.10 Base Ness (From: Gullfaks RMP, 2007).

2.3.2 Cook

Cook formation is divided into different pressure regimes based on the fault patterns. Segment H1/H2 is regarded as one pressure regime. The same goes to segment H4/H5 although there are uncertainties that these segments are in communication with segment H3. Segment G is in communication with segment H based on the similarities of the initial reservoir pressure. Segment I1 is isolated from the rest of the Cook formation with the potential of being in communication with Brent formation in the northern parts of the segment. Segment J2 seems to be isolated from the rest of the segment.

2.3.3 Statfjord formation included Krans and Sverdrup

The Statfjord Formation is a layered formation with some major pressure barriers, both vertical and along the faults. The formation is divided into six production areas with varying communications. The faults in the Statfjord formation may provide a seal in some areas and communication paths in other areas which have been proven in several cases. The Lunde Formation, Krans Member and Sverdrup Member have primarily been developed in Segments K and L. These segments have varying degrees of communication with the Statfjord Formation. The Statfjord Formation in segment I1 represents a separate production area, and segment K1 seems to be separated with the rest of the K segments.

2.3.4 Lunde Formation

This formation is split into two formations called Lunde-in-pressure communication and Lunde-in-isolation. Lunde-in-pressure-communication is stratigraphically the shallower and in pressure communication with Statfjord in Segment K. Lunde-in-isolation communicates at a greater depth, from Lunde C1 to Lunde E. This segment has not been proven to be in communication with the

Statfjord Formation in Segment K. There are varying degrees of communication between the individual sands in the Lunde formation. This is a proof that there is internal communication in the Lunde Formation and that the pressure communication with other formations are poor.

2.3.5 Structural Map Study

A study of the number of segments that are surrounded by faults was conducted for Top Tarbert, Top Ness, Base Ness, Top Cook, Top Statfjord and Top Lunde from the structural depth maps of Gullfaks in RMP, 2007. The goal was to find how many isoloated segments similar to H1 there are in Gullfaks. The result was a total of 89 segments, which is a very high number. Table B.3 in Appendix B shows the results of the study in detail. The result is much higher than from the literature study, and one reason may be due to the fact that faults can act not only as isolators, but also as communication paths between segments. The structural depth maps show the individual segments based on the boundary lines between faults, so it is not possible to determine whether the faults allow communication. Neither is it possible to determine isolation vertically between formations in each segment. For example, it is not possible to see from the maps whether segment D5 in the Tarbert formation is isolated from the segments in Ness formation.

Although the outcome of the study of isolated segments is very uncertain, it is definitely an evidence of the high complexity with many faults in the reservoirs in Gullfaks.

2.4 PRESENTATION OF RECOVERY FACTORS IN GULLFAKS MAIN FIELD

A combination of complex faulting and a large variation in reservoir properties cause a wide range of recovery factor values across the Gullfaks field. The average recovery factor for each formation is presented in Figure 2.11.

The highest recovery factors in general are found in Tarbert Formation, with an average of 66 % in 2008 (Gullfaks YSR, 2008), mostly because of its decent reservoir properties and a long history of water flooding. On the other end of the scale is Lunde Formation with a recovery factor of only 7 % in 2008 (Gullfaks YSR, 2008). This is mainly due to its nature of poor reservoir properties and the lack of communication with other formations, which again result in limited pressure support. As a consequence, Lunde Formation has been given little attention compared to the other formations and is far from completely developed.

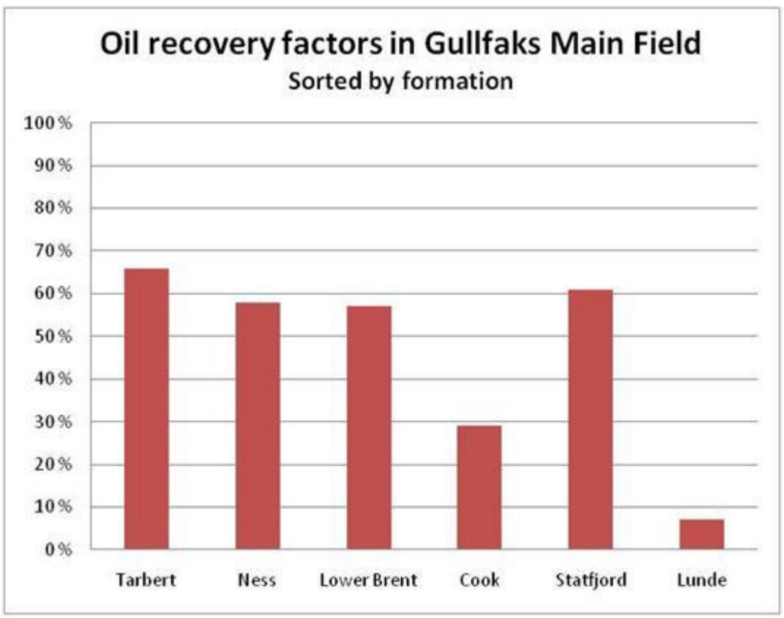

Figure 2.11 Average recovery factors by formation (Data from: Gullfaks RMP, 2007).

Average recovery factors for each segment in Gullfaks Main Field are found to be relatively uniform, ranging from 45 % in segment L to 72 % in segment E, as seen in Figure 2.12. The rest of the segments all average around 60 %, with segment D as the only exception. The reason for the high recovery factor in segment E is that it is only present in Tarbert Formation.

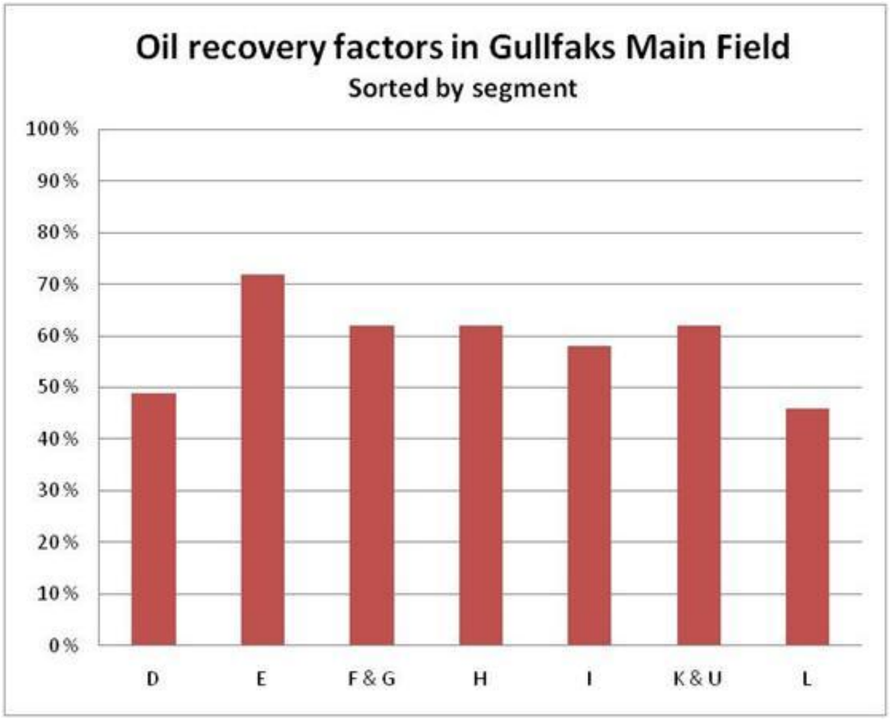

Figure 2.12 Recovery Factors in different segments (Data from: Gullfaks RMP, 2007).

Figure 2.13 shows the recovery for segments and formations in more detail. Segment I in Tarbert formation has a very high recovery factor of 83 %. This is a result of a good pressure support from injection wells in the southern and the northern parts of the segment combined with good communication throughout the segment.

Variations in recovery factors are results of many factors related to the reservoir properties. The main factors are faults which caused segmentation in the reservoirs, and the different drainage methods used for each formation and segment. Hence, as Gullfaks Field matured, the reservoir became more complex due to the relationship between formations and segments; Major communications, partial communications and no communications between each segment, and formations being affected by the pressure distribution from water injection, and also the sweep efficiency from the injector to producer. This has resulted in several segments without enough pressure support, where some of them has been produced below the saturation pressure; resulting in a more complex drilling and production planning and development schemes.

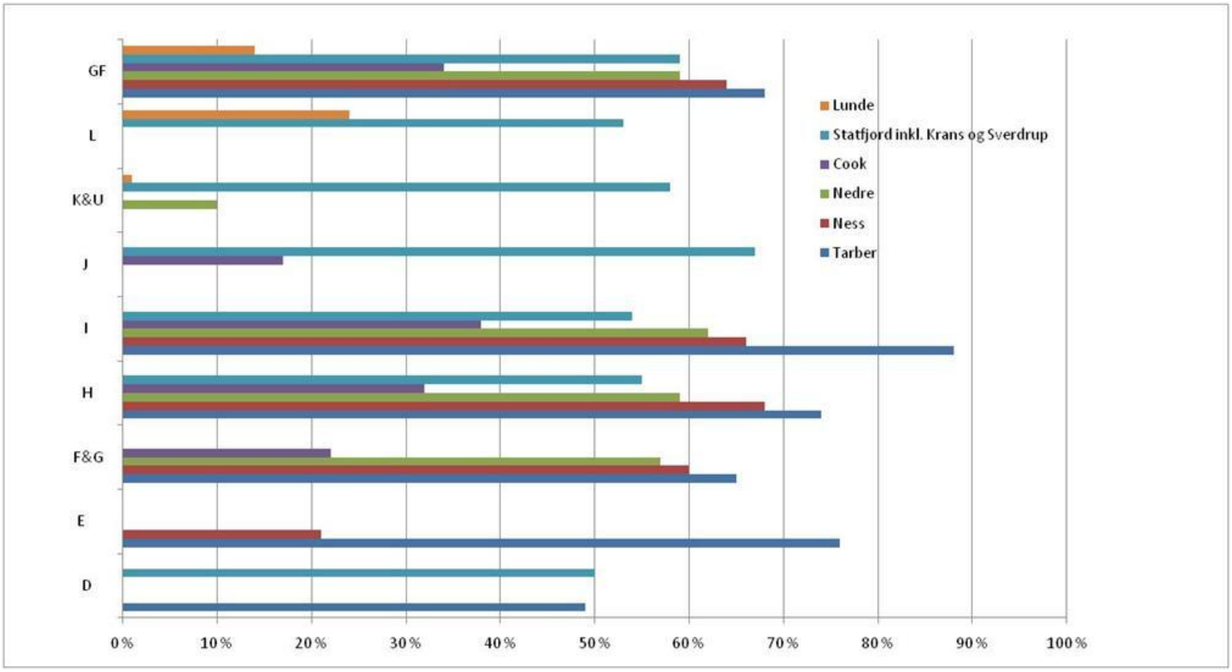

Figure 2.13 Recovery Factors in different formations and segments (Data from: Gullfaks RMP, 2007).

3 IOR IN THE NORTH SEA

Less than ten years after the petroleum production on the Norwegian Continental Shelf started the oil companies had already started to implement measures to improve the oil recovery in the first fields. Measures that are implemented in order to optimize production is known as Increased Oil Recovery (IOR). Gas injection was commenced in Ekofisk in 1975, only 4 years after the production start on the field.

The most current production plans for Norwegian oil fields states that approximately half of the original oil deposits are left in the reservoirs when production is shut down. The average recovery factor in the North Sea was estimated to 46 % in 2009 (Utvinningsutvalget, 2010). Lots of measures have been made in the past to reach this recovery factor, but it is still possible to increase the recovery further by the implementation of new techniques. Development and implementation of technology is essential to increase the oil recovery further. Other aspects such as regulations by the government and operating companies' attention to costs and profitability can also both limit or help increasing the oil recovery.

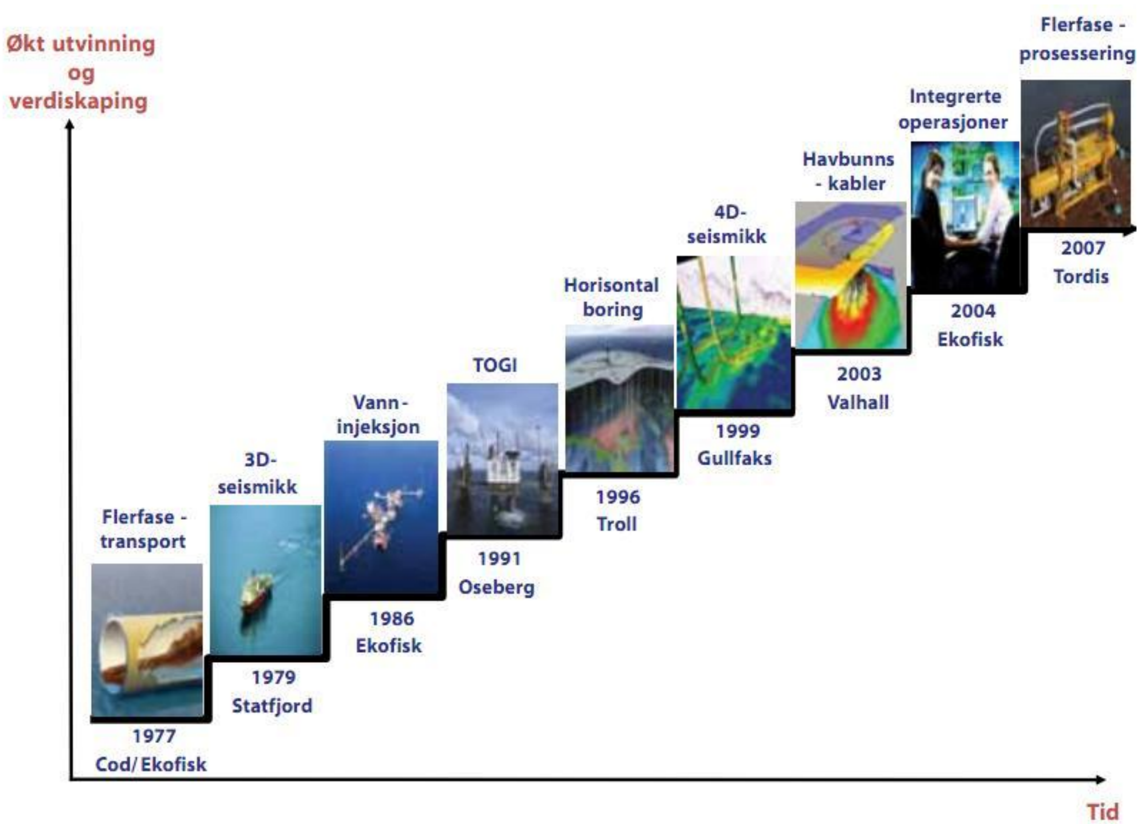

Figure 3.1 Important IOR milestones (From: Utvinningsutvalget, 2010).

3.1 AVAILABLE METHODS TO INCREASE OIL RECOVERY

3.1.1 Drilling and well

According to the report from the IOR-committee (Utvinningsutvalget, 2010) an increased number of production and injection wells is the most important measure to increase the production. For mature fields such as Gullfaks the number of wells that can be drilled is often limited by the rig capacity. Much of the time is used for well interventions in good wells and drilling of side tracks in old wells.

Previous experience with drilling and well for IOR in Gullfaks

Infill drilling has an important role among the IOR activities in Gullfaks. Also various kinds of conventional and advanced drilling and completion techniques have been applied in the field. Highlighted points are applying Coiled Tubing (CT) and Through Tubing Rotary Drilling (TTRD) techniques to reach the target at very low cost. Ten TTRD were drilled in the period 1997-2005. In addition, from 1998 until 2008 a total of 5 wells on Gullfaks were completed with smart well technology (Talukdar & Instefjord, 2008), DIACS (Down-hole Instrumentation And Control System), which has led to increased recovery from low permeable reservoirs.

Various types of sand control have been applied in most of the production wells in Gullfaks. Several techniques such as gravel packing, injection of resin slurries in perforation tunnels and direct injection of consolidating chemicals have been applied. Today, sand screens and prepacked screens are most frequently used due to their effectiveness and cost.

Selective perforations have also been used to avoid sand production in high permeable and less consolidated sands. Perforation strategies have also been used to avoid water and gas production, by re-perforating when necessary. This way the sweep efficiency was improved and oil production increased. A high number of well operations have been performed in Gullfaks for many years.

Strategies to produce oil from small satellite fields around Gullfaks in the most economic manner have led to introduce long and complicated wells by Extended Reach Drilling (ERD). Gulltopp is a good example, a reservoir with 9 km horizontal distance from the Gullfaks platforms.

Future potential for drilling and well in Gullfaks

Infill and side-track drilling are required to take advantage of the seismic surveys. Gullfaks Main Field has a large number of faults that make up small and isolated reserves that can only be reached by new wells or side-tracks from old wells. On Gullfaks and similar large oil fields it is challenging to take advantage of improved reservoir characterization because of limited rig capacity. In mature fields, much of the rig capacity is used for plugging old wells or maintenance of good producers, and consequently the capacity for drilling new wells is reduced.

Because parts of the formations in Gullfaks are depleted, drilling may be very difficult and in several situations it is necessary to make use of unconventional drilling methods which requires modifications to the equipment and a trained drilling crew.

Infill drilled wells may be expensive, and the drilling process challenging, therefore the predicted outcome of the increased production is a decisive factor for whether or not such wells should be drilled.

3.1.2 Increased recovery with various injection techniques

One group of the available measures for increasing the oil recovery is various types of injection methods. Gas injection, water injection or Water-Alternating-Gas (WAG) injection have been equipped in most fields, with WAG being the most common EOR method in the North Sea. Surfactant injection and polymer injection are new methods that are still under development.

Previous experience with injection techniques for IOR in Gullfaks

Water flooding is the main IOR method with top priority among other techniques. Water injection was carried out already at the very start of Gullfaks production. Early production experience and simulation results showed a high potential recovery from the field, but since the water influx was not sufficient to get enough pressure support, water injectors were placed to give pressure support to the producers.

Gas injection was started in the late 1980’s in a production well in the Cook Formation, mainly because of restricted capacity on the gas-transport line to Kårstø. After periods of gas injection, the production rate proved to be higher than normal, and the result was a much higher oil recovery than expected.

WAG injection was applied for the first time in Gullfaks in 1991 in well A-11, which had until then been used as a water injector. WAG injection has later been implemented in a total of 25 wells in Gullfaks until 2008 (Talukdar & Instefjord, 2008). Generally three advantages achieved by WAG are 1) draining of attic oil 2) sweeping other area not contacted by water 3) reduction in water-cut and gas lifting of high water-cut. Because of a strong gravitational segregation in the reservoir the volumetric sweep in the reservoirs was improved by WAG injection compared to one-phase injection.

In first half of 1992, a pilot test of surfactant injection was employed successfully, but large scale implementation has not been done yet and it is under investigation.

Gel blocking and water diversion methods were implemented successfully in two wells, B-5 in July 1993 and A-13 in September 1994. The result in B-5 was a reduction in water-cut from over 80% to 70% and an increase in oil production from 450 Sm3/d to 700 Sm3/d.

Reverse sweep is another recovery method which was conducted in few of the lower Brent wells in H1and I1 with considerable mobilized and produced oil through changing the direction of water injection and more studied are ongoing to expand and develop it in Gullfaks zones.

In 2006, aerobic microbial EOR was performed as pilot but with no significant success.

Future potential for various injection techniques in Gullfaks

Flow diversion

In segments that are already in production it is likely that some areas have lower recovery than others. In many cases the volumetric sweep is ineffective and the water that is injected follows developed “highways” towards the producer. Such highways often contain reservoir rock of higher permeability than the surrounding rock, and a large amount of oil is left behind in the reservoir rock with lower permeability.

Because of the large variations in the Gullfaks stratigraphy, flow diversion is likely to be a good option for increased oil recovery. In addition, measurements in Gullfaks have shown that the residual oil saturation in many cases is low. This gives an indication that high permeable waterways exist, and chemical plugging of the highways will lead to a better sweep.

Surfactant injection

Surfactant injection to reduce the residual oil saturation and produce immobile oil may be a good EOR measure in the future, but right now there are several reasons that argue against surfactant injection as a promising EOR measure. The outcome of surfactant injection depends on a decent and balanced injection. The challenges that is encountered in the reservoir today involves inefficient sweep in heterogeneous rock, which means that only parts of the reservoir will be affected by surfactants. Surfactants have been injected in fields all over the world with good results, but measures to increase the recovery of mobile oil should be implemented before the attention is directed toward the immobile oil. In addition, the fact that most of the chemicals are classified as red lead to limitations for this method. Measurements of oil saturation after water injection in Gullfaks show that the water sweep is already very effective, and the residual oil saturation is measured to close to 10 % (ref. ÅSR 2008).

Low saline (fresh) water injection

Low saline water is another potential EOR method that is under investigation for pilot tests due to encouraging laboratory results. In spite of the successful laboratory results and the relatively low costs involved, low saline water injection is not yet proven to be a valuable method compared to other advanced enhanced recovery methods.

Water-Alternating-Gas

WAG is been used in Gullfaks for many years and have made a significant impact on enhanced recovery. Continued injection will be important also in the future to avoid considerable pressure depletion in the reservoir.

3.1.3 Integrated Operations

By implementation of Integrated Operations (IO) the oil recovery can be increased. IO involves the enhancing of operational efficiency, better decision making and decreased operating costs.

Future potential for Integrated Operations at Gullfaks

The potential of IO is estimated to give an average of 4-5 percentage points increase in oil recovery on the Norwegian continental coast (Utvinningsutvalget, 2010). As a long time project, continuous improvements are required to improve efficiency and reduce operating costs in the Gullfaks field. Today all Statoil's platforms are hooked up to broad-band networks, resulting in interactive operations by joint sea-land teams (EDB Ergo Group, n.d.). Integrated Operations will always be an important part of IOR, especially these days when oil reserves become more difficult to access and more expensive to develop and produce.

3.1.5 Reservoir characterization

Reservoir characterization is another IOR method. The use of 3D and 4D seismics contribute to a better understanding of the reservoir which again leads to more accurate drilling and optimized production.

Previous experience with reservoir characterization as IOR in Gullfaks

In order to locate the remaining oil in a field with complex geological structures it is necessary to conduct seismic surveys. Four repeated 4D-seismic surveys was acquired from 1995 until 2008. This has led to successful infill drilling of 14 targets and consequently increased the revenue and recovery factor of the main field (Helland, R., 2008) In 2001, Ocean Bottom Seismic monitoring with re-deployable cables where applied at Gullfaks (Amundsen & Landrø, 2009).

Future potential for reservoir characterization in Gullfaks

One of the most valuable of the widely used and available IOR methods is the application of reservoir characterization in terms of 4D seismic. Until now 4D seismic have resulted in increased recovery in Gullfaks worth around 6 billion NOK (Utvinningsutvalget, 2010). 4D seismic surveys reveal the effects that production and injection has on the reservoir, which is really important in a mature field in order to optimize the production. 4D seismic has also proven to be a valuable aid in mature fields where a common challenge is to localize remaining reserves that has not been reached by the current producing well.

3.1.6 Subsea Solutions

Many of the new discoveries in the North Sea today are developed by subsea technology instead of the use of fixed platforms. This is because most of the discoveries are small and often at deep water, so the use of subsea solution is the only way to make these oil reserves feasible and profitable. Developments of existing fields, like Gullfaks (satellites), are mostly developed subsea. In fact about 1/3 of the production in the Norwegian shelf today are from subsea wells. Arguments against subsea systems compared with fixed platforms are reduced recovery factor, difficulty with well maintenance, drilling costs, and operational costs.

Future potential for Subsea solutions at Gullfaks

Because Gullfaks Main Field is a large and mature field already developed with three platforms, which also receive produced fluids from various surrounding sub sea fields like Tordis and Vigdis Fields and Gullfaks Satellites, it is likely that a development of subsea solutions in Gullfaks Main Field would make more challenges than what it is worth. First of all, subsea wells are costly to maintain and tend to result in lower recovery rates. Secondly, the high water cuts experienced at Gullfaks MF makes the recovery rates completely dependent on a successful subsea seperation system.

3.2 Summary of future potential of IOR methods in Gullfaks Main Field

Because Gullfaks is a large and mature field with a long history of applications of various methods for increasing the oil recovery it is necessary to look past the currently mobile oil and try to find solutions to recover the immobile oil. However, because of the comprehensive size of the Gullfaks Field it is still possible to increase the recovery with common methods. The different IOR and EOR measures are divided into the categories that are found in the Åm-report. Table 3.1 shows our evaluations of the future potential of IOR methods in Gullfaks Main Field based on the literature study in Section 3.1. A short summary of the evaluations is given below.

Table 3.1 Summary of future potential of IOR methods in Gullfaks Main Field

IOR / EOR method	Evaluation
Infill drilling	Very important
Flow diversion	Has potential to be important
Surfactant injection	Not important in comparison with other methods
Low saline water injection	Not important in comparison with other methods
WAG	Very important
Integrated operations	Very important
4D seismic	Very important
Subsea solutions	Considered not important

The combination of reservoir characterization with 4D seismic and infill drilling is a very important method for increased recovery also in the future because of potential oil filled pockets that can only be recovered with new wells. In addition, satellite fields may be drilled and produced from the main field to avoid unnecessary field development costs. The rig capacity is however a limitation, and the high expenses associated with challenging drilling operations must be taken into account.

Water injection and WAG injection is considered very important to avoid pressure depletion in the reservoir. Injection of surfactants is considered less important because it requires a balanced sweep for a good outcome, which the Gullfaks field does not have because of the complex formations. Low saline water injection is inexpensive, but experience has shown little effect of this EOR method (Low saline water injection has been tried in the Snorre field) and the method is therefore considered not important.

A focus on integrated operations is considered important for increased recovery and value because the outcome will be higher efficiency and reduced costs.

Finally, flow diversion, which will be examined in detail in Part B of this report, is considered potentially important because of the heterogeneity in the reservoir sections in Gullfaks.

PART B

4 PART B INTRODUCTION

Water injection has been used as the main oil recovery method at Gullfaks since the production start to maintain the reservoir pressure above bubble point pressure. The water injection proved to be very effective and have left heavily flooded areas with residual oil saturation down to 5 % (Talukdar & Instefjord, 2008). However, due to the large heterogeneity in the reservoirs, the injected water tends to follow high permeability flow channels, leaving oil in areas surrounding these channels behind. Because of this the average residual oil saturation may still be relatively low in areas with a long history of water injection. One of the most recent challenges in Gullfaks Main Field is how to obtain a good oil production from the low permeable volumes in heterogeneous reservoir zones. This challenge could be solved by infill drilling, but the possibility of intersecting an area that already has been flushed is high, so other methods such as chemical plugging of high permeable zones are being tested. If no measure is implemented, the result is limited oil recovery from the sands of lower permeability that is adjacent to better quality sands.

Statoil decided to implement a relatively new technique of in depth profile control technology called inorganic gel coating in Gullfaks H1 in an attempt to increase the water sweep efficiency. A pilot with batches of WJSTP chemicals was injected in the A-35 well in the H1 segment from September to November 2010. When the WJSTP chemicals react with the formation water they form micro gel particles, called Abio Gel. The inorganic gel sticks to the surface of pores and thereby reduces the permeability by sealing the flow channels. This will force injected water to find new paths and give possibilities of displacing more oil for production.

Figure 4.1 show graphics that prove the high differences in residual oil saturation in segment H1 in Gullfaks Main Field. The graphics are from an Eclipse simulation and describes the status of oil saturation of 2 June 2012. Layer 40 has been subjected to a good water sweep and has low oil saturation compared to the layers above and below.

Several scenarios have been simulated in Eclipse to evaluate the potential of Abio Gel injection in the H1 segment. The procedure and results are presented in this part of the document.

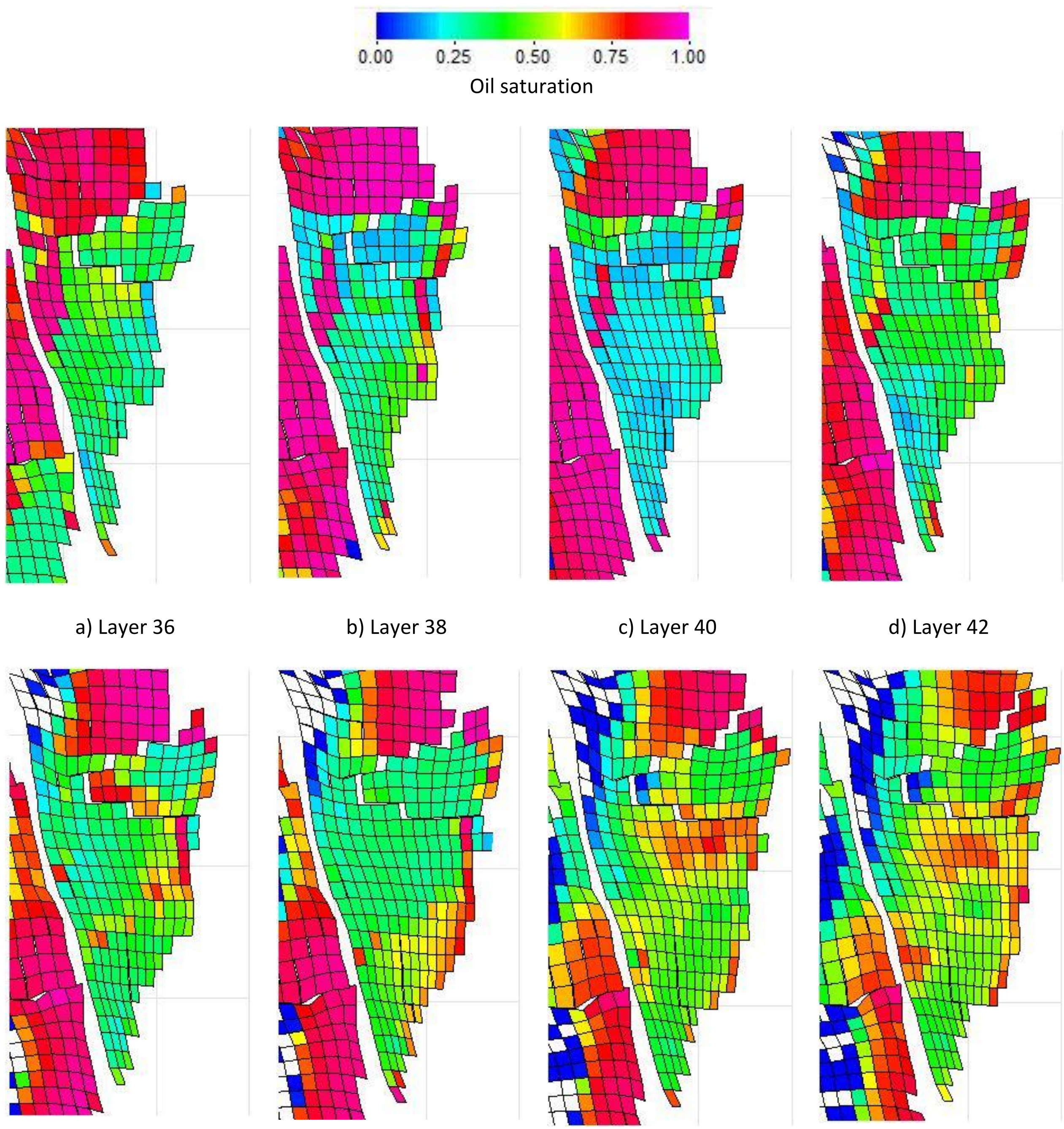

Figure 4.1 Oil Saturation, 2 June 2012

5 IN DEPTH PROFILE CONTROL TECHNOLOGY

When water is injected from the injecting well to the producer the water will move through the volume that will result in the lowest total pressure drop. Darcy's law is the preferred method to calculate pressure drop in porous media:

$$Q = \frac{-kA}{\mu}\frac{dP}{dx}$$

Here, the fluid with viscosity μ flows a distance x with a flow rate Q through an area A of a porous media with permeability k. The only variable that is related to the porous media is the permeability. From the equation it can be interpreted that pressure drop increases with decreasing permeability and increasing length, and thus, the injected water will find the most effective way to travel based on those factors. In a heterogeneous reservoir the variations in permeability cause oil situated in volumes of less effective displacement to be left behind during the water injection. In depth profile control technology has been developed in recent years with the purpose to reduce the permeability in heavily flooded areas so the injected water becomes more spread in the reservoir. Water shutoff and profile control play an important role in raising the production rate in the tail-end production in mature fields with high water cut. The more complicated the reservoir becomes after water- and polymer flooding, the better the in depth profile control technology is.

5.1 OVERVIEW OF IN DEPTH PROFILE CONTROL TECHNOLOGY METHODS

Profile control has been applied in oil fields in China for about 50 years (Caili et al., 2010), but its effectiveness in large reservoirs has been limited because of short gelation time and strong strength which only resulted in plugging near the wellbore zone. In such situations the water bypasses the plugging zone and flows in the already established water channels. In depth profile control technologies have been developed since the 1990's and give the possibility to reduce the permeability in large volumes deeper in the formation and greatly divert the water swept volumes. Many of the methods have been used with great social and economic benefits, but the strict regulations in the North Sea limits the application of in depth profile technology on the Norwegian Continental Shelf. Most of the technologies with a decent resulting effect that are developed are classified as possibly harmful to the environment, where one exception is the inorganic gel coating 'Abio Gel'. Another factor that affects the utilization of the in depth profile control methods are pressure and temperature limitations of the chemicals in use. A short presentation of some of the most recent developed methods is given in the following.

Microorganism

This method involves injection of bacteria that can produce polymers into the reservoir. The bacteria and polymers can be adsorbed on the surface of pores resulting in reduced permeability. The bacteria may reproduce greatly and lead to a thick layer on the pore surface.

Inorganic Gel Coating

Inorganic Gel Coating was developed because of the constrained application of polymer gels in high temperature and high saline environments. Inorganic particles have good thermal and salinity resistance in contrast to polymer gels, and may therefore be used in challenging environments. Previously the limitation of inorganic particles has been that they can only plug the pores near the wellbore. An inorganic gel coating agent that avoids this limitation has recently been developed, called WJSTP. The gel coating agent, WJSTP, react with formation water and produce a gel that adsorbs to the rock. The produced gel is called Abio Gel and is presented in detail in Section 5.2.

Polymer Microsphere

This method works by the expansion and adsorption of polymer microspheres to rock surface when they are in contact with water. The expansion takes some time and lets the microspheres flow a distance into the formation before they get stuck in a too small pore throat. A challenge is to control the relationship between the size of polymer microspheres and the pores in the reservoir.

5.2 Abio Gel

5.2.1 Description

Abio Gel is a commercial name for a gel formed from a chemical compound called WJSTP, which consists primarily of sodium silicate, $Na_2O.mSiO_2$ (Tang et al., 2004). The WJSTP will react with divalent cations (i.e.Ca^{2+} and Mg^{2+}) in the formation water. The reaction depends on the concentration of divalent cations. If the concentration exceeds 1% then it will form a stiff gel, otherwise it will behave like a cement paint that coats the matrix and the pores (Figure 5.1).

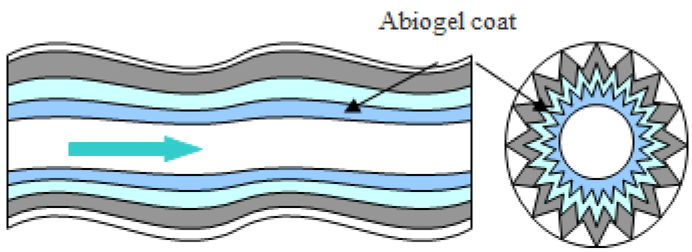

Figure 5.1 Schematic of pore coatings. (From Statoil Bergen presentation, 2012)

Abio Gel is introduced in the reservoir by injecting WJSTP chemicals in several batches through an injection well. The flow channels will gradually narrow because of the gel coating, and the water front is forced to find new paths. The new water paths will invade the less water flooded areas, sweep the bypassed oil and increase oil recovery.

Initially, the Abio Gel was developed in China to solve problems in the reservoirs in Tarim Basin. The reservoirs in this area are at a depth around 5000 m and are characterized by high temperature (above 140°C) and high salinity (up to 25% TDS and 1% Ca^{2+} + Mg^{2+}). Donghe and Lunnan oil fields, which are operated by PetroChina, was developed with water flooding, but the producing water cut indicated that there was an uneven water sweep in the reservoirs due to rock heterogeneities. Therefore an in-depth profile control agent that could control the water flow and also could stand such harsh reservoir conditions was needed. This resulted in an inorganic agent of profile modification, WJSTP. This inorganic profile modification agent met the requirements for high temperature and high salinity reservoirs. Previous profile modification agents, such as cross-linked polymer, were sensitive to high temperature and had a tendency to flocculate with multivalent ions. Other agents such as cement, inorganic particles and precipitable agents that can stand such harsh reservoir conditions weren't able to modify in-depth, due to their limited injection depth (Tang et al., 2004).

5.2.2 Experimental Study

Experiments were conducted to study the effectiveness of the gel in block fractures and thief zones; whether gel coating formed in near wellbore zone only; the gel's ability to withstand washouts; and the effect of wettability on the gel coat. Cores and formation water from two fields were used in the experiment, which involved a setup of slim tube with multipoint pressure measurements as seen in Figure 5.2.

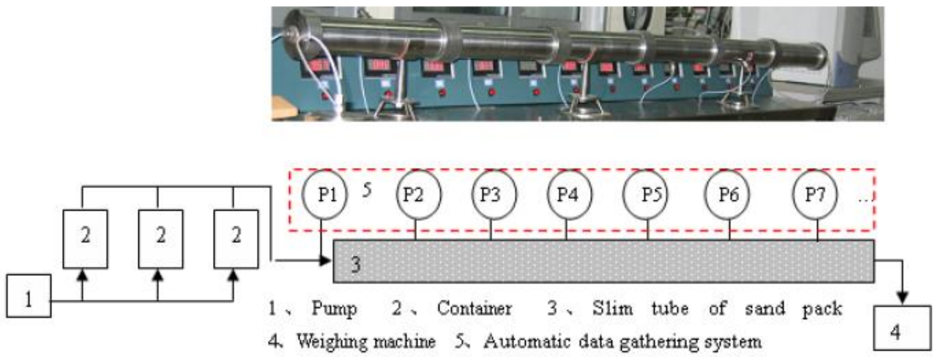

Figure 5.2 Schematic of WJSTP experimental set up (from Tang et al., SPE 88468, 2004)

Laboratory experiments with cores with permeability ranging from 7 – 50 D were performed by Tang et al. in 2004. The results showed that each batch of injected WJSTP will cause a gradual decrease of permeability in the rock, implying that the permeability reduction is dependent on the number of injected batches of WJSTP. The first batch gave a permeability reduction of 60 %, and after three batches the permeability was reduced by 90 %. But the experiments also proved that larger volumes of each batch resulted in more effective blocking. This way it is possible more or less to compute the desired degree of fluid diversion if the properties of the reservoir are well known. The experiment with multipoint pressure measurements showed that as times of coating increased, flowing resistances along the cores increased to a variable degree (Figure 5.3a). The farther the distance away from the inlet, the less the degree of increase was (Figure 5.3b).

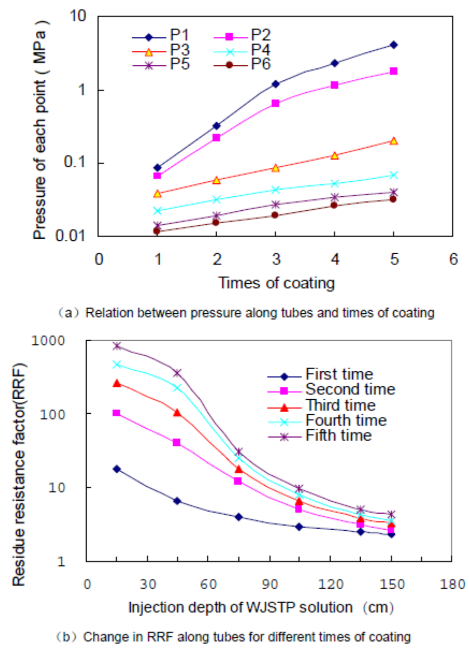

Figure 5.3 Effect of coating times on flow resistance and RRF along tubes (From Tang et al., SPE 88468, 2004)

In oil bearing cores, the first batch gave a permeability reduction of 20%. This value is three times lower than in water phase because oil bearing cores had relatively less formation water to react with WJSTP solution. After 3 batches, almost all oil had been produced. This treatment showed a 30 % increase in recovery efficiency compared to water drive treatment.

Selective injection to heterogeneous layers was simulated using double tubes of sand packs with different permeability. After a while the flow resistance in the cores with high permeability increased because of a permeability reduction. This indicates the ability of the gel to redistribute fluid flow in a heterogeneous reservoir. Another experiment compared injections with and without insulating liquid (fresh water was used as insulating liquid) between agent solution and simulated formation water. This experiment demonstrated that if agent solution and formation water were injected alternately without using insulating liquid, gel coating may adhere to injection pipes, especially tubing.

5.2.3 Field experience / Implemetation in China

Abio Gel has been used for in-depth flow profile control in various reservoirs with different temperatures and salinity conditions, such as in Lunnan Oilfield of the Tarim Basin, in Yuejin oil region of the Qaidam Basin, and in Dagang Oilfield. The field applications involve single well group and whole block, with success ratio up to 100%, average injection pressure of well group increasing by 2–3 MPa, and the effective rate of oil production increase and water-cut decrease of producers are over 80%.

5.2.4 Planned implementation in the North Sea

Statoil selected segment H1 in Gullfaks field to pilot test the Abio Gel for the first time in field scale. Segment H1 is an isolated segment which is produced by means of water injection. The segment has at the moment four active wells, two wells are perforated in Lower Brent (A-35 injector and A-39A producer) and two wells in the Upper Brent (B-37 producer and A-38A producer). A-35 is a vertical well situated in the southern end of H1. A-39 A is a horizontal well that stretches out from north to south in the eastern part of H1 deep in Lower Brent. Figure 5.4 shows that A-35 is perforated from layer 36 through 49, while Figure 5.5 shows that A-39 A largely is placed in and above layer 49. The targeted formations are Etive and Rannoch. These formations are produced with water injection to maintain pressure and sweep the oil to the producing well. After a long period of time, water paths had been created from the injecor to the producing well, leaving un-swept area which still have feasible amount of oil saturation. Figure 5.6 is another illustration of the active well positions in segment H1.

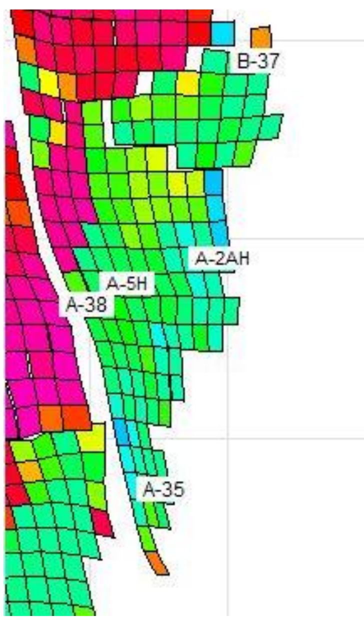

Figure 5.4 Layer 36

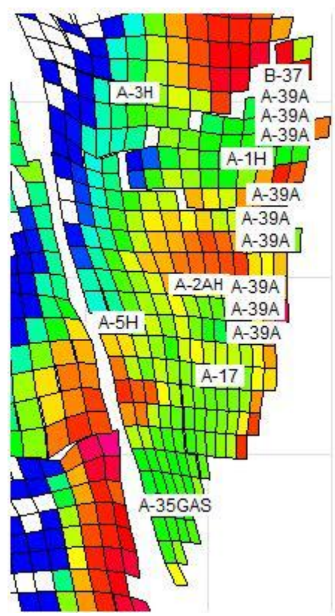

Figure 5.5 Layer 49

Figure 5.6 H1 well positions

Abio Gel is introduced in the reservoir by injection of chemicals through the injection well A-35. Following the chemical injection is the water injection pushing the chemicals to follow the water path. The chemicals react and form gel that reduces the permeability of the water path area. The reduction in permeability will increase the flow pressure gradient (dP/dx) in that area, and will cause the water injected behind the gel to find a new path with smaller pressure gradient. This new path will lead to the un-swept area of the reservoir that still contains high oil saturation.

Thus, increasing the recovery of oil and decreasing the water cut. The schematics of the project implementation is shown in Figure 5.7.

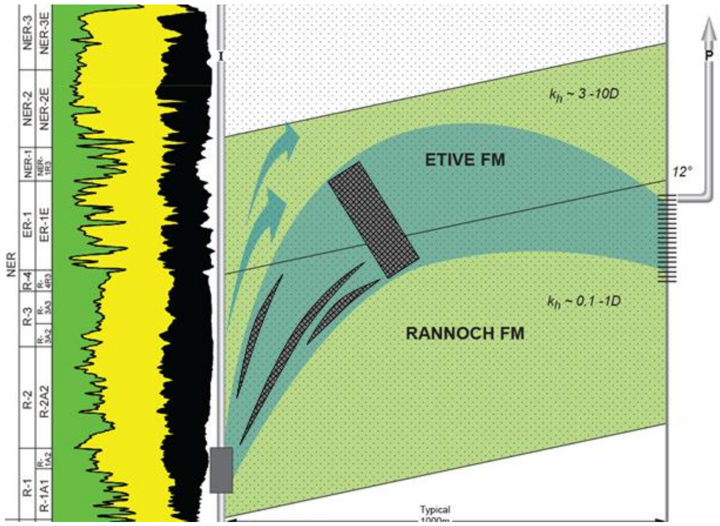

Figure 5.7 Implementation schematics. (From Statoil Gullfaks Village, 2012).

6 SIMULATION FOR GULLFAKS H1 PILOT

6.1 SIMULATION OF ABIO GEL IN ECLIPSE

Simulation of the Abio Gel in ECLIPSE reservoir simulator starts by selecting an algorithm for the degree of flow restriction in the reservoir, and determine the approximate position where in the reservoir the gel coating will appear. The algorithms and modifications are entered in other software, FloViz, which is a part of the ECLIPSE software package.

The WJSTP chemical flows with the fluid along with the injection. It is assumed that it will follow the path of water injection. Therefore, the “tracer options” is used in the reservoir simulation. “Tracer options” is a feature of the simulator that detects the concentration of the preferred tracers; In this case, water is used as tracers. An initial volume of the tracer is selected before simulation. The simulation will calculate the tracer movements along with water and the change of concentration as a result of mixing for each time step, during the flow.

The concentration of the tracer is used in the algorithm to determine the degree of gel coating in each grid block. The pore plugging effects explained in this report will refer to changes in transmissibility values and will be explained in Section 6.2. When the algorithm is applied in FloViz, a new static model with modifications in the grid transmissibility values and positions is generated. The steps taken to generate the model are explained in Appendix A.

The changes in grid transmissibility will depend on the transmissibility multiplier while the position will depend on which time-step is used to generate the model. These new models will be used as a restart file in Eclipse to simulate the water injection flow. The transmissibility multiplier and its position will be a decisive factor for changes in the recovery factor.

6.2 TRANSMISSIBILITY MODIFICATION

In petroleum literature the definition of transmissibility is

$$T = \frac{kh}{\mu}$$

where k is permeability, h is the height of the area and μ is the viscosity of the fluid.

The Cartesian transmissibility calculations are a bit more complicated in Eclipse. The way the transmissibility is calculated in Eclipse can be found in Appendix C. One thing that differentiates permeability and transmissibility in Eclipse is that permeability describes the ability of a cell to transmit fluids, while the transmissibility describes the ability to transmit fluids between neighbor cells. The transmissibility is therefore a value that is linked to two cells, and is dependent on the permeability and cross sectional areas of both cells.

The tracer that was used in Eclipse to simulate the flow of WJSTP through the reservoir was injected at a rate of ? Sm3/day, with 2100 Sm3 injected. Because of the uncertainty of how long time it takes before the gel is formed in the reservoir we simulated all the scenarios with different time spans from injection of WJSTP to the solidifying of the gel.

The main uncertainty was to find the transmissibility multipliers that would give the best possible simulation of the reality. It is likely that a particular concentration of WJSTP results in a corresponding gel coating and transmissibility reduction, but since the exact values are unknown to us, we chose to run the simulation several times with different transmissibility reduction factors.

6.3 MODELING OF TRANSMISSIBILITY IN ECLIPSE

The Abio Gel coating will start to form soon after being injected in the reservoir because of the reaction with salt formation water. Therefore, the permeability reduction is likely to be detected from a short distance from the injector. The distance into the formation that the Abio Gel coating will be observed is likely to be dependent on the amount of injected gel agent. It is observed in an experiment by Tang et al. (2004) that the coating is less likely to form in low permeable areas because of the reduced content of divalent cations in these areas. This is a very favorable feature with the Abio Gel. From this discussion we imagine that the Abio Gel coating process works as previously shown in Figure 5.1.

In our simulations we were limited to apply transmissibility reduction only in association with the concentration of a simulated tracer at a given time step. The predetermined half-year time-steps limited the choices of where to apply transmissibility reduction. The simulated tracer was injected 1 January 2012. Two different time-dependent positions, at 2 June 2012 and 1 January 2013 were chosen for the application of transmissibility reduction. Graphics of the tracer concentrations at 2 June 2012 are shown in Figure 6.1. Figure 6.2 shows the corresponding tracer concentrations at 1 January 2013. The main difference between the two time steps are primarily the concentration, which is considerably higher the 2 June 2012. The position of the tracer has also changed, as it flows from high to low pressure. It may as well be interesting to see the initial transmissibility in X, Y and Z directions for different layers. Figure 6.3 shows graphics of initial transmissibility. Pay attention to the different color legends for the different transmissibility directions.

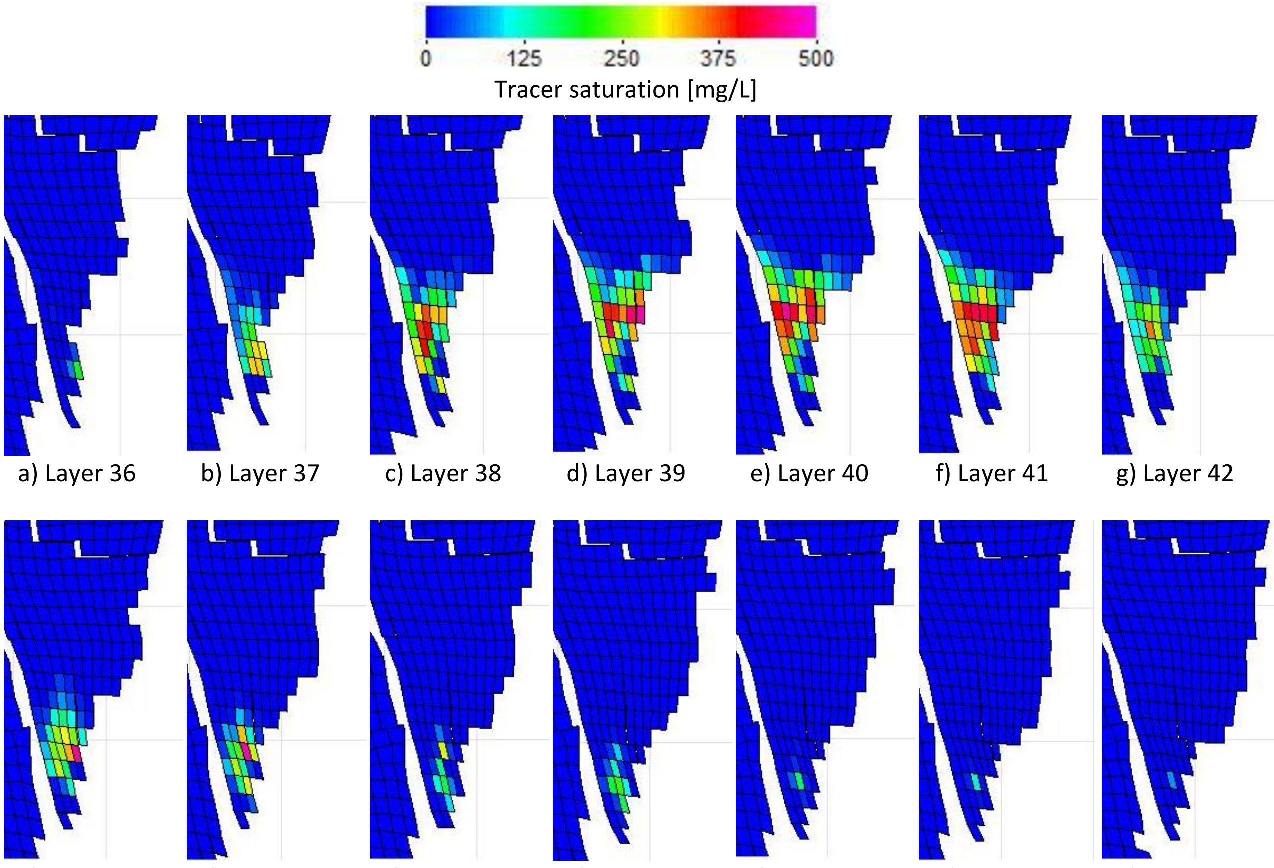

Figure 6.1 Tracer Saturation, 2 June 2012. The tracer was injected 1 January 2012.

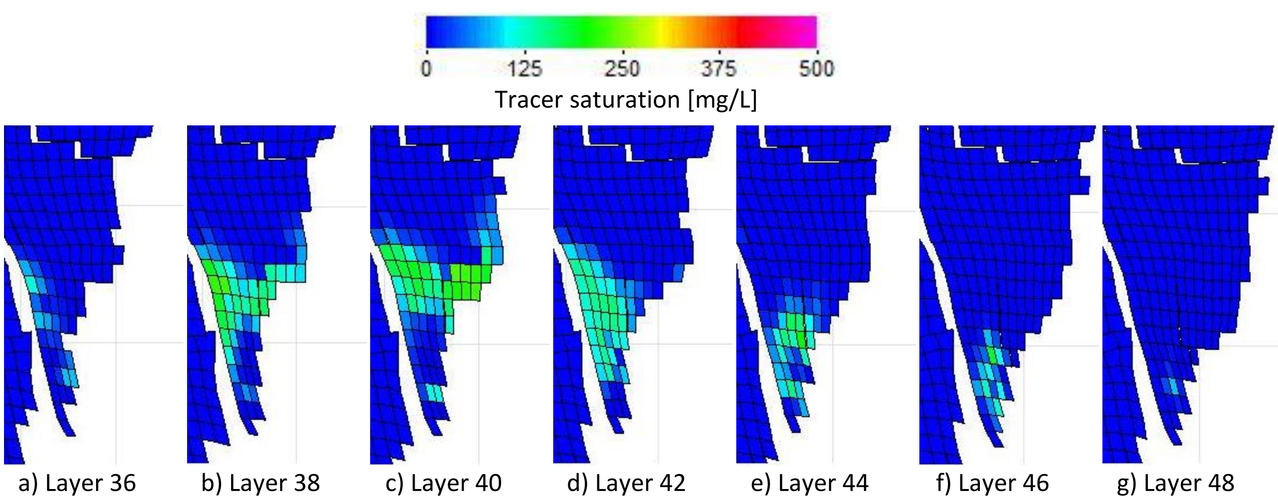

Figure 6.2 Tracer Saturation, 1 January 2013. The tracer was injected 1 January 2012

By comparing these figures with the previous statement that the gel coating will form on the rock surface both close to the well and reaching to a far (and to us unknown) distance from the well, it is seen that the tracer saturations the 2 June 2012 may be the most realistic result of the two.

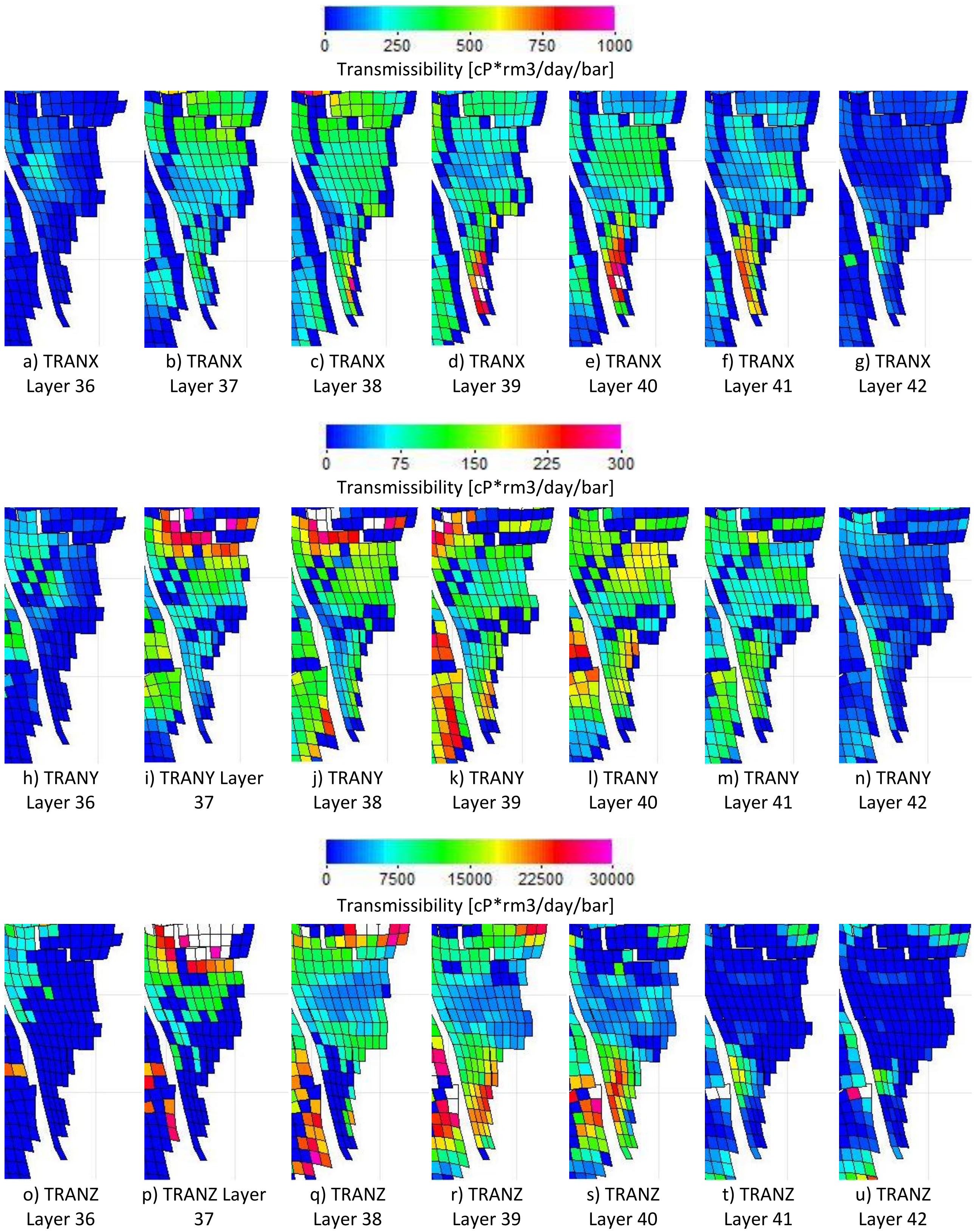

Figure 6.3 Initial transmissibility in X (a-g), Y (h-n), and Z (o-u) directions.

6.4 FINAL MODEL FOR SIMULATION RUNS (ALGORITHM C)

Algorithm C was used to run six scenarios with different values for the transmissibility reduction factor. The scenarios had reduction factors ranging from 60 % to 95 % in cells with a tracer concentration exceeding 300 mg/L. Table 6.1 shows the transmissibility multipliers that were used for each scenario dependant on the tracer concentrations of the cells.

Primarily, the transmissibility multipliers were applied only to X and Y directions. To see the influence of the Z direction, two simulations were also run with transmissibility multipliers in all directions. As presented in Section 7.1, the modifications in Z direction had only very small influence on the results.

Table 6.1 Algorithm C

	Transmissibility multiplier						
Tracer Concentration [mg/L]	**C1**	**C2**	**C3**	**C4**	**C5**	**C6**	**Cn**
>300	0.05	0.1	0.15	0.2	0.3	0.4	X
300-200	0.075	0.15	0.225	0.3	0.45	0.6	1.5*X
200-100	0.1	0.2	0.3	0.4	0.6	0.8	2*X
<100	1	1	1	1	1	1	1

All the grid blocks with a tracer concentration exceeding 300 mg/l were given the highest reduction multiplier. Grid blocks with tracer concentration between 200 - 300 mg/l were set to a lower reduction factor, while a concentration between 100 - 200 mg/l corresponds to an even less transmissibility reduction. The transmissibility of the cells with a tracer concentration below 100 mg/l was not changed. The reason for this choice of tracer concentration ranges was that ranges of equal sizes seemed to be the most organized way to do it. A higher number of ranges could be used to achieve higher detail, but the large uncertainties in the values compared to the reality meant that it was better to keep the algorithm as simple as possible.

Figure 6.4 a show a graphic of the original transmissibility in X-direction in Layer 40, and Figures 6.4 b-f show the transmissibility in X-direction after transmissibility reduction in Layer 40, with different multipliers used. Layer 40 is a heavily swept layer, and for that reason the transmissibility reduction is shown most clearly here. Based on Figure 6.4 it can be seen that the transmissibility reductions that are implemented have great impact on the model.

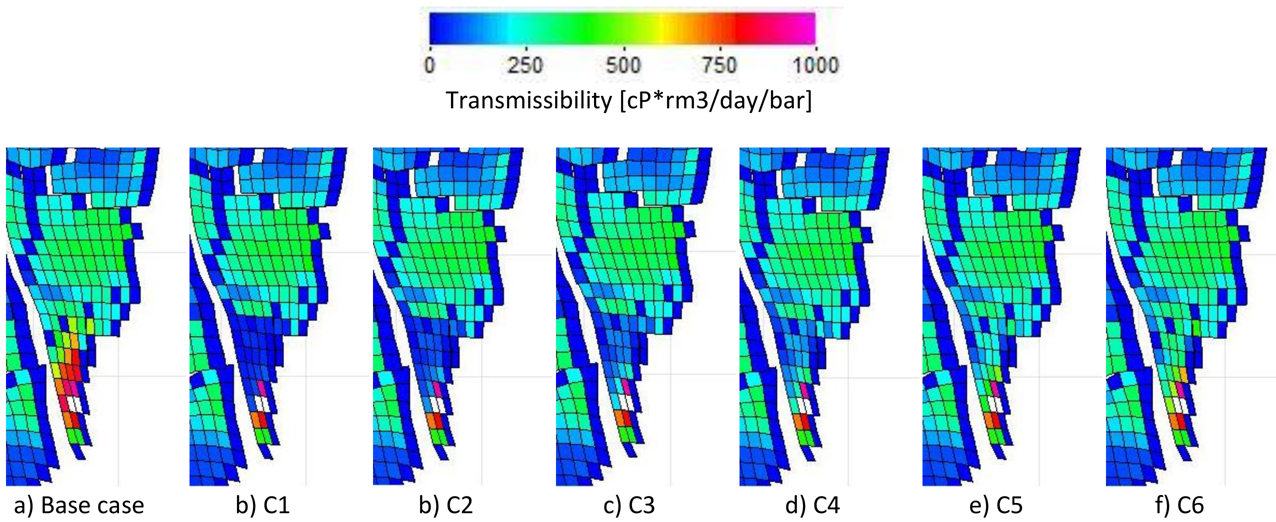

Figure 6.4 Transmissibility in X-direction before (a) and after (b-f) transmissibility modification for scenario C1-C6, Layer 40

7 SIMULATION RESULTS AND DISCUSSION

Simulations were done with transmissibility modifications as described in Section 6.3. However, because of the assumption that the most realistic positioning of the Abio Gel is when the simulated tracer is at time step '318', which is 2 June 2012 like shown in Figure 6.1, the results that are discussed here are mainly focused on this positioning of the Abio Gel. The tag '319' is added to some parts of the economic discussion in Chapter 7.4, and is related to the tracer position 1 January 2013 (Figure 6.2).

In the Eclipse model in use all the production and injection wells that are perforated in segment H1 are grouped as Group H1. Group H1 consists of the wells presented in Table 7.1, except A-38 A. A-35 was previously a producer in Lower Brent, but is now used as an injector. A-38 was previously an injector in Lower Brent, but was shut in before a side-track was made into Ness where it is now a producing well, A-38 A. A-38 A is unfortunately not included in the Eclipse model used in this report, so production data from that well cannot be analyzed.

Table 7.1 Status of wells in Group H1

	Tarbert	Ness	Lower Brent	Cook
A-1 H			Permanent P&A	
A-2 AH			Permanent P&A	
A-5 H		Shut in	Permanent P&A	
A-17			Shut in	Injecting (A-17 AT2)
A-35			Injecting	Shut in
A-38 A		Producing	Shut in (A-38 inj)	
A-39 A			Producing	
B-37	Plugged	Producing		

7.1 TOTAL OIL PRODUCTION

The results from the Eclipse simulations show a significant increase in total oil production for the scenarios with the highest transmissibility multipliers, as seen in Figure 7.1. The corresponding table with values for Figure 7.1 is found in Table B.1 in Appendix B. From Table 7.2 can be found that scenario C1 results with a production increase of 0.48 million SM3 compared to the original case, which translates to a total production increase of 39.8 % during the 12.5 years after the transmissibility reduction in the reservoir. The result from case C2 show less than half the production increase of C1, with a 0.22 mill SM3 (18.1 %) compared to the original case, which indicates that the degree of blockage has a large influence on the recovery. The increase of production in scenario C3 compared to the original case is 0.076 million SM3 (6.3 %). Scenario C4, C5 and C6 are all really close to the original case, primarily because of the little change in transmissibility. Scenario C5 and C6 result somewhat surprisingly with a slightly less total production than the base case. The reason may be that a low transmissibility multiplier in a highly flushed zone will result in less recovery in that zone, and only give a slight recovery increase in surrounding areas.

Table 7.2 Production results from the Eclipse simulations with scenario C1 to C6.

	Original	C1_318	C2_318	C3_318	C4_318	C5_318	C6_318
Total production Jun '12 - Jan '25 (mill SM3)	1.210	1.691	1.430	1.287	1.221	1.183	1.178
Production increase VS original case (mill SM3)	0.000	0.481	0.220	0.076	0.011	-0.027	-0.033
Total production Jun '12 - Jan '25 VS original case (fraction)	1.000	1.398	1.181	1.063	1.009	0.978	0.973

The increase in production may be easier to see in Figure 7.2 which shows a graphic of production rates for the different scenarios. The corresponding values are found in table B.2 in Appendix B. A transmissibility reduction in the highly water flushed zones seems to greatly improve the production rate and keep it at a relatively constant level above the original case.

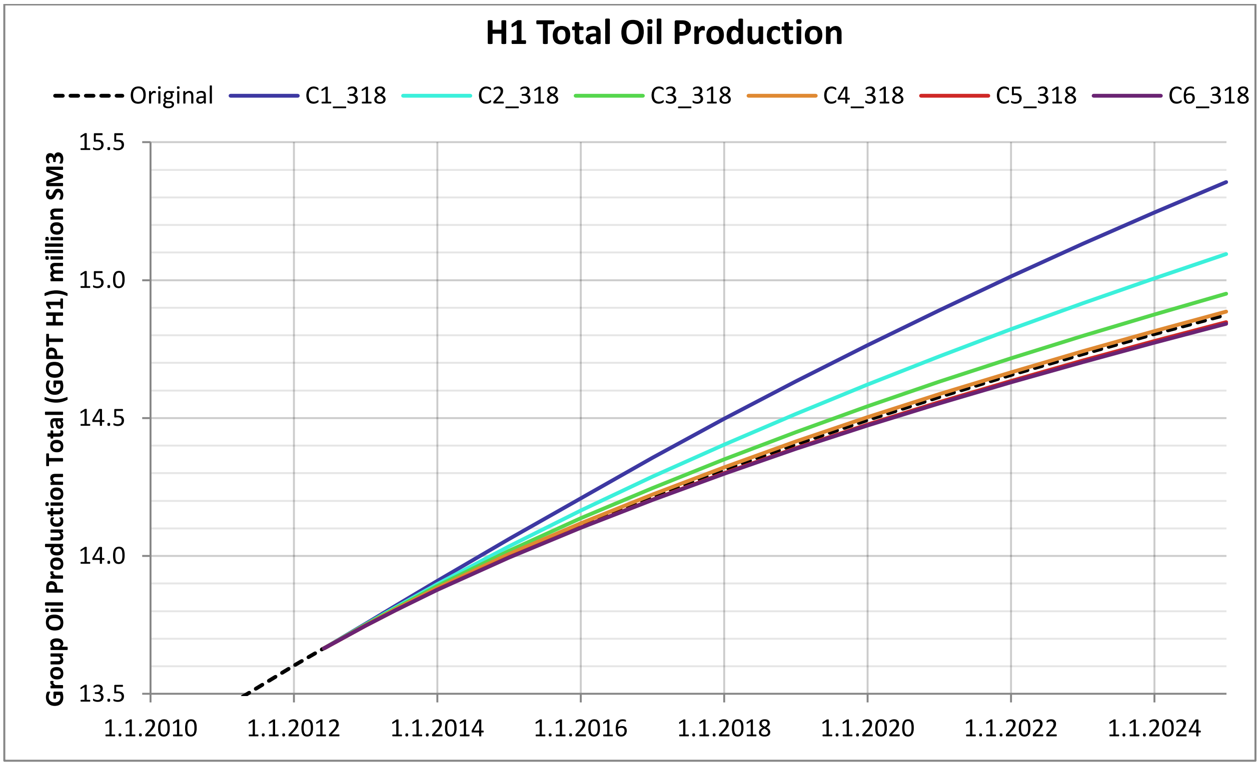

Figure 7.1 Group Oil Production Total (GOPT) for Gullfaks segment H1

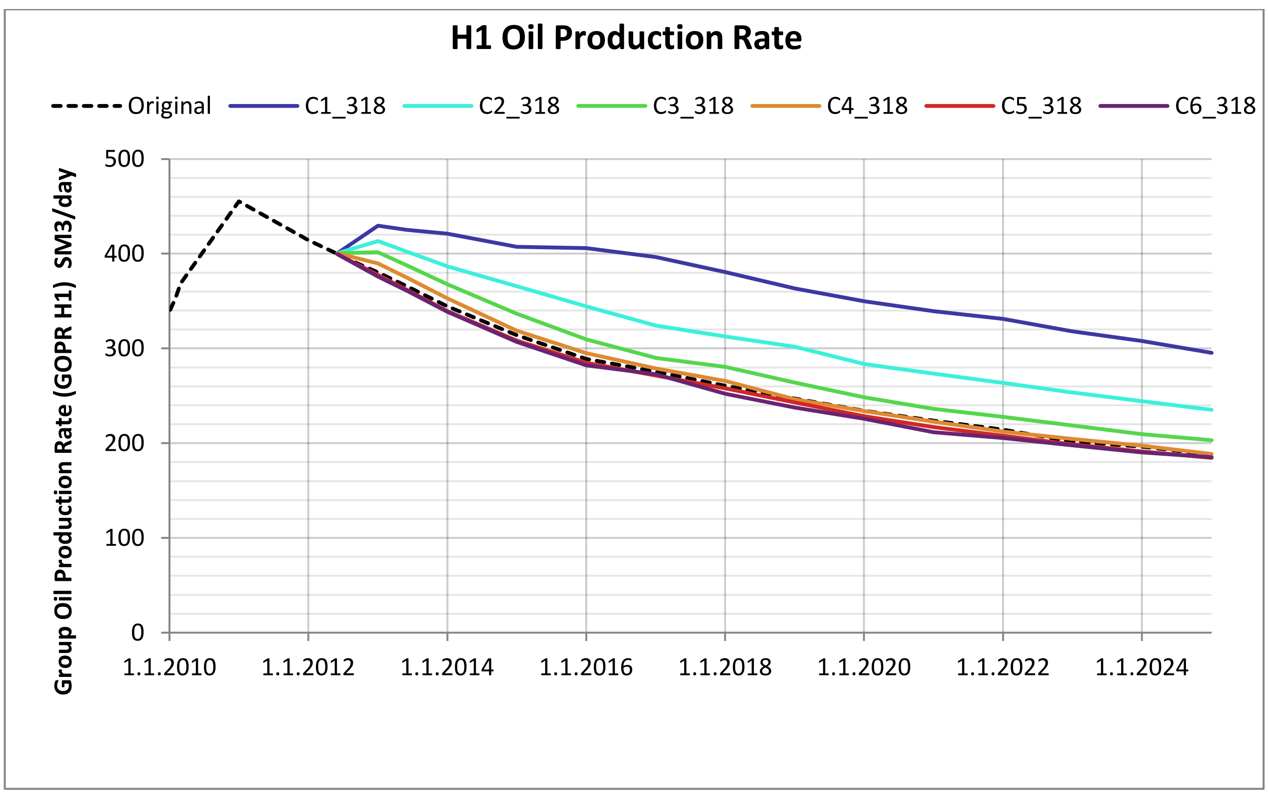

Figure 7.2 Group Oil Production Rate (GOPR) for Gullfaks segment H1

Table 7.1 shows that currently three wells are producing in Group H1. The impact of the Abio Gel differs largely between the different wells. Figure 7.3 and 74 shows the oil production rate for the six scenarios in wells B-37 and A-39 A. The oil production in A-39 A in Lower Brent increases for all scenarios, while the production in B-37 in Upper Brent is more varied, with a higher rate in the beginning and a lower rate after a few years. This indicates that the volumetric sweep is increased in Lower Brent and reduced in Upper Brent because of the transmissibility reduction. Well A-38 A was not included in the Eclipse model, and production from that well was therefore not simulated.

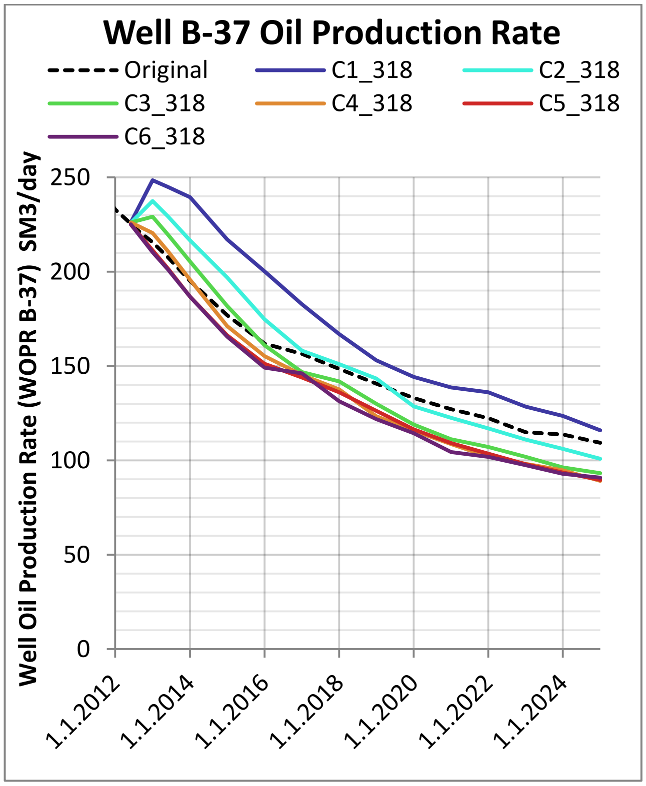

Figure 7.3 Well Oil Production Rate for B-37 (WOPR)

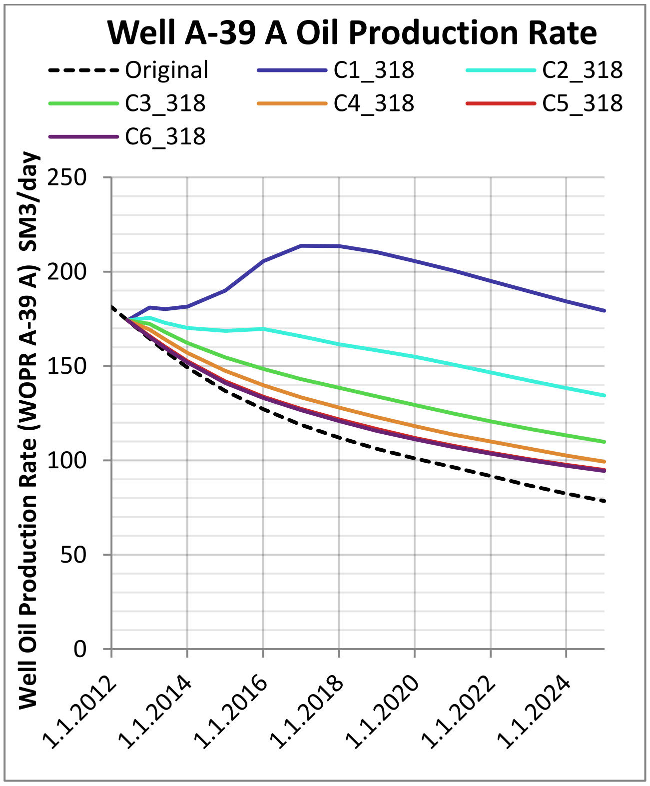

Figure 7.4 Well Oil Production Rate for A-39 A (WOPR)

It was mentioned in Section 6.3.2 that we applied transmissibility in X and Y direction only. To see the influence of the Z direction, scenario C2 and C3 were run with modifications in Z direction. The result is shown in Figure 7.5. The differences are very slightly recovery increases (only 0.07 % increase in both scenarios) from June 2012 to January 2025 when the transmissibility also is modified in Z direction.

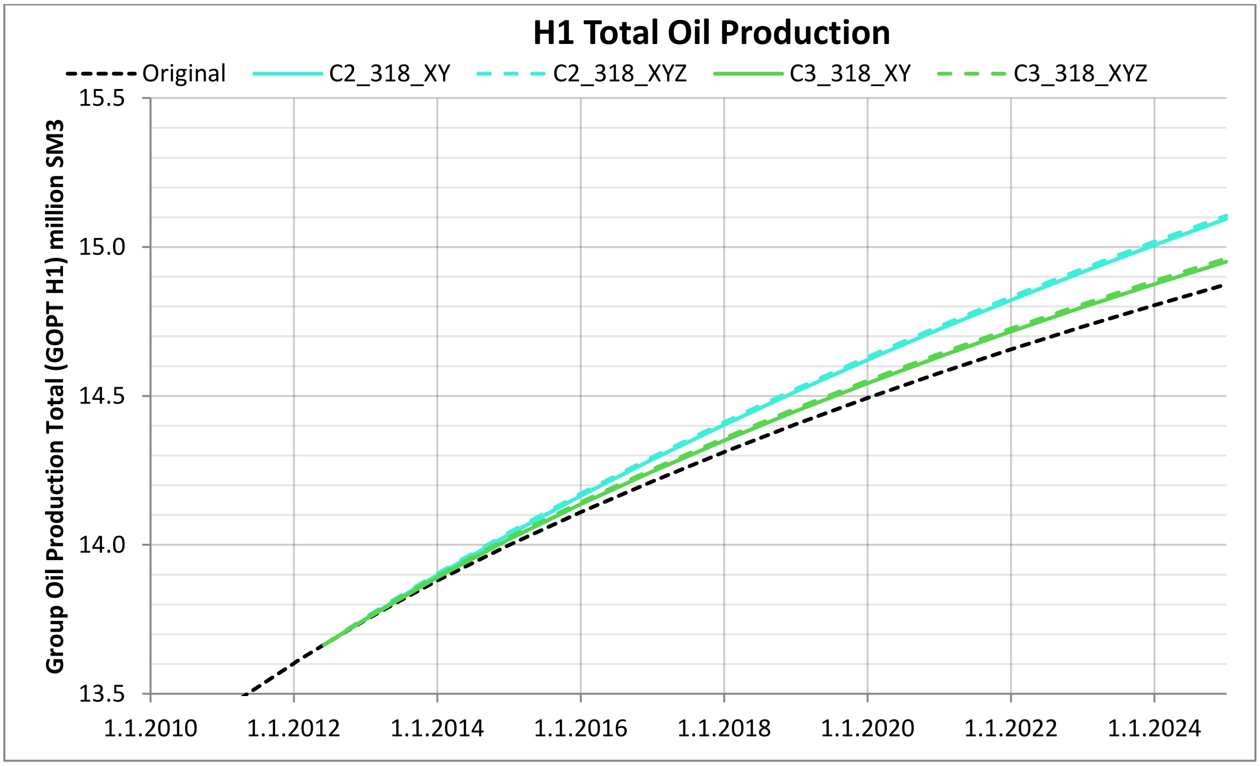

Figure 7.5 Group Oil Production Total (GOPT) for Gullfaks segment H1

7.2 OIL RECOVERY

Based on the data obtained from the Gullfaks Reservoir Management Plan 2007, there is no exact value of STOOIP for the entire segment H1. However, in Lower Brent in segment H1 the STOOIP is estimated to 20.3 million SM^3 (Gullfaks RMP, 2007). A limited communication between Lower Brent and Upper Brent makes it difficult to differentiate the recovery factor in these formations.

Recovery factor calculations are based on the oil production from the wells that are producing or have been producing from Lower Brent. These wells are listed in detail in Table 6.3. It consists of wells A-1, A-2AH, A-17, A-35, and A-39A. The recovery factor calculations are presented in Figure 7.6. The calculated recovery factor for base case is 54%, which is 3% lower than the data provided. Taking account of history matching discrepancies, these differences of recovery factor is acceptable. In addition, the estimated end of production is likely to be later than 2025.

The oil recovery increased 1.9 percentage points in scenario C1 compared to the base case. For the scenario C2 – C6 the recovery is gradually less than for C1 along with decreasing pore plugging percentage. For scenario C6 with transmissibility multiplier of 0.4 the increase in recovery is only 0.2 percentage points.

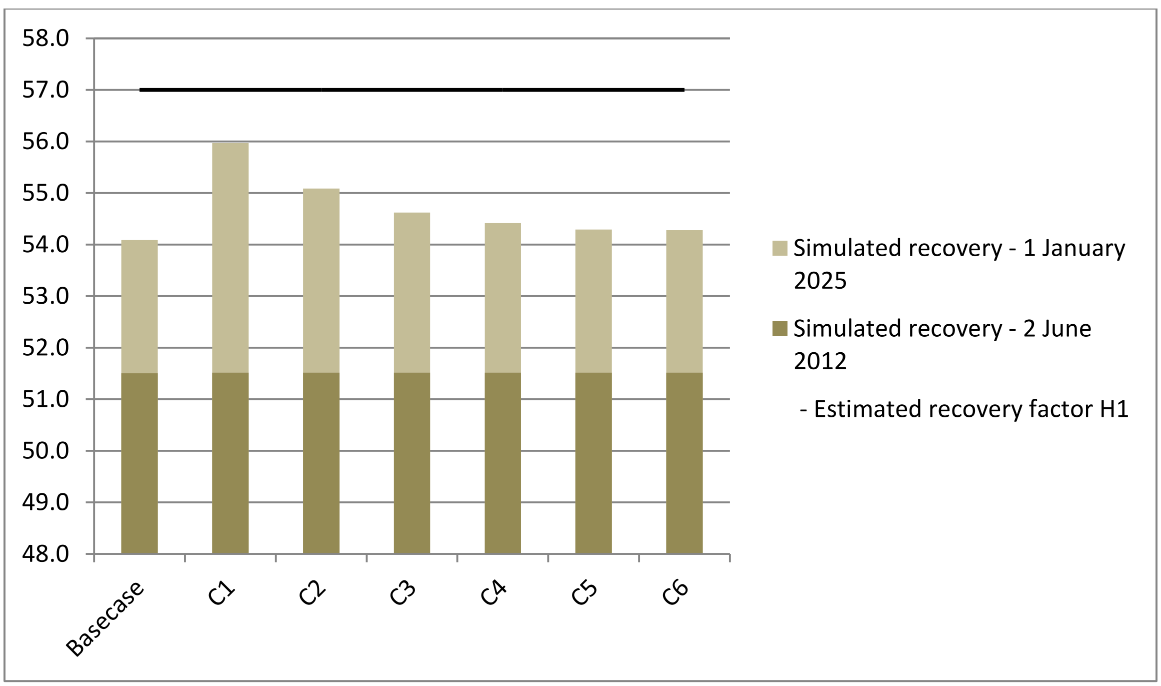

Figure 7.6 Oil recoveries from the simulations scenarios in Gullfaks segment H1, Lower Brent.

7.3 Water cut

A high water cut will occur sooner or later for many production wells in a mature field. Water takes up much of the volume of the production tubing and may limit the pressure drawdown. In Gullfaks segment H1, the injected water from A-35 flows through the reservoir and arrives after a while at the production well. If the in depth profile control is successful the injected water will displace oil in the reservoir and the result is a lower water cut. Figure 7.7 shows graphs of the water cut for the different simulated scenarios. The results are totally in agreement with the results previously presented in Chapter 7.1. The best scenario, C1, experiences a drop of approximately 5 percentage points in water cut. In comparison, the other scenarios follow the same trend as seen for total oil production in Chapter 7.1.

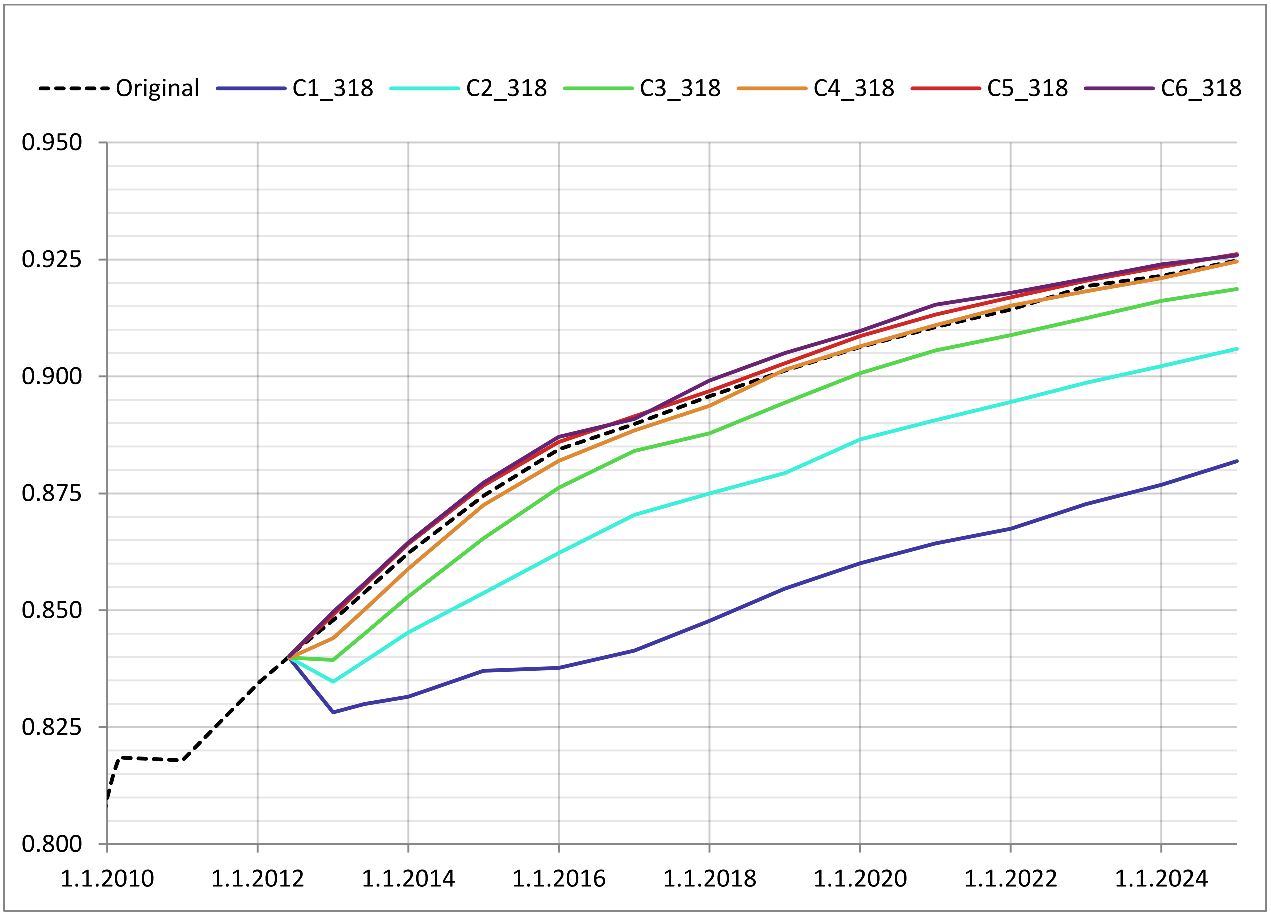

Figure 7.7 Water Cut (FWCT) for Gullfaks segment H1

7.4 EFFECT ANALYSIS OF THE ABIO GEL IN SEGMENT H1

The previously presented results show a wide range in production, from a 39.8 % increase in C1 to a 2.7 % decrease in C6 compared to the base case during 12.5 years. For scenario C1 it is assumed that the blocking effect of the Abio Gel is very high, probably unrealistically high. As mentioned in Section 5.2.2, experiments with Abio Gel in cores have shown a permeability reduction of 60 % to 90 %. In addition, an analysis by Tang, X. et al. (2012) concluded that the gelatination degree of the WJSTP is only 50-70 % with the formation water present in the reservoirs in Gullfaks. The gelatination degree is the ratio of gel volume to the total volume, and the higher the gelatination degree, the more adequate the gelatination reaction of the cross-linking system, according to Tang, X. et al. (2012). It is however likely that a low gelatination degree may be compensated for by injecting a higher number of WJSTP batches. It is also possible to add inorganic additives to improve the gelatination in reservoirs with formation water of poor salinity.

For this reason also scenario C2 may be in the high range, but with a transmissibility reduction of 80-90 % it is considered a likely case. Scenario C3 with 70-85 % reduction is also considered a likely case, although it only gives an increase in oil production of 6.3 % from 2012 to 2025 compared to the base case. Table 7.3 shows the transmissibility ranges that are used for each scenario. Economic analyses of the different scenarios are presented in Section 7.5.

The sources of errors related to the algorithm in use must however be taken into account. It is difficult to predict a realistic algorithm without results from laboratory tests with cores from segment H1. Laboratory tests with the same rock and formation water that is present in segment H1 would give an indication of the gel coating effect by the WJSTP.

Table 7.3 Transmissibility reduction for individual scenarios. Green color indicates the scenarios that we consider the most likely, yellow color might be likely, and the red color indicates scenarios that are considered not likely. These conclusions are based on the literature study presented in this report.

Scenario	Transmissibility reduction
C1	90 – 95 %
C2	80 – 90 %
C3	70 – 85 %
C4	60 – 80 %
C5	40 – 70 %
C6	20 – 60 %

7.5 ECONOMIC CALCULATIONS AND DISCUSSION

7.5.1 Initial analysis and Sensitivity.

Initial economic analysis based on the result of the base-case production prediction. The parameters included in this analysis are an assumed oil price of USD 100/barrel, conversion factor of NOK 5.78 / USD 1.00, and discount factor of 8%. Sensitivity analysis are based on oil and gas price (increase 5% or decrease 3% p.a.), production (increase or decrease 30%), and investments (increase or decrease 40%).

The analysis included all factors to interpret which parameters are dominating in determining the Net Present Value [NPV] of the project. After calculating the NPV based on changes in parameters, the changes in percentage is shown in a tornado chart.

The tornado chart in Figure 7.8 is based on project NPV calculation of the base case where no initial investment was made but taking account on changes in oil price and total production. It may be unrealistic to have an increase in production without initial investments. Nevertheless, the calculation is done to compare the changes. The result shows that the changes in oil price affected the positive NPV of the project. But a longer bar in the production parameters shows that changes in production are more sensitive towards the changes of the overall NPV.

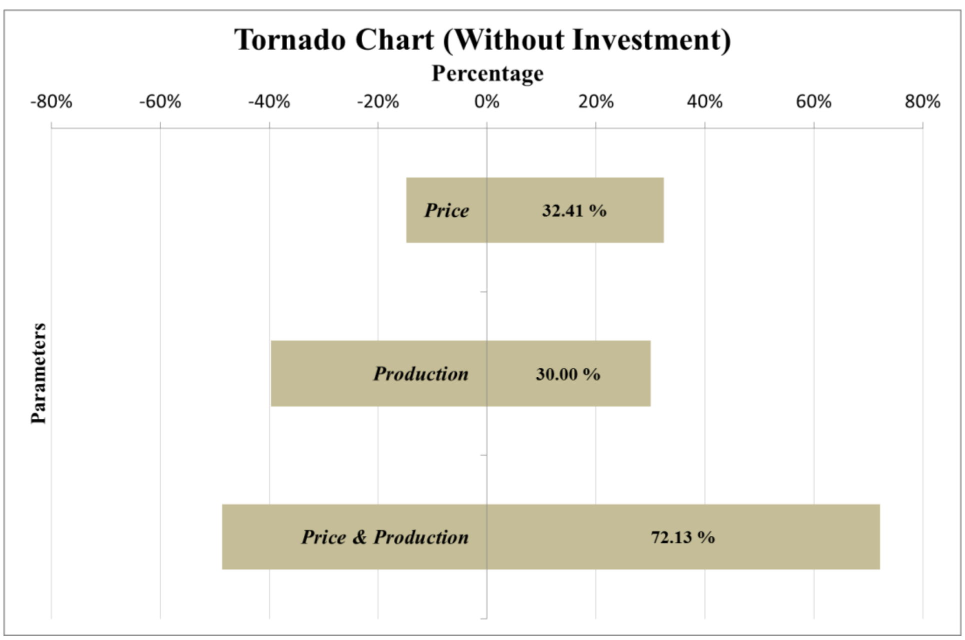

Figure 7.8 Tornado chart without taking investment into account.

The tornado chart in Figure 7.9 is based on project NPV calculation of the base case by taking account of changes in investments, oil price and total production. The result shows that the changes in price have a more positive value towards the NPV of the project. But in a single parameter basis the NPV is the most sensitive to production volume. Investment is the least sensitive towards the change of project NPV due to the high revenue of production compared to the value of investment itself. An overall analysis showed that price and production is the most sensitive parameters towards the NPV of the project.

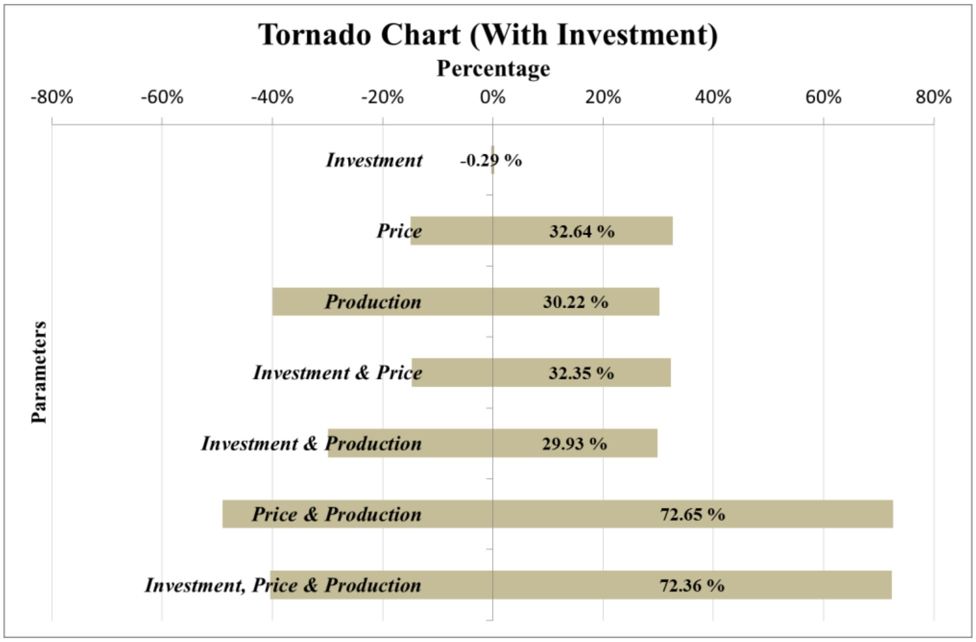

Figure 7.9 Tornado chart with taking investment into account.

The values for the tornado chart plotting are given in Table 7.4 and 7.5. Table 7.4 present the values without taking investment into account, while Table 7.5 gives values that takes investment into account. The first column is the parameters, followed by the high value, the base value, the lowest value and the last 2 columns is percentage of change with respect to the base value.

Table 7.4 Sensitivity analysis values without taking investment into account.

Parameters	Increase Value	Base Value	Decrease Value	High	Low
Price	MNOK 3,689	MNOK 2,786	MNOK 2,372	32.41 %	-14.85 %
Production	MNOK 3,622		MNOK 1,681	30.00 %	-39.66 %
Price & Production	MNOK 4,796		MNOK 1,429	72.13 %	-48.69 %

Table 7.5 Sensitivity analysis values by taking investment into account.

Parameters	Increase Value	Base Value	Decrease Value	High	Low
Investment	MNOK 2,758	MNOK 2,766	MNOK 2,774	-0.29 %	0.29 %
Price	MNOK 3,669		MNOK 2,352	32.64 %	-14.96 %
Production	MNOK 3,602		MNOK 1,661	30.22 %	-39.95 %
Investment & Price	MNOK 3,661		MNOK 2,360	32.35 %	-14.67 %
Investment & Production	MNOK 3,594		MNOK 1,938	29.93 %	-29.93 %
Price & Production	MNOK 4,776		MNOK 1,409	72.65 %	-49.04 %
Investment, Price & Prod.	MNOK 4,768		MNOK 1,648	72.36 %	-40.40 %

7.5.2 Economic Analysis based on simulation results.

The results of the simulations in terms of 'Group Oil Production Total H1' are broken down into yearly total oil production. The yearly total oil production is used to be the basis of project NPV calculations using the same parameter; assumed oil price of USD 100/barrel, conversion factor of NOK 5.78 / USD 1.00, and discount factor of 8%. The project NPV for each scenario is presented in Figure 7.10. The dark-tan bar in the figure shows the project NPV for transmissibility modifications generated at time step 318, which is on the 2nd June 2012 (as seen in Figure 6.1), and represents gel coating at a distance from close to the injection well to up to approximately 500 meters from the injection well. The light-tan bar is for transmissibility modifications generated at time step 319, which is on the 1st January 2013 and represents gelling at distance from approximately 500 to 800 meters from the injection well in layer 40. But the position is different for every layer, so refer to Figure 6.2 to see illustrations.

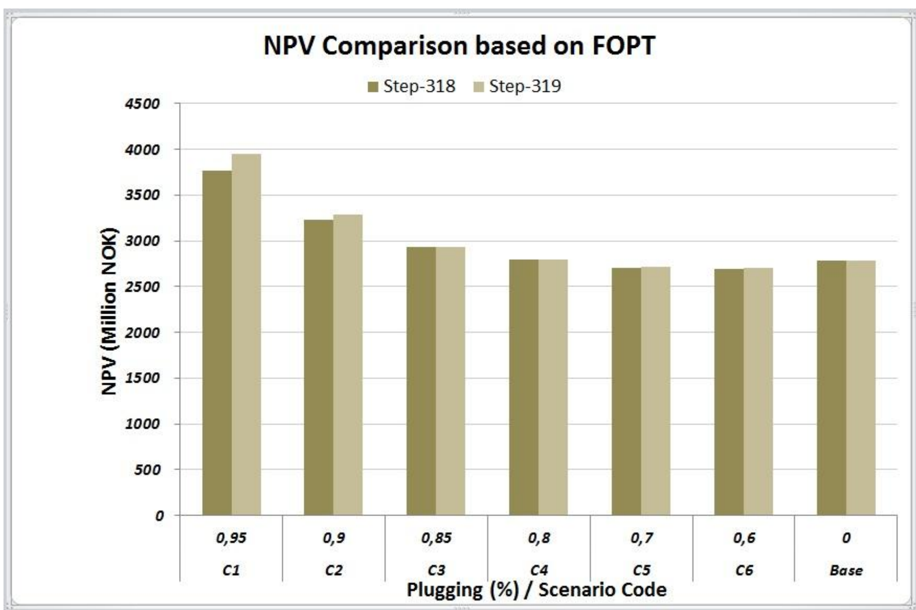

Figure 7.10 Project NPV comparison based on FOPT.

The increase of NPV with respect to base case NPV result is plotted in Figure 7.12. From this figure we can see that the best scenario is scenario C1 (95% transmissibility reduction) with placement of Abio Gel up to 800 meters from injection well (time-step 319). From scenario C3 (85% transmissibility reduction), the positioning of Abio Gel (time step 318 and 319) does not give a significant difference in term of project NPV. Further transmissibility reduction as those in the case of C5 and C6 shows that project NPV is lower than the base case (without implementing Abio Gel).

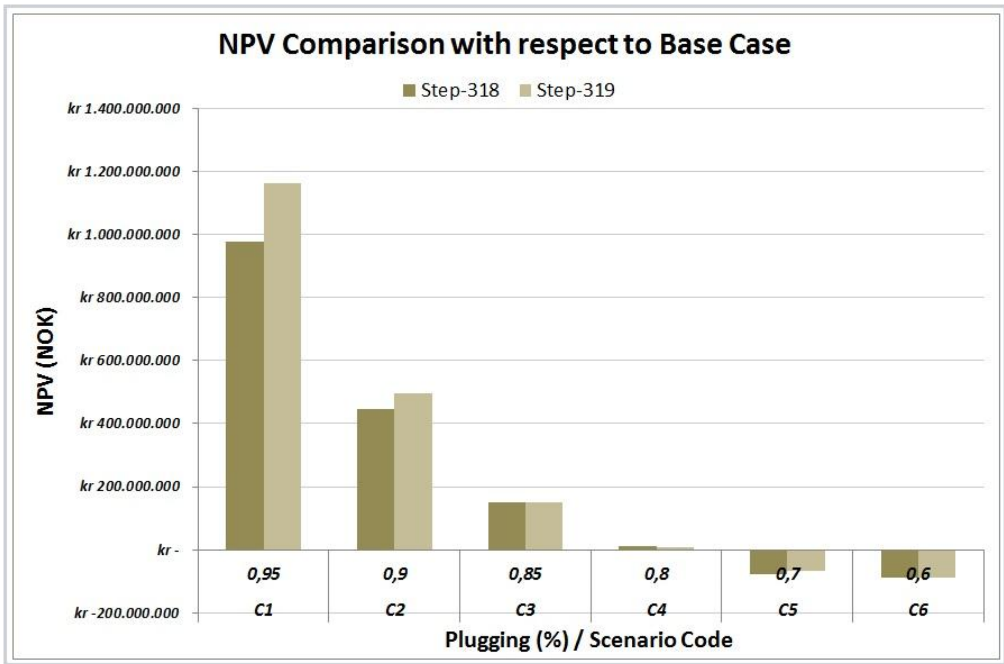

Figure 7.11 Increased in NPV with respect to base case scenario NPV.

The discussion from the simulation result in Chapter 7.4 suggested that the positioning of Abio Gel will most probably be similar to the tracer concentration at time step 318, which is up to approximately 500 meters from the injection well. Scenario C2 would be the best case scenario based on realistic value of pore plugging and position where the gelling takes place. Scenario C2 with position at time step 318 will yield a NPV of 445.41 Million NOK which is a revenue increase of 16% compared to base case. The cumulative net present value plot for scenario C2, time step 318 is shown by the darker-tan bar in Figure 7.12. In the same figure, for the purpose of comparison, a plot of cumulative present value for scenario C3, time step 318 is shown by the lighter-tan bar.

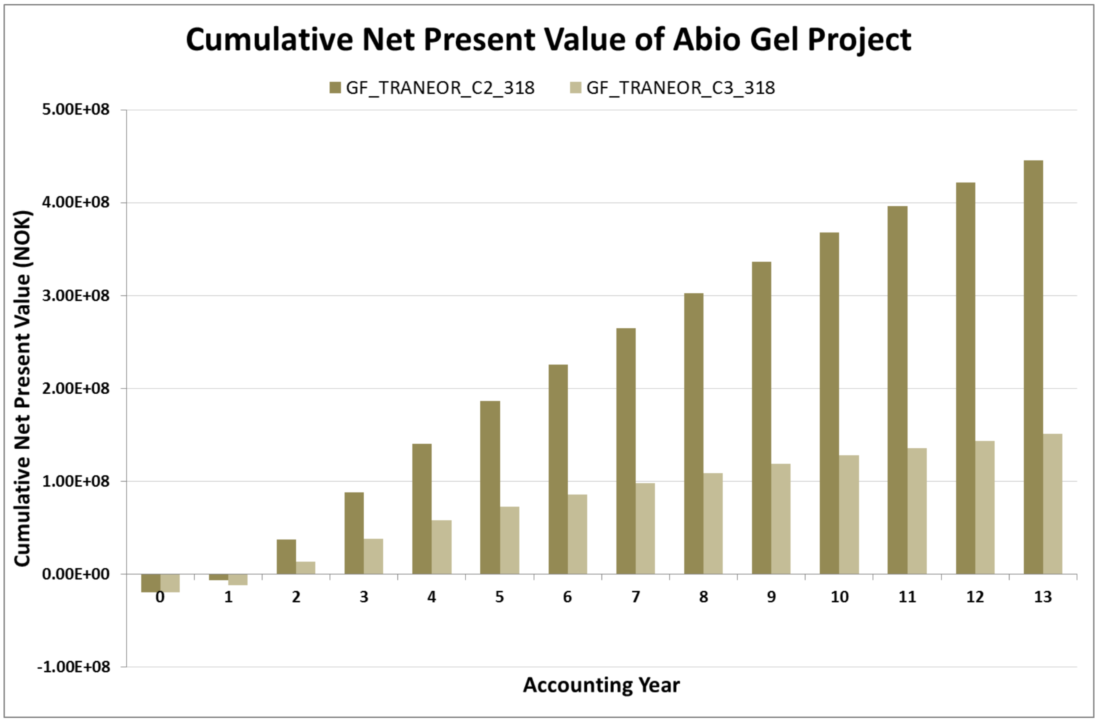

Figure 7.12 Cumulative NPV for scenarios C2_318 and C3_318.

8 CONCLUSION

Several Eclipse simulations were run to estimate the effects on oil recovery in segment H1 in Gullfaks Main Field by injection of a flow diverting agent called Abio Gel. The gel coating was simulated by modifying transmissibility between cells in a reservoir model.

The simulation results indicate that the feasibility of the Abio Gel project in the H1 segment depends highly on the degree of transmissibility reduction, which is the capability of the gel to reduce the transmissibility of the water path area.

The literature study about the behavior of in depth profile control agent along with the simulation study, suggested that a transmissibility reduction range of 80-90% and 70-85%, with 0 - 500 meters distance from injection well is the most likely case. Transmissibility reduction in the range of 80-90% up to 500 meters from the injection well resulted in a production increase of 0.22 million Sm^3 or an 18% increase in total oil produced with respect to the base case from 2 June 2012 to 1 January 2025. In monetary value, it gives an increase of 445.4 Million NOK or 16% revenue increase with respect to the base case. Transmissibility reduction in the range of 75-85% at an distance up to approximately 500 meters from the injection well resulted in a production increase of 0.076 Million SM^3 or 6.3% increase in total oil produced with respect to the base case from 2 June 2012 to 1 January 2025. In monetary value, this gives an increase of 150.8 Million NOK or 5% revenue increase with respect to the base case.

An economic sensitivity analysis suggested that the variations in production and oil price are the main parameters that are influencing the feasibility of the project in terms of net present value. A value of USD 100 per barrel of oil was used in the calculations. Therefore, as long as the oil price is above the reference value for calculation, it is very likely that the project will be feasible.

Economic calculations, based on the simulation results of oil production, indicate that a transmissibility reduction higher than the range of 60-80%, represented by scenario C4, is needed to allow the project to be feasible.

Based on the simulations that are presented in this report, the implementation of Abio Gel in segment H1 is quite likely to be successful and profitable. If the Abio Gel pilot that was injected from September to November 2011 provides good results, it should be implemented in other segments of the Gullfaks Field to improve overall oil recovery.

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APPENDIX A

This appendix shows a step by step guide of editing properties in FloViz.

1. Load the Base Case scenario in FloViz. Base case scenario is the original simulation run that includes the tracer options.

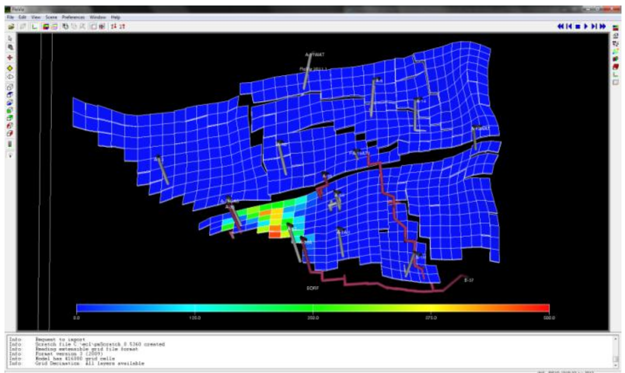

Figure A.1 Tracer Concentration at Time Step 318 (02 June 2012)

2. Select: Edit > Classic Property Calculator
   Checked the 'New Property' and click 'Create Property Type'
   In the Property Type Name: Enter the Mnemonics that we want to use.
   Select quantity : Transmissibility
   Select Families : Recurrent
   Click 'APPLY'

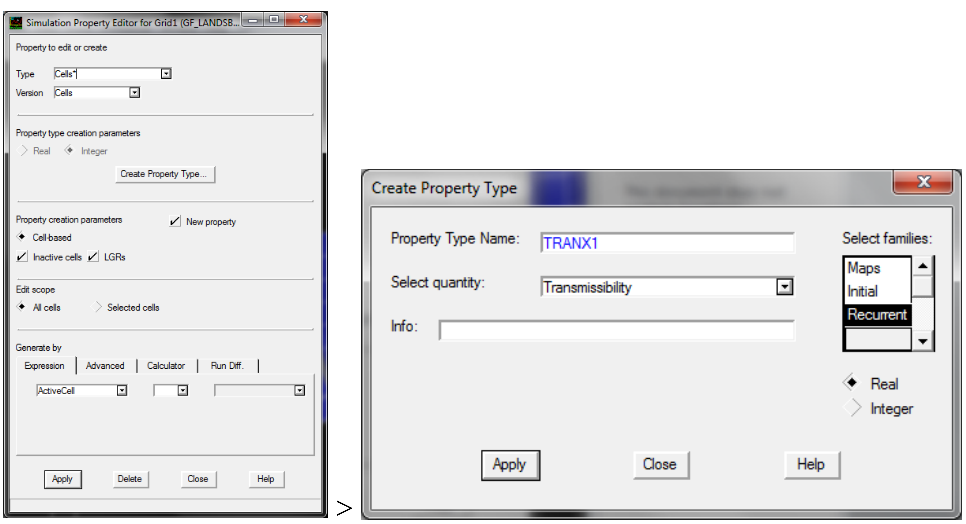

Figure A.2 Creating property.

3. The name will then show up in the ‘Type’ field.
   Change the ‘Version’ field to a suitable version known to the software. If there are no options in the drop-down menu, it is best to match it with the ‘Type’ field.
   Click the ‘Advanced’ tab and enter the algorithm that is used for recalculating the transmissibility.
   Click Apply and make sure there is a comment that appeared,
   “Expression accepted for processing.”

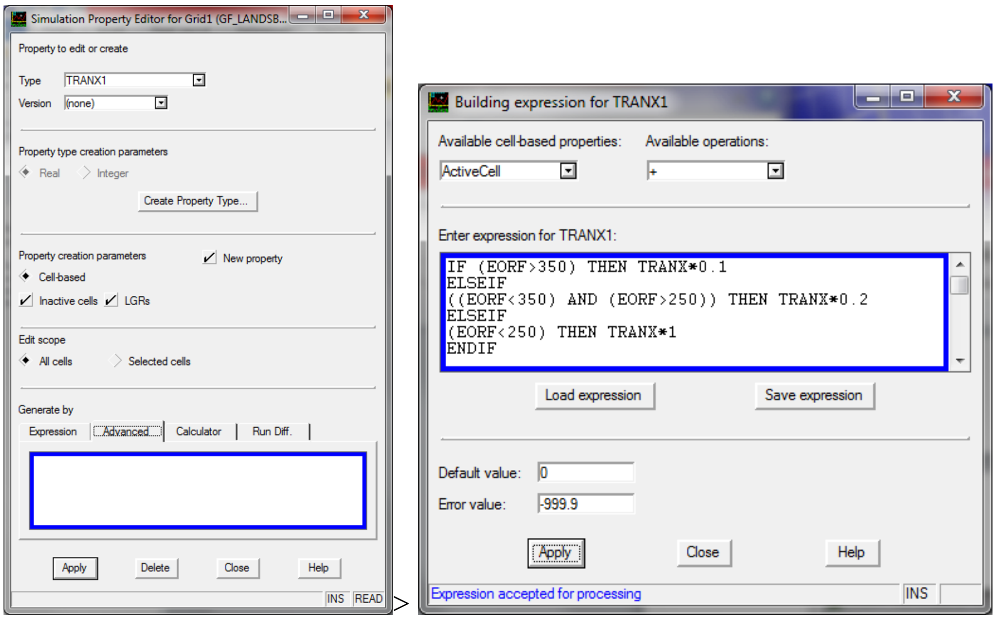

Figure A.3 Algorithm in property editor.

4. It will come back to ‘Simulation Property Editor’ with the algorithm included in it.
   Click Apply then it will start calculating the new transmissibility ‘TRANX1’ at each time step (as a result of choosing ‘recurrent’ option).

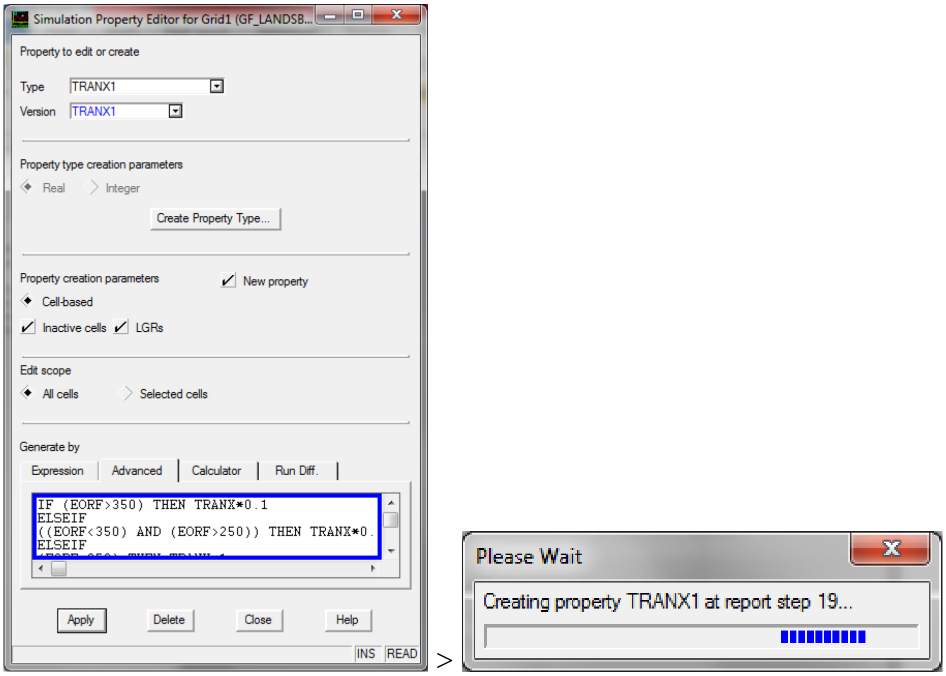

Figure A.4 Calculating new transmissibility.

5. After a SUCCESS message. Then CLOSE the window.

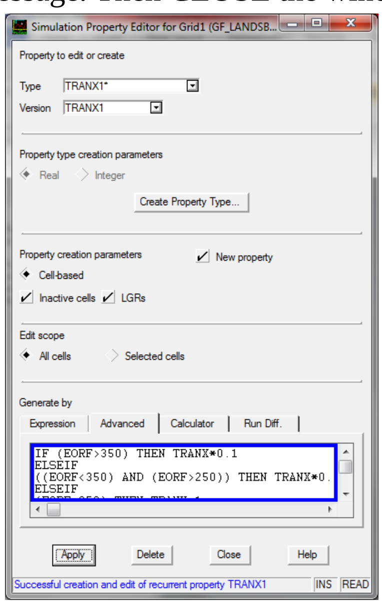

Fig A.5 The ‘Success’ message.

6. Generating a property file.
   File > Export > ECLIPSE RESTART GRDECL. Keywords
   ‘Select Properties for Output’ window will appear.

Select the time steps to generate an output of the edited file.
From ‘Recurrent Properties’ select TRANX1 to be put in ‘Selected Properties’
‘Save as..’ to file name (example: TRANX_EOR_SAMPLE)

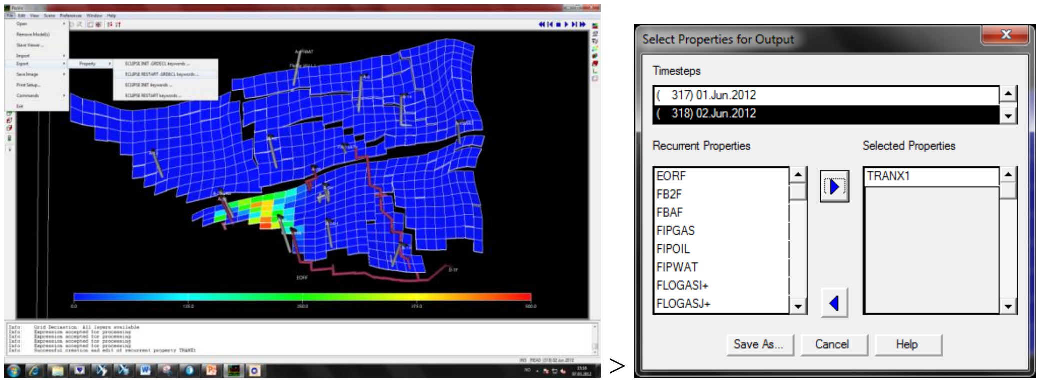

Figure A.6 Generating output properties file.

7. Open the saved file using Textpad software; Edit the file by changing the mnemonics in the file to a known mnemonics to Eclipse. In this example, changes made are from TRANX1 to TRANX. After changing, save the file and change the extension of the file to ‘.TRAN’

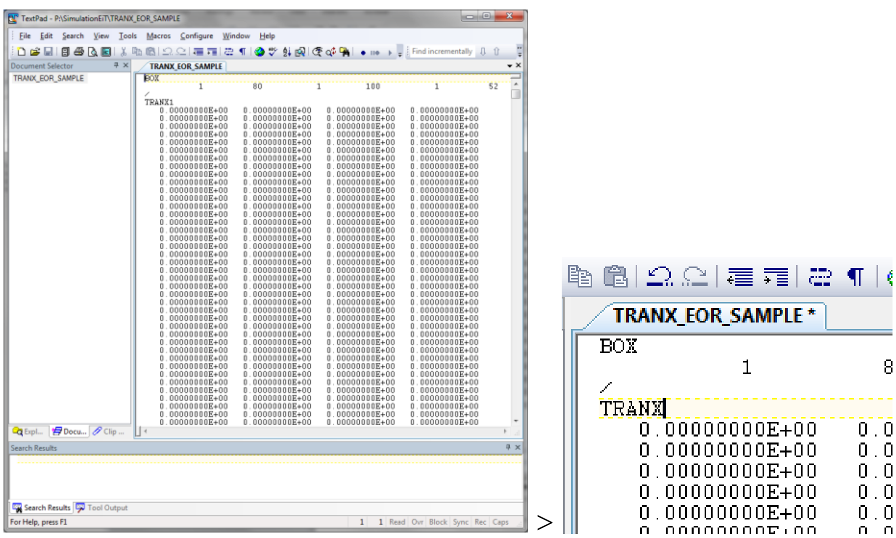

Figure A.7 Changing mnemonics of output file.

8. Afterwards, open with Textpad software the ‘.DATA’ file (the file needed to run the simulation) and under EDIT (or above PROPS) we can include our edited file by typing:

INCLUDE
TRANX_EOR_SAMPLE.TRAN /

After including this file, the simulation using the edited transmissibility value can be run.

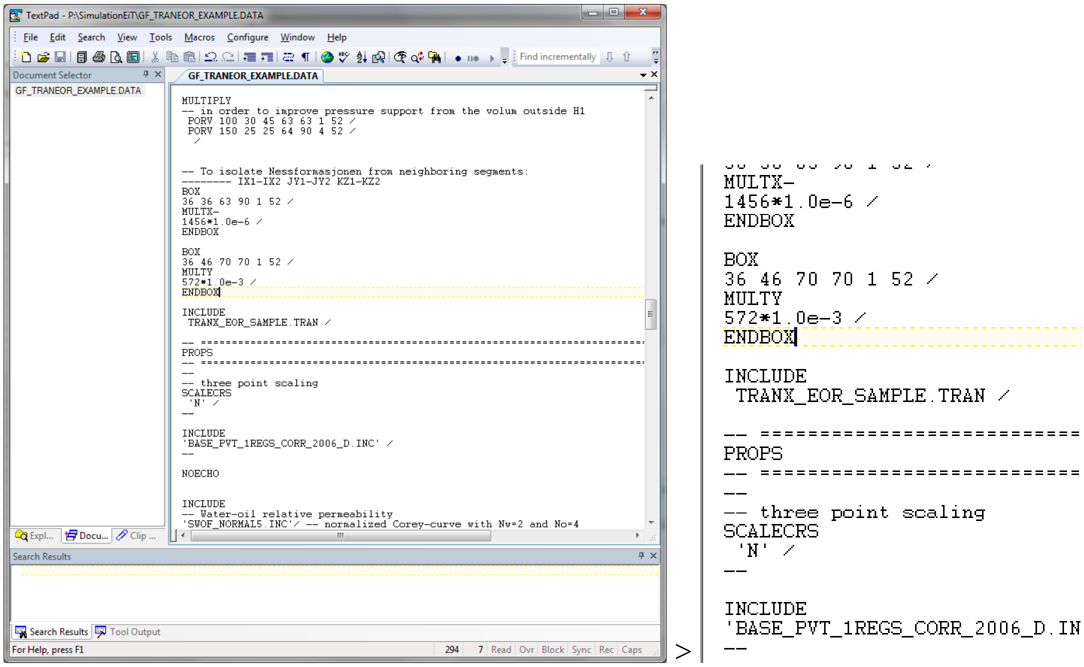

Figure A.8 Entering 'INCLUDE' statement in the '.DATA' file.

APPENDIX B

Table B.1 Group Oil Production Total for Gullfaks segment H1 (GOPT H1)

DATE	Original (mill SM3)	C1_318 (mill SM3)	C2_318 (mill SM3)	C3_318 (mill SM3)	C4_318 (mill SM3)	C5_318 (mill SM3)	C6_318 (mill SM3)
02.jun.12	13.66	13.66	13.66	13.66	13.66	13.66	13.66
01.jan.13	13.75	13.75	13.75	13.75	13.75	13.75	13.75
01.jun.13	13.80	13.82	13.81	13.81	13.81	13.80	13.80
01.jan.14	13.88	13.91	13.90	13.89	13.88	13.88	13.88
01.jan.15	14.00	14.06	14.04	14.02	14.01	14.00	13.99
01.jan.16	14.11	14.21	14.17	14.14	14.12	14.10	14.10
01.jan.17	14.21	14.36	14.29	14.25	14.22	14.20	14.20
01.jan.18	14.31	14.50	14.40	14.35	14.32	14.30	14.30
01.jan.19	14.41	14.63	14.51	14.45	14.41	14.39	14.39
01.jan.20	14.49	14.76	14.62	14.54	14.50	14.48	14.47
01.jan.21	14.58	14.89	14.72	14.63	14.59	14.56	14.55
01.jan.22	14.66	15.01	14.82	14.72	14.67	14.63	14.63
01.jan.23	14.73	15.13	14.92	14.80	14.74	14.71	14.70
01.jan.24	14.80	15.25	15.01	14.88	14.82	14.78	14.77
01.jan.25	14.87	15.36	15.09	14.95	14.89	14.85	14.84

Table B.2 Group Oil Production Rate for Gullfaks segment H1 (GOPR H1)

DATE	Original (SM3/day)	C1_318 (SM3/day)	C2_318 (SM3/day)	C3_318 (SM3/day)	C4_318 (SM3/day)	C5_318 (SM3/day)	C6_318 (SM3/day)
02.jun.12	399	400	400	400	400	399	399
01.jan.13	380	430	413	402	390	377	376
01.jun.13	366	425	402	388	375	362	361
01.jan.14	344	421	387	368	353	339	339
01.jan.15	314	407	366	336	319	308	307
01.jan.16	289	406	344	309	295	285	282
01.jan.17	275	396	324	290	279	271	273
01.jan.18	261	381	313	280	266	258	252
01.jan.19	247	363	302	264	246	243	238
01.jan.20	234	350	284	248	234	228	226
01.jan.21	224	339	273	236	223	217	212
01.jan.22	214	331	264	228	212	208	205
01.jan.23	202	318	253	219	204	199	198
01.jan.24	196	308	244	210	197	191	190
01.jan.25	188	295	235	203	189	185	185

Table B.3 Faults surrounded by faults in each formation.

Top Tarbert	Top Ness	Base Ness	Top Cook	Top Statfjord	Top Lunde
			D1	D1	
			D2	D2	
			D3		I1
			D4		
D5					
E1			E1	E1	
E2	E2	E2	E2	E2	
E3		E3	E3		
E4		E4	E4		
F1	F1	F1	F1	F1	
F2				F2	
F3	F3	F3		F3	
F4	F4	F4	F4	F4	
			F7	F7	
G1	G1		G1	G1	
G2	G2	G2	G2	G2	
G3	G3	G3	G3		
			G6		
G7	G7	G7	G7		
H1	H1	H1		H1	
H2	H2	H2		H2	
	H3	H3	H3	H3	
		H4	H4		
			H5		
			H7	H7	H7
		I1	I1	I1	
		I2			
				I3	
			J3	J3	
			K1	K1	K1
					L2
	U1	U1			
15	**12**	**16**	**23**	**19**	**4**

APPENDIX C

Eclipse uses the following equation to calculate transmissibility in X-direction

$$TRANX_i = \frac{CDARCY * TMLTX_i * A * DIPC}{B}$$

where

$TRANX_i$ Transmissibility between cell i and cell j, its neighbor in the positive X-direction

CDARCY Darcy's constant = 0.00852702 (Metric units)

$TMLTX_i$ Transmissibility multiplier for cell i

A Interface area between cell i and j

$$A = \frac{DX_j * DY_i * DZ_i * RNTG_i + DX_i * DY_j * DZ_j * RNTG_j}{DX_i + DX_j}$$

DX, *DY* and *DZ* Dimensions of cell

RNTG Net to gross ratio

B Function of permeability in cell i and cell j

$$B = \frac{(\frac{DX_i}{PERMX_i} + \frac{DX_j}{PERMX_j})}{2}$$

DIPC Dip Correction

$$DIPC = \frac{DHS}{DHS + DVS}$$

with

$$DHS = (\frac{DX_i + DX_j}{2})^2$$

and

$$DVS = [DEPTH_i - DEPTH_j]^2$$

APPENDIX D

This appendix contains a process summary of the two first concentration and transmissibility multiplier model which was made. The first two algorithms are called algorithm A and B; The result is model A and B.

Model A is the first algorithm modeled for the simulation. These models were based on the example given in the “Groups-1-2-5-6” presentation slide from Statoil (Figure D.1). But in these models, concentration ranges were modified. The ranges were made smaller, so the gel blocking will occur in a smaller area compared to those simulated based on the example algorithm given. Apart from the difference in concentration algorithm, the model was simulated with different pore plugging percentage scenarios.

The example given on the slide were a model with transmissibility multiplier of 0.02 (98% pore plugging) and a wide concentration range resulting in a large affected area. The initial concentration set in the simulation was 416 kg/m3 and it was injected at time-step.

```
– In Generated by—-Advanced, use script, for example:
      IF (EORF>250) THEN PERMX or TRANX*0.02
      ELSEIF
      ((EORF<250) AND (EORF>40)) THEN PERMX or TRANX*0.04
      ELSEIF
      (EORF<50) THEN PERMX or TRANX*1
      ENDIF
      Here RRF (Residual resistance factor) is in the range 25-50.
```

Figure D.1 Example Algorithms

The initial algorithms focused mainly to minimize the area of gel blocking. The concentration ranges were divided into three; above 350, between 350 and 250, and below 250. It was assume no more plugging occurred for the concentration below 250, so the transmissibility multiplier iwas set to 1.0 for that range. Multiple simulations were run by varying the transmissibility multiplier and positioning of abio gel. The positioning of abio gel is simulated by generating the x-direction and y-direction transmissibility properties at different time-step. Table 6.1 shows the scenarios and the algorithms we use in our initial modeling.

Table D.1 Scenario and algorithm-A.

Scenarios	Concentration and Transmissibility Multipliers
Scenario_A1_Step-318 Scenario_A1_Step-319	>350 Then TRANS * 0.1 350 – 250 Then TRANS * 0.2 <250 Then TRANS 1.0*
Scenario_A2_Step-318 Scenario_A2_Step-319	>350 Then TRANS * 0.02 350 – 250 Then TRANS * 0.04 <250 Then TRANS 1.0*
Scenario_A3_Step-318 Scenario_A3_Step-319	>350 Then TRANS * 0.05 350 – 250 Then TRANS * 0.1 <250 Then TRANS 1.0*

These modeling algorithms were not of satisfactory as there were no significant difference on the simulation results. It was concluded that by reducing the affected area with the current algorithm, the model were not able to simulate flow diversion in order to reach the un-swept zone. The pressure gradients (dP/dx) were not big enough to make the water diverts and find the area with lower pressure. After these results, the algorithms are then re-modeled for the concentration range. Figure D.2a and D.2b shows the results of the initial simulation in comparison with the prediction case and example. The base case scenario is presented in black plotting, the example scenarios were presented in red plotting and the modeling are stacked under the green line. These shows that the initial model is not good enough to simulate the abio gel pore plugging under different plugging percentage. Therefore, another model was made by adjusting the concentration range to be wider. The model that is used for simulation is model C, as discussed in Chapter 6.

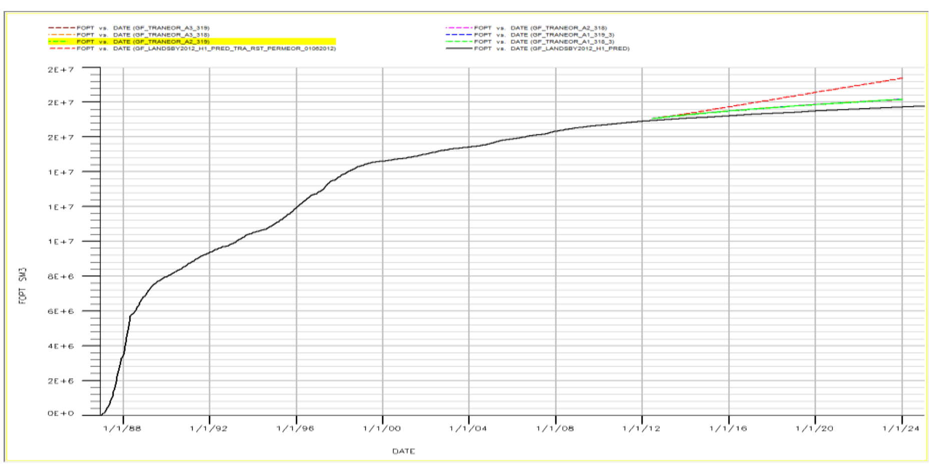

Figure D.2a Plots of Field Oil Production Total (FOPT).

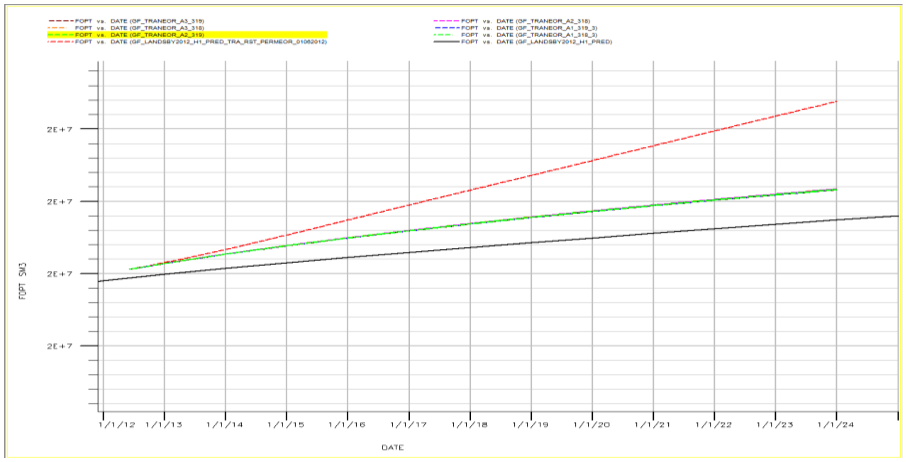

Figure D.2b Plots of Field Oil Production Total (FOPT), zooming in at tail production