Department of Petroleum
Engineering & Applied
Geophysics

Trondheim
May 2012

TECHNICAL REPORT - PART A AND B

IMPROVED OIL RECOVERY FROM GULLFAKS – IOR CHALLENGE 2

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Abstract

Many oilfields on the Norwegian continental shelf are mature fields with gradually decreasing production of oil and gas. As the technology being used by the oil companies is getting more and more advanced, previously unreachable fields might be put into production and the recovery factor of existing fields will increase. New measures are being explored by the oil producing companies to improve the oil recovery and get as much oil out of the ground as possible.

The Gullfaks field has been producing oil since the 22th of December 1986. The expected recovery at that time was 46.5% (Eltvik, P., 2012c). Because of advances in technology and a good depletion strategy the recovery is now approaching 60%. Statoil is aiming at a final recovery factor of 70% for the Gullfaks field, and to reach this goal measures must be taken. A lot of different IOR/EOR methods have been evaluated and tested on different segments of the Gullfaks field, many of them yielding promising results.

For our project we have looked at the possibility of diverting the flow of injected water through the field by reducing the permeability of certain parts of the reservoir. This way the injected water will flush previously unflushed zones, and this opens up the possibility of increased oil recovery. This method of EOR/IOR is rated by Petoro as one of the most beneficial measures that can be applied on the Norwegian continental shelf to increase oil recovery (Eltvik, P., 2012a). As a pilot project we look at a more or less isolated segment of the Gullfaks field, if the results are promising this might open up for a large scale application of the method.

Preface

This report is written as part of TPG 4851 Experts in Team, Gullfaks Village spring 2012, in cooperation with the Statoil Gullfaks license in Bergen. The goal of this village has been to challenge the students to come up with innovative solutions that could increase the oil recovery from the Gullfaks field. We would like to take the opportunity to thank the village supervisors Jon Kleppe and Jan Ivar Jensen, and the student assistants Ane, Cornelia and Thor Helge. We would also like to thank the Statoil project supervisors Petter Eltvik, Rasim Huseynov, Rune Instefjord and Erik Hodneland.

Project basis

The Gullfaks village is a village in the subject Experts in Team at NTNU. The village is cooperation between NTNU and Statoil, where the attendants work with problems related to the IOR challenges at the Gullfaks field. This year the challenge is specified against the use of Abio Gel in the injection water in segment H1, at the Gullfaks main field. The H1 block is produced with the help of water injection, but the injected water follow the high permeable layers, which act as water “highways” from the injector to the producer.

In November 2011 Statoil carried out a pilot EOR-project, where a water soluble chemical named Abio Gel was injected together with the injection water. This gel is supposed to reduce the permeability in the water “highways”, and then divert the water into lower permeability unflushed rock. These areas contain a significant amount of bypassed oil, and the goal of the measure is to increase the oil production and decrease the water cut of the segment. Task B is regarding simulation of this permeability reduction to predict future oil production rates in different permeability reduction scenarios.

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1. Part A – Current situation at the Gullfaks field

1.1 Introduction of the Gullfaks field

The Gullfaks field is a giant oilfield in the Norwegian sector of the North Sea, located mainly in block 34/10. The field is consisting of the Gullfaks main field and several satellite fields surrounding it. The main field contains 78% of the total in place oil volumes and 88% of the recoverable reserves. The filed is to day operated by Statoil who owns 70 % of the field, while Petoro own 30 % (NPD, 2012). The field was discovered in 1978 and came into production in 1986 and reached peak production in 1994 at 90000 Sm3/day. The decline in production was slowed down by the startup of the satellites in 1998, but the current production rate is about 25000 Sm3/day (Talukdar & Isntefjord, 2008).

Since the field has been into production for over two decades, the field is now into its tale production, with 93% of the basic oil reserves produced (as per 31 December 2007). The estimates of the recoverable reserves in 2008 were 358 MSm3. The goal is to increase these reserves to 400 MSm3 (Talukdar & Isntefjord, 2008).

The main field is developed with 3 concrete platforms, Gullfaks A, B and C, and subsea constructions at the satellite fields. The main field consists of Statfjord, Cook and Brent formations of early to middle Jurassic age, and is located at a giant rotated fault block at the western side of the Viking graben. This fault block is divided into internal rotated blocks, which is further divided into three main structural areas. The domino system, the horst complex and accommodation zone in the middle.

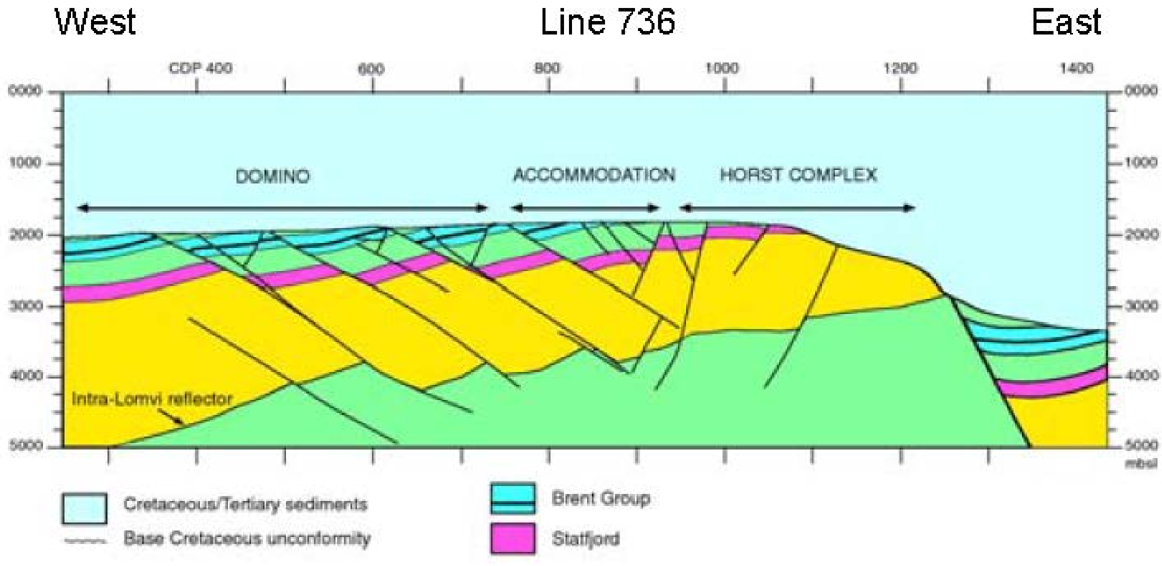


Figure 1 Structural setting of the Gullfaks main field **(Talukdar & Isntefjord, 2008)**

1.2 Isolated fluid segments in the Gullfaks main field

By looking at the structural maps in RSP 07 there are approximately 20 similar oil-bearing segments in each of the structural maps of the central field of Gullfaks (Top Tarbert, Top Ness, Base Ness, Top Cook, Top Statfjord). Top Lunde had around 10 similar segments and Top Broom lacked oil-filled reservoir segments (Statoil, 2007)

The faults separating these segments are sealed mainly by different cementations, but the sealing is not 100% tight along all the segment boundaries and some pressure communication between the segments occur (Talukdar & Isntefjord, 2008).

1.3 Oil recovery in the different fluid segments

The total extracted oil volume from Gullfaks main field is about 350 MSm3 (2011). This is 96 % of the base reserves. Hydrocarbons are produced mainly from five different pay zones (figure 2). The main portion of the oil is recovered from Tarbert and the lower Brent formations with 130.5 MSm3 and 96.1 MSm3 respectively. The production from the Cook and Ness formations is minor and total recovered volumes are 17.5 MSm3 and 41.5 MSm3 respectively. The Krans and Lunde formation is marginal producers with a total recovery at 0.2 MSm3 and 0.5 MSm3 respectively (Statoil, 2008).

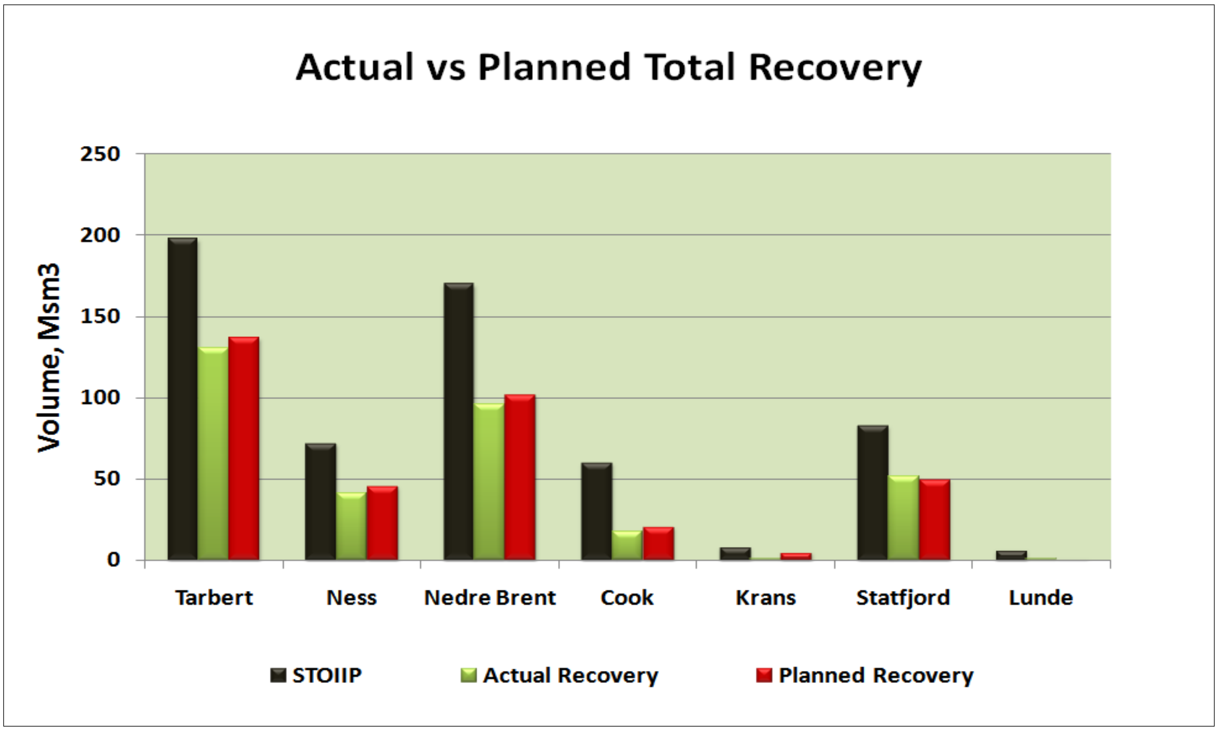


Figure 2 Actual vs. planned recovery in the different formation in the Gullfaks main field **(Statoil, 2008)**.

The Statfjord formation ads a considerable contribution to the total production with a total recovery of 52.3 MSm3. The actual recovery of the Statfjord formation is higher than the planned recovery (Statoil, 2008), but this might be caused by the fact that the fluid segment is not completely isolated, and a certain contribution is added by other segments.

Gullfaks main field is divided into segments and the production varies in each segment. Comparison of production and the volumes in place in different segments is shown in figure 3. From the plot it is clear that the F&G and H segments in the Tarbert formation, H and I segments in the Lower Brent contains most of the STOIIP, and stands for major parts of the production. Large proportions of the remaining oil in the mail field are in the mentioned segments, and enhanced recovery in these segments has a large upside.

Lower production and low STOIIP are observed in I segment in Tarbert, Ness and Cook formations, F&G segment in Ness, Lower Brent and Cook formations and in the H segment in Ness, Cook & Statfjord formations.

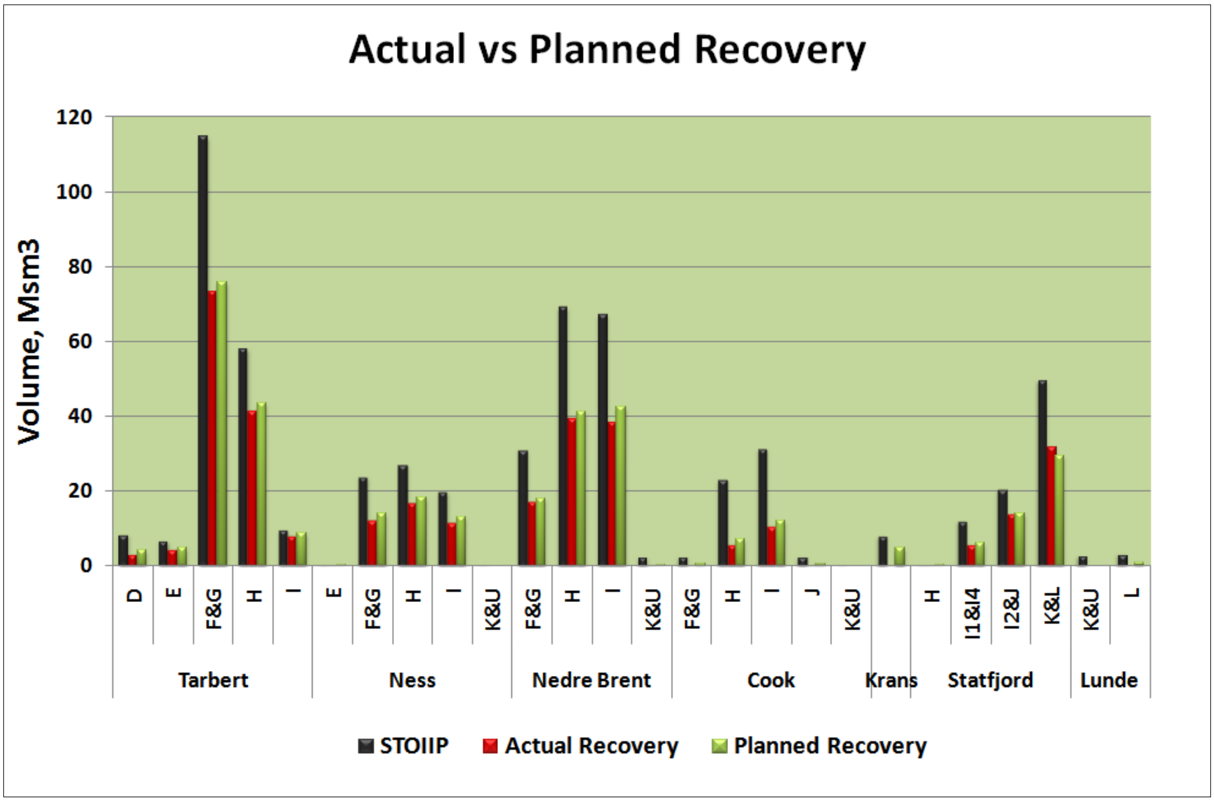


Figure 3 Actual vs. Planned recovery in the different segments at the Gullfaks main field, **(Statoil, 2008)**

In figure 4 the actual and planned recovery factor is compared with the STOIIP in the different segments and formations. The planned recovery factor and the actual recovery factor are relatively similar in the different segments, but in the Ness and Cook formation the actual recovery is lower than the planned. The actual and planned recovery factor is especial in the H and I in the Tarbert formations very high (close to 90%). This is an unrealistic high recovery factor and could be explained by communication between the different formation and segments. Communication could lead to that oil is flowing from one segment or formation to another, and causing to high recovery factor in one segment and too low in the neighboring segment or formation.

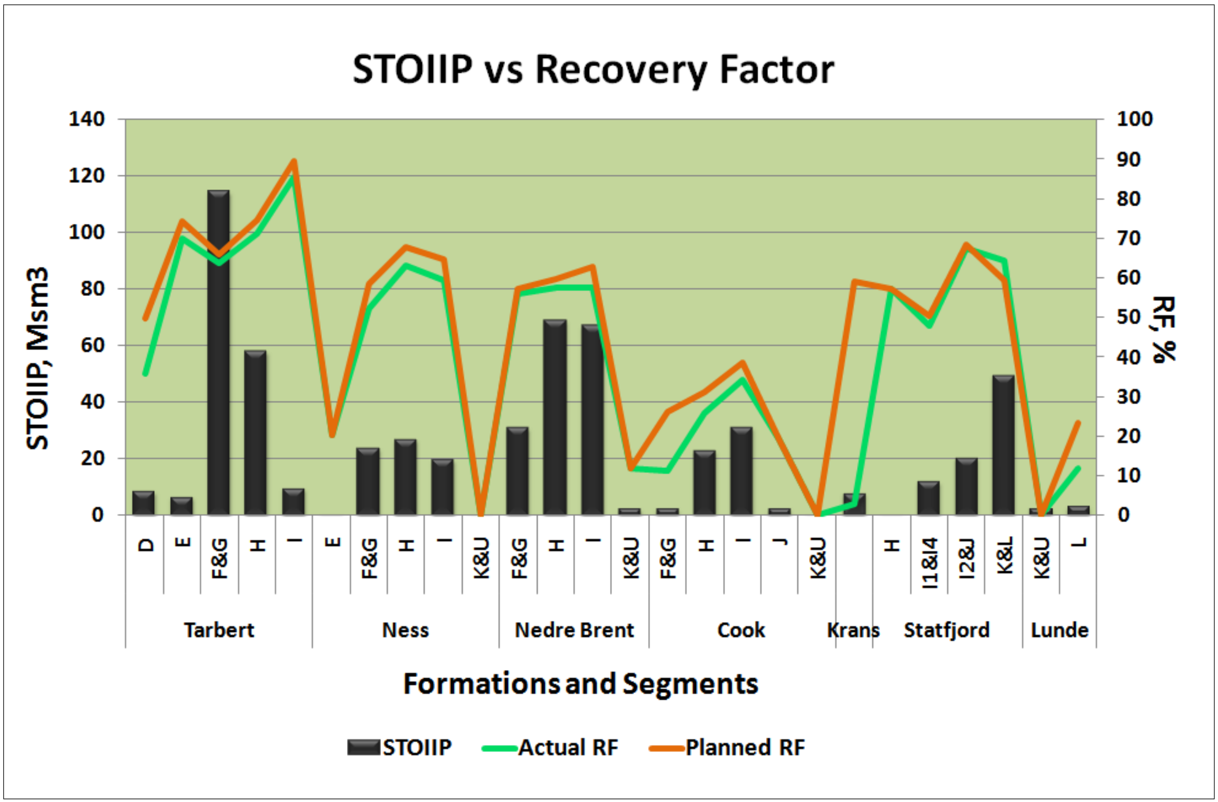


Figure 4 STOIIP vs Actual and Planned recovery factor in the different segments at the Gullfaks main field **(Statoil, 2008)**

The different recovery factors in the different segments and formations is discussed above and presented in figure 4. The Cook, Krans and Lunde formations all have relatively low recovery factors, compared with the other oil bearing formations. The cook formation has large permeability differences due to heterogeneous layering, and common calcite layers. These heterogeneities create difficulties in producing the remaining oil and the recovery factor is low. The Lunde formation is a small formation with low permeability and high initial water saturation, which set down the recovery factor (Talukdar & Isntefjord, 2008).

In the Tarbert formation which is considered to be a very good reservoir, sand production is the main factor that set back the recovery factor. The Ness formation is also an important producer, but the reservoir quality in this formation is of moderate quality, due to low permeable/impermeable calcite, coal and clay layers. The sand layers have is also often not continuous in the lateral direction. This makes water flooding by water injection more difficult and the recovery factor is lower than in the Tarbert formation (Talukdar & Isntefjord, 2008).

The lower Brent package which consist of the Broom, Rannoch and Etive formations, is the second most important producer after the Tarbert formation. The Broom formation is not a significant reservoir (Talukdar & Isntefjord, 2008), but the Rannoch and Etive formations have produced large volumes of oil. There are still large volumes of oil left in these to formations, but permeability differences creates water highways, and leave large volumes of rock unflooded by the injection water. High H2S content in the production fluids is also setting down the production and recovery factor in these formations (Talukdar & Isntefjord, 2008).

The Statfjord formation consists of the Nansen, Eirikson and Raude formations (Talukdar & Isntefjord, 2008). The Raude formation is a modereate to bad reservoir and contains clay layers and clay rich sands that sets down the recovery factor. The two upper members of the Statfjord formation, the Nansen and Eirikson formation are considered to be good reservoirs, with good lateral and vertical continuity, but low permeable siderite fillings disturbs the flow pattern in the formation (Talukdar & Isntefjord, 2008), and sets down the recovery factor.

The many different geological formations show large differences in reservoir quality and, this cause differences in the recovery factor between the different segments, because different geological formations are represented in the different segments. The formations also show lateral heterogeneities and therefore the same geological layer produce different recovery factors due to lateral position.

Production strategy is also a factor that influences recovery factor. Placement of production and injection wells is critical and will affect the recovery factor greatly. Oil recovery by pressure depletion and pressure support through water injection is the main production method on the Gullfaks main field, and to achieve a high recovery factor it is critical that the injection water flush thru major parts of the segments. The heterogeneities mentioned above complicate this achievement, and creates water highways and large volumes of rock might not be flooded in an efficient manner.

In addition to this there are large numbers of sub seismic fractures with varied sealing potentials. If a segment contains sealed fractures, the placement of injectors and producers may not be ideal for achieving maximum recovery factor in the segment. High resolution seismic and correct interpretations are there for important factors in the work of best possible well placement.

Sand production and high levels of H2S in the produced fluids also affect the recovery factor in many of the segments. Sand production is a major problem in many of the high porosity and high permeability reservoir sands on the Gullfaks field (Talukdar & Isntefjord, 2008). Sand grain loosens from the reservoir rock and follows the produced water and oil upstream. The sand erodes the production equipment, and production rates have to be set down to avoid damage on the equipment.

H2S is naturally present in the formation as product of microbiological activity in the oil-bearing formations (Talukdar & Isntefjord, 2008). The bacteria's is further stimulated by water circulation caused by water injection. The H2S pollutes the export gas from the field, and is also harmful to the equipment and environment on the platform. Segments with major H2S production have to shut down wells and the recovery factor will not be optimal.

1.4 Methods for improved and enhanced oil recovery for the Gullfaks field

The Gullfaks field is a mature field that has been producing since 1986 and a lot of IOR methods have already been tested out with different results. A total of 338 MSm3 of oil has so far been produced with a recovery factor at 57% (Statoil, 2008). Statoil is aiming at a total recovery of 70% for the Gullfaks field in the future, and to obtain this advanced IOR methods must be applied. Water injection has been used for pressure support since the beginning, but to get out the last oil, new methods must be applied.

The Gullfaks field is considered to be a complex reservoir that sometime requires flexible IOR measures to get an optimum oil production. In order to determine the measure that has the highest potential for the field, an understanding of the main challenges in the field is needed.

There are several main challenges on Gullfaks that can be summarized as follows:

1. Complex structural geology
2. High water production and fingering because of water highways
3. Large permeability contrasts
4. Late phase oil production with more immobile oil than mobile oil left
5. Unconsolidated reservoir sand
6. H2S content

The following IOR measures are suggested to be applied at the Gullfaks field due to their abilities to overcome the mentioned problems.

1. 4D seismic survey

   Considering the fact that the Gullfaks field is a complex field in regards to faults, heterogeneities and many different fluid segments, this IOR measure has a very large potential to increase the recovery. 4D seismic will give an enhanced understanding of the development of the field, and will help us find fluid communication paths, pressure distribution over time and untrained volumes of oil. This might have considerable influence on total recovery for the entire field, and is in our opinion one of the most beneficial IOR measures that can be applied to this field.

2. Gel blocking and water dispersion

   Because of the large permeability contrasts in the field, it has been observed that the injected water will choose the path of least resistance (highest permeability) through the segments, creating water highways leaving large oil volumes unflushed. Residual oil saturation in the primary flooded areas is in the range of 10-20% but it may be 30 – 50% in the non-primary flooded areas (Talukdar & Isntefjord, 2008).

   This IOR method applies a chemical into the injecting water in order to change the water path. The chemicals will move into the reservoir and form micro gel particles, which will stick to the surface of the pores and thereby reducing the permeability in the zones that the water flowed through initially. The water might be diverted and find new paths through the reservoir, hence flooding previously unflooded parts of the reservoir and hit the bypassed oil and increase the oil recovery eventually.

   Combination polymer assisted surfactant flooding and water dispersion through gel blocking has an even higher potential for higher recovery. By gel blocking, the water will sweep the reservoir more effectively and sweep more of the previously bypassed oil. After having the most efficient sweep path, the surfactant will mobilized the immobile oil to the surface and eventually increase the oil recovery dramatically.

   The disadvantage of these techniques is that the chemicals used are often environmentally harmful, and this might make this IOR method less favorable. The government has strict restrictions on the use of many of these chemicals making the application more difficult. In addition to this, the use of chemical comes at an additional cost, and the headroom for total earnings is reduced.

3. Water based IOR measures/methods, i.e. surfactant and polymer assisted surfactant

   Since the field pressure has been maintained through water injection since the production start, the addition of a surfactant chemical to the injection water might be a good option. The Gullfaks field is currently on tail production, and a large quantity of the oil left is immobile.

   The recoverable oil through traditional IOR techniques is limited by end point saturations in the reservoir. Beside the fact that the field has more immobile oil, the high permeability, low oil viscosity, low reservoir temperature, low salinity of formation water and moderate low clay content makes the field a good candidate for surfactant and polymer flooding. The surfactant and polymer injection have been tested and showed a mobilization of previously immobile residual oil. The recovery in a pilot section showed as high recovery as 70% through this method (Talukdar & Isntefjord, 2008).

   This method is uncertain and certainly more expensive than other methods. We also have environmental aspects to be considered, due to release of production water to the sea. But a high oil price and solutions of environmental related problems might justify applying this method on a larger scale in the future.

4. Infill Drilling

   If undrained volumes can be discovered through 4D seismic, new wells can be drilled to these areas to get the oil that was previously left behind. Infill drilling is, on the Norwegian Continental Shelf, regarded as the most important factor in increasing the short term recovery factor.

   Advanced wells with multiple targets, long horizontal sections and smart wells have further improved the initial recovery (Talukdar & Isntefjord, 2008). Cost and rig availability is a limiting factor in the addition of more wells.

5. Hydraulic fracturing

   The Gullfaks field consists of sections with varying permeability. For the low permeability sections, hydraulic fracturing can increase the effective permeability, and also increase the oil recovery. It is also effective in reducing sand production.

6. Gas and water injection (WAG)

25 wells have been used as gas injection wells on the Gullfaks main field. A total of 7 wells have been tested with water alternating gas method for increased oil recovery. This contributed to a considerable amount of incremental oil. The Brent formation is the most favorable for WAG injection. Gravitational segregation of the injection gas gives better sweep in areas not contacted by water. And a total contribution of 10 MSm3 is estimated to WAG (which is around 3% of today's recovery). However, the method is limited by the availability of injection gas at Gullfaks, since Gullfaks had a gas sale agreement. It was also deemed too expensive (Talukdar & Isntefjord, 2008).

7. CO2 WAG injection

   Because of the high costs associated with water alternating associated gas was deemed too expensive, CO2 WAG injection was also considered. Simulations done on the Brent reservoir with 5 million tons CO2 per annum over a period of 10 years showed a potential for 28 MSm3 more oil recovery by 2030. This is an improvement of 8% over today's recovery. Because of limited availability of CO2 for the Gullfaks field, the MWAG project was not implemented (Talukdar & Isntefjord, 2008).

1.5 Conclusion

The Gullfaks field is a complex field with a wide variety of challenges when it comes to increasing the recovery factor. The challenges can be divided into several categories.

The first one is that the injection water not flushing thru the entire volume of reservoir rock, due to a wide variety of reasons where heterogeneous reservoir rock is the main challenge, and then leave large volumes of oil bearing rock unflushed by the injection water.

The second challenge is sand production from unconsolidated reservoir rock that erodes on the production equipment and forces the production to be lowered to a certain limit where the equipment is not destroyed. This is a widespread problem in the petroleum industry and sand screens or gravel pack might remedy this at relatively low cost.

The third challenge relates to the abnormally high content of H_2S in the produced fluids. This gas is produced by bacteria in the reservoir. The production stream is polluted by this very toxic gas and the oil and gas might not fulfill sales specs, making thorough cleaning a necessity. There will also be costs and logistical problems associated with getting rid of the hydrogen sulfide. The hydrogen sulfide problem might be reduced by injecting chemicals to kill the bacteria. It has also been suggested that the gel used to block the high permeability zones might remedy the problem because it will coat the bacteria together with the reservoir rock (Instefjord, 2012).

The fourth challenge is that complex structural geology and poor seismic resolution makes it difficult to find the remaining pockets of oil. This will further increase the complexity of finding ideal well trajectory to hit small pockets of undrained volumes. In addition to this, the fractures and heterogeneity of the field makes the sweep of the entire reservoir much more difficult.

In our opinion the most beneficial IOR/EOR measure to date is the 4D seismic to get a good understanding of the pressure and fluid distribution of the field, together with gel blocking and infill drilling to access the undrained oil volumes.

2. Part B – IOR challenge for the H1 segment

2.1 Introduction

Since the Gullfaks field is a mature field that has been going on decline for quite some time, several EOR methods have been evaluated to increase the final oil recovery of the field. The H1 segment of the field is known to be relatively isolated, and a lot of data have been collected over the time of production. This makes this segment ideal to carry out a pilot project on different EOR methods.

In our project we will look at the possibility to reduce the permeability of high permeability zones in the reservoir through chemical injection. The Gullfaks field has severe reservoir heterogeneities and the permeability varies by a factor of around one hundred for different parts of the reservoir. The water that is injected into the segment has a natural tendency to choose the path of the least resistance, and hence the formation of water highways through the reservoir has occurred. In practical terms, this means that the water that is injected into the formation flows through the zones with higher permeability, and leaves some zones partly or entirely unflushed. This is unfavorable because of the fact that the injected water does not sweep the entire reservoir, and some oil will be left behind in the zones that are not properly flushed.

It is favorable to reduce the permeability in certain parts of the reservoir because this might force the injected water to find new paths through the reservoir, and thereby flood previously unflooded parts of the reservoir. However, the choice of chemical to use is difficult because of environmental aspects, and the complexity of the field. In our case we will reduce the permeability of certain zones with a chemical called Abio Gel. It will form micro particles when it comes into contact with divalent cations in formation- or injection water that will stick to the reservoir rock, over time a layer of this stiff gel will have formed effectively reducing the permeability of the zone in question.

To simulate the chemical injection we will use the Eclipse model of the segment and apply the permeability reduction to certain parts of the reservoir. There is no built in function for permeability reduction with Abio Gel in Eclipse, so we will use tracer and FloViz to do this. We will also run a sensitivity analysis in regards to how much the permeability is reduced, and where the reduction is taking place.

To estimate the feasibility of the method, we will also look at the net present value for the specific measure.

2.2 The H1 segment

The H1 block is located at the central parts of the Gullfaks main block, isolated by more or less sealing faults to the south, west and north against the T4, G2 and H2 blocks. At the eastern flank the block is flanked by an erosion contact.

The H1 block consists of several different geological layers in the vertical direction. For the pilot with the Abio Gel the lower Brent package was chosen. There are several reasons for this: The lower Brent has only a recovery factor of 57 %. It has been in production for a long time since it was the first production area, and is therefore connected to a lot of data (Eltvik, 2012a)

It has 2 active wells in lower Brent, one producer (A-39A) and one injector (A-35). The upper Brent package has 2 active producers in the H1 segment, well B-37 and A-38A (Eltvik, 2012a). There are pressure communication between B-37 in the upper Brent and the injectors in the Lowe Brent. There is lack of information of possible pressure communication between the lower Brent and A-38A, and the well is therefore not taken in account in our simulations. (Eltvik, 2012a).

In addition the segment has problems with H2S in the production water. There are indications that the Abio Gel can reduce the growth of H2S producing bacteria.

One of the reasons for the relatively low recovery factor in the H1 segment is that the injection water is not flushing thru the whole stratigraphy, and the water flow is concentrated to high permeable zones in the stratigraphy. In this study we will look at the lower Brent formation and the attempt to partly block the high permeable zone in lower parts of the Etive formation and uppermost parts of Rannock formation. See figure 5 below.

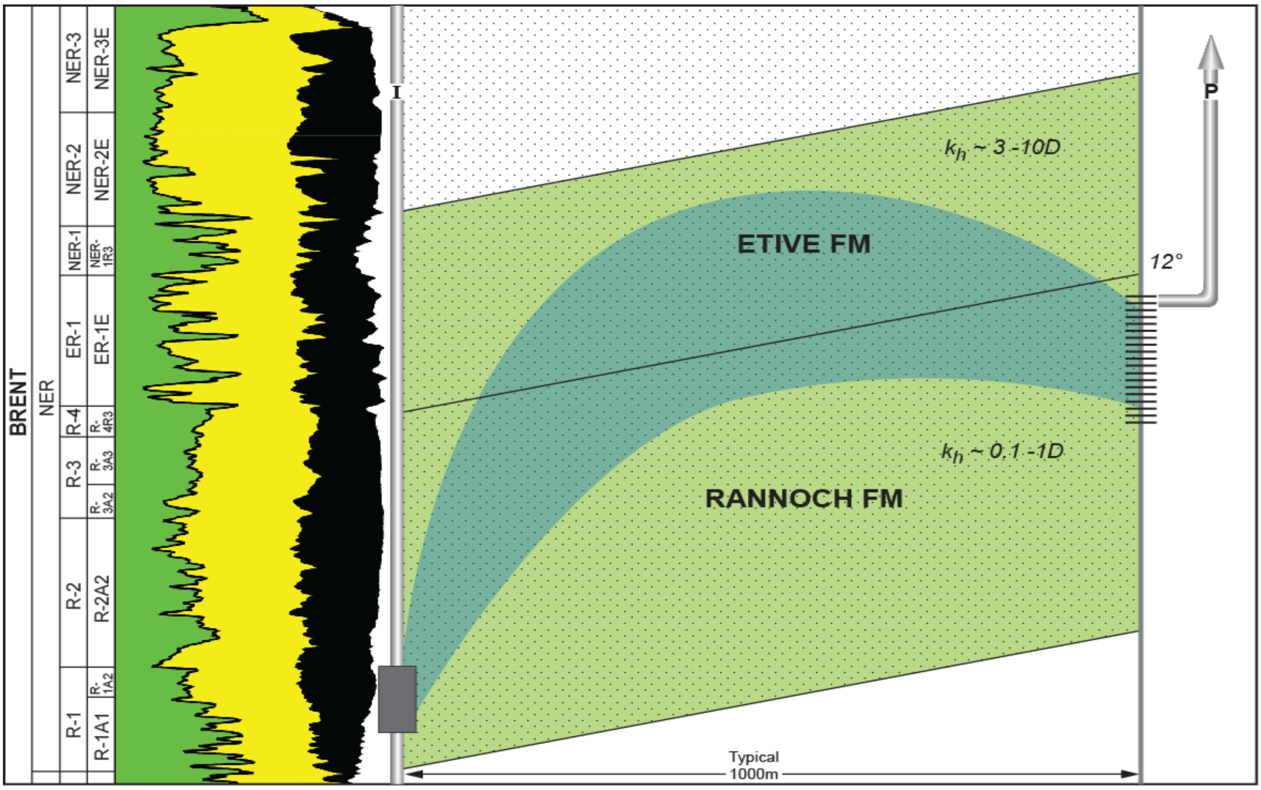


Figure 5 Water Highway in Rannoch and Etive formation **(Eltvik, 2012a)**

The Etive and Rannock formations are considered to be good reservoir rocks, consisting of sand layers deposited by a prograding delta front. The Etive formation is high porosity (33%) and high permeable (2.0-5.0 Darcy) sandstone deposited in a beach setting (Talukdar & Isntefjord, 2008). The Rannock sandstone is deposited in deeper water further down on the delta front. Deeper water means lower energy level and lower grain size than in coarse grained Etive formation. The porosity in the Rannock formation ranges from 11% in the lower parts to 33% in the upper part (Talukdar & Isntefjord, 2008). The permeability range is from

0.03-0.13 Darcy in the lower part to 0.5-2.0 Darcy in the upper part (Talukdar & Isntefjord, 2008). The Rannock formation has therefore a trend of less permeability downwards.

The permeability difference therefore prevent flooding of injection water in the parts of the formation with less permeability than the high permeable water "highway" in the lower Etive and upper Rannock. The goal with the pilot is therefore to reduce the permeability in high permeability zones with in depth profile Modification Technique as described below in part 2.3 and force the injection water to flush less permeable zones of the formation, and then produce more oil.

The high permeable zone in the lower Etive formation can locally have permeability up to 10 Darcy, as in the illustration above. This means that the permeability reduction by the in depth profile Modification Technique (Abio Gel) have to reduce the permeability dramatically to completely diverge the injection water to other zones.

2.3 Permeability reduction through the use of Abio Gel

2.3.1 What is Abio Gel

The Abio Gel itself is produced from the reaction between an inorganic agent called WJSTP and the divalent cations (mainly Ca^{2+} and Mg^{2+}) found in formation or injection water. When the agent reacts with the cations, a stiff gel will form. The WJSTP agent consists of $Na_2O.mSiO_2$ and NaOH (silica based) and is in the form of a powder (Tang, et al., 2004). It is mixed with the injection water and pumped down into the reservoir.

General characteristics of the gel/chemical are as follows:

1. The gel solution is transparent and nontoxic. It has very similar properties to water in regards to viscosity and density. Because of this, the solution does not sink and is homogeneously distributed on the surface of the pore paths. Gelation time is dependent on the temperature, and a higher temperature will lead to shorter time for the stiff gel to form.
2. The chemical is classified as yellow in regards to environmental aspects because of the fact that the concentration of aluminates is below 1%. From an environmental standpoint, the chemical is unproblematic to use. However the Norwegian state has decided that the limit on import and transport of the chemical is 1000 metric tons (Eltvik, 2012a).

3. High salinity and multi valence ions do not decrease the gelation. For the formation of stable Abio Gel, the higher the salinity the better. The concentration of the WJSTP agent, and the divalent cations does not affect the gelation time of the chemical, however it makes the gel stronger and more stable.
4. The gel is stable for temperature range 30 to 200°C.
5. Compared to other blocking agents, the Abio Gel solution is rather cheap. The price of the solution per cubic meter is only about one third of the price of cross linked polymer solution at the same concentration.

(Tang, et al., 2004)

2.3.2 How the injected water is diverted away from the water highways

As we have discussed previously the water that is injected into the H1 segment flows mostly through the high permeability zones of the Upper Rannock and Etive formation, bypassing zones with less permeability. The principle of diverting the water is in theory done by reducing the permeability of a certain zone to the extent that the water flow will meet less resistance by choosing a new path through the reservoir. The permeability reduction is obtained by injecting a chemical that will form a stiff gel in a certain part of the reservoir; this gel is called Abio Gel.

To form the Abio Gel in the reservoir rock a silica based chemical is diluted in seawater and injected into the reservoir through the A-35 injector well of the H1 segment. When the chemical comes into contact with divalent cations that can be found in reservoir- or seawater, micro gel particles will form and stick to the rock surface. Over time the Abio Gel will create a coating on the grain surface of the reservoir rock, this will narrow down the flow path and gradually reduce the permeability of that particular part of the reservoir (Tang, et al., 2004). When the water highways in the reservoir gets an increased flow resistance, the injected water might be diverted and flow through paths with less resistance.

Consequently, after the permeability reduction of the high permeability zones the injected water will be redistributed and the efficiency of the water flooding will be improved. Flow of following injection is redistributed and the efficiency of water injection/flooding is improved.

2.3.3 Previous in field use of Abio Gel

Abio Gel has been tested by the Chinese oil company CNPC, as a profile control agent in the Dagang oilfields in China in August 2007, and in several reservoirs in the Tarim basin. The reservoir where the Abio Gel is applied is sandstone reservoirs with relatively high reservoir temperature (99 - 108°C) and average permeability of 57 x 10-3 μm2 (Dai, et al., 2010). The wells are developed by water injection. The formation water has salinity of 13700 mg/l. After treatment, there were improvement on the injectivity profile (Figure 21, appendix), oil production rate and water cut. Large amounts of precipitation was generated which coated the grains and reduced the permeability in the high permeability zones. The reservoir heterogeneities was modified and sweep volume of water flooding, and eventually enhance oil recovery was improved (Dai, et al., 2010).

2.3.4 Benefits of Abio Gel compared to other chemicals

The Gullfaks field is considered as a suitable reservoir for Abio Gel treatment due to the fact that the reservoir is sandstone with large contrasts in permeability. The temperature of the field is well within the range for stable formation of the Abio Gel. The salinity of the formation water is fairly high at 42000 mg/l (Talukdar et al., 2008), and this is the most crucial factor for stable formation of Abio Gel. The salinity at the Gullfaks field is actually higher than that of the fields that previously have been treated with Abio Gel with good results in China (Tang, et.al., 2004).

The number one reason for choosing the Abio Gel is the fact that it is unproblematic to use in regards to environmental aspects. Most of the blocking chemicals on the market is rated red or black by the Norwegian government, making them impossible to use on the Norwegian continental shelf, and the Abio Gel is one of few chemicals that can be applied (Statoil, 2012).

2.3.5 Risks

When injecting the Abio Gel into the H1 block it is important to investigate the possibility for the Gel to have a negative impact on the reservoir quality and production. One of the risks with injecting Abio Gel is that the gel could block the low permeability zones with high remaining oil saturation, and lowering the recovery factor. Experiments described in the article of Tang et.al., 2004 indicates that the risk of blockage of low permeable zones is low. The reason for this is that the formation of coating on the grains is related to permeability and the content of formation water. Since we have a good understanding of the original flow path of the injected water, this risk should be very low.

The compound reacts with ions in the formation water to form the grain coating. Low permeability zones with small pores that contain small amounts of formation water will not be affected by the coating effect as much as high permeability zones with large pores and large amounts of formation water. This observation leads to the assumption that injection of the agent should do little harm to zones with low permeability and/or high oil saturation (Tang, et al., 2004).

Another risk related with injection of Abio Gel is related to equipment damage. In case of prematurely formation of rigid gel inside production/injection tubing pressure spikes may be observed, and this might subject some parts of the injection tubing and equipment to high pressures. In order to prevent the possible damage detailed and accurate hydraulic calculations should be performed while planning the operation and the equipment should be tested according to maximum severe situation (pressure) before the operation. The conditions under which Abio Gel is formed should also be evaluated so that these conditions are not present in production tubing or equipment.

Also quick formation of rigid gel can occur inside the injection string and it can cause blockage of pipe and the completion equipment which can increase the non-productive time and hence increase operation expenses.

It is also not beneficial that the permeability reduction will happen very close to the injection well, and effectively act as an imposed skin factor of that particular well. This will hinder the future injection of water and make that injection well less effective.

2.4 How the use of Abio Gel can be simulated in Eclipse

As mentioned earlier there is no built in function for permeability reduction by the use of Abio Gel in Eclipse. The permeability reduction therefore has to be done manually in FloViz. First we apply a tracer to the model to represent the flow of injected water through the reservoir. The tracer concentration is measured in milligrams per liter and can also represent the amount of chemical in a certain part of the reservoir. As the tracer moves through the reservoir with the injected water, the tracer is dispersed and the concentration goes down while the area affected by the tracer is increasing. For every grid cell and time step values for permeability and tracer concentration is stored in the reservoir model. Since the concentration of tracer in a given cell is directly related to the concentration of water in a given cell, and the Abio Gel chemical is injected with the injected water, the tracer concentration also describes the amount of Abio Gel chemical at that specific grid cell. Because of this we assume that the permeability reduction can be described by the tracer concentration alone. Since there is a limited knowledge of how the Abio Gel behaves in the reservoir, it is in our case beneficial to us a simple expression for the reduction in permeability.

The successful formation of Abio Gel is as previously mentioned dependent on salinity, temperature, concentration of formation water, oil saturation and geology. We assume that the salinity is high enough (i.e. above 1% concentration of divalent cations) for the Abio Gel to form. The temperature at the Gullfaks field is well within the boundaries for the Abio Gel to be stable (Eltvik, P. 2012c), and the rest of the uncertainties we overlook in our simulation.

To reduce the permeability of our model we upload the reservoir model with the tracer added to FloViz. We then add a new property calculator with a simple FORTRAN expression to reduce the permeability in a grid cell based on the tracer concentration. What tracer values that correspond to which permeability reduction is very hard to predict, and in our simulation we have decided to base it on what was suggested by Mr. Huseynov at our visit to Bergen the 8th of February 2012. In light of the complexity of the problem, we will include a sensitivity analysis on different parameters. The FORTRAN expression includes an upper and a lower tracer concentration threshold. If the tracer concentration in a cell is above the upper threshold the permeability is reduced by a given factor, if the tracer concentration is above the lower threshold the permeability is reduced by a smaller factor. If however, the tracer concentration is below the lower threshold, no change is done to the permeability of that cell. The permeability is also only reduced for x and y directions in the model.

We then calculate the new permeability for both x and y direction with the property calculator for every grid cell in the model and export the new properties at a given time step to a include file. This include file is included in a new Eclipse simulation and the result of the permeability reduction can be observed by a change in both oil production and water cut.

2.5 Placement and size of the zone of permeability reduction

The size and placement of the Abio Gel "plug" will have a dramatic effect on the success of the project. For our particular case it has been suggested by Statoil that the most beneficial placement of the permeability reduction is about 200 meters from the injection well into the reservoir in the Etive and upper Rannock formations (Instefjord, R., 2012). In our simulation we will look at different cases for both size and placement of the permeability reduction, and how this ultimately affects the oil recovery of our segment compared to the base case.

When simulating it is possible to can change the placement and size of the zones that will have reduced permeability by choosing different time steps to export the properties, or change the threshold values in the FORTRAN expression. In our simulation the tracer is injected the 2th of January 2012 and moves through the reservoir, following the water flow. The tracer will move further into the reservoir for every time step and be dispersed horizontally.

If we export the properties in FloViz at a later time step, the zone of permeability reduction will move further into the reservoir. This is because the tracer is injected at a specific time, and then moves through the reservoir. And then the grid cells with increased tracer concentration will also move further into the reservoir, away from the injection well, for every time step. If we lower the threshold for applying a permeability reduction the zone that will be change will increase in size.

In the reservoir model the tracer is injected into layers 36 to 47 which is the high permeability formations Etive and upper Rannock. From figure 17 we can see where the permeability reduction will take place. In the zone in question each grid cell has a length of around 45 meters in x direction, 100 meters in y direction and 3 meters in z direction. This means that the plug will form from around 200 to 300 meters to 500 to 600 meters from the injection well. This is in compliance with what was suggested by Statoil. By comparing figure 17 with figure 18 we see the effect of lowering the threshold values for permeability reduction. For the case with the highest thresholds we see that almost all of the grid cells in the interval we want the “plug” to form have reduced permeability. However, some of the cells around the edges of the formations have to low tracer concentration and will not experience permeability reduction. When we lower the threshold we see that all grid cells will have permeability reduction in the interval in question. We also see that the area with the highest permeability reduction is increased, and we can conclude that the plugging effect of this case is higher.

When exporting the properties at a time step 6 months later (i.e. in January 2013 instead of June 2012) we see from figure 19 that the “plug” has moved to around 500 to 600 meters from the injection well. In this case the tracer is distributed a bit more in the reservoir and the case with the highest threshold does not reduce the permeability in an effective way.

However, for the case with the reduced threshold we see that there will form a plug of reduced permeability for the entire flow path of the injected water.

2.6 Simulation results

2.6.1 Base case

As a base case we run a simulation in Eclipse from present, until 2025, without any changes to the properties of the reservoir. This represents how the oil production and water cut will evolve over time if no IOR/EOR methods are initiated. The output of the simulation gives us a base case that we can use to compare the different cases with permeability reduction, and to calculate the net present value of the project. Figure 6 below shows the predicted oil production and water cut until 2025 for the H1 segment.

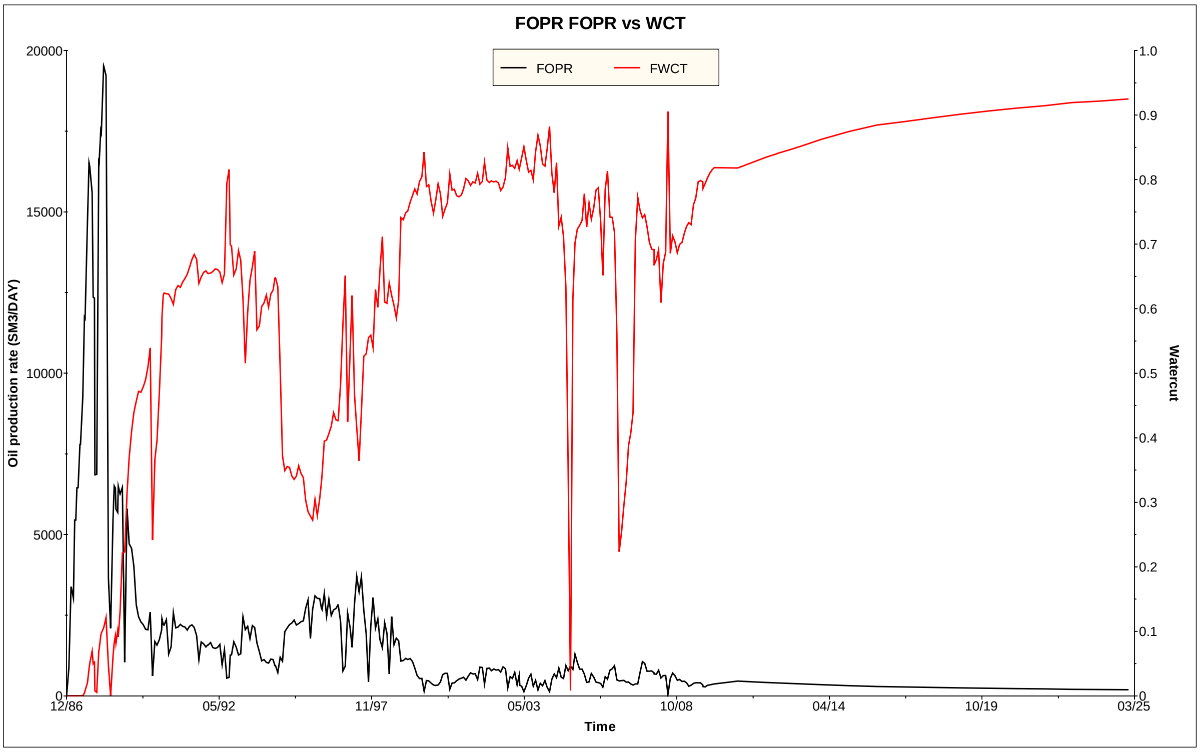


Figure 6 Base case simulation of water cut and oil production

2.6.2 Simulation of Abio Gel injection

After running the base case simulation we apply a permeability reduction according to the procedure explained previously. A total of eight cases of different permeability reduction were run for two different values of tracer threshold concentration. The model will have tracer values for every grid cell at every time step. In our simulation we will reduce the permeability by a certain factor if the tracer concentration is above a certain upper threshold, and reduce it by a smaller factor if it is above a certain lower threshold. If it is below the lower threshold the permeability will remain unchanged.

We will look at cumulative oil production and water cut for all cases to evaluate the success of the measure. We observed from our simulation results that permeability reduction below 40% had little to no effect on both water cut and oil production, and these cases are not included in this report. The eight cases we have decided to focus on in this report are listed in table 1.

Case	Upper threshold	Lower threshold	Permeability reduction if tracer concentration is above upper threshold	Permeability reduction if tracer concentration is above lower threshold
150_80_60	150	50	80%	60%
150_70_50	150	50	70%	50%
150_60_40	150	50	60%	40%
150_40_20	150	50	40%	20%
250_80_60	250	100	80%	60%
250_70_50	250	100	70%	50%
250_60_40	250	100	60%	40%
250_40_20	250	100	40%	20%

Table 1: Different simulation cases

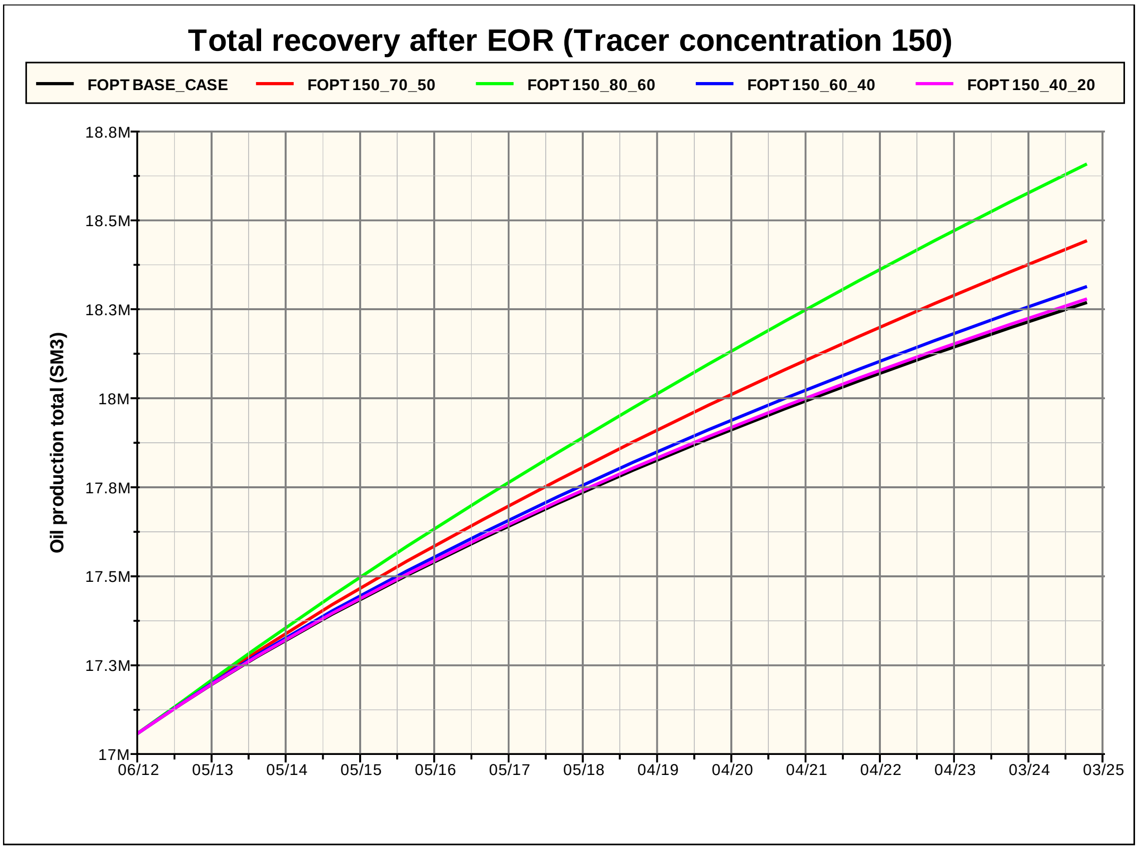


Figure 7 Total recovery of oil after EOR, with Tracer concentration of 150 from 2012 to 2025

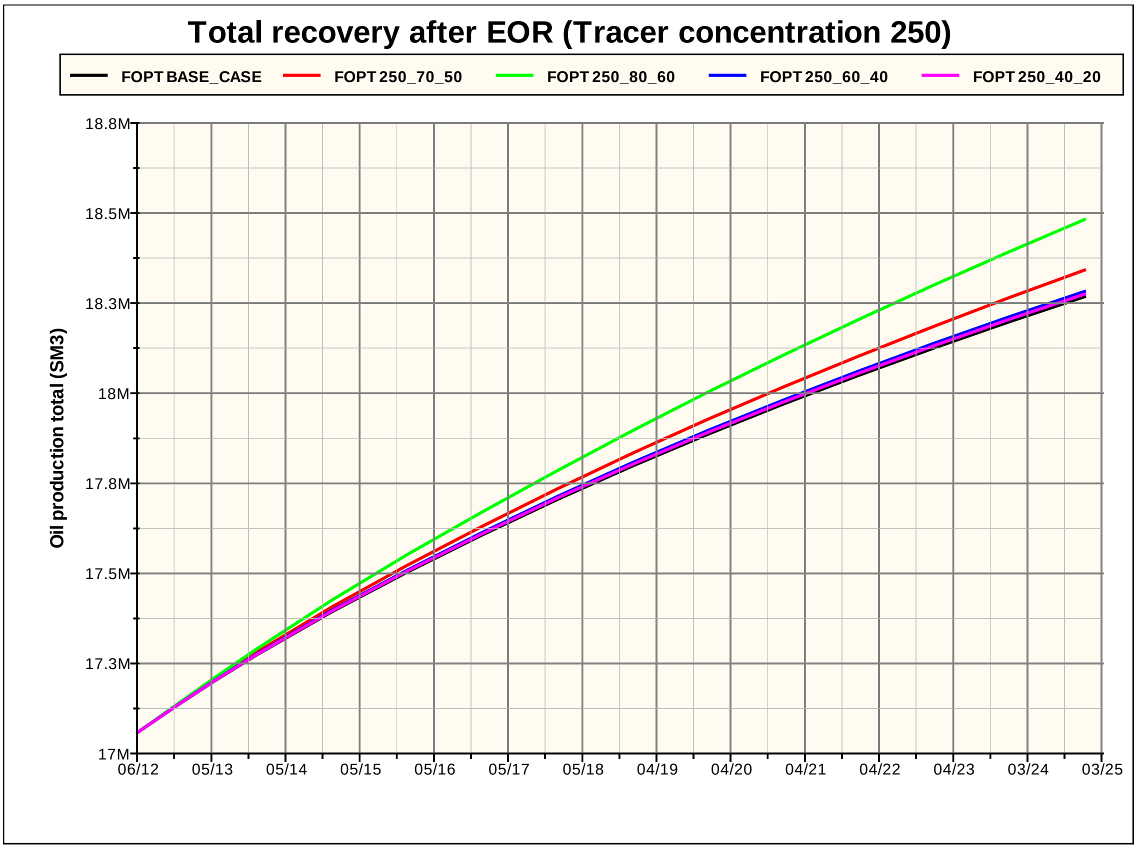


Figure 8 Total recovery of oil after EOR, with Tracer concentration of 250 from 2012 to 2025

From figure 5 and 6 we can observe the effect on cumulative oil production for all eight cases. As expected we see a positive contribution to the oil production for all cases, however the effect is almost negligible when permeability is only reduced by 40-20%. Table 2 shows the results from all cases compared to base case.

Case	Total oil production [MSm3]	Increase in total oil production [MSm3]	Percent of total production compared to base case	Percent of production from 2012 compared to base case
Base Case	18,2677			
150_80_60	18,6565	0,39	2,13%	32,12%
150_70_50	18,4410	0,17	0,95%	14,31%
150_60_40	18,3126	0,04	0,25%	3,71%
150_40_20	18,2777	0,01	0,05%	0,83%
250_80_60	18,6032	0,33	1,84%	27,72%
250_70_50	18,3718	0,10	0,57%	8,60%
250_60_40	18,3024	0,03	0,19%	2,87%
250_40_20	18,2768	0,009	0,05%	0,76%

Table 2: Result in oil recovery for different cases

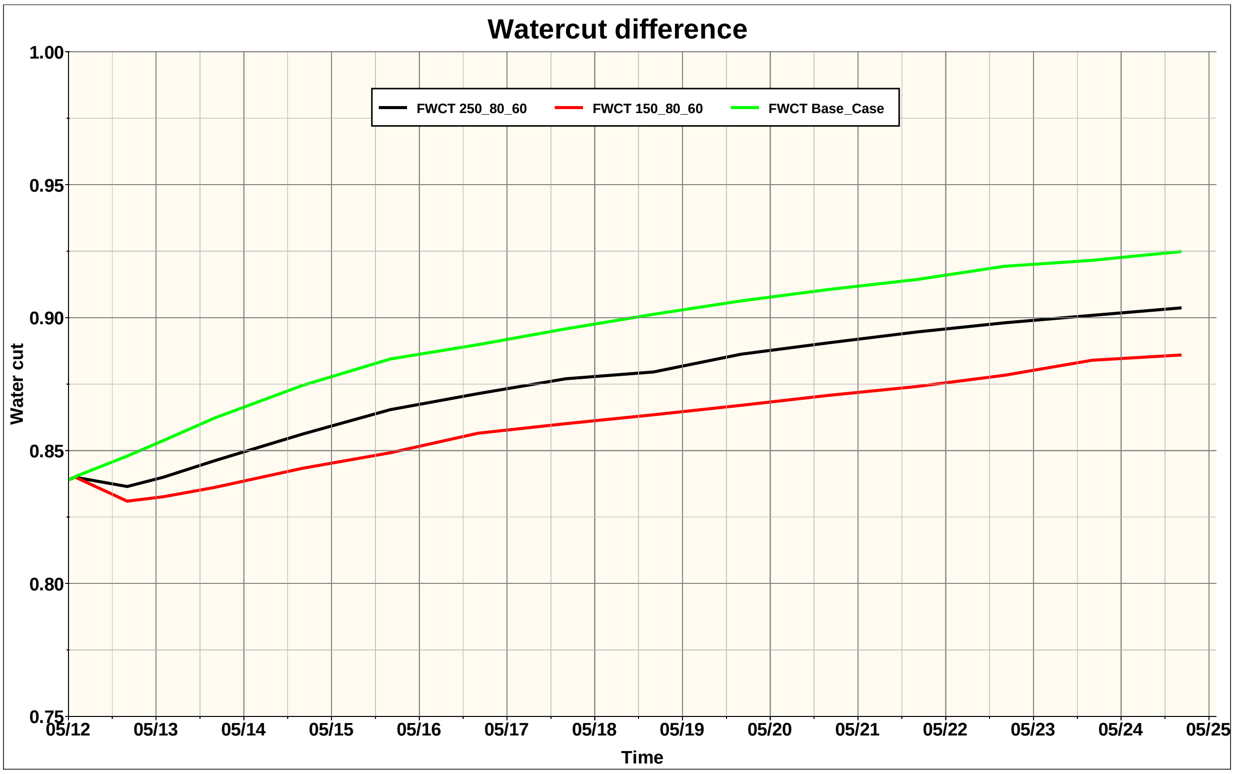


Figure 9 Water cut in 80%-60% permeability reduction with tracer concentration of 150 and 250 compared to Base Case from 2012 to 2025

There are significant differences in water-cut in the simulations of the 80%-60% permeability reduction scenario and the base case. The difference in water-cut between reducing the permeability in cells with a tracer concentration of 150 mg/l and in cells with a tracer concentration of 250 mg/l is also well visible. The reduction in water cut is observed straight after the injection of the Abio Gel. The most significant reduction of water-cut is within the first 6 months. After this the reduction flattens out and the water-cut starts to increase again. It stays stable at a level of approximately 2.8 % below the base-case for the 250 mg/l case, and approximately 3.5% below the base case for the 150 mg/l case.

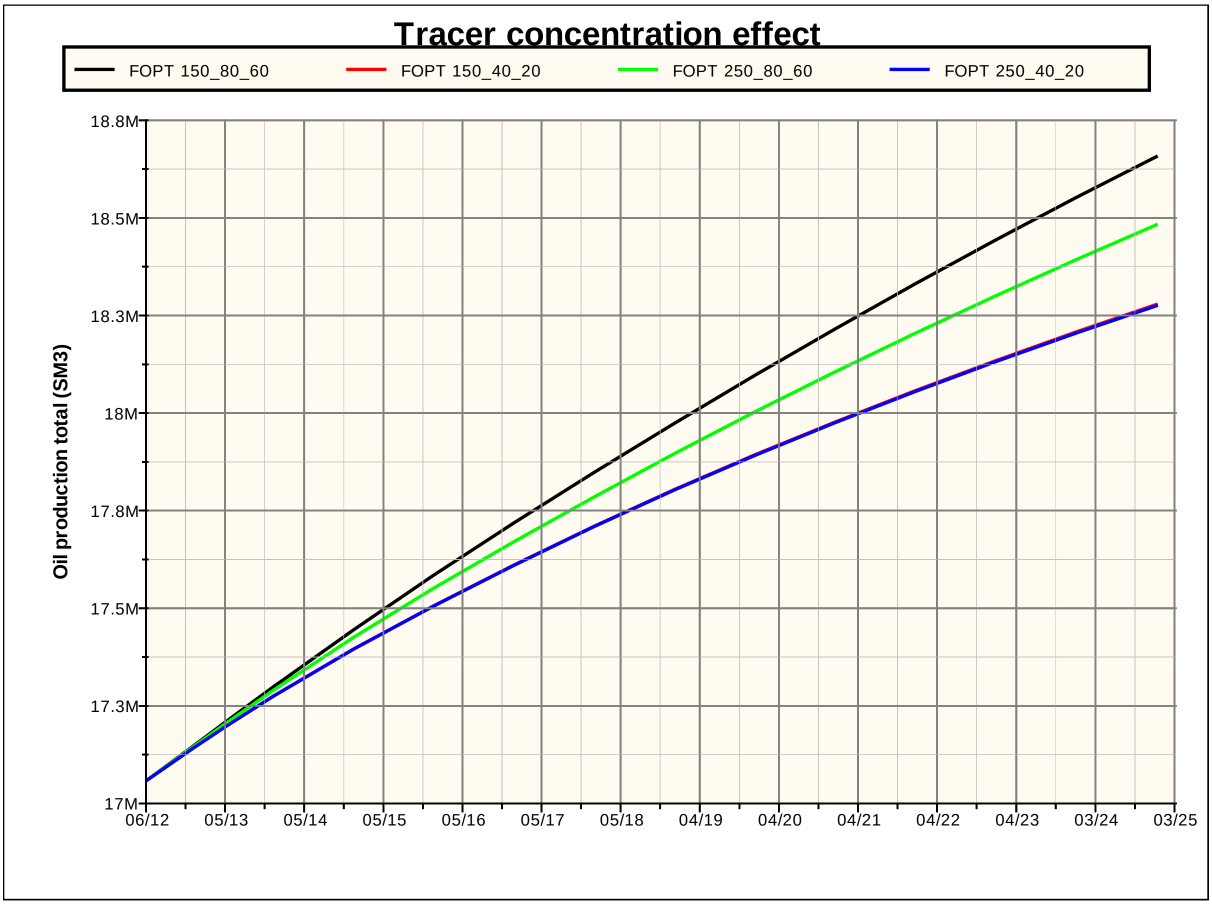


Figure 10 The effect of choosing different tracer concentration on total oil production from 2012 to 2025.

Analysis of results for different tracer concentration shows that the best case is 80%-60% of permeability reduction with 150 of tracer concentration. 40%-20% permeability reduction in both 150 and 250 of tracer concentration does not make any observable difference in total production. The plot also shows the sensitivity of total recovery from tracer concentration at 80%-60% reduction of permeability. By the end of the forecast there is a difference of 174550 sm3 in total recovery between 150 and 250 concentrations.

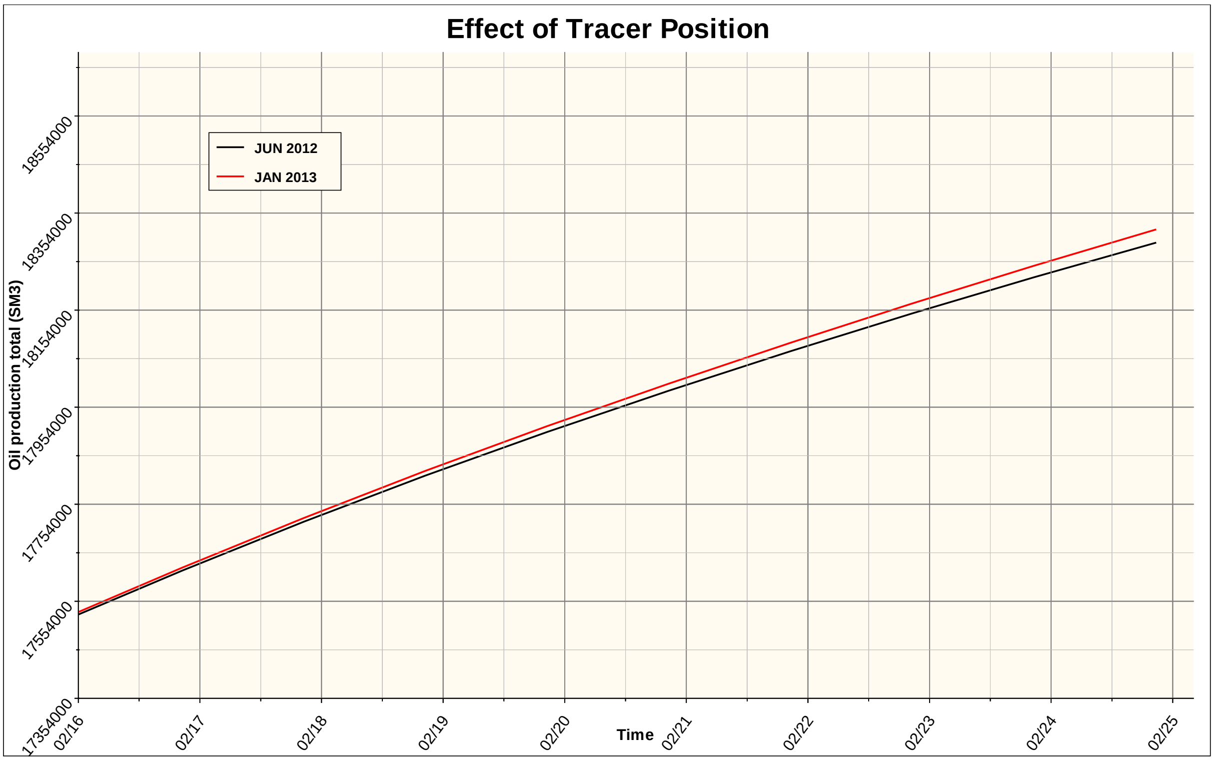


Figure 11 The effect of position of tracer on total oil production from 2016 to 2025

The placement of the tracer varies from the first time-steps after injection to later time steps. Blockage effect changes depending on the current position of the tracer in the formation. The plot describes changes in recovery using the permeability parameters according to different time steps. At the beginning of injection the permeability reduction area is relatively limited compared with later stages. This is why simulation results show low production while using the permeability according to start date of EOR. As water injection continues the tracer flows from the injection well and further into the formation and covers a larger area. Hence a larger area of the formation gets a reduced permeability with using a time-step 6 months later and more oil gets produced from the formation.

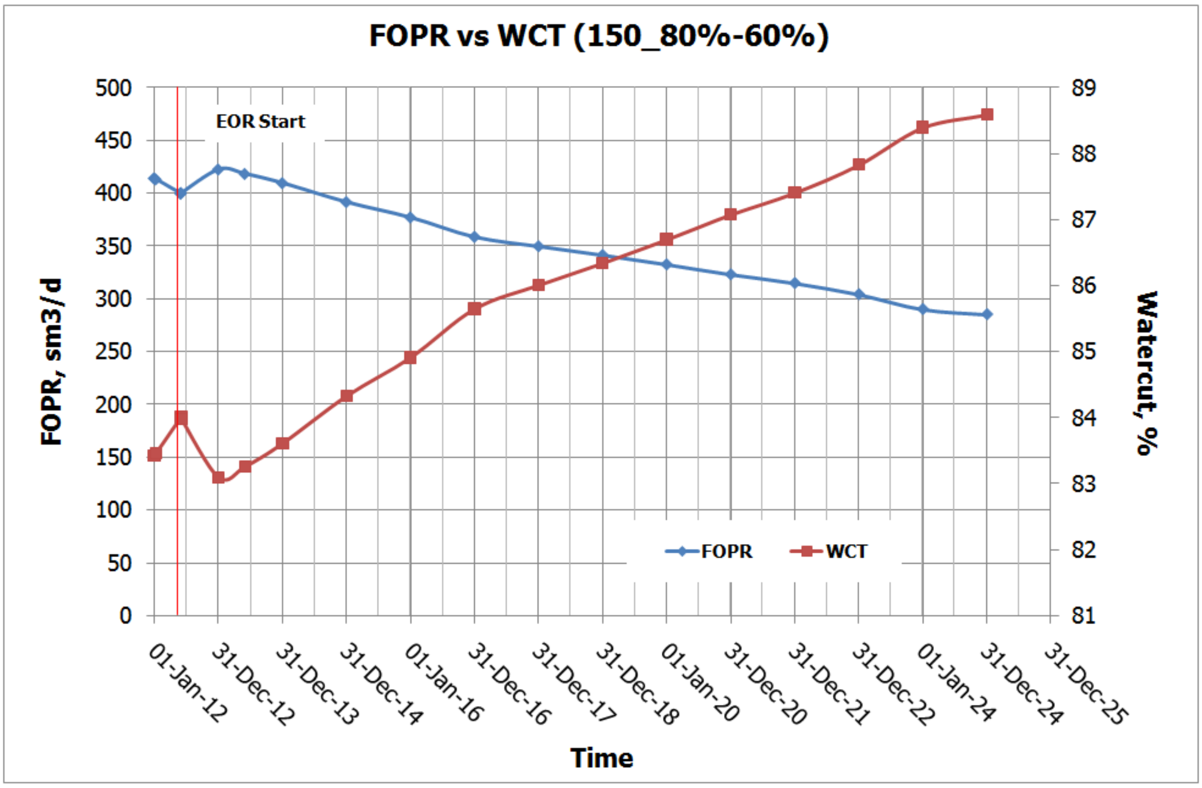


Figure 12 Field oil production rate (sm3/day) vs. Water cut (%) with a concentration of 150 and 80-60% permeability reduction, 01 January 2012-31 December 2025

Figure 12 shows the field oil production rate and the water cut for the 80 – 60% permeability reduction case (best case). The injection of the Abio Gel in June 2012 is marked with the red line. Following the injection of the chemical in June 2012 we can observe a very noticeable drop in water cut and an increased oil production rate. This shows that the measure is successful, and the goal of reducing the water cut together with producing the previously bypassed oil is achieved. Starting from the beginning of year 2013 we see that water cut once again is starting to increase and the oil production rate is going down. However, these values are much better than the base case.

After running simulations for different cases of permeability reduction, together with plug size and placement, we calculate the total increase in recovery factor compared to the total base case production. This will be the main indicator of production performance since the goal of the project was to increase the oil recovery of the segment. The results are presented in table 3. We observe that the case with 80 to 60% permeability reduction with the lowest threshold for permeability reduction gives us a total increase in recovery factor of above 2% for the H1 segment.

Concentration, mg/l	Permeability Reduction, %	Increase in RF
150	40-20	<0.5
	60-40	1%
	70-50	1.25%
	80-60	2%
250	40-20	<0.5
	60-40	<0.5
	70-50	1.1%
	80-60	1.4%

Table 3: Increase in recovery factor for different cases of permeability reduction and plug size

2.6.3 Economical calculation

Profitability analysis of the project is the key evaluation after the technical analysis is completed. This analysis is the basis for investment decision of the project. Investment decisions are often based on several criteria's that are calculated from the profitability analysis such as Net Present Value (NPV), Payback Period, and Internal Rate of Return (IRR). A project is categorized as a profitable project when its net earnings are greater than the cost of capital that is reflected in the main parameter: NPV. The larger the additional earnings, the more profitable the project is, and it is easier to justify putting the capital or investment at risk.

NPV is an indicator of how much value an investment adds to the company. Positive NPV indicates that the project may be accepted. A high NPV indicates a high profitability from the project. NPV takes into account the value of cash earned in the future and converts the money to the present value through the following formula:

$$NPV = -CF_0 + \sum \frac{CF_t}{(1+i)^t}$$

i is discount rate which in this case is set to 8%. The lifetime of the project is assumed to be 12 years. Since there will be two kinds of expected cash flows, which are, (1) cash flow with Abio-gel project and (2) cash flow without the project, we use incremental NPV analysis to make a decision.

$$\text{Incremental NPV}_{A\text{-}B} = \text{NPV}_A - \text{NPV}_B$$

Where:

NPV_{A-B} = Incremental NPV of project A over B
NPV_A = NPV when carrying out the Abio Gel project at the H1 block
NPV_B = NPV when "do nothing", running with the existing production without using Abio Gel

Incremental NPV is positive when Abio Gel project generates additional profit to the base case (production without Abio Gel). It means that the project is feasible. Meanwhile the incremental NPV is negative when additional revenue generated from Abio Gel project could not cover the money invested for the project. It means that the project is not feasible.

Two tracer concentrations are used; 250 and 150. At each tracer concentration, the permeability reductions are varied into 4 cases that are 80-60%, 70-50%, 60-40% and 40-20%. This has been explained extensively in previous parts of this rapport. As base condition, it is assumed that oil price, Abio Gel cost and cost of Abio Gel injection to the reservoir is 100 USD/barrel, 20 million NOK and 50 million NOK (Eltvik, 2012b) respectively. The oil price is assumed constant (inflation free) along the whole project period.

The investment is spent in 2012. As the oil production already increases in 2012, the project has generated revenues in 2012. Thus, in 2012, not only investment cost is considered but revenues generated are also taken into account.

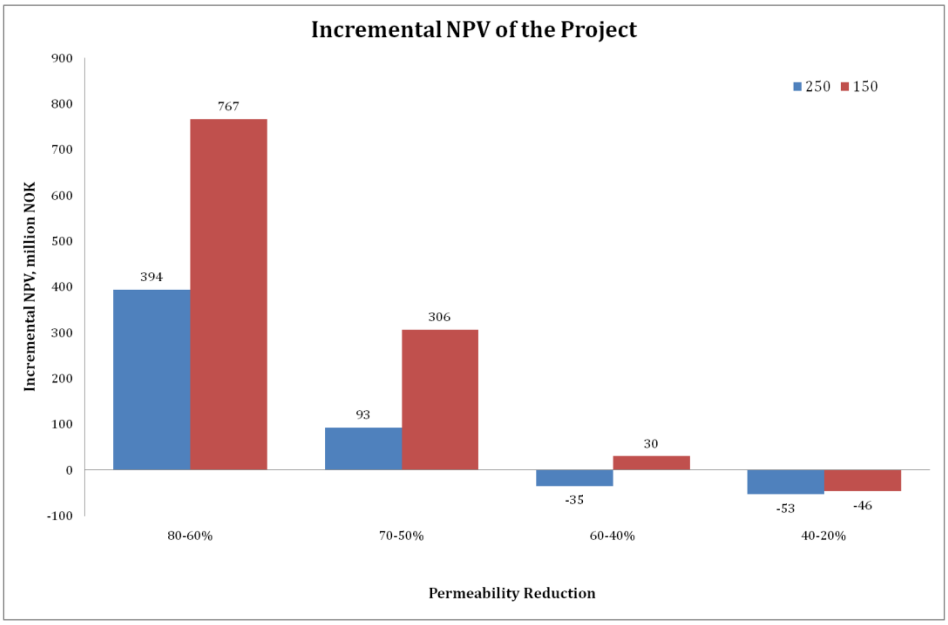
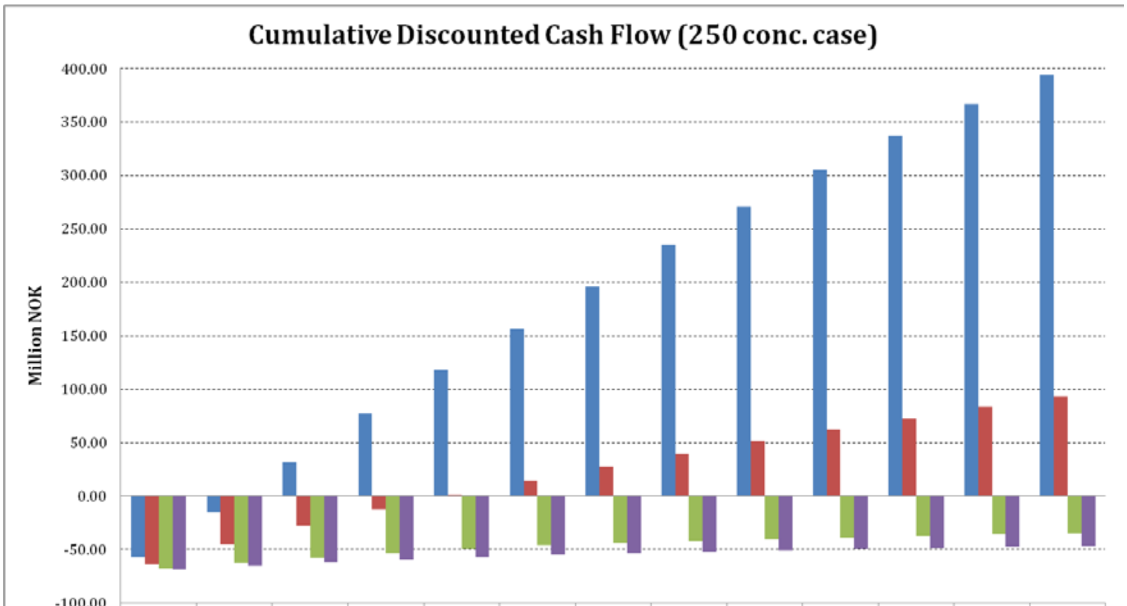


Figure 13 Incremental NPV of the Project at various permeability reductions and tracer concentrations

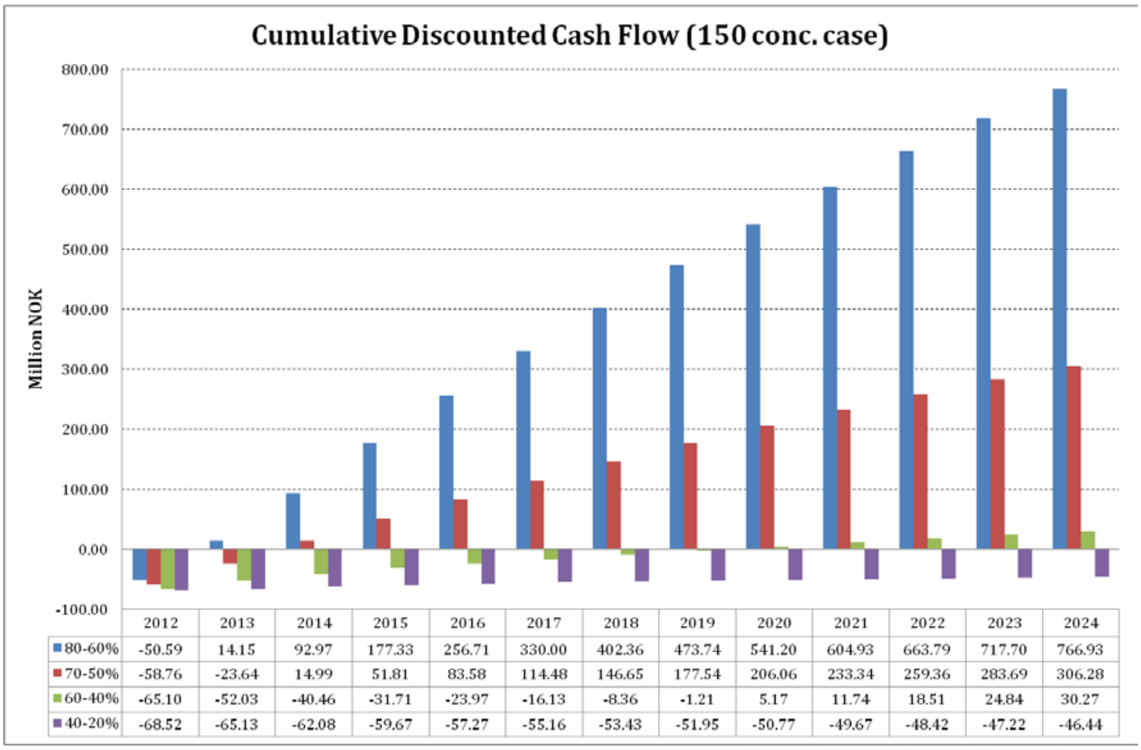
Figure 13 show the incremental NPV of different measures compared to the original case (the case which is resulted from the original production rate without injection Abio Gel). For concentration 250, the 60-40% permeability reduction gives negative incremental NPV. Hence, the project will only be feasible when the permeability reduction is 70-50% or greater. Meanwhile, for concentration 150, the 60-40% permeability reduction gives positive incremental NPV and will still be feasible.

Figure 14 and 15 show the profile of cumulative discounted incremental cash flow of the project over the original case for each concentration.



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
80-60%	-56.93	-15.25	31.77	77.66	117.68	156.18	196.18	234.96	271.08	305.02	337.03	366.88	394.45
70-50%	-63.62	-45.26	-27.35	-12.17	1.29	14.53	27.60	40.03	51.22	62.10	72.91	83.38	92.94
60-40%	-67.68	-62.13	-57.45	-53.68	-49.61	-46.18	-43.58	-41.63	-40.28	-38.77	-37.10	-35.89	-35.18
40-20%	-68.52	-65.13	-62.08	-59.67	-57.27	-55.16	-53.43	-51.95	-50.77	-49.67	-48.42	-47.22	-46.44

Figure 14 Cumulative Discounted Cash Flow for tracer concentration of 250



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
80-60%	-50.59	14.15	92.97	177.33	256.71	330.00	402.36	473.74	541.20	604.93	663.79	717.70	766.93
70-50%	-58.76	-23.64	14.99	51.81	83.58	114.48	146.65	177.54	206.06	233.34	259.36	283.69	306.28
60-40%	-65.10	-52.03	-40.46	-31.71	-23.97	-16.13	-8.36	-1.21	5.17	11.74	18.51	24.84	30.27
40-20%	-68.52	-65.13	-62.08	-59.67	-57.27	-55.16	-53.43	-51.95	-50.77	-49.67	-48.42	-47.22	-46.44

Figure 15 Cumulative Discounted Cash Flow for tracer concentration of 150

Sensitivity analysis

A sensitivity analysis is carried out in this project to examine the effects of uncertainties in the forecasts and assumptions on the profitability of the project. There are three main parameters that will be evaluated: (1) oil price, (2) chemical Abio Gel cost, and (3) cost for injecting the chemical to the reservoir. The results of the sensitivity analysis are described in Figure 16. From the figure, it is concluded that the oil price deviation from the base case (basic assumptions) will give higher impact to the feasibility of the project than the other parameters.

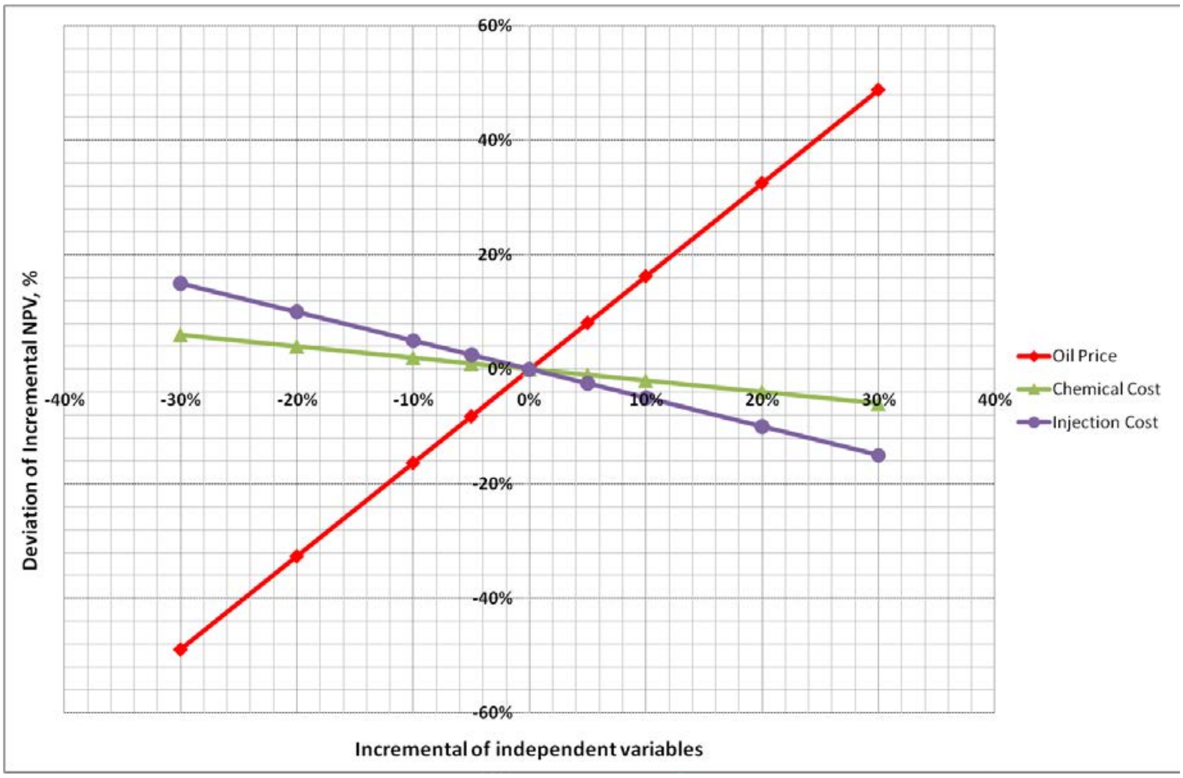


Figure 16 Sensitivity analysis of the project

2.7 Discussion

2.7.1 How to simulate the permeability reduction with Abio Gel.

In principal the Abio gel reduces the permeability by coating the sand grains it comes into contact with when exposed to divalent cations that can be found in formation and injection water. In reality the case is much more complex. The reservoir in question has severe heterogeneities and faults runs through much of the Gullfaks field. The reservoir model that has been used in the simulation is simplified and the result might vary from what will be observed in real life. It is very hard to predict exactly how the chemical will move when injected into the reservoir and how it will react and form the gel once it comes into contact with divalent cations. The successful formation of stable Abio Gel is dependent on both salinity and temperature. To form Abio Gel we need at least 1% concentration of divalent cations and a temperature range between 30 and 200°C (Eltvik, 2012a). The temperature at the Gullfaks field is around 74°C (Talukdar & Isntefjord, 2008), but the salinity might vary and complicate matters even more. The oil saturation will also vary across the segment, and might hinder the formation of Abio gel further.

When applying the permeability reduction with the FORTRAN expression in FloViz we decided to base it on what was suggested by Huseynov at the Statoil office in Bergen. This is off course a simplification, and in reality it is much more complex and dependent on many more factors besides tracer concentration.

Because of the many different factors that comes into play when trying to simulate the permeability reduction, and the complexity of the problem at large, we came to the conclusion that it would be the most beneficial to use as simple of a model as possible. When doing this, we will reduce the amount of uncertainties, and show the principle of the case in the most understandable and clear way possible. To account for the many uncertainties of our problem we have run sensitivity analysis of both size and position of the Abio gel "plug", as well as different cases of permeability reduction.

It is also worth noting that when simulating the permeability reduction the changes are constant and does not vary with time. In real life this might not be true because the Abio gel might not have a life span of over 13 years like we have used in our case. In real life the Abio gel might deteriorate over time and additional injections might be required.

2.7.2 Base case

The base case simulation has been run from year 2012 to 2025 with no changes in permeability to forecast the future oil and water production of the field if no EOR measure is initiated. The objective of the base case forecast is to be able to compare the effect of different EOR applications. From the base case simulation water cut and field oil production rate is reviewed (Figure 6). From production data we can observe that water cut is increasing and oil production is starting to decline from 1994. A similar trend is observed in the forecast simulation from year 2012 to 2025. Production is slowly declining, and by the end of the forecast we see a production of around 200 Sm3/day. The low production rate, and high water cut, might be explained by the fact that most of the moveable oil has been flushed away in the high permeability zones where water highways have formed. Because of this the injected water flows through the relatively drained high permeability zones where they have an easy flow path, and the production stream consists predominantly of water. According to the base case forecast the water cut is around 90% by the end of the simulation.

If we look at Figure 6 we see a distinct difference between the actual production data, and the forecasted production data. This is because the forecast will show the general trend of the oil production and water cut, while the actual data also shows more specific variations that might be caused by shut in, choking of the production or other situations. It is obvious that the production after year 2012 will vary like this also, but the forecast will show the general development of the oil and water production.

By observing the trend of the water cut and oil production, and with the knowledge of between 2 and 5 MSm3 of potential moveable oil left in the segment (Eltvik, 2012a), it might be in the interest of the owners to initiate measures for enhanced oil recovery of this segment.

2.7.3 Simulation of Abio Gel injection

Since it is the first time this particular EOR method has been used on the Norwegian continental shelf we had very limited knowledge on how the chemical actually would react down in the reservoir. As we have mentioned before, uncertainties like reservoir heterogeneity, salinity and temperature variations in the reservoir etc. made the case even more complex. These factors can dramatically affect the behavior of the injected chemical and make it difficult or even impossible to apply the EOR measure successfully and increase the recovery of the segment. Depending on the rock properties and the reservoir conditions different level of pore blockage may occur by the chemicals. It can be reflected in calculated permeability values of the layers and production forecast. Based on all of these uncertainties and risks different possible scenarios have been evaluated and comparisons executed between each case.

The maximum production is achieved with 80%-60% (80% reduction in areas where the chemical concentration is higher than 150 and 60% where the concentration is between 150 and 50) permeability reduction at 150 mg/l of tracer concentration. Increase in total production compared to base case is observed also if permeability reduces down to 70%-50% and 60%-40% at concentration of 150 mg/l. Predicted value of recovery with concentration of 250 mg/l is lower relative to concentration of 150 mg/l. No increase in total production forecast is observed below 70%-50% permeability reduction. It is almost identical with base case at 60%-40 and 40%-20% reduction of permeability.

The reason for the higher oil production for lower threshold concentration is because using these thresholds will effectively increase the area of which the permeability is reduced (more blocked cells). Plugging most of the high permeability layers increases the chance for water to flow through the upper and lower layers where the bypassed oil can be found.

From the comparison of two concentration cases we observe that in both cases 40%-20% reduction of permeability doesn't make any difference. It means even after reducing the permeability, water was not directed to other layers and still flows through the high permeable zone. This outcome may be an indication that the permeability difference between the high water way zone and above/below layers is not less than 40%.

After the permeability reduction has taken place, we see a steep drop in water cut and an increase in oil recovery. Since the water cut is defined as water produced over total produced volumes, it is obvious that the water cut will decrease when oil production increases. After only half a year we see that the water cut starts to increase again, and the oil production goes down. This indicates that a lot of the bypassed oil is produced in the second half of 2012, and that the injected water is back produced after this. The values for water cut and oil production is still more favorable than the base case, and we observe that the principle of the measure has been successful. The feasibility of the project depends on economic factors, together with volumes of increased oil production.

2.7.4 Sensitivity Analysis on simulation part

In our sensitivity analysis we have looked at the size and placement of the Abio gel plug, and also different cases of permeability reduction. As we can observe from the simulation results these factors have a very large impact on overall oil production, and might define the profitability of the measure.

First of all, what values of permeability reduction we might get from the injection of the Abio Gel solution is very difficult to predict. As our simulation results indicate, a permeability reduction below 40% will not cause an increased oil production high enough to justify the cost of the operation. Laboratory tests on sandpacks shows a permeability reduction of 10% for the pores that is hit by the chemical (Statoil, 2012). However, other experiments shows that the permeability might be reduced by up to 90% for high permeability zones if the section is treated with the chemical numerous times (3-6 plugs of chemical) (Tang, et al., 2004). For our case we see we need at least a permeability reduction of 60%, depending on the size of the Abio Gel plug.

By reducing the threshold of the permeability reduction we effectively increase the size of the area that will have decreased permeability. We can see from figure 7 that this almost doubles the additional oil recovery for the 80-60% case. Since this is dependent on the salinity of the formation and injection water it is hard to predict exactly what threshold values to use, but as we observe the lower the threshold value the higher the oil recovery. The same effect might be achieved by repetitive chemical injection, and hence effectively increasing the size of the Abio Gel plug.

The chemical will move towards the production wells once it is injected into the reservoir together with the injection water. When the conditions are right the formation of the Abio Gel will take place, and a rigid gel is formed within 24 hours. By applying the permeability reduction to the reservoir in FloViz, and exporting the properties at different time steps we effectively move the Abio Gel plug further into the reservoir. When doing this, the chemical is dispersed and the concentration of tracer in the cells will also be reduced. But we can see from figure 11 that it might be beneficial to place the plug further into the reservoir when using lower threshold values for permeability reduction (150 mg/l for high permeability reduction and 50 mg/l for lower permeability reduction).

2.7.5 Project profitability

The profitability evaluation revealed that at the base case (oil price is 100 $/barrel and total cost is 70 million NOK) this project is feasible when permeability reduction in the range 70-50% at 250 tracer concentration or permeability reduction in the range of 60-40% at 150 tracer concentration.

The profitability of the project is very sensitive to the assumptions of crude oil price instead of to the chemical and injection cost. But, with the current high oil price situation, the project seems very interesting and will gain more profit.

The Figure 22 (appendix) shows oil price prediction for the coming years. The oil price is predicted to be relatively stable in the coming years, which is favorable for this project, due to some factors for example the increasing of demand from China, India and other emerging countries while in other side the oil production increases slowly, geopolitical factors, risks and instability in major resource countries and high production costs in many important areas of oil production.

2.8 Conclusion and Recommendation

Through our analysis of the H1 segment it is clear that the section is ideal for a IOR/EOR pilot. The Gullfaks field is a mature field and a lot of data has been acquired, together with a good understanding of the structural geology of the field. The H1 segment is more or less isolated, large variation in permeability have resulted in the formation of water highways from the injector well through the high permeability Etive and Upper Rannock formations and into the production wells. Since the injected water does not flush the entire reservoir, pockets of bypassed oil are still left in the lower permeability zones of the reservoir. Because of this we have come to the conclusion that water diversion by gel blocking is one of the most beneficial measures for improved oil recovery for this segment, and maybe also the Gullfaks field as a whole.

In the second part of our project we have looked at the possibility of using a chemical called Abio Gel to reduce the permeability of the water highways. This will ideally result in a diversion of the injection water, and previously unflooded parts of the reservoir will be flooded. We have run simulations on the H1 segment reservoir model, reducing the permeability of certain parts of the reservoir. We have also completed a sensitivity analysis in regards to how much the permeability is reduced, how large the area of permeability reduction is and placement of the affected area. After this we have done an economical evaluation to check the feasibility of the measure.

As we have discussed previously we have concluded with the fact that tracer concentration is directly related to permeability reduction. Because of large uncertainties in regards to what tracer concentration corresponds to what permeability reduction we have decided to use two cases. One with high thresholds for tracer concentration, and one with lower. These cases are explained in detail previously. In the economical evaluation we came to the conclusion that 70-50% permeability reduction was needed with high thresholds for the measure to be economically feasible, while 60-40% reduction was enough when using lower thresholds. For our best case scenario we are looking at a total increase of a little above 2% in recovery factor for the segment. This represents a large amount of extra oil from the segment.

Even though some laboratory tests indicates a permeability reduction of around 10%, other tests have shown that repeated injection might lead to 90% permeability reduction in high permeability layers. Because of this we conclude that the permeability reductions we have used in our simulations are possible to achieve in real life.

We have come to the conclusion that the measure should be initiated because of the large value it will generate if it is done properly. It is also a valuable experience to see the effect of the Abio Gel in a real world scenario, and it might be a good alternative for other segments of the Gullfaks field, together with other fields on the Norwegian continental shelf. Since Statoil is aiming at a recovery factor towards 70% on the Gullfaks field, we believe that this IOR/EOR measure will bring the recovery one step closer to this goal, and it is one of the most promising methods for improved oil recovery at least for the Gullfaks field.

3. References

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4. Appendix

2.1 Tracer concentration distribution for layers 36 to 47 (time step 1. June 2012)

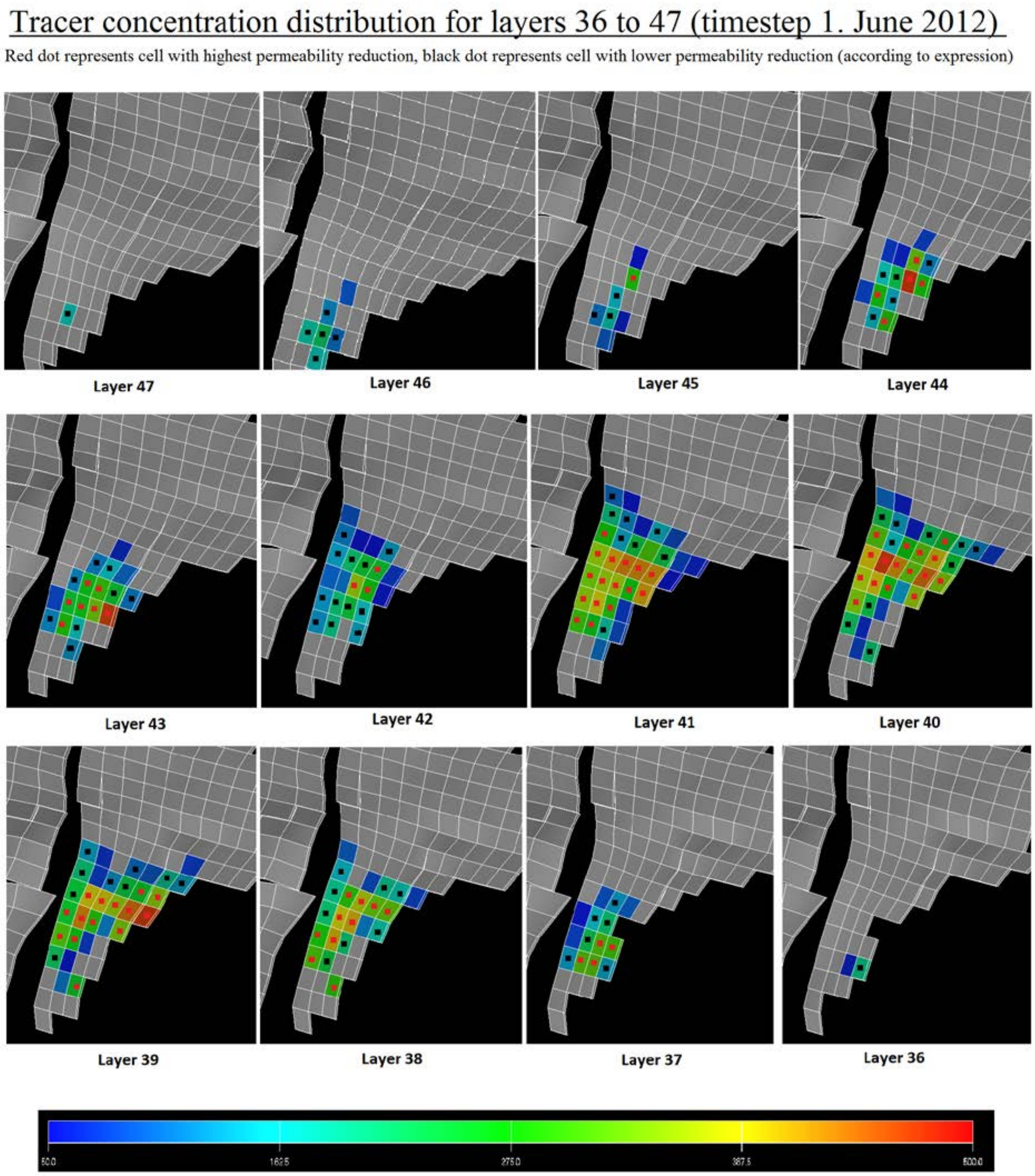

Figure 17 Tracer concentration distribution for layers 36 to 47 (time step 1. June 2012)

2.2 Tracer concentration distribution for layers 36 to 47 (time step 1. June 2012) for case with lowered threshold values

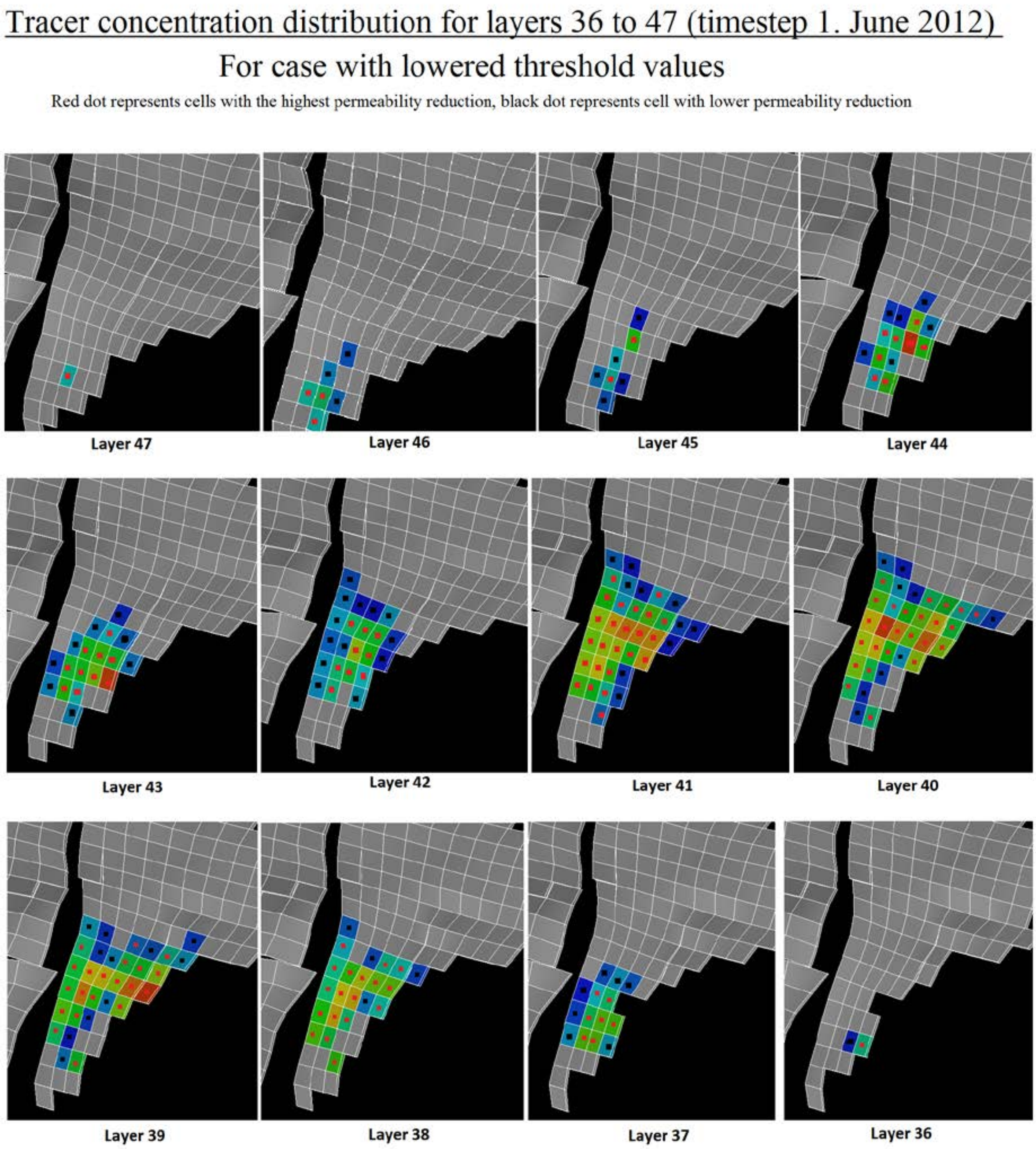

Figure 18 Tracer concentration distribution for layers 36 to 47 (time step 1. June 2012) for case with lowered threshold value

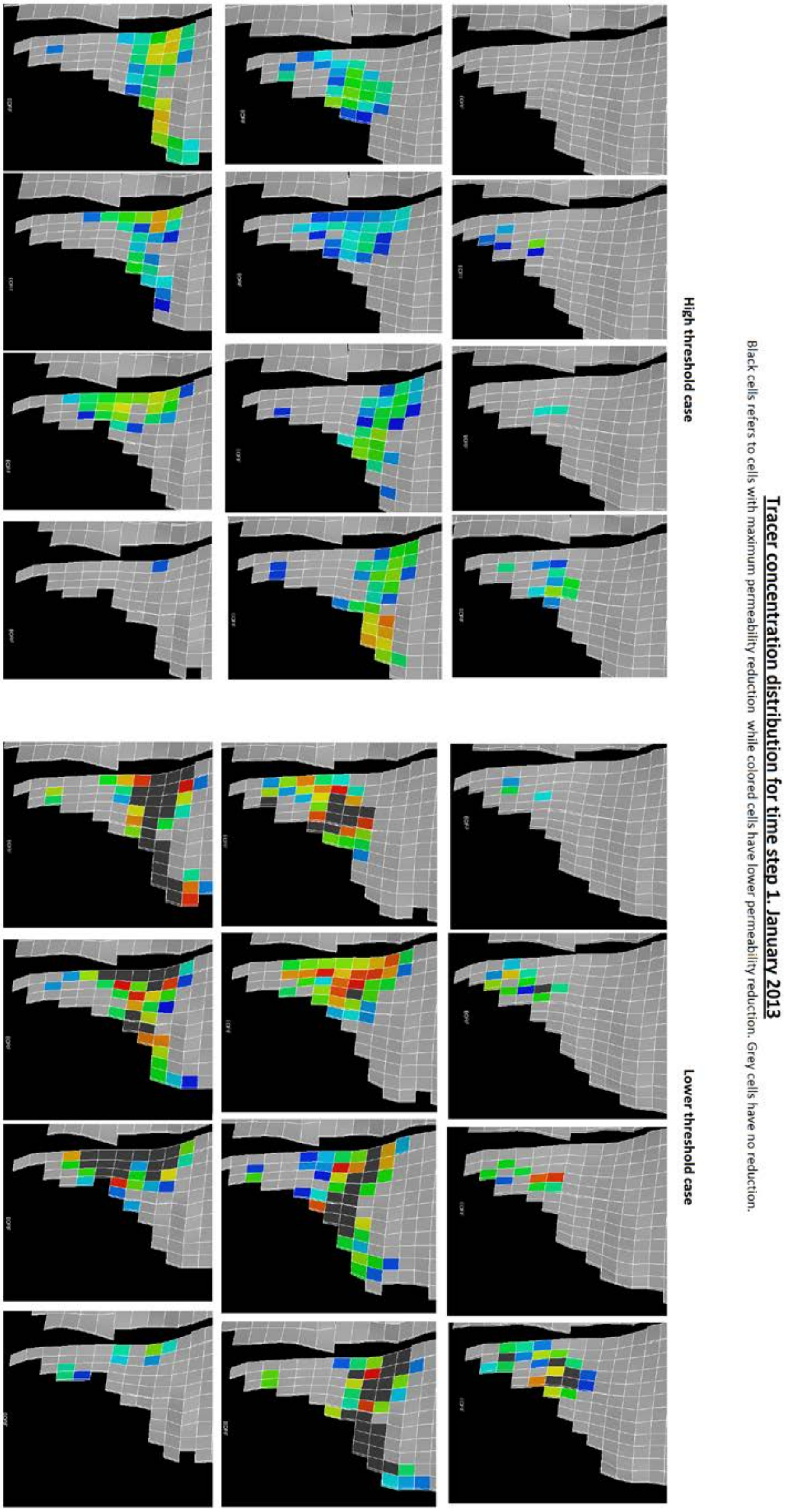

Figure 19: Size of plug for both thresholds when using time step 1. January 2013.

2.3 Different mechanism of profile modification for inorganic gel and cross-linked polymer

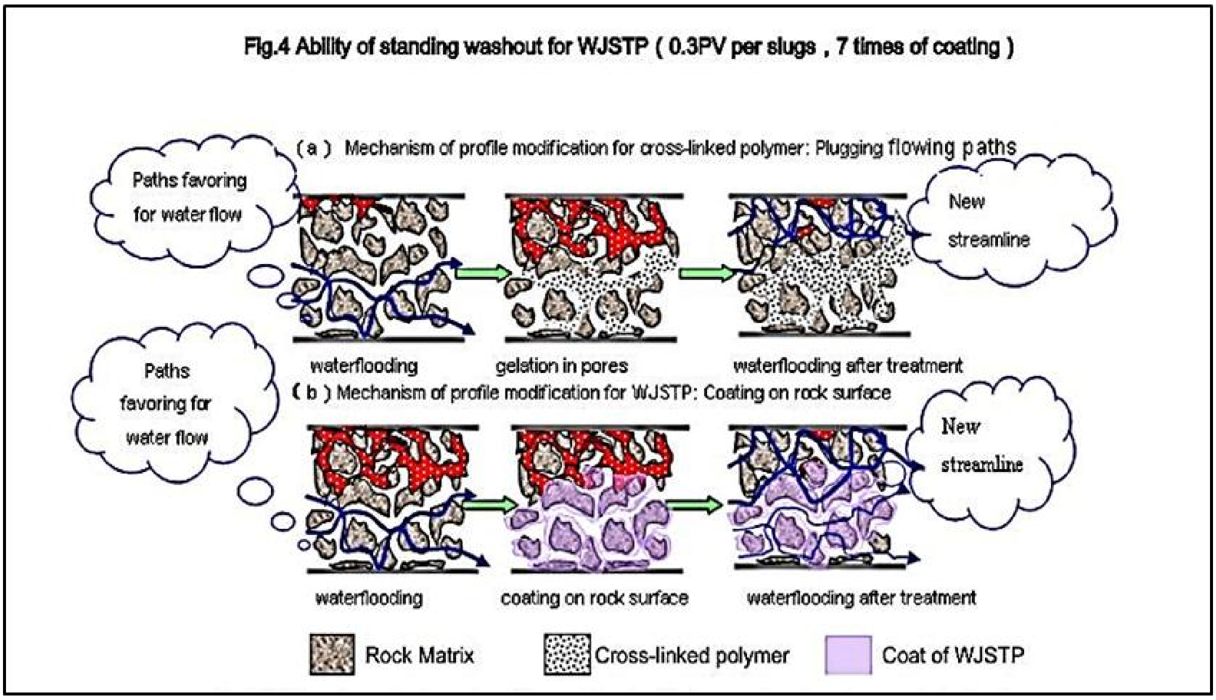

Figure 20 Different mechanism of profile modification for inorganic gel and cross-linked polymer Sensitivity Analysis of the Project

2.4 Performance of the gel coat on oil bearing cores

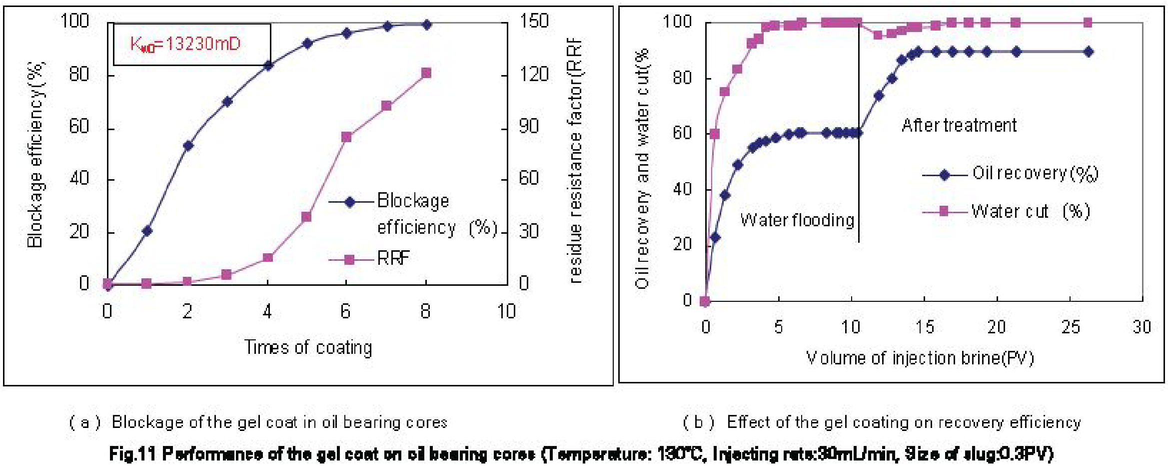

Figure 21 Performance of the gel coat on oil bearing core.

2.5 Oil price forecast

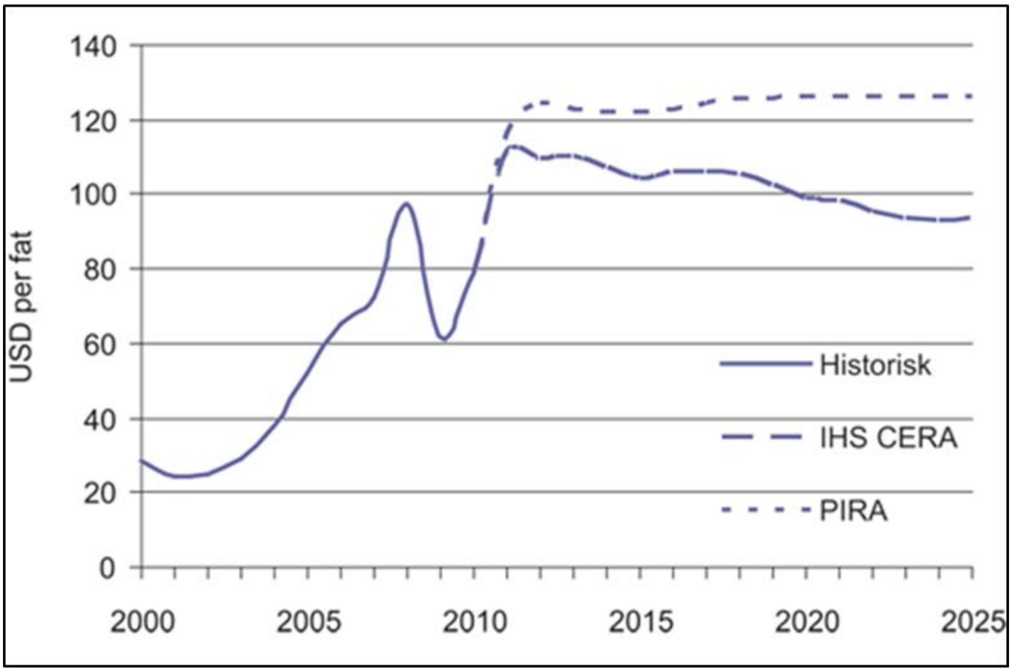

Figure 22 Oil price development NPD