EXPERTS IN TEAMWORK 2012

Gullfaks Village

Project Report – Group 5

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ABSTRACT

This report summarizes Group 5 project work in Gullfaks Village of Experts in Teamwork 2012. This report consists of two sub-reports, Part A report and Part B report. The assigned project is cooperation between NTNU and Statoil with the main purpose of increasing the oil recovery from the Gullfaks Field.

The purpose of Part A project is to understand the challenges related to tail-end production at Gullfaks Main Field. The purpose of Part B project is to analyze the effect of an EOR technique applied to the existing H1 model through permeability modifications.

The main issue in Part B is to increase oil production in the upcoming years by sweeping the residual oil in the low permeability zones. The existing model shows that the injected water goes directly to the high permeability zones; thus by-passes and un-sweeps the oil in less permeable zones. The Abio gel placement and the value of permeability reduction are two parameters to be analyzed further in this project by using reservoir simulation. There are several cases and sensitivities that have been run. Both technical and economic analyses were also applied on the model. We hope Statoil will find some of the ideas worthwhile.

PART A - UNDERSTANDING OF CHALLENGES RELATED TO TAIL-END PRODUCTION AT GULLFAKS MAIN FIELD

CHAPTER 1 INTRODUCTION

The Gullfaks Field is located in the Norwegian sector of the North Sea, about 160km west of the Sognefjord. It was discovered in 1978 and production commenced on December 22, 1986. The field has been developed with three large production platforms – Gullfaks A, B and C. Oil is transported to land by shuttle tankers while gas is piped to the Kårstø processing plant in Tysvær. The gas is exported to Europe after processing at Kårstø.

In this report the focus will be on the Gullfaks Main Field (MF). The Gullfaks area has also satellite fields – Gullfaks South, Rimfaks, Skinfaks and Gullveig. These satellites have been developed with subsea installations controlled from the Gullfaks A and C platforms.

Gullfaks Main Field is in the tail-end production phase. Peak production was reached in 1994 and numerous techniques have been proposed to increase the oil recovery. Some of these methods have been implemented, others not. They will be discussed and ranked according to their potential.

CHAPTER 2 GEOLOGY OF GULLFAKS FIELD

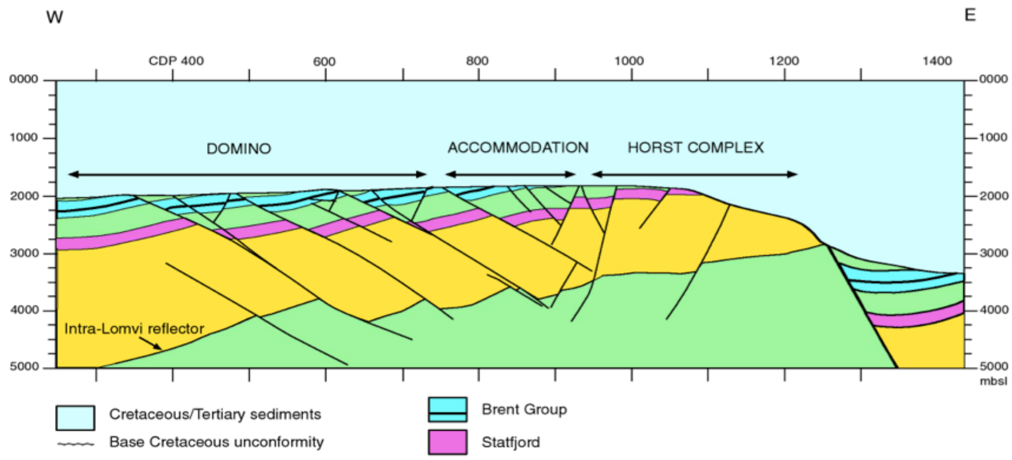

Figure 1 The Gullfaks Main Fields [4]

The Gullfaks Main Field has four oil-bearing sands. On top we have the Brent group. The underlying formations are called Cook, Statfjord and Lunde respectively. The overall geology is complex due to a large number of rotated fault blocks and big permeability contrasts. Permeability is ranging from a few milli-Darcies in the Cook Formation to several Darcies in the Tarbert Formation. This complexity makes communication and flow patterns challenging to analyze. Some of the highly productive sands are poorly consolidated. This causes sand production problems. In addition, H_2S content is high in some parts of the reservoir. H_2S is strongly corrosive and may pose a significant human health risk. It is important to be aware of the problem and know how to effectively reduce it.

2.1 The Brent Group

We often subdivide Brent into Lower Brent (Broom, Rannoch & Etive) and Upper Brent (Ness & Tarbert).The uppermost reservoir at Gullfaks is the Brent Group. This is the most important reservoir containing more than 73% of the in-place volumes of hydrocarbons. It is deposited in a river delta system in the mid-Jurassic period. As previously mentioned, sand bodies (mostly mouth bars) are located in top.

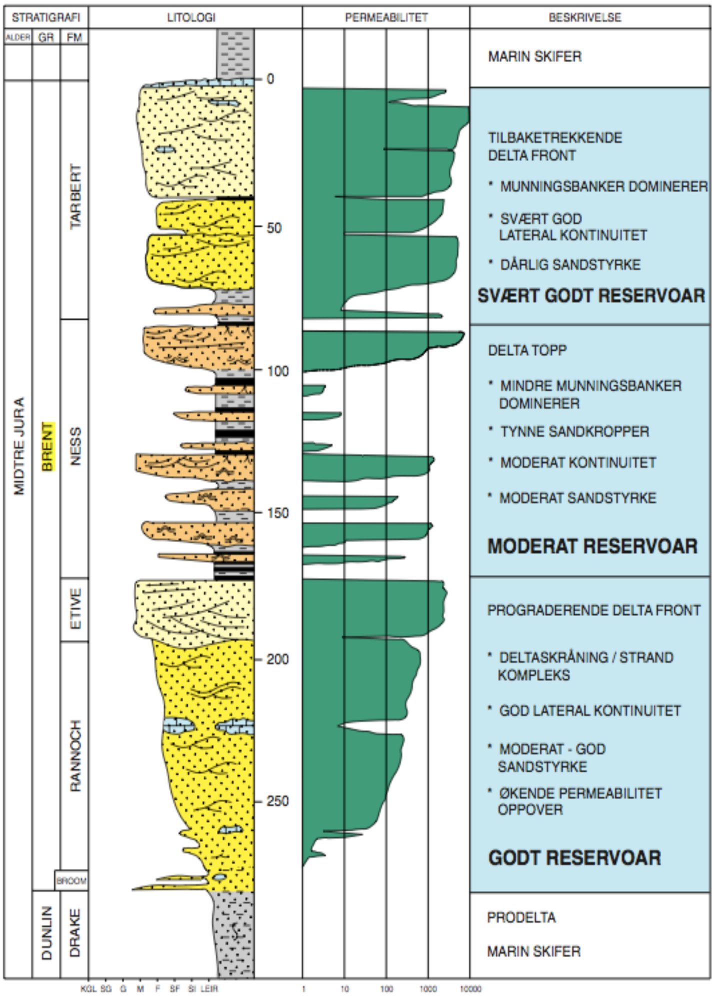

Figure 2 Lithostratigraphic column of the Brent Group from Gullfaks Main Field [4]

Brent displays excellent reservoir properties. This section is interpreted to be part of a retreating delta front. Poorly consolidated sands causes sand production problems. Sand control is necessary to maintain a high production rate.

Calcite, coal and shale may affect vertical communication in some parts of the Brent Group, especially in Ness. This is the least productive part of the Brent Group. Sand bodies are relatively small and continuity is moderate. Broom does not represent a significant reservoir. Current recovery factor for the Brent Group is about 60%.

2.2 The Cook Formation

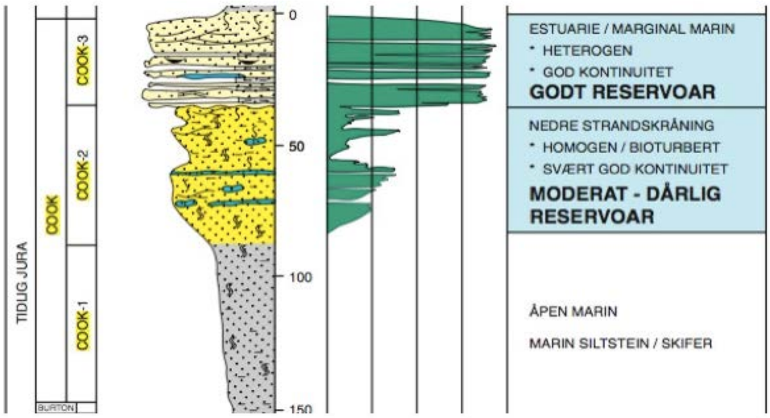

Figure 3 Lithostratigraphic column of the Cook Formation [4]

The boundary between Cook-2 and Cook-3 is believed to represent a hiatus. Calcite layers are observed in both Cook-2 and Cook-3. These layers affect the fluid flow.

The Cook Formation is usually subdivided into Cook-1, Cook-2 and Cook-3. It is characterized by large permeability contrasts between Cook-2 and Cook-3. Cook-1 is dominated by marine shale and does not contribute to the production. Cook-2 consists of fine-grained bioturbated sandstones and mudstones with good continuity. Reservoir quality is moderate to poor. It is interpreted to be shallow marine deposits. Cook-3 is the best part of the Cook Formation. This is non-bioturbated medium to fine-grained sandstones that are relatively heterogeneous.

Recovery factor in the Cook Formation is about 28%. This is much lower than in Brent and Statfjord.

2.3 The Statfjord Formation

It is often subdivided into Nansen, Eiriksson and Raude. The Statfjord Formation was deposited in the late Triassic/early Jurassic period. The formation was deposited during a gradual change in the depositional environment from alluvial environment with episodic flood events in the lower part (alluvial plain) to swamps and river channels in the upper part.

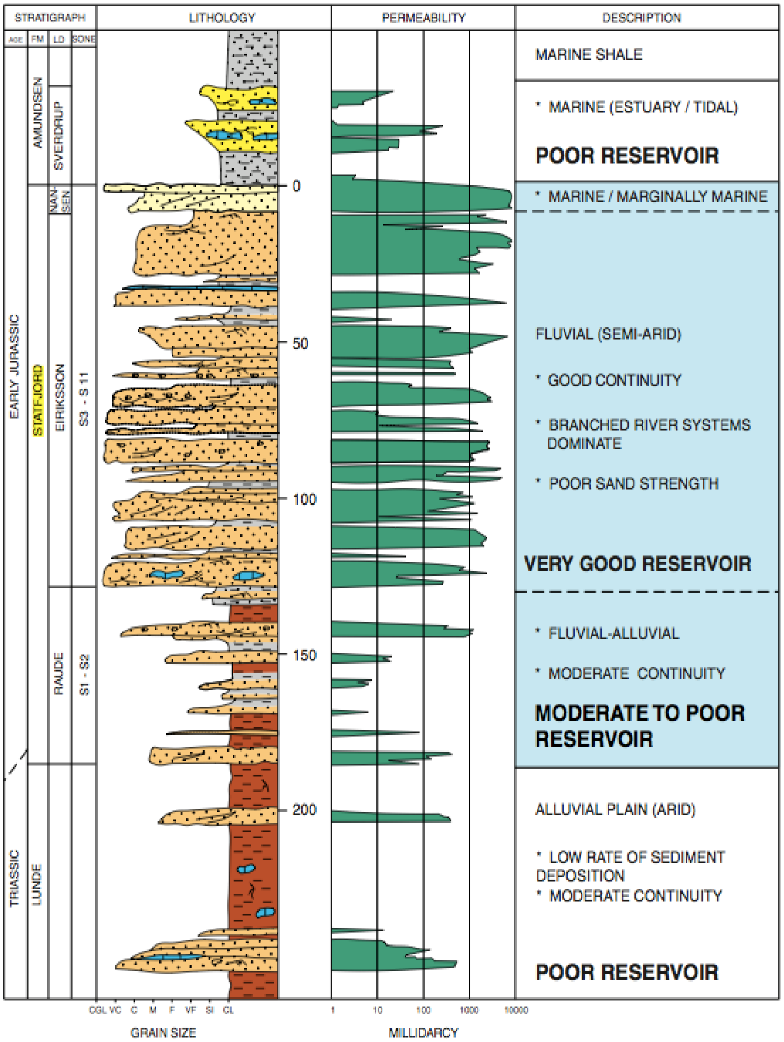

Figure 4 Lithostratigraphic column of the Statfjord Formation [4]

The sand bodies in the Statfjord Formation are often divided into so-called young sands and old sands. This is based on Sm/Nd ratios and mica content. It turns out that the young sands, especially the Nansen and Eiriksson members, have better reservoir properties. Porosity, permeability and continuity are very good. But also here we have poorly consolidated sands leading to sand production problems. Overall recovery factor for the Statfjord Formation (including Krans Fm) is 56%.

2.4 Lunde Formation

The Lunde Formation is the lowermost reservoir at Gullfaks. It is relatively small compared to the other reservoirs. The Lunde Formation is characterized by alternating sand and shale. Reservoir properties vary from moderate to poor.

Large areas of the Lunde Formation contain substantial amounts of water, reaching initial water saturations of 40% in some parts. The lack of good internal reflectors makes it difficult to be mapped by seismic. The Lunde Formation has not yet been fully developed and therefore, the recovery factor is very low (about 8%).

CHAPTER 3 EVALUATION OF RECOVERY FACTOR GULLFAKS FIELD

Gullfaks Main Field's STOOIP is 599 MSm^3 (Table 3.1), the production in the end 2007 was 334.5 MSm3 (56 % oil recovery factor). As of the end of 2011, the oil production is 351.3 MSm^3 of oil [1], making the oil recovery factor as 58.65 %. Using Table 1, one can see that the total oil production since 31 December 2007 is increased by 5.02 % (from 334.5 to 351.3 MSm^3). Let's assume that all reservoir units showed the same index of 5.02 %. Then current oil recovery factor of different fluid formations can be evaluated. It is presented in Table 3.2.

Table 1 Status of different reservoir units in terms of in-place volume, cumulative production, recovery factor and basic reserves (end 2007) [5]

Formation	In-place (MSm3)	Production (MSm3) 31 Dec. 07	Rec. Factor (%)	Reserve (MSm3)
Brent Group	440	265	60	282
Tarbert	198	129	65	135
Ness	72	41	57	46
Lower Brent	170	95	56	101
Cook	60	17	28	20
Statfjord including Krans	93	52	56	55
Lunde	6	0.5	8	1
Total	599	334.5	56	358

Table 2 Current (end 2011) evaluated status of different reservoir units

Formation	**In-place (MSm^3)**	**Evaluated end 2011 production (MSm^3)**	**Recovery factor (%)**
Brent Group	**440**	**278,30**	**63,25**
Tarbert	198	135,48	68,42
Ness	72	43,06	59,80
Lower Brent	170	99,77	58,69
Cook	**60**	**17,85**	**29,76**
Statfjord including Krans	**93**	**54,61**	**58,72**
Lunde	**6**	**0,52**	**8,75**
Total	599	351,3	58,65

3.1 RECOVERY OF EACH SEGMENTS

From Chapter 4 of Reservoir Management Plan [4], one can see resources and recovery in different segments. Summing all the segments we obtain a STOOIP as 597.76 MSm^3 (which is just 0.2% difference with the previous table) and production of 332.79 MSm^3 as of mid-2007. So, the total oil production since mid-2007 is increased by 5.56 % (from 332.79 to 351.3 MSm^3). Let's assume that all reservoir segments showed the same index of 5.56 %. Then current oil recovery factor of different segments can be evaluated. It is presented in Table 3.

Table 3 Mid 2007 and current (end 2011) evaluated status of different segments

Segment	STOOIP, M Sm^3	Recovery Mid 2007		Formation	Recovery End 2011	
		M Sm^3	%		M Sm^3	%
D1. D3 & D4	7.90	3.00	38	Tarbert including Krans	3.17	40.09
D2 & D3	0.49	0.18	37		0.19	38.78
E2 + E3	6.70	4.60	69	Tarbert	4.86	72.47
F	43.90	13.80	31		14.57	33.18
G	70.60	58.20	82		61.44	87.02
H	58.20	40.60	70		42.86	73.64
I	9.70	8.00	82		8.44	87.06
D	0.00	0.00	0	Ness	0.00	0.00
E	0.50	0.10	20		0.11	21.11
F	1.10	0.00	0		0.00	0.00
G	22.90	12.20	53		12.88	56.24
H	27.10	16.50	61		17.42	64.27
I	19.90	11.50	58		12.14	61.00
G1/2/3	23.50	13.30	57	Lower Brent	14.04	59.74
G4/5/6/7	7.70	4.00	52		4.22	54.84
H1	20.20	11.40	56		12.03	59.57
H2	21.10	11.90	56		12.56	59.53
H3	0.10	0.00	0		0.00	0.00
H4/5/6	27.40	16.10	59		17.00	62.03
I1	10.40	4,50	43		4,75	45.68
I2/3/4/5	57.00	33.40	59		35.26	61.85
U1	2.50	0.30	12		0.32	12.67
G	2.68	0.30	11	Cook	0.32	11.82
H1/2	16.83	5.06	30		5.34	31.74
H3/4/5	6.36	0.77	12		0.81	12.78
I1	2.90	0.35	12		0.37	12.74

I2 - I5A + J1	28.80	9.82	34		10.37	35.99
J2/3	2.30	0.41	18		0.43	18.82
K	0.20	0.00	0		0.00	0.00
H2	1.30	0.19	15	Statfjord	0.20	15.43
I1	11.00	5.20	47		5.49	49.90
I2A + J1 + J2	12.30	9.00	73		9.50	77.24
J3	8.20	4.80	59		5.07	61.79
I4B	1.20	0.40	33		0.42	35.19
K1	3.10	0.70	23		0.74	23.84
K2	12.70	5.10	40	Statfjord including Krans and Sverdrup	5.38	42.39
K3	35.80	21.30	59		22.48	62.81
L	8.80	4.80	55		5.07	57.58
M1	0.00	0.00	35	Statfjord	0.00	36.95
L2	3.40	1.00	29	Lunde	1.06	31.05
K3	1.00	0.01	1		0.01	1.48
SUM	597.76	332.79	56		351.30	58.77

The segments data as of mid-2007 can be presented graphically in Figure 5 and Figure 6.

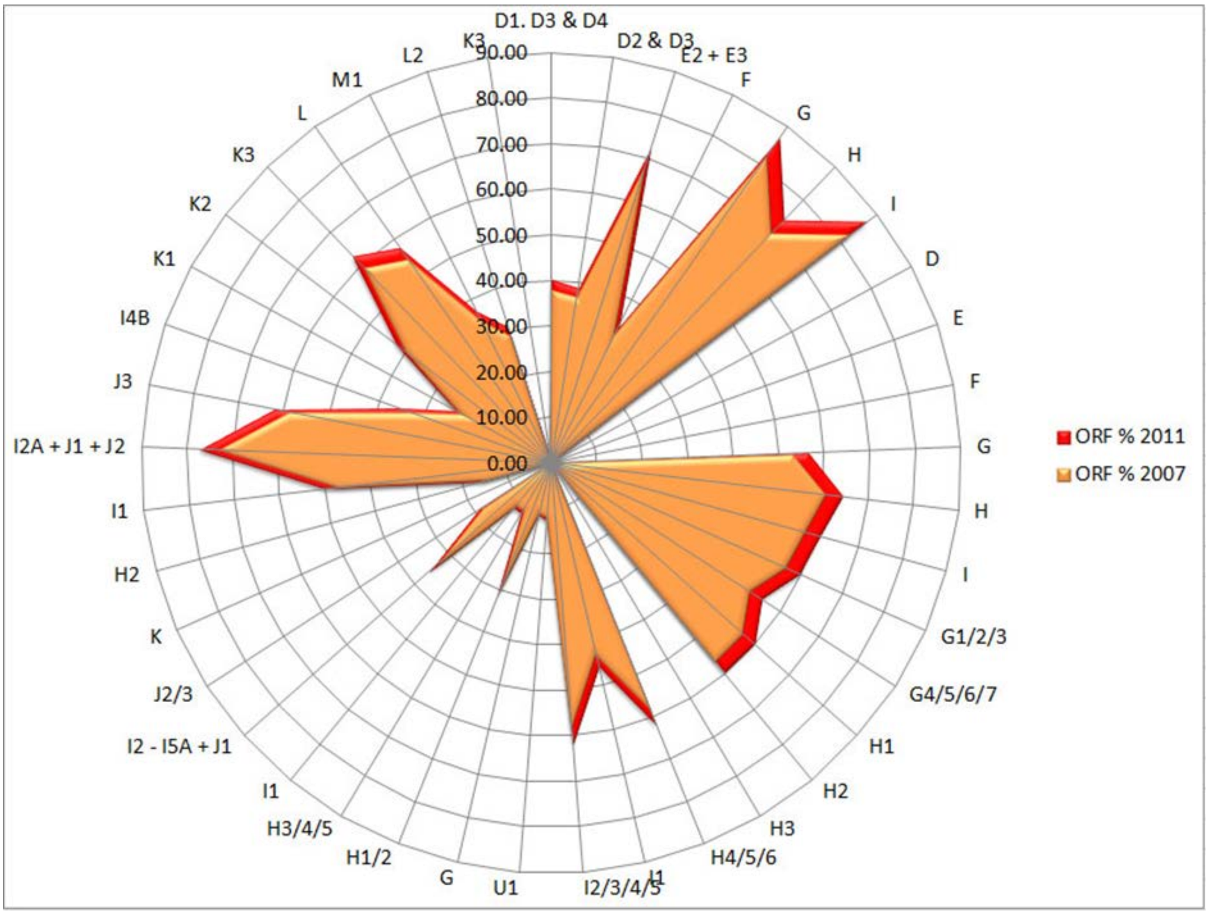

Figure 5 Recovery status for different segments (mid 2007, %)

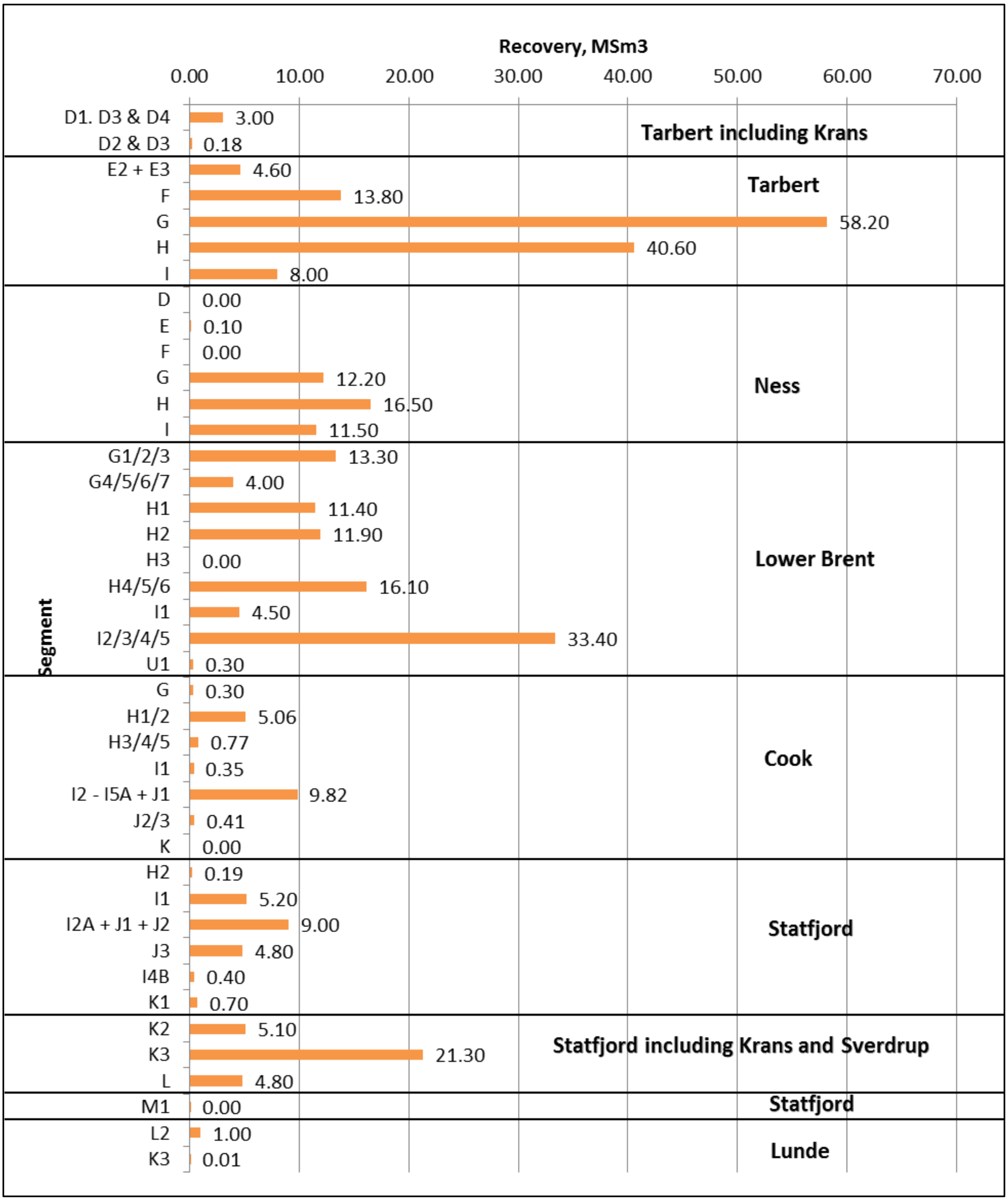

Figure 6 Recovery status for different segments (mid 2007, MSm^3)

CHAPTER 4 H1 SEGMENT AND ANALYSIS OF ISOLATION SEGMENTS

4.1 ISOLATED SEGMENT – H1

An isolated segment means there is no or very limited communication in pressure between layers. H1 is one of the segments where the pressure communication to other parts of the field is limited. The location of H1 segment is shown in the Figure 7 below.

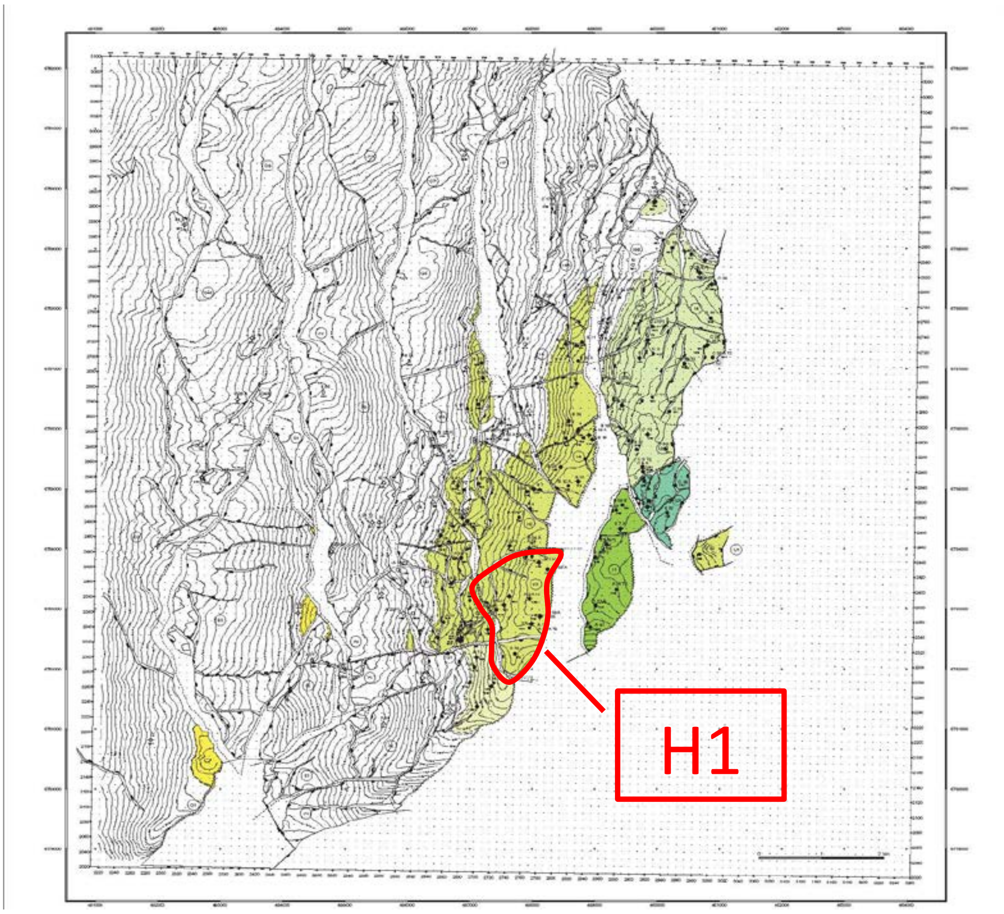

Figure 7 Location of H1 Segment [4]

4.2 ISOLATED SEGMENT IN GULLFAKS

A segment can be defined as "isolated" only when it is isolated both vertically and horizontally. Since the "Brent, Cook and Statfjord formations are mostly isolated from each other, except for limited communication at a few places" (Reservoir Management Plan for

The Gullfaks Field and Gullfaks Satellites 2007). We will check those three formations respectively.

4.2.1 The Brent Group

There are three sub formations in Brent Group, Tarbert, Ness and Broom, the map of which are Attachment 3.3.2-3.3.5 of Reservoir Management Plan for The Gullfaks Field and Gullfaks Satellites 2007. Only segments that are isolated in all the formations can be defined as “isolated”, as is shown below.

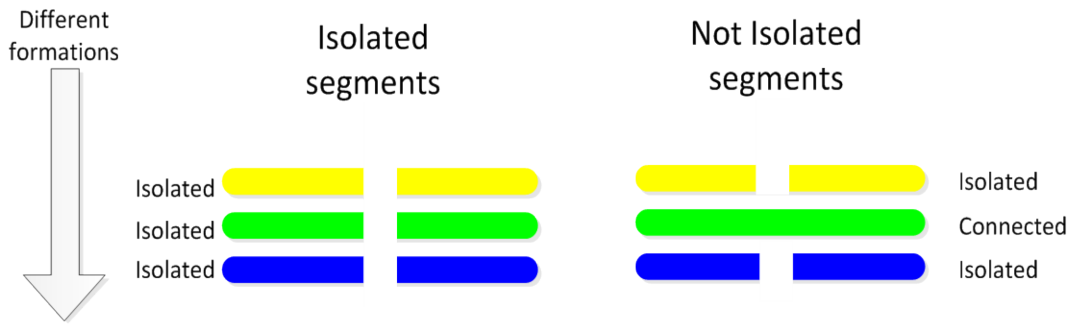

Figure 8 Isolated Segment Analysis

First of all, we start with the Attachment 3.3.4 (Reservoir Management Plan for The Gullfaks Field and Gullfaks Satellites 2007), the Top Ness Structural Map. It is a relatively large map and we check all the isolated segments. The result of which is shown in the table below.

Table 4 Result of Analysis Isolated Segment from Top Ness Stuctural Map

Segment	Segments connected to
I1	Isolated
U1	Isolated
I2A	Isolated
I2C	I3B
I3B	I2C, I4, I5A
I4	I5B, I3B
I5A	I3B, I5B
I5B	I4, I5A
H1	Isolated
H2	Isolated
H4	Isolated
H5	H7
H6A	H6B

H6B	H6A
H7	H5
G1	Isolated
G2	Isolated
G3	Isolated
G4	G5
G5	G4, G6
G6	G5
G7	Isolated
F1	Isolated
F2	Isolated
F3	Isolated
F4	Isolated
F5	F6
F6	F5, F7
F7	F6
E1	Isolated
E2	Isolated
E3	Isolated
E4	Isolated
D1	D2, D3
D2	D1, D3
D3	D1, D2, D4A, D4B
D4A	D3, D4B
D4B	D3, D4A, D5
D5	D4B

We can see 18 segments are isolated in this map, which are shaded in the table and listed below: I1, U1, I2A, H1, H2, H4, G1, G2, G3, G7, F1, F2, F3, F4, E1, E2, E3 and E4.

Secondly, we check all other maps one by one to see whether each of the isolated segments is also isolated in other formations, and rule out the ones connected to other segments. Also, if there are new isolated segments that appear in other maps, the number of which is expected to be quite limited, we will look at it in all previous maps again to make sure it is really isolated.

From Attachment 3.3.2 (Reservoir Management Plan for The Gullfaks Field and Gullfaks Satellites 2007), *The Top Tarbert Structural Depth Map*, no segments are ruled out.

From Attachment 3.3.32 (Reservoir Management Plan for The Gullfaks Field and Gullfaks Satellites 2007), *The Top Ness Structural Depth Map*, we see that the H4 and H5 segments are connected, and thus they are eliminated.

From Attachment 3.3.5 2 (Reservoir Management Plan for The Gullfaks Field and Gullfaks Satellites 2007), *The Top Broom Structural Depth Map*, F1 & G1, F2 & E1 and F2 & F3 are seen to be connected respectively. So F1, G1, F2, F3 and E1 are deleted from the list.

At last, we reorganize the isolated segments in the Top Ness Map, delete the connected ones and add the new found isolated ones as follows.

Table 5 Result of Further Analysis Isolated Segments

Segment	Remarks
I1	
U1	
I2A	
H1	
H2	
H4	Ruled out in Attachment 3.3.3
G1	Ruled out in Attachment 3.3.5
G2	
G3	
G7	
F1	Ruled out in Attachment 3.3.5
F2	Ruled out in Attachment 3.3.5
F3	Ruled out in Attachment 3.3.5
F4	
E1	Ruled out in Attachment 3.3.5
E2	
E3	
E4	

So, the isolated segments in Brent Formation in Gullfaks Main Field, which are shaded in the table, are I1, U1, I2A, H1, H2, G2, G3, G7, F4, E2, E3 and E4, 12 in total.

4.2.2 Cook

Similar to Attachment 3.3.4 (Reservoir Management Plan for The Gullfaks Field and Gullfaks Satellites 2007), we check the Attachment 3.3.6 (Reservoir Management Plan for The Gullfaks Field and Gullfaks Satellites 2007), the *Top Cook Structural Depth Map,* and find the isolated segments in this formation listed below:
I1, K1, H3, H4, H5, G1, G2, G3, G4, G5, G6, G7, F4, F7, E1, E2, E3, E4, D1, D2, D3 and D4, 22 segments in total.

4.2.3 Statfjord

In Attachment 3.3.7 (Reservoir Management Plan for The Gullfaks Field and Gullfaks Satellites 2007), the Top Statfjord Structural Depth Map, we find the following isolated segments in this formation:
K1, K2, K3, J3, I3A, I1, H1, H2, H3, G1, G2, F7, F4, F3, F2, F1, E1, E2, D1 and D2, 20 in total.

4.2.4 Lunde

In Attachment 3.3.8 (Reservoir Management Plan for The Gullfaks Field and Gullfaks Satellites 2007), the Top Lunde Structural Depth Map, the following segments are shown to be isolated:
H3, H7, I1, K1, J1, J2, L1 and L2, Eight in total.

All the isolated segments in different formations are shown in the table below.

Table 6 Summary of Isolated Segments

Formations	**Isolated Segments**
Brent	I1, U1, I2A, H1, H2, G2, G3, G7, F4, E2, E3, E4
Cook	I1, K1, H3, H4, H5, G1, G2, G3, G4, G5, G6, G7, F4, F7, E1, E2, E3, E4, D1, D2, D3, D4
Statfjord	K1, K2, K3, J3, I3A, I1, H1, H2, H3, G1, G2, F7, F4, F3, F2, F1, E1, E2, D1, D2
Lunde	H3, H7, I1, K1, J1, J2, L1, L2

CHAPTER 5 IMPROVED OIL RECOVERY IN GULLFAKS MAIN FIELD

The high demand for oil and gas has forced the oil companies to increase their production. As almost all large fields have been produced or at least the movable oil was completely produced, those companies are facing new challenges to increase their recovery factors by trying to mobilize and produce the non-movable hydrocarbons. Therefore a series of Improved Recovery Techniques were implemented in almost all oil fields; the same case applies to the Norwegian offshore fields including Gullfaks. Some of those techniques were already implemented, others turned out to be not effective in Gullfaks and others are still under investigation. In the figure, the production is shown in green for North Sea Fields and blue for Norwegian Sea Fields

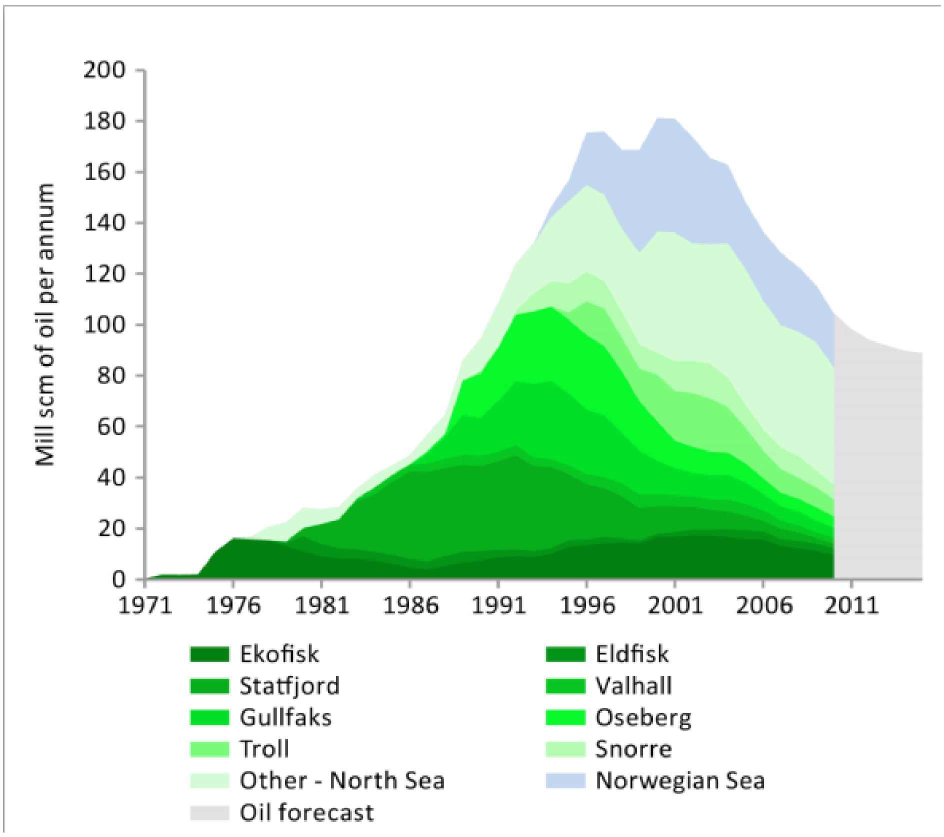

Figure 9 Historical Oil Production and the forecast to 2015. [2]

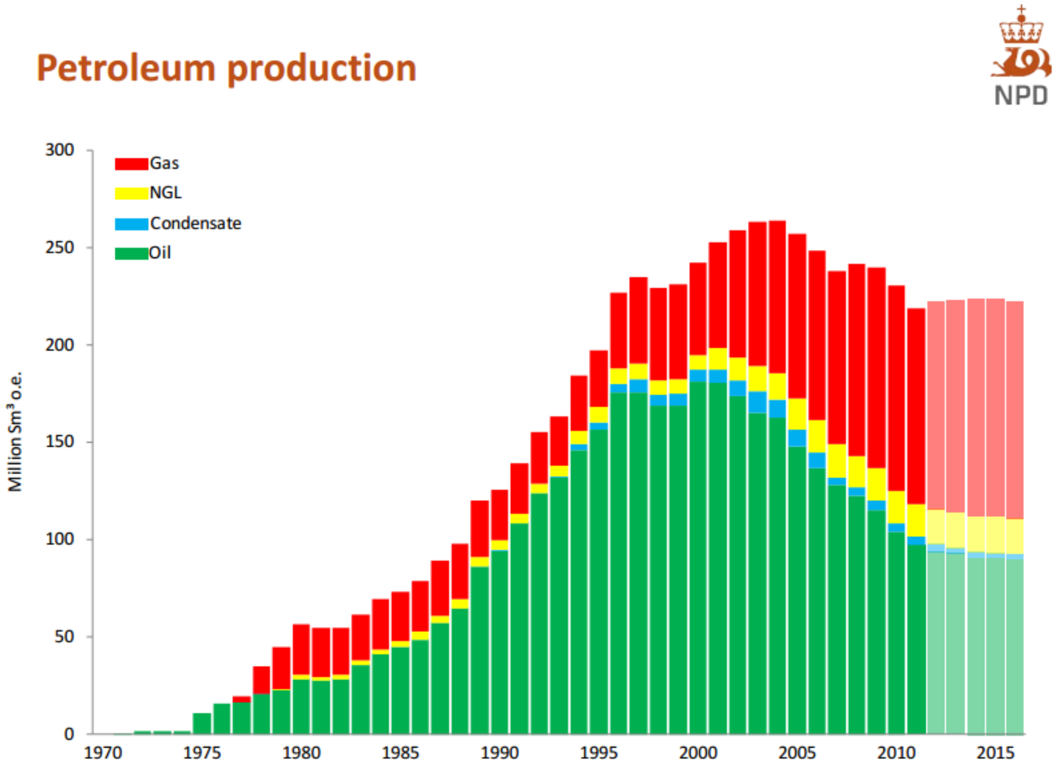

Figure 10 North Sea Hydrocarbon Production and Its Prediction (1970-2016) [2]

Enhanced oil recovery (EOR) is oil recovery by the injection of materials not normally present in the reservoir (Tertiary Recovery). While for the definition of Improved Oil Recovery (IOR), secondary recovery (water and gas injection) and tertiary recovery are included. From the figure below, EOR methods are used in order to take immobile oil or to get better displacement.

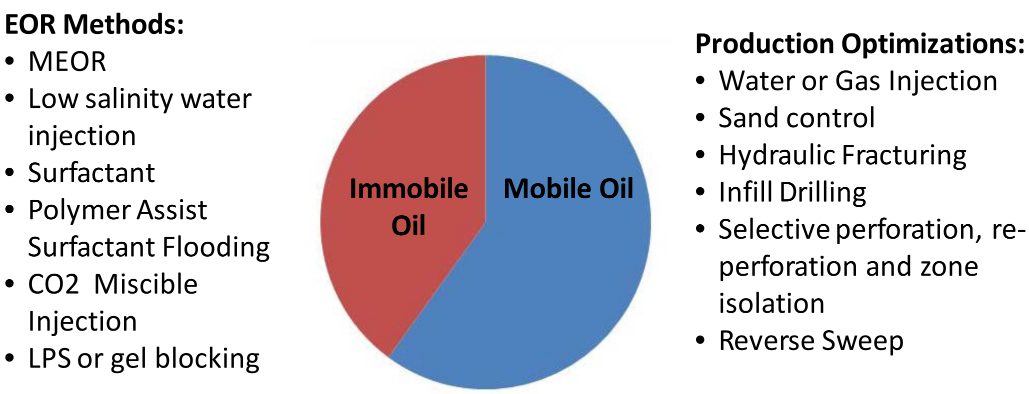

Figure 11 EOR Methods and Production Optimizations

As we see from figure below, which is the prediction of oil production, the trend of oil production decreases. The challenge is either to discover new reserves or to find methods to delay the decline.

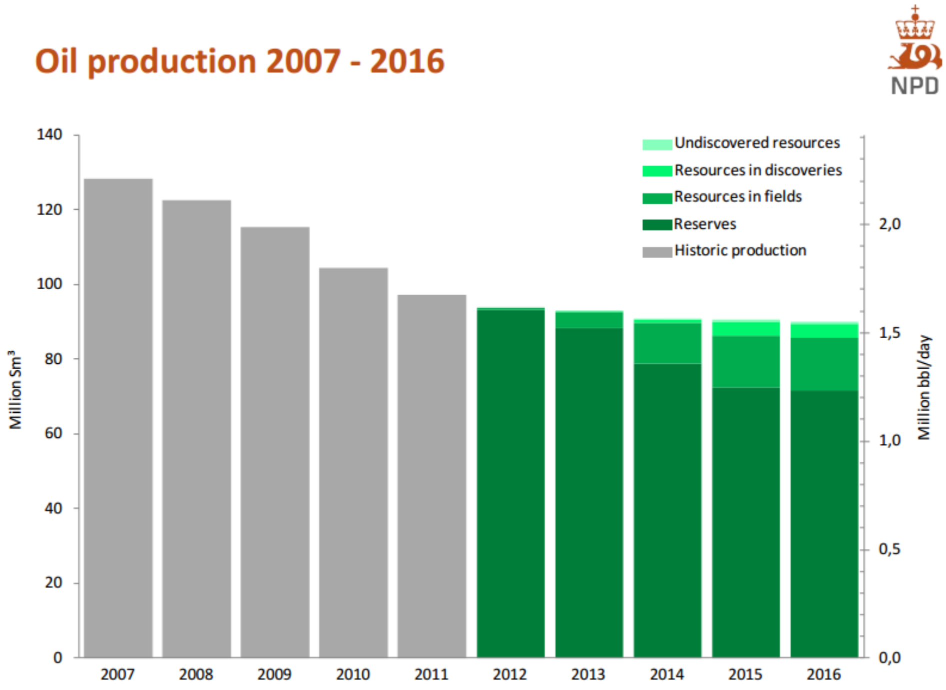

Figure 12 Oil Production until 2011 and oil production prediction until 2016. [2]

The relevance of these IOR methods is related to the main challenges faced in Gullfaks Main Field. The challenges are listed below:

1. The complex structural geology due to the large number of faults and the difficulty in the communication pattern among different fault segments
2. The large permeability contrasts leading to the uneven fluid movement, the pressure differential and the cross flow in different zones causing a poor recovery in low permeable reservoirs
3. The unconsolidated reservoir sands as most of the highly productive sands are poorly consolidated and after water breakthrough the maximum free rate is to be reduced
4. The H_2S content caused by the water circulation creating favorable conditions for H_2S to generate bacteria close to the injection wells placed in the oil zone

To use the Improved Oil Recovery, long term considerations should be thought of including cost, technology, forecast of oil price and risk.

5.1 IMPLEMENTED IOR IN GULLFAKS MAIN FIELD

The following measures represent the techniques implemented in the Gullfaks Main Field as stated in the SPE 113260 "Reservoir Management of The Gullfaks Main Field".

5.1.1 Water Injection

Water injection is one of the secondary recovery methods. Water flooding through water injection, which is one the main recovery mechanism applied in Gullfaks Main Field, is used to keep the pressure above the bubble point since the water influx from adjacent aquifer is not enough to maintain the pressure needed. Gullfaks Main Field has 40 water injection wells and more than 700 MSm^3 of water injected to the reservoir.

In Gullfaks Main Field, the injectors placed close to the Oil Water Contact (OWC) within the same major communication unit to achieve full voidage replacement when production takes place, provide the producers with pressure.

Pros:

1. The pressure is maintained high thus the recovery potential becomes very high and the residual oil saturation is as low as 5%.
2. This is a low cost method as no water treatment is needed since sea water is compatible with the reservoir condition.
3. It can sweep the residual oil from the lower parts of the reservoir.
4. The capacity of water production treatment in Gullfaks can handle a 95% water-cut.

Cons:

1. Water injection is unable to sweep the low permeability zones (few mD) as easier paths can be found through the high permeability zones (~10D). The difference in permeability is one of the main challenges to be solved in this field.
2. In order to increase recovery in the sweet spot area, the number of water injection wells should be increased then the cost will be increased as well.

5.1.2 Gas- and Water-alternating- gas injection (WAG)

The WAG injection process aims to squeeze more oil out of the reservoirs. In Gullfaks Main Field, WAG has been performed on 7 wells and has given additional considerable amount of incremental oil.

In WAG injection, water injection tends to sweep the lower parts of a reservoir while gas injected sweeps more of the upper parts of a reservoir. This is done following 3 mechanisms including draining of attic water, sweeping of other areas not contacted by water and finally reducing the water-cut and the gas lifting of high water-cut wells.

Pros:

1. Injection gas gives better sweep in the areas not contacted by water injection.
2. Water-alternating-gas injection (WAG) helps to maintain oil production high during low gas export period.

Cons:

1. WAG is a very expensive method unless a surplus of gas is available.
2. WAG mechanism is not highly used due to gas injectors' availability.

5.1.3 Huff and puff gas injection

This technique consists of a cyclic gas injection and oil production. This method has been applied on 6 wells in the Gullfaks Main Field. In this method, gas is injected and well is shut in for a period of time before the well is back-produced. The gas segregation and better drainage of attic oil has contributed in additional recovery.

Pros:

The production rate is increased during back-production and resulted in higher recovery.

Cons:

Applying this method on a larger scale may cause a delay in production and will have an impact on the market demand, since we have to shut in the well for some period.

5.1.4 Infill Drilling

In Gullfaks Main Field, many small and large infill targets were drilled which helped to improve the oil recovery. In order to improve the recovery in mature fields, small un-drained pockets at a low cost need to be drilled. Advanced drilling and completion techniques were implemented in infill drilling. Infill drilling well design and completion technique should allow the well to operate easily in addition to frequent well interventions.

Pros:

Increased recovery was observed in the low permeability area due to the usage of Smart well technology (completion technique). It was implemented in the Gullfaks Main Field where 5 wells were drilled using DIACS/Smart Well.

Cons:

The cost of drilling new wells is high (especially in the offshore field, the rig cost is very high)

5.1.5 Hydraulic fracturing of low permeable reservoirs

In Gullfaks, this method known as the Indirect Vertical Fracture Completion (IVFC) is used to improve the overall sweep. Wells are perforated in Rannoch (low permeability zone) and using hydraulic fracturing will allow the communication with the Etive (high permeability zone). In Gullfaks Main Field, 36 fracture jobs have been performed in 20 wells of the field.

Pros:

This technique reduces the sand production of unconsolidated sand from Etive Formation, which solves one of the main challenges in Gullfaks Main Field.

Cons:

Gullfaks showed that the production of water is more than the oil, if hydraulic fracturing is applied, there is a possibility for water channeling.

5.1.6 Sand Control

Most of the highly productive sands are poorly consolidated. It caused some sand production after water breakthrough, and some sand control measures were to be considered. Gravel packing, an expensive process due to rig occupancy, was one of methods used for controlling the sand production. In this field, to make gravel packing more economic, separate snubbing rigs had to be constructed leaving drilling rigs for further well drilling.

Some Chemical Sand Control methods were also implemented with some success result; these include injection of resin slurries in perforation tunnels and injection of the consolidating chemicals in the formation. Other methods, such as sand screens and pre-packed screens, were also introduced due to their effectiveness and low cost.

Pros:

It helps solving one of the major challenges of the field through controlling sand production

Cons:

It requires additional intervention time and cost for installing sand control completion.

5.1.7 Selective perforation, re-perforation and zone isolation

Selective perforation is one of the techniques to increase the oil recovery from the low permeable zones and to overcome sand production in highly permeable unconsolidated sands. In order to increase the sweep efficiency, another technique was applied; it consists of selecting perforation and re-perforation intervals of the new and existing wells respectively.

In order to drain more oil from less-drained intervals, shutting –off of the high water/gas producing intervals can be applied, e.g. mechanical isolation. Thus the use of mechanical zone isolation has helped in improving the recovery as well as the sweep efficiency. Similar well intervention operations were highly performed on Gullfaks.

Pros:

1. Increase in the oil recovery from the low permeable zone and prevention of sand production in highly permeable unconsolidated zones are the result of a selective perforation.
2. Zone isolation increased the sweep efficiency.

Cons:

Applying this method in larger scale may need additional cost (more well intervention)

5.2 IMPLEMENTED IOR (REQUIRE FURTHER STUDY)

Some other IOR practices have been approved to increase the recovery factor in some of the fields but turned out to be ineffective when it comes to Gullfaks Main Field. These techniques are listed below.

5.2.1 Aerobic Microbial EOR (MEOR)

A pilot test was made on a specific segment of Gullfaks (segment I1) on which the effects of MEOR can be observed. Expectation on implementing this method are reduction injectivity due to change in skin, reduced sea water fraction, less water-cut and increasing circulation time for injection water. The plan was implemented on this segment with all the aspects being respected, but the results turned out to be disappointing. It showed no response on neither the water-cut nor the production profile from wells in the pilot area.

Pros:
On the laboratory scale, the result of MEOR showed an increase in recovery.

Cons:
In the field scale, the result is not suitable with laboratory result. Since the bacteria used in MEOR is not suitable with the real environment of the reservoir. As an example, H_2S present in Gullfaks field due to extensive flooding has reduced the oil saturation through an anaerobic MEOR process prior to the aerobic MEOR.

5.2.2 Surfactant Injection

Several parameters of the Gullfaks field are favorable for enhancing the oil recovery using surfactants. In order to check the validity and effectiveness of this method, a single well pilot test with only surfactant was performed leading to a mobilization of the residual oil. About 40-70% of the water flood residual oil was mobilized. But this method is not yet implemented on a larger scale.

Pros:

1. Since the Gullfaks has been injected by water, there should be residual oil left in the reservoir.
2. It reduces the residual oil (microscopic)
3. Surfactants can easily be added to untreated water injections as seawater is compatible with the reservoir conditions.

Cons:

1. This method will be costly as surfactants are quite expensive.

2. The surfactant are chemicals, and as Gullfaks is in the offshore, maybe the environment is one of the concerns.
3. Not yet tested on larger scale wells.

5.2.3 Polymer assisted surfactant flooding (PASF)

More than 70% of the waterflood residual oil was recovered, but crude oil price was not high enough for PASF to be commercially attractive. Increased oil recovery potential by PASF simulated on a limited area of Gullfaks, since current oil price is high. This method can add an extra recovery of 3-5%.

Pros:
Since The Gullfaks has been injected by water, there should be residual oil left in the reservoir. To reduce residual oil (microscopic and macroscopic recover), polymer and surfactant are one of the methods to get a better sweep efficiency.

Cons:
It depends on the oil price; if the oil price is high then this expensive method is applied otherwise it won’t be economically attractive.

5.2.4 CO_2 miscible injection (Miscible CO_2– WAG/MWAG)

MWAG has not been implemented on Gullfaks due to marginal economy and high risk. Furthermore, the source of CO_2 was not readily available.

Pros:

1. The injection of CO_2 decreases the viscosity of the oil and can provide better or more efficient miscible displacement.
2. An official report which stated that the recovery with CO_2 injection would increase more oil as compared to water injection.
3. If there is any CO_2, it can reduces the CO_2 tax and storage cost.

Cons:

1. Before one can start injection of CO_2, certain modifications on offshore installations have to be done. This is of course very expensive.

2. WAG requires CO_2 injection which is not readily available in the North Sea. Large amounts of CO_2 are needed (around 25 million tons per year, which means that Norway has to buy CO_2 from other countries).

5.2.5 Gel blocking and water diversion (LPS, bright water, Na-silicate)

Water soluble chemicals are injected in the reservoir to reduce permeability of the water channels establishing new water paths, better sweep at both micro and macro level.

LPS (Linked Polymer Solution), Bright water, Na-silicate are used to block water production and divert injected water. LPS is an aggregated gel (alloidal dispersion gel) that acts as a blockage gel in zones where the residual oil is low, so the water flooding can go through the zone where the residual oil saturation is still high.

Bright water is a solution of polymers and surfactants. To work, there should be a temperature gradient (different) between injector and producer.

Na-silicate is quartz dissolved in NaOH which forms a glass like solution.

The pore space is sealed by trapping of binary ions and re-crystallization of quartz by neutralizing the solution. The core floods studies have showed very encouraging results.

Pros:

1. The chemicals shall move into the reservoir and form micro gel particles in zones of high permeability. These gel particles will reduce the permeability and thus force the water to find new paths and invade less water flooded areas.
2. It increases the macroscopic and microscopic sweep.

Cons:

1. A major problem with this method is that many of the chemicals used are marked as red, which is environmentally unfriendly. The chemicals that are used by Statoil (Abio gel) are silica based and marked as yellow (environmentally acceptable).
2. The gel used in this method is blocking the path for other new recovery methods that might be developed in the future but it would be efficient to find a gel that is removable, extractable or even decomposable in order to sweep the residual oil.

5.2.6 Low saline water (LSW)

Under further investigation, the Gullfaks lab results are encouraging. The brine composition, the extent of dilution, and the rock and fluid properties, are all sensitive to this process.

Pros:

Using this method, the equilibrium system of high salinity will be shifted and thus the oil recovery will be higher.

Cons:

1. It needs extra cost for the processing of low salinity water.
2. The availability and continuous supply of low-saline water is a big challenge for oil companies.

5.2.7 Reverse sweep

Injecting water (or gas) for a produced period and then changing the direction of flooding by moving the injection point to get a different drainage direction as, for example, moving the injection point from west to south or north of the producer (un-swept oil volumes outside the established water (and gas) channels may be contacted mobilized and produced).

Pros:

This method can reach the un-swept zones (sweet spot zone) and it is expected to make additional recovery.

Cons:

It needs further studies since if the selection of the converted well (from production to injection) is wrong, it may cause a decrease in production.

CHAPTER 6 SUGGESTION OF IOR TO BE APPLIED IN GULLFAKS

As water injection has been applied, the residual oil saturation may be higher in the reservoir. So these are some of methods that we expect them to be able to increase the recovery.

1. Surfactant Injection

   This method can reduce oil residual saturation and may increase the recovery factor.

2. Gel blocking or LPS

   It is expected that some zones with low permeability have not been swept by water injection. According to practical experience, this method is effective to increase the oil production while the water cut decreases.

3. Polymer assisted surfactant flooding(PASF)

   This method can reduce the residual oil saturation and may increase the recovery factor. But using polymers with surfactants will be costly. The increase of recovery should thus exceed the cost of the PASF method.

4. Infill drilling(with Sand control and smart well)

   Selection of the position and the trajectory of the well should be determined precisely. Since the main purpose of the infill drilling is to get the oil in the sweet spot area. Better trajectory (horizontal well or multilateral well) can be applied, while Smart wells may be applied as one of the strategies to control the production.

5. Selective perforation and stimulation could be done simultaneously when the well is on production.

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PART B - EOR-CHALLENGE AT EXISTING H1 MODEL WITH PERMEABILITY MODIFICATIONS

CHAPTER 1 BACKGROUND

The challenge for the Gullfaks Village 2012 is to increase the oil recovery from the Gullfaks Main Field. Infill drilling and water diversion technique are the two methods expected to have the largest potential for increased oil production from Gullfaks[1].

Since the residual oil saturation is very low on Gullfaks and assuming that Stock Tank Oil In Place (STOOIP) is correct, the volumetric sweep efficiency is probably less efficient. After water breakthrough, the water mainly moves through the shortest and easiest paths leaving behind a large bypassed oil volume. 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. If permeability to water can be reduced in the existing water 'highways', thereby forcing water to flood other parts of the reservoir, increased oil recovery is expected (shown in Figure 13).

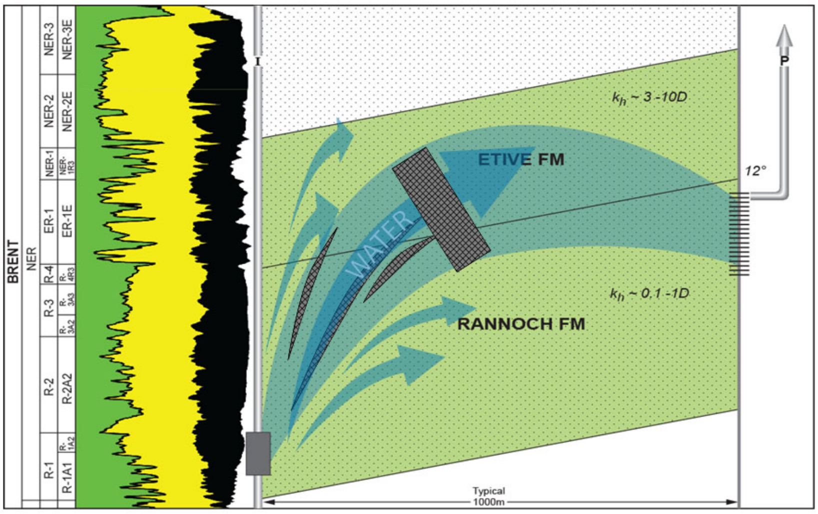

Figure 13 Illustration of water diverging [1]

To address the problem, a process which takes advantage of the multi-valence cations concentrated in both the formation and injected water and injects a compounded silicate to react with the cations to form gel is developed. A pilot EOR-project to reduce the permeability in the water "highways" was carried out in November 2011 with several batches of water soluble chemicals injected along with the water in an existing water injection well – A-35.

CHAPTER 2 H1 SEGMENT DESCRIPTION

Increasing oil production has always been one of the major concerns of all the companies involved in the oil and gas industry as the demand for oil keeps on rising. Gullfaks field has been so far exploited to a great extent as almost 90% of the removable oil has been produced. Gullfaks Main Field has a recovery factor of 56% as of mid-2007 based on the data provided by Reservoir Management Plan for The Gullfaks Field and Gullfaks Satellites 2007. So our main task is to improve the recovery for one of the segments of that field, the H1 segment (the Lower Brent to be more specific), using the gel injection which is one of the EOR techniques recently implemented in the industry and which is more oriented towards sweeping the un-swept areas of the reservoir.

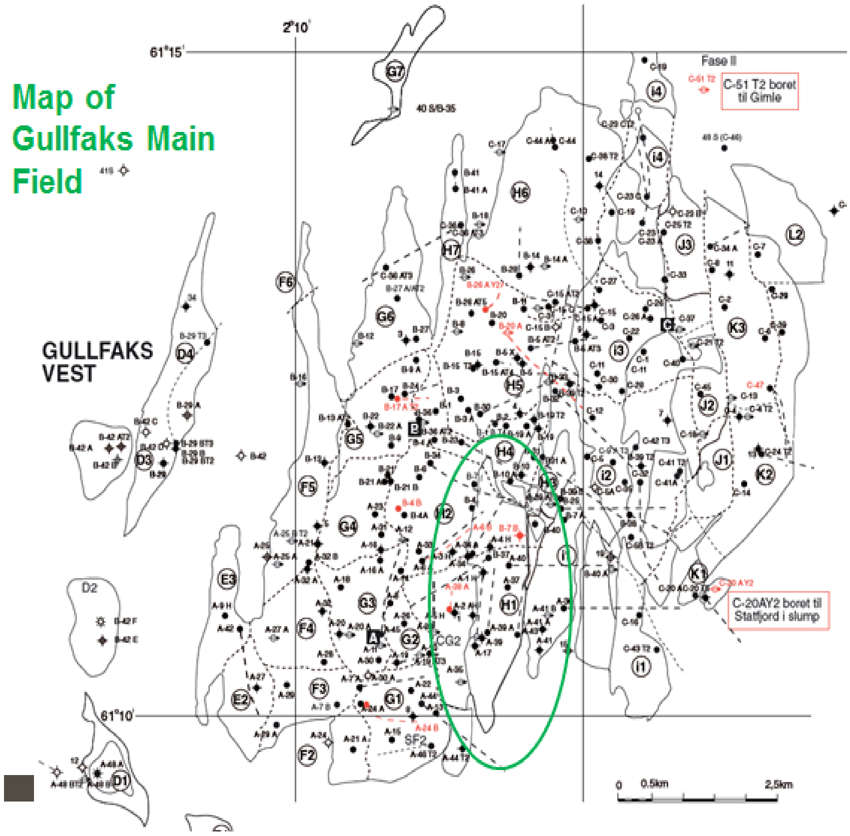

Figure 14 General Map of the Gullfaks Main Field including the H1 segment which is of interest for our study [5]

Segment H1 is isolated from the rest of the field as it has a number of internal faults with very complex communication pattern. As most of the segments of the Gullfaks field, H1 segment has the 4 major formations: Brent Group, Cook, Statfjord and Lunde.

This is a brief distribution of the initial oil in place in the reservoir:

Table 7 The initial oil in place and the recovery factor for the different formations in H1 segment [5]

Segment H1			
STOOIP	**Recovery Factor**		**Formation**
MSm3	**MSm3**	**%**	
58.2	40.6	70	Tarbet
27.1	16.5	61	Ness
20.2	11.4	56	Lower Brent
16.83	5..06	30	Cook

H1 segment is located to the South East of the main Gullfaks Field. It has 3 producers A-39, B-37 and A-38A; the latter can be ignored in this context as it is not in communication with the other wells. It has, as well, an injector A-35 which is placed in the southern part of the segment. It is located on a down faulted region compared to the position of the producers located in the northern part of the segment. This area has several separate oil traps between the layers and the faults towards Segment G1 and towards the base Cretaceous in the area south of A-35 and this is due to the heterogeneities present. Well B-37 showed a communication with the G segment. Production in the H1 segment is taking place at a reservoir pressure below the saturation pressure.

The Lower Brent formation of this field has a particular pressure gradient from the north to the south where the northern part has a high pressure due to the injector locations. As mentioned previously, the injectors in the H1 segment are located to the South. This position affects the water flow due to the northwardly dipping, kaolinite-rich layers. Injecting additionally in the South would reverse the sweep and thus increase the recovery factor in the Lower Brent area. The A-35 injector also located in the Lower Brent provides a pressure support for Ness in B-37.

H1 segment is in communication with the G segment, i.e. there is an East-West directed communication among the segments. This refutes an outdated argument of a very poor communication between the segments in the East-West direction.

From the data provided, the H1 is somehow heterogeneous as it is, for example, oil-filled in the Cook formation which is in turn oil-filled in 5 structural traps. On the other hand, in the

Statfjord formation, the H1 segment is water-filled. As well, the Oil-Water Contact (OWC) is at 1926m for the H1/H2 segment.

Table 8 Reservoir parameters of the Cook formation for all the segments including the H1 segment [5]

Reservoir parameters	Cook Formation						
Segment(s)	G1	H1-H2	H3-H5	I1	I2-I5	J	K
Top structure	1,850	1,750	1,760	1,720	1 760	1 780	1 870
OWC	1,947	1,926	1,900	1,786	2 090	2 090	2 090
Initial temp. (^{0}C)	-	76		72			
Initial pressure (bar)	311	311		311	319		
Bubble point pressure (bar)	-	210		195	230		
Rs (Sm^3/Sm^3)	-	75		105	130		
Bo (Rm^3/Sm^3)	1.2			1.4	1.4		
Oil gradient (bar/m)	-	0.07		0.07	0.06		
Water gradient (bar/m)	0.103						
Oil viscosity (cp)	-	1.28		0.91	0.5		
Formation water salinity (g/l)	43						
Perm. (D) Cook-3	1.5-3.0	0.50-3.5		0.1-2.5	0.1-5.5		
Cook-2	0.02-0.1	0.02-0.1		0.02-0.1	0.02-0.2		
Por. (fraction) Cook-3	0.26	0.27		0.28		-	0.3
Cook-2	0.24	0.25		0.25		0.27	0.26
Sw (fraction) Cook-3	0.34	0.27		0.30		-	0.35
Cook-2	0.88	0.69		0.57		0.45	0.56

Table 9 Resources, reserves and recovery factor in the H segment [5]

Segment	STOOIP	Recovery				Active well point	
		As of 1 July 2007		Final		As of 1 July 2007	
	MSm³	MSm³	%	MSm³	%	P	I
H1	20.2	11.4	56	12.2	60	1	1
H2	21.1	11.9	56	12.3	58	1	1
H3	0.1	0	0	0	0	0	0
H4/H5/H6	27.4	16.1	59	16.9	62	2[1)]	2
Total H	**68.8**	**39.4**	**57**	**41.3**	**60**	**5**	**3**

The horizontal well A-39A which is perforated in the Rannoch-1/Rannoch-2 was shut-in and choked several times as large amounts of H_2S have been forming in the reservoir due to the excessive water circulation. In general, segment H has water injection as the primary drive mechanism; water has been injected from the west towards the east accompanied with some pressure support from the water basins located in the north and northwest of some of the segment.

CHAPTER 3 IN-DEPTH PROFILE MODIFICATION

Water flooding to improve the recovery of oil is the most common secondary recovery process used in modern oil industry. Though water-drive can significantly enhance oil recovery, unwanted water production would become more and more troublesome as reservoir development progresses. All these years, many techniques for water control have been studied and practically applied in oil fields. Among these, in-depth profile modification for injection wells is now attracting much attention and gets relatively high success rate of application, especially after cross-linked polymer was widely used in the industry [7].

In 2004 Donghe and Lunnan oil fields were starving for a new method of in-depth profile modification which could control water production and at the same time, increase oil production.

In order to solve this problem, PetroChina conducted a research project to develop an agent which would improve sweep efficiency of water flooding at temperature above 120 and salinity above 25% TDS. One inorganic agent of profile modification, named WJSTP, was developed in the project. Beaker test and core flood test showed that it had excellent ability of water shutoff under the conditions of high temperature and high salinity while the formations treated were still permeable [7]. As shown in reference [8], WJSTP gel is also called Abio gel.

Several systems/chemicals are used onshore for diverging worldwide, but none on the Norwegian Continental Self (NCS) [1]. Most of the systems used are “Red” or “Black” from environmental and/or health point of view. The Gullfaks pilot used a sodium silicate Abio gel. CNPC has used Abio gel in several reservoirs in the Tarim and Dagang basins, covering a wide range of properties. In most cases the treatment has resulted in increased oil recovery[2.]

3.1 COMPOSITION AND CHARACTERS OF ABIO GEL

Main technical specifications [7]:

1. Main agent – Abio gel white milk or white particles or powder (see figure 15)
2. Appearance of Abio gel: transparent or white (see figure 16)
3. Gelation time:4~24hrs
4. Density of gel:1.0-1.05 g/cm^3

5. Suitable temperature: 30-200 ^{o}C, thermal stable for a long period in 140 ^{o}C
6. Salinity stability: no upper limit, the higher the better
7. Suitable reservoirs: sandstone or conglomerate with high permeability, high heterogeneity. Not suitable for fractures.

Figure 15 Abio gel powder and particles [7]

Abio gel for profile modification in the paper is a kind of silicate gel. It is compounded primarily from $Na_2O.mSiO_2$ and NaOH. It is unitary constituent and in the form of powder. After injection into formations, Abio gel solution first reacts with cross-linker, i.e. multi-valence cations concentrated in both the formation and injection water, then inorganic gel comes into being in the form of particles and suspends in the water. Afterward, it coats on rock surface of the formations. Characters of the agent are as follows.

The agent solution is innoxious and transparent. Its specific gravity and viscosity are close to that of water. After mixing with cross-linker, it appears gray white. Then, after 1-6 hours in the temperature ranging from room temperature to 140^{o}C, translucent or gray white gel comes into being (Figure 16). The higher the temperature is, the shorter the reaction time is. Since specific gravity of the gel is approximately equal to water, it hardly sinks in water, which benefits gel coating on the surface of pore paths.

Figure 16 Inorganic gel produced from the reaction of Abio gel and injection brine (130 ^{o}C) [7]

High salinity and multivalence ions do no harm its gelation. On the contrary, the higher the salinity is, the better the gelation is. Both concentration of the agent solution and concentration of the cation have much effect on the degree of gelation and have little effect on the time of gelation. For beaker tests, when ratios of the agent to the formation water are in a definite scope, bulk gel forms (Figure 17). Otherwise, disperse gel or particle gel appears. This character not only benefits coating on rock surface but also can avoid waste of the agent.

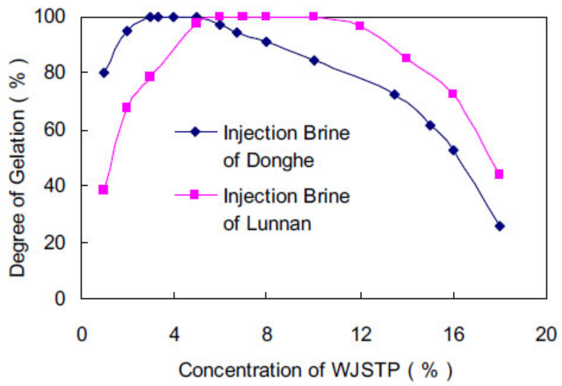

Figure 17 Relation between concentration of Abio gel solution and degree of gelation (130^oC) [7]

The agent is applicable to in-depth profile modification at temperature varying from 30 to 200 ^oC. The inorganic gel formed in beakers stabilizes in solution of 5-15% hydrochloric acid, 2-10% NaOH and fresh water, respectively. It has long-term thermal stability at high temperature (Figure 18). Furthermore, the gel formed in porous media can effectively stand scouring of formation fluid (Figure 19).

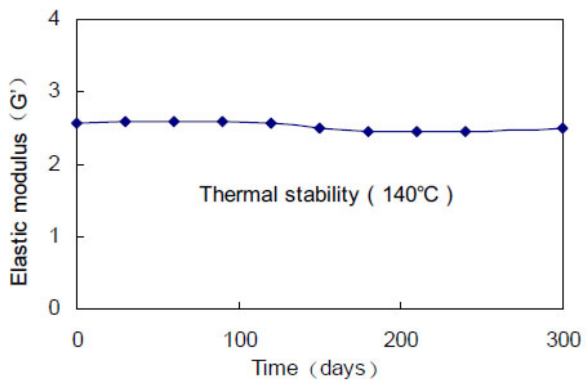

Figure 18 Long-term thermal stability of the gel coat (formed by 4% Abio gel and injection brine) [7]

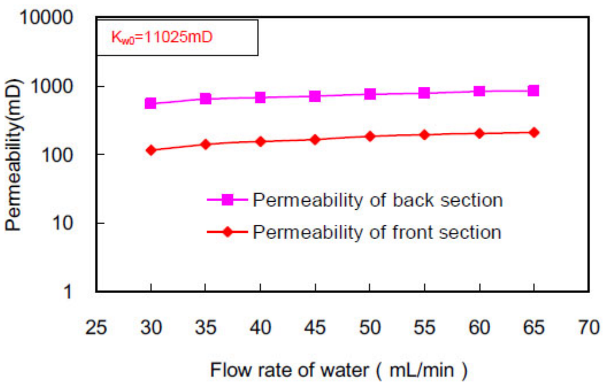

Figure 19 Ability of standing washout for Abio gel (0.3PV per slugs, 7 times of coating) [7]

Since Abio gel is solid and unitary constituent, mixing, transportation and treatment are convenient. In addition, price of Abio gel solution per cubic meter is only one third of the price of cross-linked polymer solution with the same concentration.

3.2 ABIO GEL PROFILE MODIFICATION MECHANISM

For cross-linked polymer and swollen particles commonly used in fields, their mechanism of water shut-off is to block flowing paths between pores to modify profile and redistribute fluid flow. Profile modification mechanism of Abio gel is completely different from this. The gel, produced from the reaction between Abio gel and multivalence cations concentrated in both the formation and injection water, has the ability of coating on rock surface, which makes flowing paths become narrow. Flowing resistance engendered limits or stops flowing in the paths. Consequently, flow of following injection fluid is redistributed and the efficiency of water flooding is improved (Figure 20). Furthermore, some factors, such as gelation time and concentration of the agent, which should be paid much attention in usual treatments of water shutoff, have little effect on the gelation.

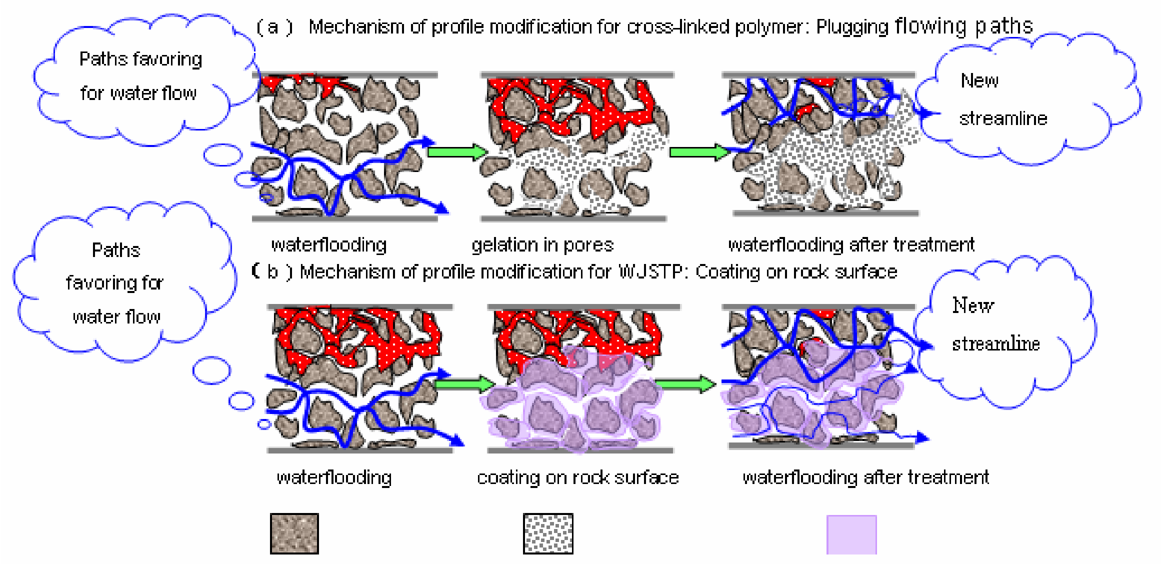

Figure 20 Different mechanism of profile modification for inorganic gel and cross-linked polymer [7]

Abio gel is a compound consisting primarily of Sodium silicate. When Abio gel is brought into contact with divalent cations (i.e. Ca and Mg) in formation- or seawater it reacts to form a microcrystalline suspension which may become a stiff gel if concentration of divalent cations exceeds about 1 %. Otherwise it behaves as a cement paint coating the rock matrix. It is actually a gel used in chromatography and is also a brand name for cement paint.

The chemicals shall move into the reservoir and form micro gel particles, which will stick to the surface of the pores and thereby reducing the permeability in invaded zones. In favor of in-depth fluid diversion the gel can narrow the flow channels gradually and keep certain permeability (Figure 21).

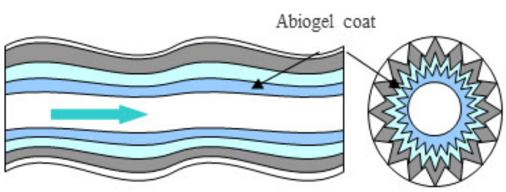

Figure 21 Abio gel coating the pore [2]

The chemical is classified as yellow, due to less than 1% of aluminates. It is environmentally acceptable and unproblematic to use. Alternative chemicals from other suppliers are mostly red. There is an obvious difference between using Abio Gel in different fields (different pressure, permeability, typical formation depth etc.), that's why Gullfaks pilot studies are held (details below).

3.3 PILOT STUDIES IN H1 SEGMENT

Segment H1 on Gullfaks which is relatively isolated (Figure 22) and is well suited for piloting EOR methods. The effect seen in the producers will be due to actions in the segments injector, and not affected by outside events. One thousand ton of chemicals were injected in A-3 in a 15% solution (15 ton chemicals and 85 m^3 water gives a 100 m^3 solution). Laboratory test on sandpacks has showed a reduction factor of 10% in the pores that are hit by the chemicals. The principle of operation is that the chemicals absorbs at the pores and functioning like painting the pores [6].

The STOOIP in lower Brent is 20.2 MSm^3 oil, which is "only" 56 % recovery factor for H1 (potential 2 - 5 MSm^3 mobile oil left) [2].

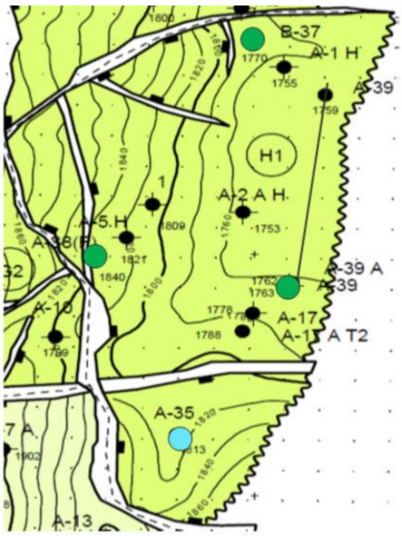

Figure 22 Studied pilot area, Lower Brent, segment H1 [1]

3.4 APPLICATION ABIO GEL IN RESERVOIR SIMULATION

Abio gel will be injected together with water in the water injection well. Its function is to coat the grain of the rock and will cause a decrease in permeability. Abio gel can be simulated in Eclipse (Reservoir Simulation Software). The water injection path of the base case model is analyzed, since we want to know the area where the permeability modifier will be applied. In order to see the water path, we applied a tracer in water injection at the base case model. From the water injection path, which is shown by the tracer, we can determine which area has a high permeability.

One of the purposes of this project is to model the Abio gel and see the effect on the oil production. The way to get additional oil production is to try sweeping the low permeability area. Applying the Abio gel as permeability modifier is expected to reduce the permeability in the high permeability zone. Hence, the injected water can lead to sweep the low permeability area. By setting the properties of Abio gel, we could set where the Abio gel will react.

The following steps show the procedure adopted to simulate the Abio gel in Eclipse.

1. We open the file which contains the base case of the problem. The base case is the case that we use to predict the field performance without applying the Improved Oil Recovery (IOR) techniques.

2. The model of the H1 Segment of the Gullfaks Field will be opened (figure 23). We can choose the property EORF which shows the tracer in the water injected. It means we can know which area has high permeability. In the figure below, there is a color bar which contains number. The numbers show the concentration of the tracer. The higher the number, the bigger is the concentration of the tracer. It means if the concentration of the tracer is high, injected water flows to the high permeability zone.

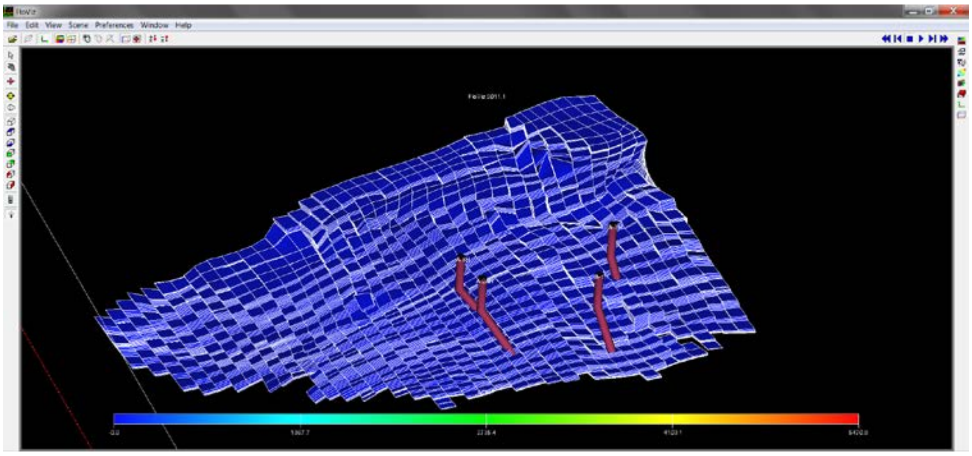

Figure 23 H1 Segment Model

We analyze the tracer around the layer where perforation of the well exists. For example, since the water injector well A-35 was perforated from layer 36-49, our analysis was made around those layers. The figure below is only showing layer 39. We also adjusted the scale on the color bar to be 100-250 so that we get a more accurate understanding of the tracer path in the area of study. It means we can only see the grid which has tracer concentration within this range. The figure below shows the position of the tracer which has a concentration between 100 and 400 in June 2012. Since one grid block indicates 100m, the figure shows that the water has reached around 200-400 meters from the injection well.

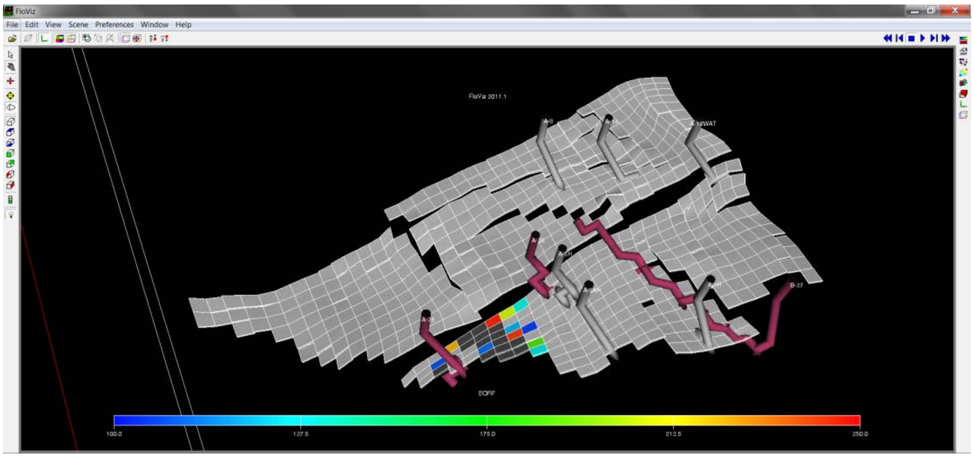

Figure 24 Position of Tracer Concentration Between 100-250 at June 2012

3. We analyze the value of the permeability modifier that will be applied in the area that has been chosen. We can modify the permeability using FloViz with Classic Property

Calculator in Edit Toolbar. We will create a new property which will represent the effect of Abio gel or permeability modifier.

We will modify permeability in x and y directions, while the permeability in the z direction and porosity are to be constants. First we have to create a new property and then assign a Property Type Name that will be filled with the new property. We assigned PERMXEOR* and PERMYEOR* as new place where the new property of permeability in x and y direction is kept.

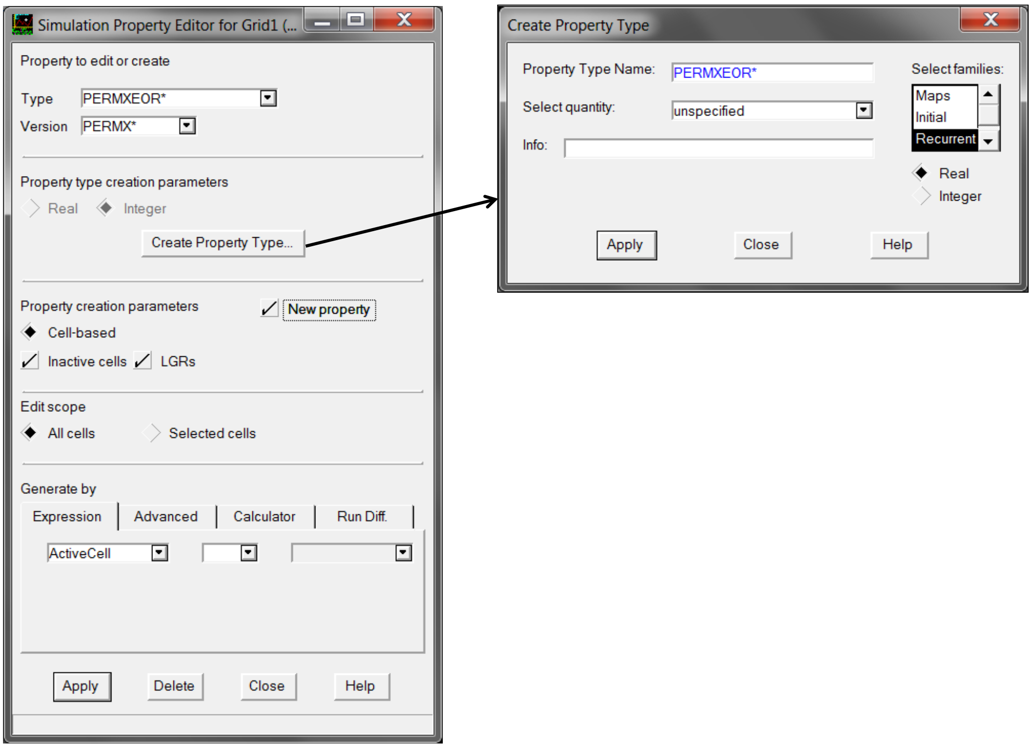

Figure 25 Classic Property Calculation to make new property

We apply the command to change the permeability in the area of our interest. The following picture shows one of these commands:

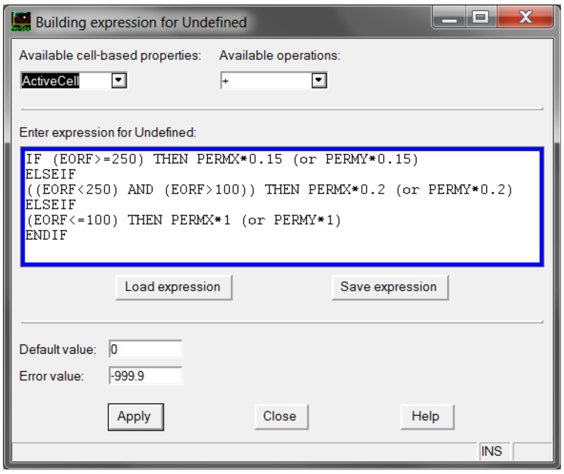

Figure 26 Expression to modify permeability

The expression used to modify the permeability includes an if-statement that conditions the reduction of permeability in x and y directions based on the variation in the concentration of the tracer.

Here is one example of how this expression can look like:

IF (EORF>=250) THEN PERMX*0.15 (or PERMY*0.15)

ELSEIF

((EORF<250) AND (EORF>100)) THEN PERMX*0.2 (or PERMY*0.2)

ELSEIF

(EORF<=100) THEN PERMX*1 (or PERMY*1)

ENDIF

It means that if the tracer concentration is above 250, the permeability will be multiplied by 0.15 which means that the permeability is now reduced by 85%. A change in the permeability will occur as the tracer concentration is between 100 and 250; permeability will be multiplied by 0.2 thus reduced by 80%. The concentration which is out of the range 100 and 250 will remain the same.

4. After making the new property of permeability in x and y direction, we have to assign its modification to the reservoir model. We have to export the new property into a specific date when the reservoir will be affected by the Abio gel or the permeability modifier; as an example we can apply it in 1 June 2012. We have to save the file that contains new property and we have to change PERMXEOR* or PERMYEOR* inside the file into those keywords PERMX and PERMY readable by eclipse. Finally we include the file into

.DATA file. And we run the updated model with the new value of permeability which has been modified into the specific date.

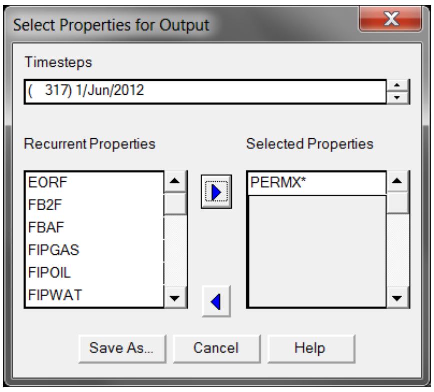

Figure 27 Expression to export new permeability

5. After running the model, we can check the effect of the permeability modifier by opening the .GRID result into Floviz. Figure 28 shows the original permeability before the permeability modifier was applied. Figure 29 shows the effect of the permeability modifier in the specific position (which is represented by the tracer's concentration) and time. W

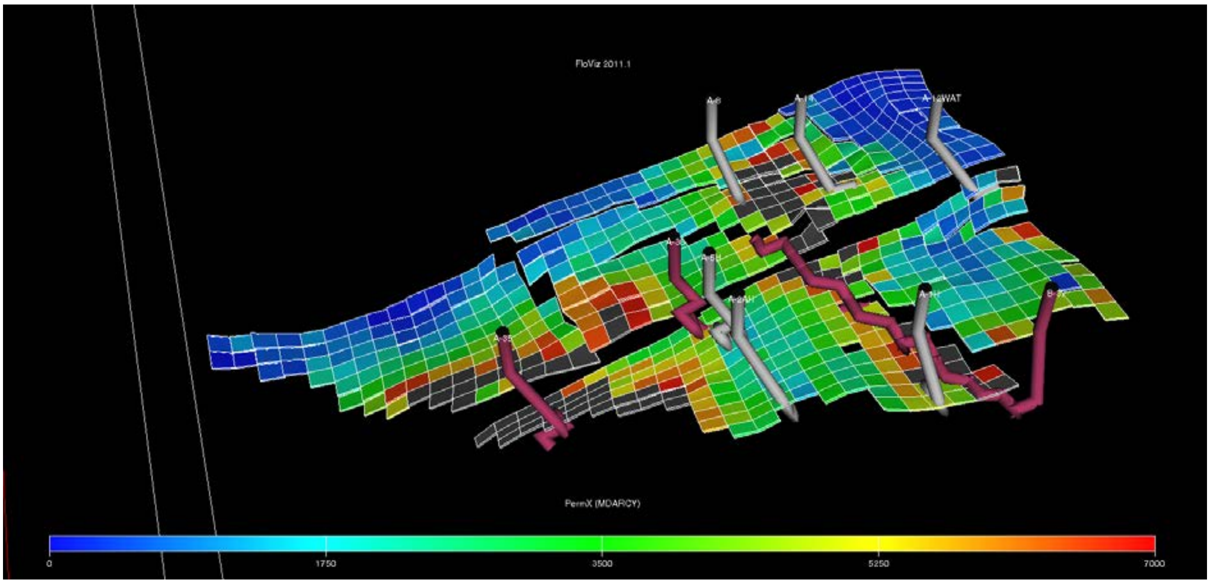

Figure 28 Permeability in x-direction of layer 39 before permeability is modified

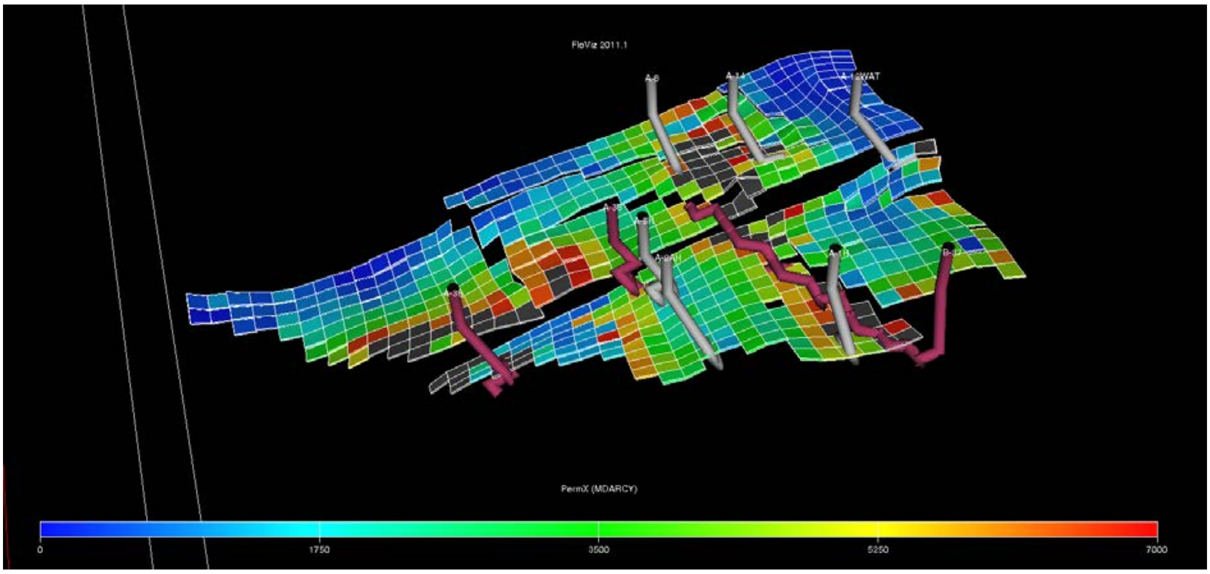

Figure 29 Permeability in x-direction of layer 39 before permeability is modified

CHAPTER 4 APPLICATIONS OF ABIO GEL IN H1 SEGMENT

4.1 ANALYSIS OF ORIGINAL PERMEABILITY OF H1 SEGMENT

Before we apply permeability modifier in the model, we check the permeability of the model and compare it to the background of this project. It is said that permeability in the upper part is higher than the lower part. From the figure 30, we can see the permeability spreading in the model. We choose to see the permeability in layer 35 until 46, since the perforation of the injector well and perforation of the production wells is mostly in these layers.

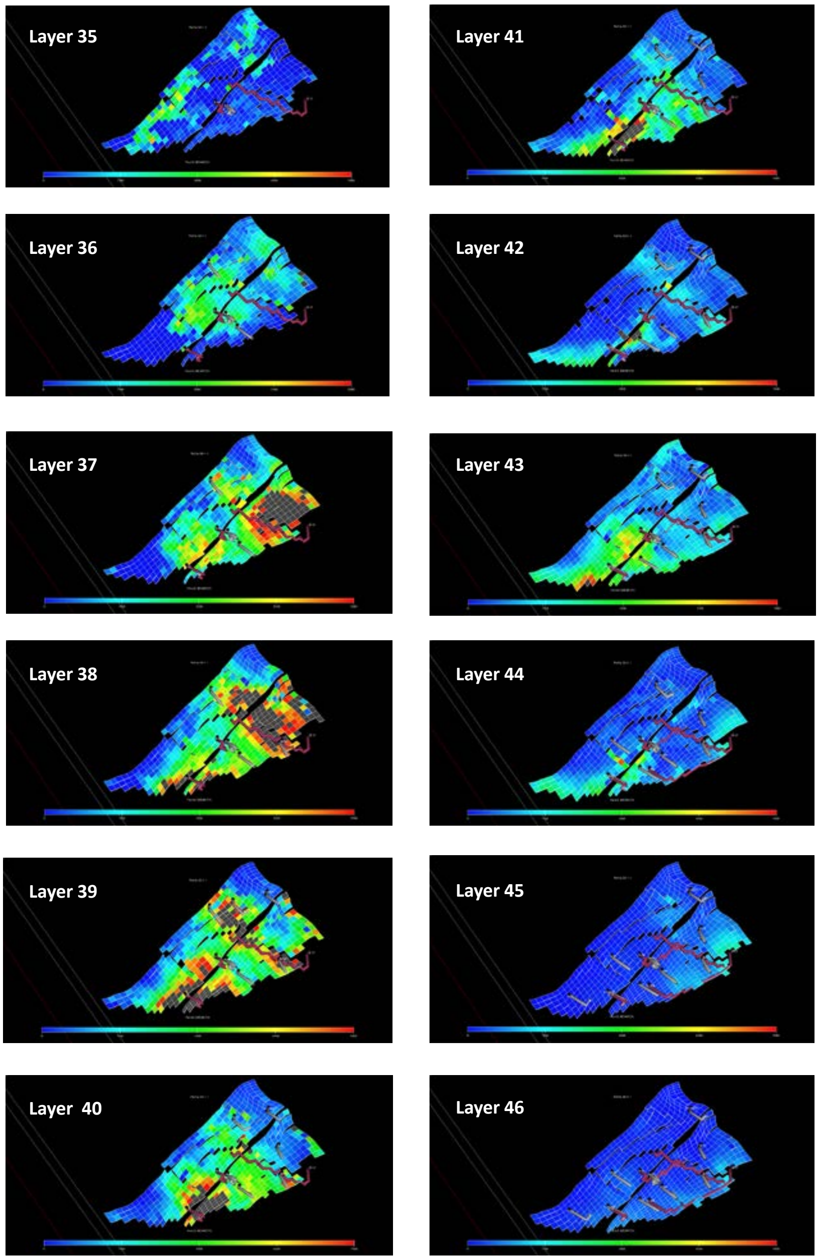

Figure 30 Permeability spreading in x-direction

The color shows us the range of permeability. Blue shows 0 mD, red shows 7000mD, gray shows more than 7000mD and other colors show the permeability between 0 and 7000mD. If we see the color spreading, it shows that the permeability in the upper part is higher than the lower part. We expect that the water injection goes to the upper part only and displaces the oil in there. It is in line with the background of this project which said that the oil injection goes to The Etive Formation (high permeability area) and misses The Rannoch Formation (low permeability area).

4.2 SIMULATION OF ABIO GEL OR PERMEABILITY REDUCER

Some analysis is done before applying the Abio gel or permeability reducer in the model. From the reference [7], it is said that for porous media with permeability ranging from 7D to 50D, the permeability can be reduced by 90% after injecting 3-6 slugs which average 0.2 Pore Volume. For media with permeability lower than 1380mD, it shows smaller effects. Since in this case only 1 slug injection of Abio gel will be applied together with water injection, the permeability reduction is expected to be lower than 90 %.

The position of the injection and the production wells was also one of the concerns. Abio gel is expected to decrease the permeability around 200 – 500 meters from the injector well. If the Abio gel modifies the permeability near the injector well, we expect that the effect of the Abio gel will not be significant on the oil production. We also expect if the Abio gel modifies the permeability in areas further than 500 meters from A-35 injection well, it also will not give significance in increasing the oil production. We will see our hypothesis by running some cases with different placecements of Abio gel and different effects of it in reducing the permeability.

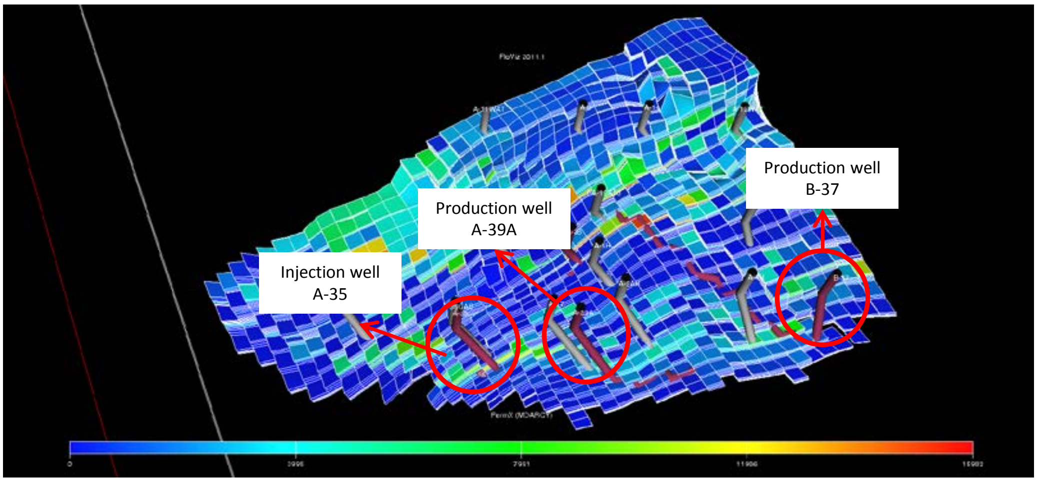

Figure 31 Position of injection well and production wells

The placement of Abio gel is analyzed by checking some ranges of tracer concentrations and their positions. In order to apply the effect of Abio gel in different places, the time step of the simulation is changed and then the position of the tracer at the selected time step is determined. By analyzing the permeability value in the model, the effect of Abio gel as permeability reducer can be estimated. For example, in the area where we expect the Abio gel to reduce the permeability, we check the range of the values of permeability around this area. If the permeability in the interested area is more than 7D, the permeability multiplier of 0.1 (meaning that the permeability becomes 10 % of the original value) may be applied.

The figures 32 and 33 show one of the cases that we ran. It shows the tracer concentration between 100 and 250. The tracer concentration also shows us the permeability indirectly. The bigger value of tracer, the higher is the permeability. Those cases also show different time steps meaning that we have different effects of Abio gel in different locations; this is what we expected. Since one grid block represents 100 meter, the figure 32 shows that the modification of the permeability reducer will affect areas around 300 – 400 meters from the A-35 injection well.

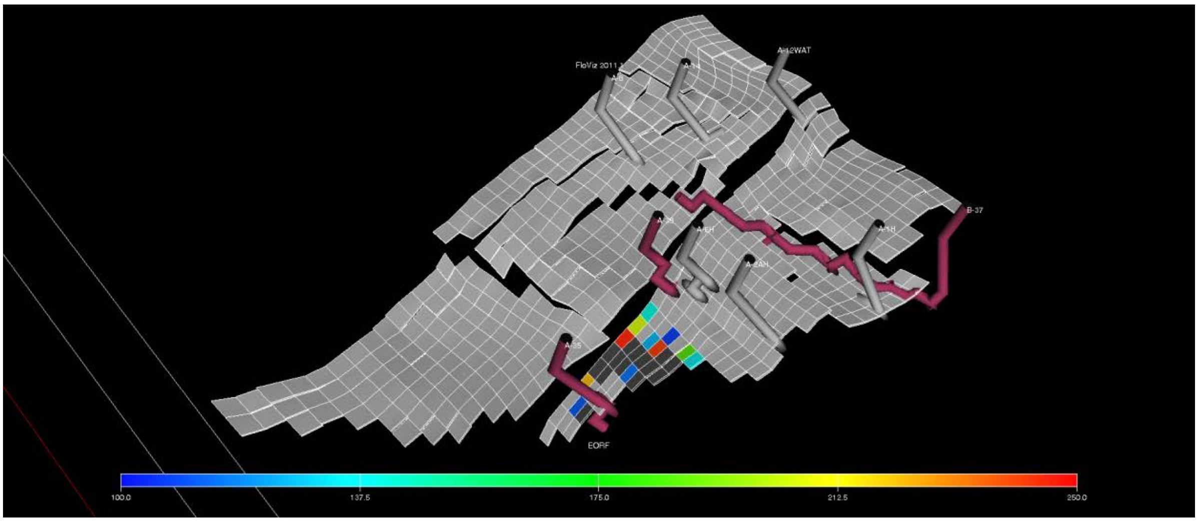

Figure 32 Position of tracer which has concentration between 100 and 250 at timestep June 2012

On the other hand, figure 33 show that the modification of the permeability reducer will affect the area around 400 – 500 meters from the A-35 injection well. Both figure 32 and figure 33 also show how big the area will be affected by the Abio gel.

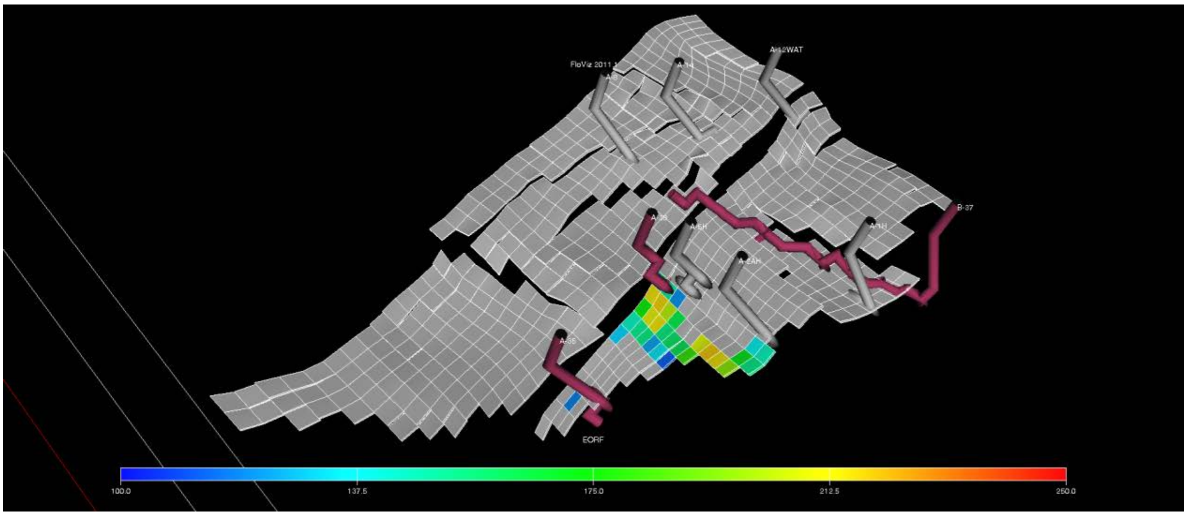

Figure 33 Position of tracer which has concentration between 100 and 250 at timestep January 2013

Different values of the permeability reducer were applied in both areas. Simulations of some other cases were also run to get some results and see the effect of the placement of Abio gel and permeability reducer on the production rate.

From the first time, we discussed and decided to choose three time steps which mean three different placements of the Abio gel's effect. The time steps are 1 June 2012, 1 January 2013, and 1 June 2013. It also means that we do analysis of Abio gel's effect in different approximated areas which are less than 400 meters, between 400 and 500 meters, and more than 500 meters from the A-35 well injection, resepctively.

The parameter of the reservoir which will be modified due to the Abio gel placement in this project is permeability. Permeability in x and y direction will be modified in this project. The mechanism of water injection which displaces oil in both x and y directions becomes a consideration for why only permeability in x and y direction is affected by Abio gel.

Table 10 below shows some complete sensitivities which have been run. The tracer concentration shows the interest area which will be affected by Abio gel. Permeability modifiers show the value of multiplication that will affect permeability because of the Abio gel placement. For example, if the permeability modifier is 0.15, it means the permeability becomes 15% of the original permeability value. In our simulations, permeability modifier will not be less than 0.1. According to the reference which we read, the maximum permeability reduction caused by Abio gel is 90%.

Table 10 Sensitivity of Simulation

Case	**Tracer Concentration**	**Permeability modifier**	**Sensitivity**	
			Time step	**Approximated distance of the placement of Abio gel**
1	300 300-150 150	0.15 0.2 1	1-Jun-12 1-Jan-13 1-Jun-13	< 400 m 400 - 500 m > 500 m
2	300 300-150 150	0.2 0.25 1	1-Jun-12 1-Jan-13 1-Jun-13	< 400 m 400 - 500 m > 500 m
3	300 300-150 150	0.3 0.4 1	1-Jun-12 1-Jan-13 1-Jun-13	< 400 m 400 - 500 m > 500 m
4	250 250-100 100	0.15 0.2 1	1-Jun-12 1-Jan-13 1-Jun-13	< 400 m 400 - 500 m > 500 m
5	250 250-100 100	0.2 0.25 1	1-Jun-12 1-Jan-13 -	< 400 m 400 - 500 m -
6	250 250-100 100	0.3 0.4 1	1-Jun-12 1-Jan-13 -	< 400 m 400 - 500 m -
7	225 225-125 125	0.15 0.2 1	1-Jun-12 1-Jan-13 -	< 400 m 400 - 500 m -
8	225 225- 25 125	0.2 0.25 1	1-Jun-12 1-Jan-13 -	< 400 m 400 - 500 m -
9	225 225- 25 125	0.3 0.4 1	1-Jun-12 1-Jan-13 -	< 400 m 400 - 500 m -
10	200 200-75 75	0.1 0.15 1	1-Jun-12 1-Jan-13 1-Jun-13	< 400 m 400 - 500 m > 500 m
11	200 200-75 75	0.15 0.2 1	1-Jun-12 1-Jan-13 1-Jun-13	< 400 m 400 - 500 m > 500 m
12	200 200-75 75	0.2 0.25 1	1-Jun-12 1-Jan-13 1-Jun-13	< 400 m 400 - 500 m > 500 m
13	200 200-75 75	0.3 0.4 1	1-Jun-12 1-Jan-13 -	< 400 m 400 - 500 m -
14	350 350-125 125	0.15 0.2 1	1-Jun-12 1-Jan-13 -	< 400 m 400 - 500 m -

15	350 350-125 125	0.2 0.25 1	1-Jun-12 1-Jan-13 -	< 400 m 400 - 500 m -
16	350 350-125 125	0.3 0.4 1	1-Jun-12 1-Jan-13 -	< 400 m 400 - 500 m -
17	275 275-75 75	0.15 0.2 1	1-Jun-12 1-Jan-13 -	< 400 m 400 - 500 m -
18	275 275-75 75	0.2 0.25 1	1-Jun-12 1-Jan-13 -	< 400 m 400 - 500 m -
19	275 275-75 75	0.3 0.4 1	1-Jun-12 1-Jan-13 -	< 400 m 400 - 500 m -

4.3 SIMULATION RESULTS

The initial model of H1 Segment model has been run as a Base Case. We want to see, the reservoir performance when Abio gel is not applied. Figure 34 shows the Field Oil Production Rate and Field Water Cut of Base Case model of H1 Segment. We observed that the Field Oil Production Rate is decreasing gradually whereas the Field Water Cut is increasing. On the contrary, we need to increase the oil production rate and decrease the water production.

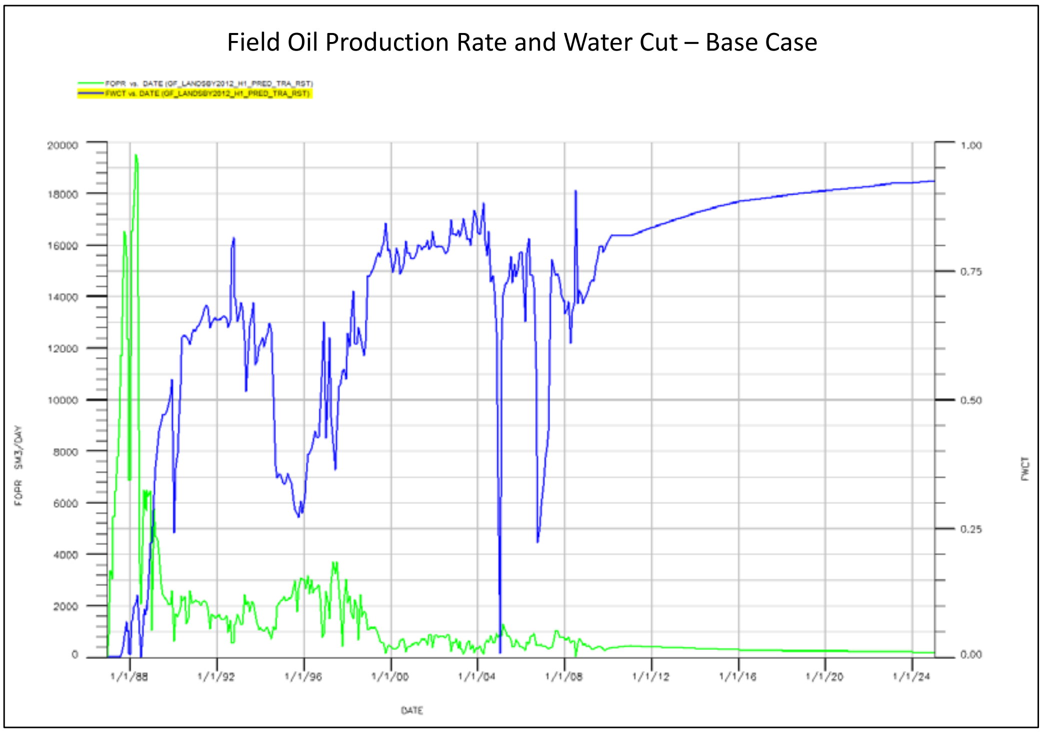

Figure 34 Field Oil Production Rate and Water Cut of Base Case

The purposes of the simulations are to see the effect of Abio gel on the oil rate, water cut, and also to analyze the economic impacts of applying the Abio gel. This Base Case will also be compared to all the other simulations where Abio gel is applied. Sensitivity analysis has been done to get the best results and to get better understanding about the effect of the placement of the permeability reducer.

If you see table 10, there are some cases where we only run two time steps, since we did some analysis regarding the results of simulations. In figure 35, some results from some cases that have been run are shown. The trend indicates that when the placement of Abio gel is farther than 500 meters, oil production will drop compared to the other placements. We can see that when we place the Abio gel in the 1 June 2013 time step, thus when the distance of Abio gel placement is more than 500 meters from the A-35 injection well, the additional oil production will be lower compared to Abio gel in time step 1 June 2012 (less than 400 meters distance) and 1 January 2013 (between 400 and 500 meters distance).

We came to a conclusion that the optimum of the additional oil production happened if Abio gel is placed at a distance less than 500 meters from the A-35 injections well. We expect that if the Abio gel is placed beyond 500 meters, the oil in the lower zone (low permeability) will not be swept effectively. Water injection will go to the upper zones (high permeability zone) and miss the lower zone.

We also see permeability spreading in 500 meters distance from injection well. It has lower permeability than the permeability near the injection well. The purpose is to get additional oil from the un-swept zone which is a low permeability zone, one of the ways to get it by reducing the high permeability area, so the injected water will be directed to the lower permeability zone and then, will be able to sweep the oil. When we placed the Abio gel in more than 500 meters distance from the injection well, the water injection was still unable to sweep the oil in the low permeability zone. Based on this analysis, some cases were only run with two positions of Abio gel placement, which are 1 June 2012 and 1 January 2013. But in the appendix, some of the simulation results with Abio gel placement more than 500 meters are shown. It is shown as a comparison to other cases.

We have done 38 simulations of different scenarios. We compared all the scenarios based on the Recovery factor and the Percentage of the additional oil production. (For further data and results, refer to appendix.)

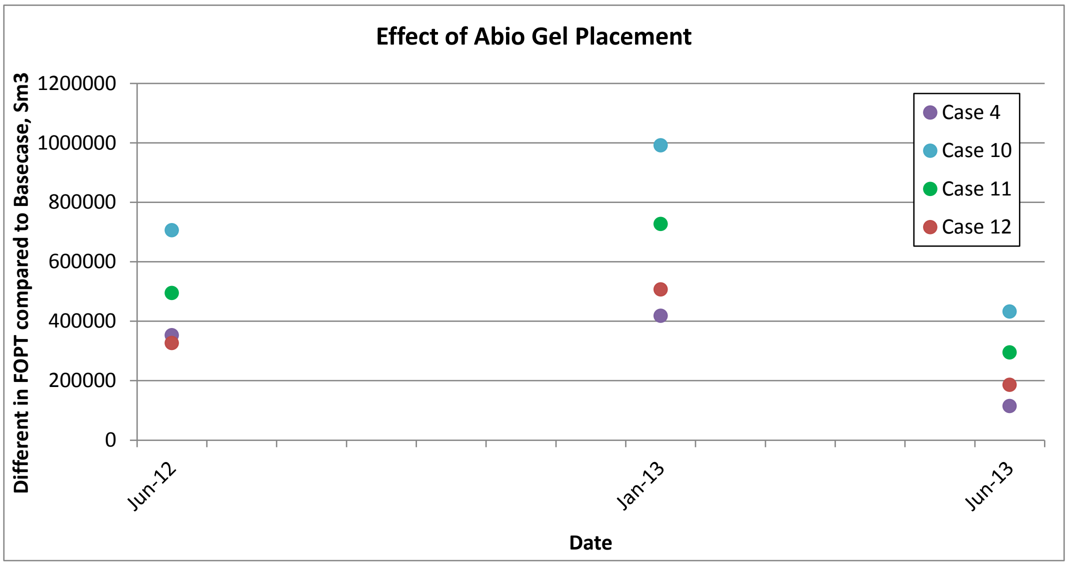

Figure 35 Effect of Abio gel placement

In the analysis of the results, we choose production data of 1 January 2012 as point of comparison. We also compare all the results of Abio gel placements to the case where Abio gel is not applied.

The figure 36 and figure 37 show the results of simulations of Abio gel placement in the model. If we see the trend of oil rate of both placement, which is 1 June 2012 (<400m) and 1 January 2013 (400-500m), the effect of Abio gel is able to increase the oil production. We can also see that the water cut of the cases where Abio gel is applied, is decreased. The biggest increase of oil production rate is approximated to be 2 times more than the oil rate of the base case.

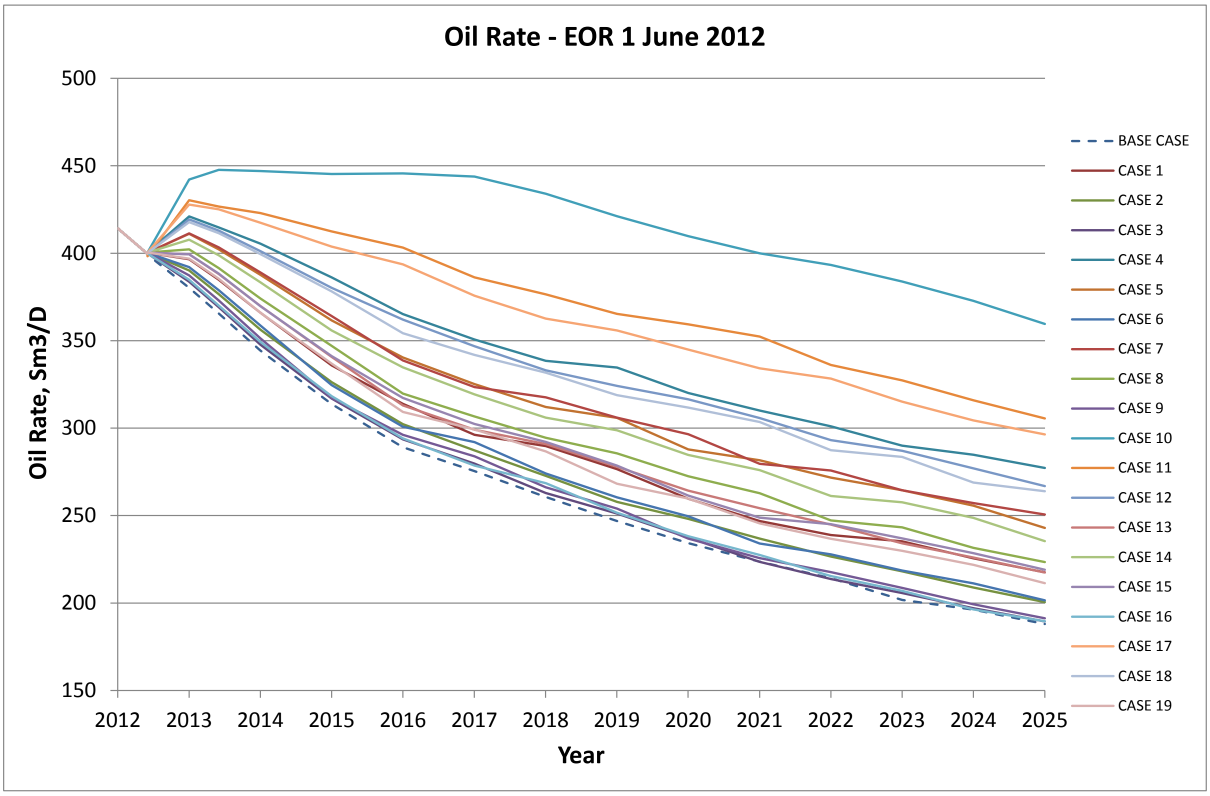

Figure 36 Oil Production rate of Abio Gel Placement in June 2012 (<400 m distance)

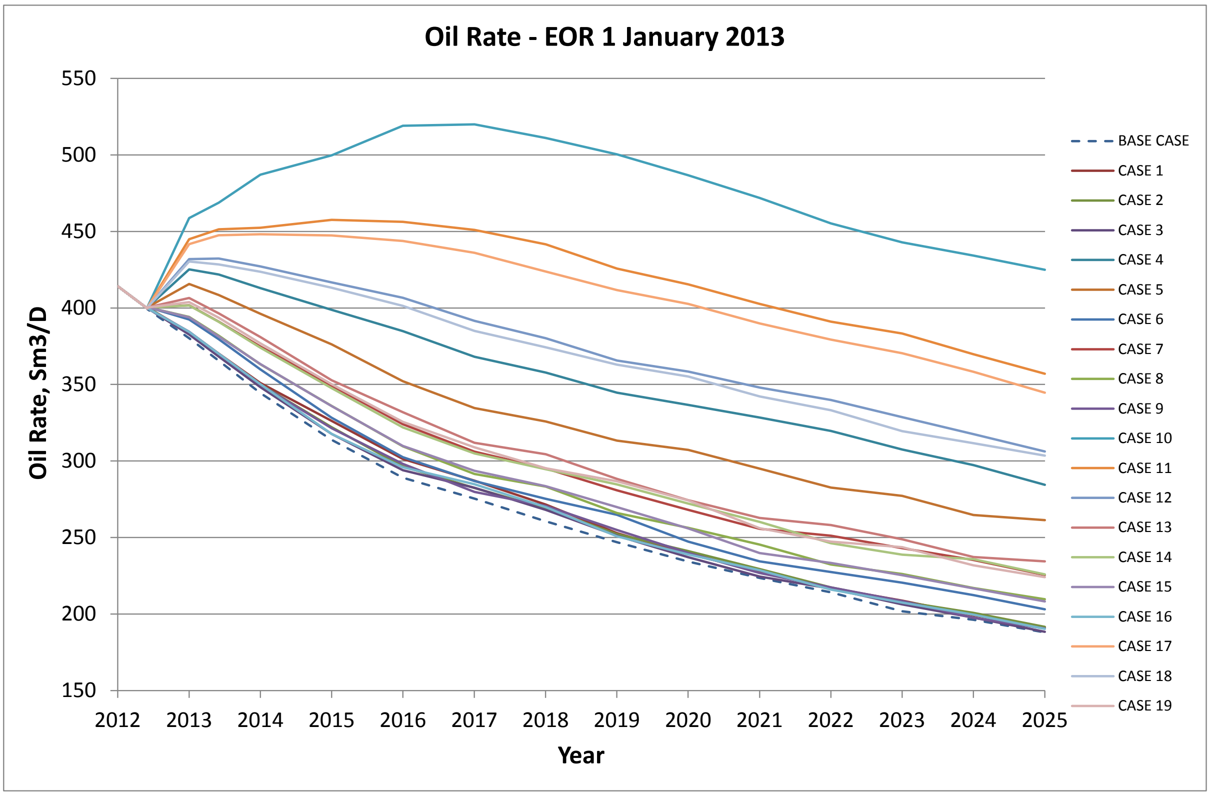

Figure 37 Oil Production rate of Abio Gel Placement in January 2013 (400-500 m distance)

Figure 38 and figure 39 show the water cut of the field if we placed Abio gel in the reservoir. The water cut of the field is decrease in all the cases where the Abio gel is applied in the reservoir. It also means that the oil production is bigger if we do not apply Abio gel in the reservoir (base case). The largest decrease of water cut is approximated to be 10% less than the water cut of the base case.

It shows us that the Abio gel is able to plug the high permeability area. The injected water is able to sweep the oil in the low permeability area. It is shown by the increasing of the oil production and decreasing of water cut. If we see the tracer concentration and its result in the oil rate, there is no direct implication. Spreading of tracer concentration at the specific range show us how big is the area that will be affected by Abio gel. For example, the oil production rate of Abio gel placement in tracer with a concentration of 150-350 is smaller than where the Abio gel is placed in tracer with a concentration of 100-250. We suspected that area of tracer with concentration 150-350 is smaller than tracer with concentration 100-250. Although the area of tracer with concentration 150-350 has bigger permeability, but it shows that its area is not big. It means that the water injection still go back to the area with the high permeability and un-sweep the oil in low permeability area.

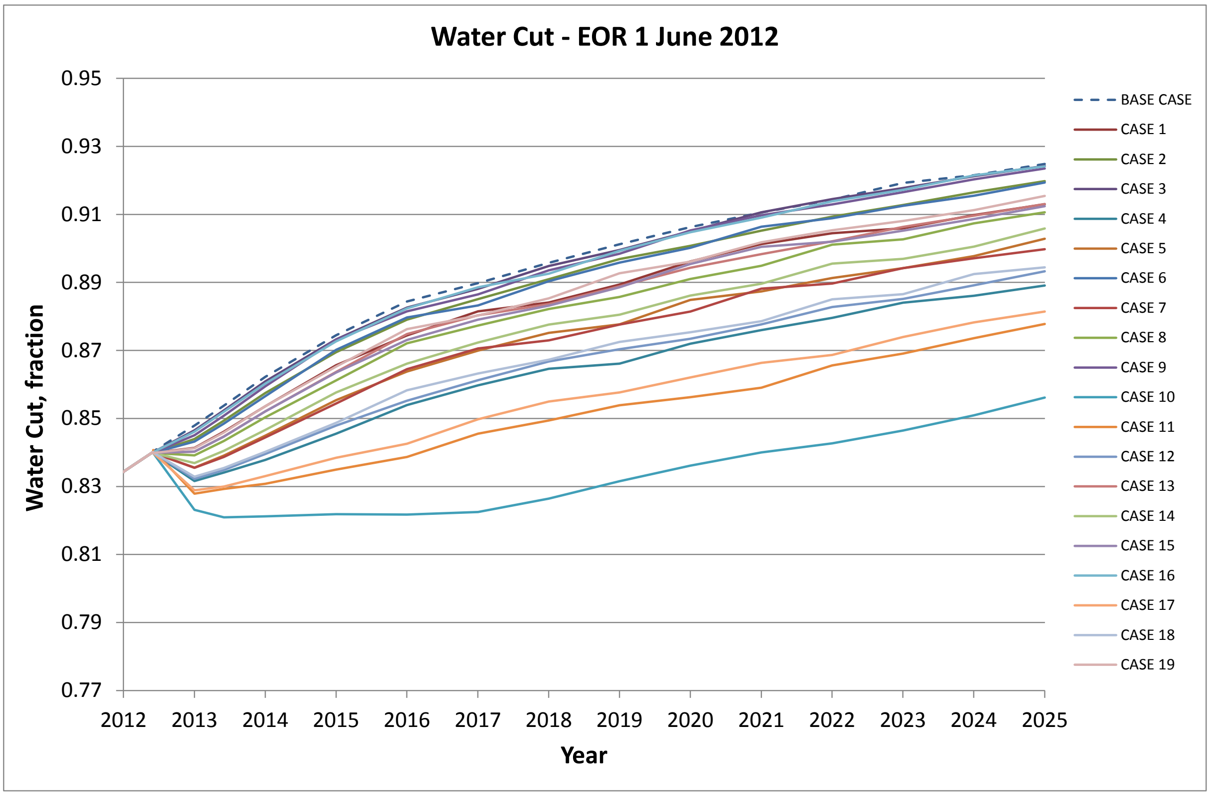

Figure 38 Water cut of Abio Gel Placement in June 2012 (<400 m distance)

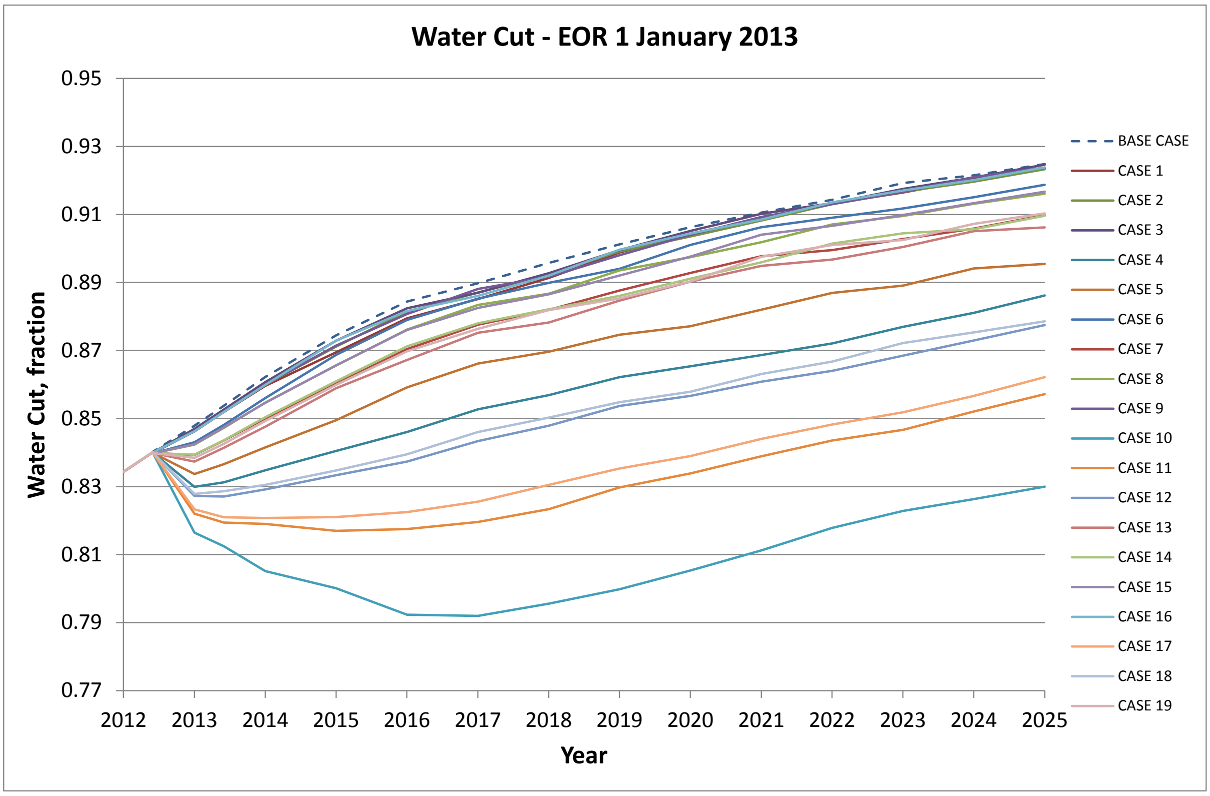

Figure 39 Water cut of Abio Gel Placement in January 2013 (400-500 m distance)

We also analyzed the water cut of the field. We can see from figure 38 and figure 39, water cut of the field for all cases is decreased compared to that of the base case. From some paper it said that permeability reducer, which is made of polymer, is more effective to reduce permeability to water more than to oil or gas. It is may be as result of changing the wettability (cations) in the surface grain of the rock.

Figure 38 shows the result of Abio gel placement at 1 June 2012 (<400m), while figure 39 shows us the result 1 January 2013 (400-500m). If we compare those two placements, Abio gel placement in 1 January 2013 (400-500m) gives us a better result. The water cut decreasing in this model is bigger than if we place Abio gel in 1 June 2012 (<400m). We expect that the Abio gel is able to decrease a bigger area which has a high permeability value. Injected water is able to sweep the oil in low permeability zone. In the other way, effect of permeability reducer is more effective to reduce the permeability relative of water.

4.4 SELECTION OF THE CASES

As a first step, choosing the cases to be further investigated was not random. Initially, it was decided to choose the cases based on the recovery factor of each of the cases. To calculate the recovery factor, the initial oil in place has to be determined. This number should have been found, in a way, in the Eclipse documents given by Statoil, but unfortunately, the number was not there. Then, in the reservoir management plan, the initial oil in place for the Lower Brent in the H1 segment was found to be 20.2 MSm^3. Since the H1 segment, and more specifically the Lower Brent part of it, was isolated from its surrounding for this analysis, this number can be used as the initial oil in place. To make sure that this number is compatible with the Eclipse model, a back-calculation of the initial oil in place of the model was made.

As taken from the reservoir management plan 2007, the recovery factor for the H1 segment in the Lower Brent is 56%. This recovery factor was one of the assumptions made for the back-calculation. From the data of the Eclipse model, the total field oil production is also given; therefore, by manipulating those two numbers, the initial oil in place of the Eclipse model was calculated and it turned out to be 28.8MSm^3 which is higher than that provided by the Reservoir Management plan 2007. In this case, this difference in number might reflect that the H1 segment in the Eclipse model has been history matched or is not fully disconnected from the other segments due to history matching of the model.

Using the back-calculated initial oil in place as it reflects more the results of the Eclipse model, the recovery factor of each of the 38 simulation cases was calculated. The recovery factors were very close to each other and deciding on which case to be further investigated and analyzed was hard and somehow inaccurate.

Due to the uncertainty of this analysis, a different approach was adopted. The difference in the total field oil production of the base case and the case in question is calculated. Afterwards, those differences were arranged in an ascending order. The frequency, the relative frequency probability and the cumulative frequency were all calculated and plotted.

The choice of the major cases was then decided to be based on the cumulative probability. At first, it was decided to choose 5 cases in order to show the diversity of the results of the simulation, as a big variation was seen. Those 5 cases were P0, P25, P50, P75 and P100. After discussion, we found that it is irrelevant somehow to show the cases of P0 and P100 as they are off the limits of being accepted or applied. Deleting those two cases and keeping P25, P50 and P75 was also a choice but with this set of probabilities the extreme cases won't be shown. Thus, it was decided at the end to express the well-known P10, P50 and P90 cases as the low, medium and high probability of occurrence respectively. The P10 is the case with the highest difference in the total oil field production in 2025; P90 is the case with the lowest difference in the total oil field production in 2025; and P50 is in between.

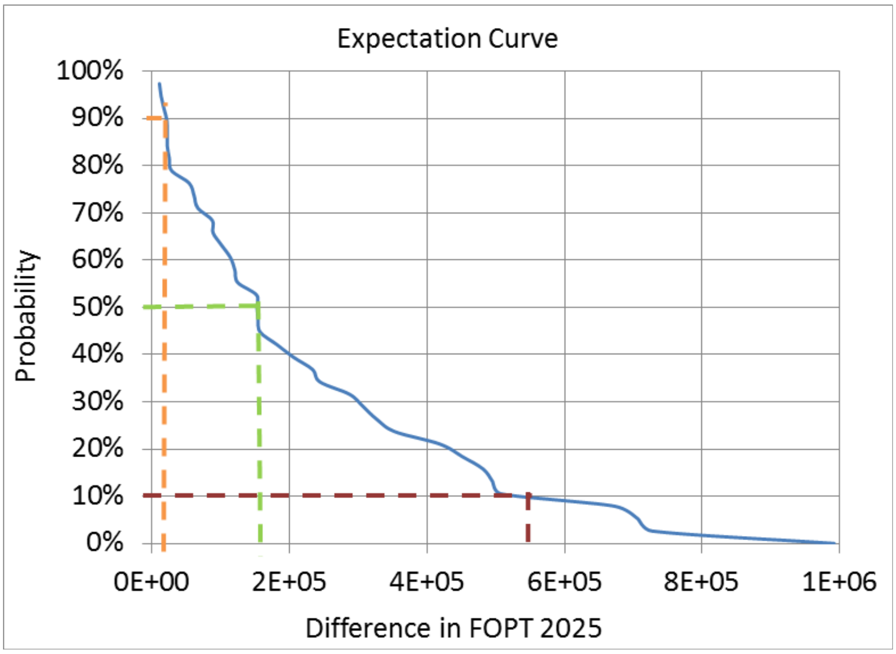

Figure 40 Expectation Curve showing the probability of occurrence of every difference in FOPT in 2025

In the table below, the difference in FOPT as of 2025, the recovery factor, the profitability, the expectations and the probability of each of the 3 cases are represented in the table below.

Table 11 Brief description of some numbers of the 3 cases chosen

Probability	**Case Number & Date**	**Difference In FOPT as of 2025 (Sm^3)**	**Recovery Factor (%)**	**Profitability/ Expectations**
P90	Case 16 – January 2013	22196	63.34%	Low
P50	Case 14 – January 2013	152916	63.79%	Medium
P10	Case 12 – January 2013	507440	65.02%	High

According to Jahn, Cook and Graham in their book "*Hydrocarbon Exploration and Production*", the degree of steepness of the slope of the expectation curve reflects the degree of uncertainty in the parameter in question. The steeper the curve, the less is the uncertainty; and the lower steepness, the higher is the uncertainty. In our case, the expectation curve slope is steep which reveals a low uncertainty in the difference in total oil production of the field in 2025.

4.3.1 Base Case

As stated before, the base case is the scenario where Abio gel is not included in the analysis. Here, the water is still bypassing the low permeability layer belonging to the Rannoch formation and going through the high permeability layer of the Etive formation. In this case the total oil production of the field is 18,267,698 Sm^3 which is equivalent to a recovery factor of 63.26%. This recovery factor is calculated based on the assumption of having 28.8MSm^3 as initial oil in place (IOIP). Furthermore, the additional production expected between 2011 and 2025 when this scenario is applied is assumed to be 1.27E+06 Sm^3.

4.3.2 Low Expectation

The low expectation case is the scenario where the least oil is extracted and swept from the formation after injection of Abio gel. In our case, it is represented by case number 16 – 1 January 2013. According to the expectation curve, this case has a high probability of occurrence. Abio gel starts to show its effect at a distance of 400 to 500 m away from the injection well but has also some effect on a smaller area 300m away from the injector. This distance is slightly higher than the expected distance mentioned by our advisor from Statoil Mr. Instefjord. It should be noticed that if it is applied in June 2012, an area of 200 to 400m away from the injector will be affected but then the recovery factor will be slightly lower (a decrease of 0.01%) and the amount of oil extracted will be lower.

We modified in this case the water concentration limits and reduced the permeability by 60-70%. The table below will show a more explicit representation of the exact numbers used in the simulation. The total oil production as of 2025 will be 18,289,894 Sm^3 which represents a recovery factor of 63.34%. The additional production expected between 2011 and 2025 is 1.29E+06 Sm^3 which is an equivalent of 2% increase from the additional oil produced from the base case. The oil production rate is also increased compared to the rate provided by the base case. Along with the increase in the total oil production, there is a decrease in the water-cut which is now 0.924 instead of being 0.925 for the base case as in 2025.

Table 12 Detailed data and information of our interest about the low expectation case 16 (P90)

Case 16 - 1JANUARY 2013 - Data as of 2025									
Probability	**EORF**	**Perm Modified**	**FOPT**	**FOPR**	**FWCT**	**RF**	**Additional Oil from January 2012**	**Increase in oil compared to BCS**	**Difference in FOPT**
%			**Sm^3**	**Sm^3**		**%**	**Sm^3**	**%**	**Sm^3**
90	350 350-125 125	0.3 0.4 1	18289894	190.4	0.924	63.34	1294330	2	22196

4.3.3 Medium Expectation

The medium expectation case is the scenario where a moderate amount of oil is extracted after injection of Abio gel. This can be considered as our base case. It is represented by case number 14 – 1 January 2013. According to the expectation curve, this case has a 50 % probability of occurrence. Abio gel starts to show its effect at a distance of 400 to 500 m away from the injection well and as well smaller area at a distance of 200 and 300m. We modified in this case the water concentration limits and reduced the permeability by 85 and 80%. The total oil production as of 2025 will be 18,420,614 Sm^3 which represents a recovery factor of 63.79%. The additional production expected between 2011 and 2025 is 1.42E+06 Sm^3 which is an equivalent of 12% increase from the additional oil produced from the base case. The oil production rate is also increased compared to the rate provided by the base case. Along with the increase in the total oil production, there is a greater decrease in the water-cut which is now 0.91 instead of being 0.925 for the base case as of 2025.

Table 13 Detailed data and information of our interest about the low expectation case 14 (P50)

Case 14 - 1JANUARY 2013 - Data as of 2025									
Probability	**EORF**	**Perm Modified**	**FOPT**	**FOPR**	**FWCT**	**RF**	**Additional Oil from January 2012**	**Increase in oil compared to BCS**	**Difference in FOPT**
%			**Sm^3**	**Sm^3**		**%**	**Sm^3**	**%**	**Sm^3**
50	350 350-125 125	0.15 0.2 1	18420614	225.9	0.91	63.79	1425050	12	152916

4.3.4 High Expectation

The high expectation case is the scenario where considerable amount of oil is swept after injection of Abio gel. This can be considered as the most optimistic case in our analysis. It is represented by case number 12 – 1 January 2013. According to the expectation curve, this case has a 90 % probability of occurrence. Abio gel starts to show its effect at a distance of 400 to 500 m away from the injection well and as well smaller area at a distance of 200 and 300m. We modified in this case the water concentration limits and reduced the permeability by 80 and 75%. The total oil production as of 2025 will be 18,775,138 Sm^3 which represents a recovery factor of 65.02%. The additional production expected between 2011 and 2025 is 1.55E+06 Sm^3 which is an equivalent of 40% increase from the additional oil produced from the base case. The oil production rate is also increased compared to the rate provided by the base case. Along with the increase in the total oil production, there is a significant decrease in the water-cut which is now 0.878 instead of being 0.925 for the base case as of 2025.

Table 14 Detailed data & information of our interest about the low expectation case 12 (P10)

Case 12 - 1JANUARY 2013 - Data as of 2025									
Probability	**EORF**	**Perm Modified**	**FOPT**	**FOPR**	**FWCT**	**RF**	**Additional Oil from January 2012**	**Increase in oil compared to BCS**	**Difference in FOPT**
%			**Sm^3**	**Sm^3**		**%**	**Sm^3**	**%**	**Sm^3**
10	200 200-75 75	0.2 0.25 1	18775138	306.2	0.878	65.02	1547468	40	507440

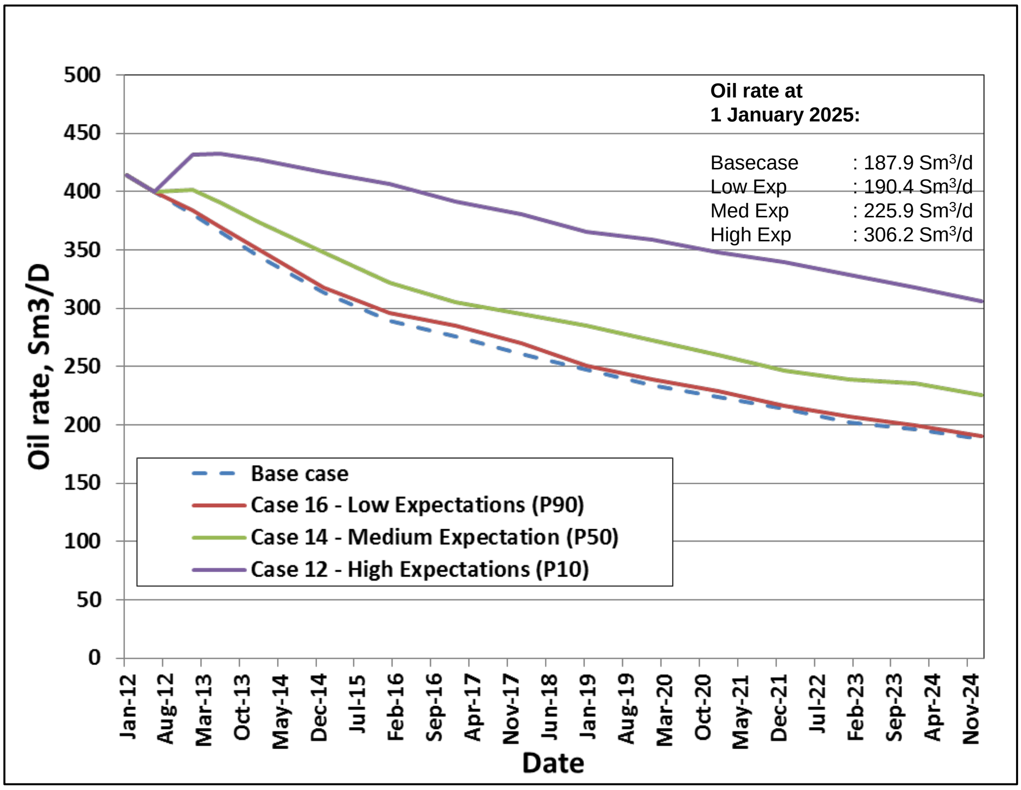

Figure 41 The oil rate curves for the 3 chosen cases compared to the base case

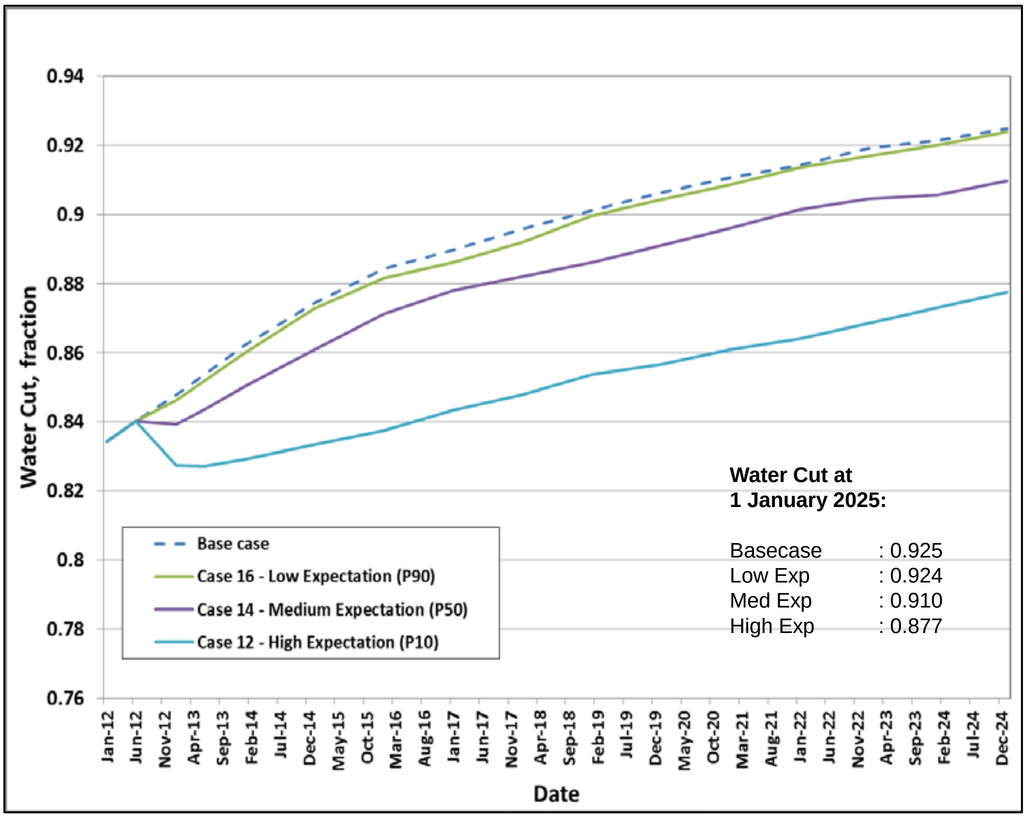

Figure 42 The water cut curves for the 3 chosen cases compared to the base case

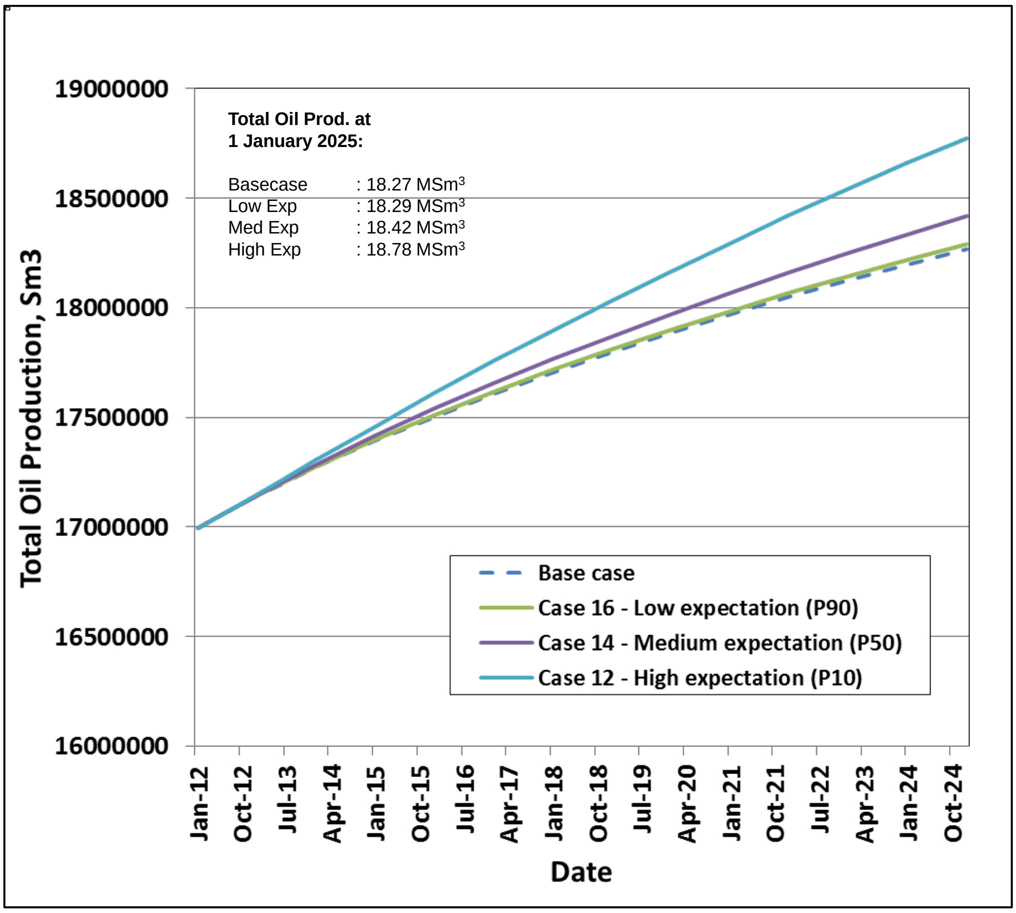

Figure 43 The total oil production curves for the 3 chosen cases compared to the base case

CHAPTER 5 ECONOMIC ANALYSIS OF ABIO GEL IN H1 SEGMENT

5.1 NPV PROJECT CALCULATION

In order to know the feasibility of the 3 cases chosen, the net present value of each of the 3 cases must be calculated.

As a first step, the net present value of the base case and the 3 other chosen cases without any sensitivity analysis i.e. no changes in oil price, oil production or investments, was calculated. The oil price was set as 100$/bbl, the oil production depends on each of the cases and the investment was set as 70MNOK. The investment price is a combination of the price of the Abio Gel injected which is 20MNOK and the operational costs of the Abio Gel which is 50MNOK. This is the only expense to be accounted in this study as the costs of drilling a well to inject the gel should not be accounted since the well has already been drilled and the gel is being injected along with water in the water injection well. It should be noticed as well that this expense should not be included in the base case analysis as there is no Abio gel injected.

Since the currencies used for the various parameters in question are not the same and the budget should only be in one currency, thus, conversions should be made. The oil production which is in Sm^3 should be converted into barrels.

In order to calculate the net cash flow, the revenues and the expenses must be accounted. The revenue that we are getting from this analysis is from the oil production only, no gas has been considered in this case. To get this revenue, the oil production should be multiplied by the oil price which is in USD/bbl; thus, the revenue will be in USD when it should be in MNOK. Therefore, the USD should also be converted into MNOK. We assumed a constant exchange rate from USD to MNOK even though this number might change regularly and should be provided by the finance and monetary department of each company. Based on one of the exchange rate website, every 1USD equals 5.786NOK. As for the expenses, capital expenditures or CAPEX are the only expenses to be spent as the cost of the Abio gel is considered as an asset since it is used to improve the profit of the company. As for the operational cost of the gel, it is accounted only once so it will also be considered as a CAPEX, if it was to be paid every year then it should have been accounted as operational expenditure or OPEX.

Afterwards, the cash flow should be calculated which is the difference between the sum of revenues and the sum of the expenses. This net cash flow will be subject to discounting with an 8% discount rate. We need to discount it in order to check what value this cash flow will have in the future. To do so, the discount factor should be calculated; afterwards, this number will be multiplied by the net cash flow. At the end, the cumulative present value is calculated and plotted.

Table 15 NPV of chosen cases

Case Number	NPV as of 2025 (MNOK)
Base Case	3246.8
Case 16 - P90	3230.7
Case 14 - P50	3523.8
Case 12 - P10	4313.0

5.2 EOR VALUE

The EOR value represents the profitability of the project compared to that of the base case when doing sensitivity analysis. The EOR value will be referred to profitability throughout the text. A negative EOR value means that is better not to apply EOR. On the other hand, a positive EOR value means it will be an advantage in an economic aspect if we apply Abio gel or permeability modifier in the reservoir.

5.3 SENSITIVITY ANALYSIS

To check the effect of the uncertainty of an input on the uncertainty of the output, sensitivity analyses are implemented. The sensitivity analysis here is applied in a way so that only one parameter is changed at a time. Sensitivity had to be done on 3 different input parameters: the oil price, the oil production and the investment.

Normally to accept a project, the NPV has to be positive. In all the cases that we have, the NPV is positive but to know whether it is feasible to add the gel or not, the NPV of the 3 cases should be compared to that of the base case. If the case's NPV is lower than that of the base case then it will be impractical to use the gel as it will be additional costs for the company instead of adding to its profits.

5.3.1 Sensitivity Analysis on Oil Price

Given the range of variability of the oil price provided by the question data, the Net Present Value (NPV) had to be calculated when the oil price has an annual increase of 5% and when it has an annual decrease of 3%. This sensitivity was applied to the base case and the 3 other cases. From the calculation of the NPV and comparing each of the 3 cases to the base case where the Abio gel was not used, it is possible to get the feasibility of the case. As the sensitivity was done on the oil price, it shows that the high probability case of low expectation is not feasible in both situations of oil price increase and decrease. The project costs more than what it will pay off in the future. As for the two other cases, it is always feasible to do add the gel regardless of the increase or decrease in oil price as additional profits are always the result. The additional gain can reach the 1462MNOK.

Table 16 NPV results showing the feasibility of all cases when sensitivity is applied on oil price

	5% Annual Increase in Oil Price			3% Annual Decrease in Oil Price		
Case	**NPV as of 2025**	**Profitability**	**Feasibility**	**NPV as of 2025**	**Profitability**	**Feasibility**
Number	**(MNOK)**	**(MNOK)**	**-**	**(MNOK)**	**(MNOK)**	**-**
Base Case	4025.29	-	-	2870.82	-	-
Case 16 - P90	4024.32	-0.97	Not Feasible	2847.38	-23.45	Not Feasible
Case 14 - P50	4419.07	393.78	Feasible	3093.50	222.68	Feasible
Case 12 - P10	5487.74	1462.45	Feasible	3752.70	881.87	Feasible

5.3.2 Sensitivity Analysis on Oil Production

The NPV is now to be calculated based on the variability of the oil production. As given in the question sheet, the NPV should be calculated when the oil production is increased by 30% and when it is decreased by the same percentage. The feasibility of every case can be determined the same way done for the sensitivity on oil price. As well, the high probability, low expectation and profitability case shows a negative profitability; therefore it will be non-economic to apply the gel. As for the two other cases, it is always feasible to apply the gel technique as the profits can be up to 1023MNOK.

Table 17 NPV results showing the feasibility of all cases when sensitivity is applied on oil production

	30% Annual Increase in Oil Production			30% Annual Decrease in Oil Production		
Case	**NPV as of 2025**	**Profitability**	**Feasibility**	**NPV as of 2025**	**Profitability**	**Feasibility**
Number	**(MNOK)**	**(MNOK)**	**-**	**(MNOK)**	**(MNOK)**	**-**
Base Case	4210.64	-	-	2267.27	-	-
Case 16 - P90	4210.49	-0.15	Not Feasible	2234.88	-32.39	Not Feasible
Case 14 - P50	4590.68	380.03	Feasible	2439.60	172.33	Feasible
Case 12 - P10	5614.13	1403.48	Feasible	2990.68	723.41	Feasible

5.3.3 Sensitivity Analysis on Investment

The price of the Abio gel and its application are also subject to changes due to changes in the market. Therefore, after assuming a total cost of acquiring and applying the gel adds up to 70MNOK, an analysis on the variation of this number was applied. A sensitivity of +/- 40% will be implemented on this investment. Therefore, the NPV will be calculated when the costs are 98MNOK and 42MNOK. In this case, the increase in the investment will lead to a non-economic case for the high probability, low expectation and profitability case. As for the rest of the cases, they are all profitable and the additional gain when adding the Abio gel is high and reaches 1091MNOK.

Table 18 NPV results showing the feasibility of all cases when sensitivity is applied on investment

	40% Annual Increase in Investment			40% Annual Decrease in Investment		
Case	**NPV as of 2025**	**EOR Value**	**Feasibility**	**NPV as of 2025**	**Profitability**	**Feasibility**
Number	**(MNOK)**	**(MNOK)**	**-**	**(MNOK)**	**(MNOK)**	**-**
Base Case	3238.96	-	-	3238.96	-	-
Case 16 - P90	3194.69	-44.27	Not Feasible	3250.69	11.73	Feasible
Case 14 - P50	3487.14	248.18	Feasible	3543.14	304.18	Feasible
Case 12 - P10	4274.40	1035.45	Feasible	4330.40	1091.45	Feasible

To determine which parameter has the highest impact on the variation of the NPV when varied for each of the 3 cases, spider diagrams were plotted. When analyzing the results, we noticed that the oil price variation has the most impact on the NPV. The spider diagrams below represent the base case and the 3 other cases.

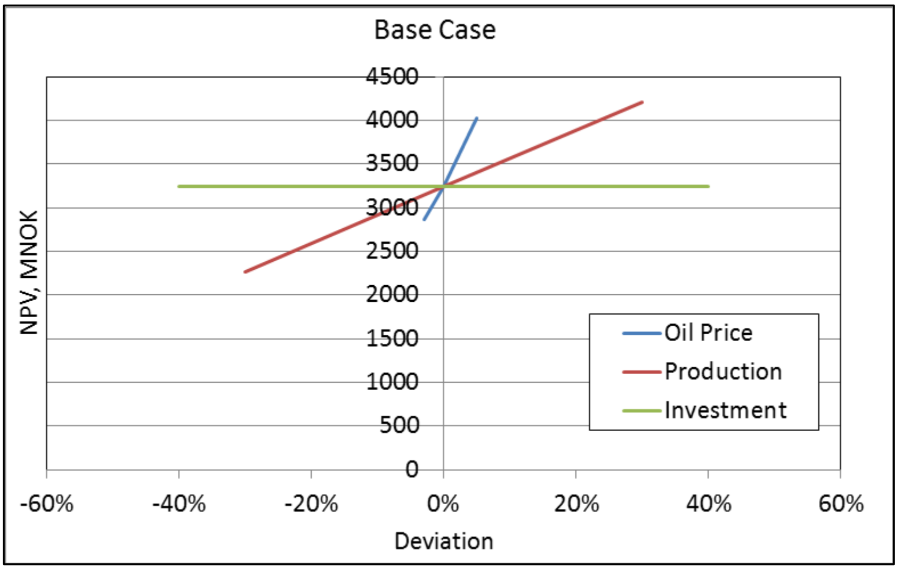

Figure 44 Spider Diagram of the base case

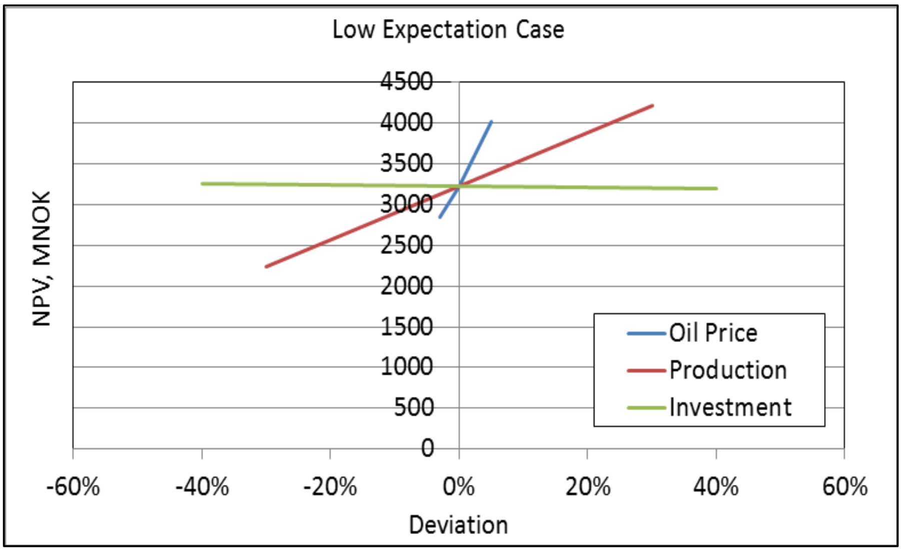

Figure 45 Spider Diagram of the low expectation case (P90)

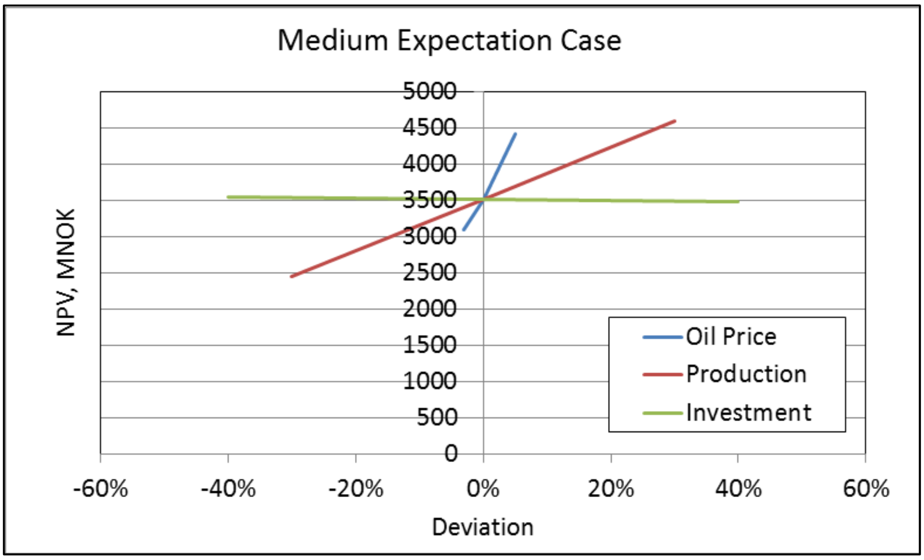

Figure 46 Spider Diagram of the medium expectation case (P50)

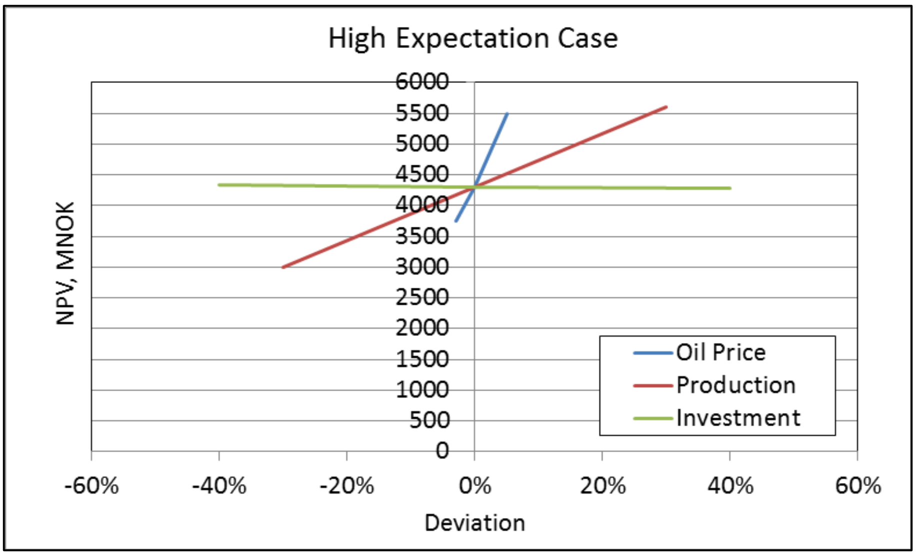

Figure 47 Spider Diagram of the high expectation case (P10)

The following graphs represent the variation of the NPV as a function of the oil price, oil production and the investment. They represent the sensitivity analysis graphically.

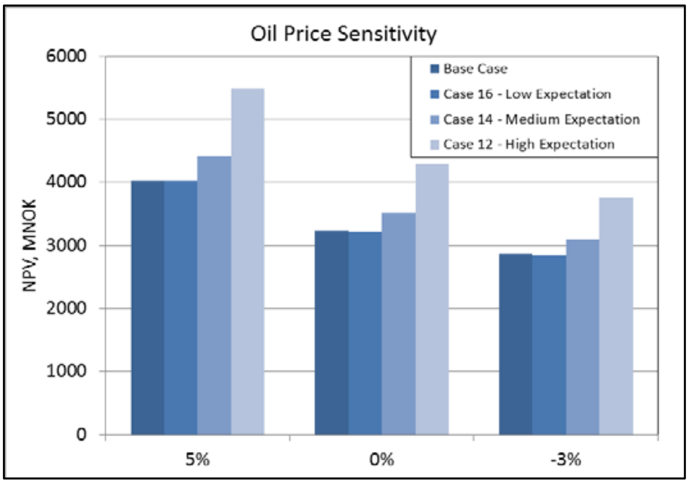

Figure 48 NPV variation as a function of the increase of oil price by 5% and of decrease of oil price by 3%

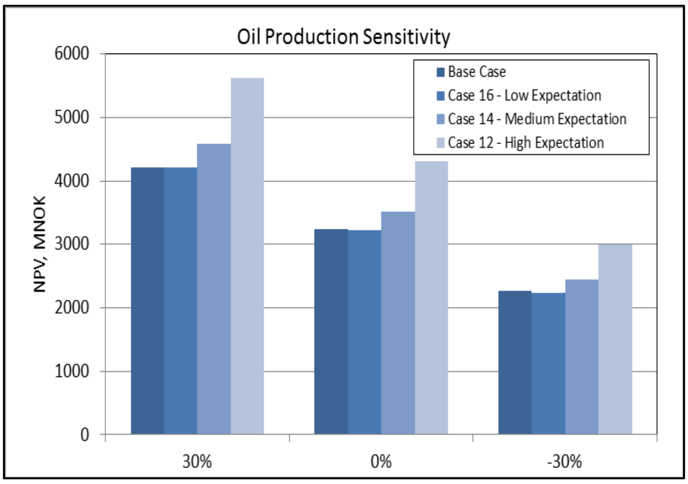

Figure 49 NPV variation with +/- 30% variation in the oil production

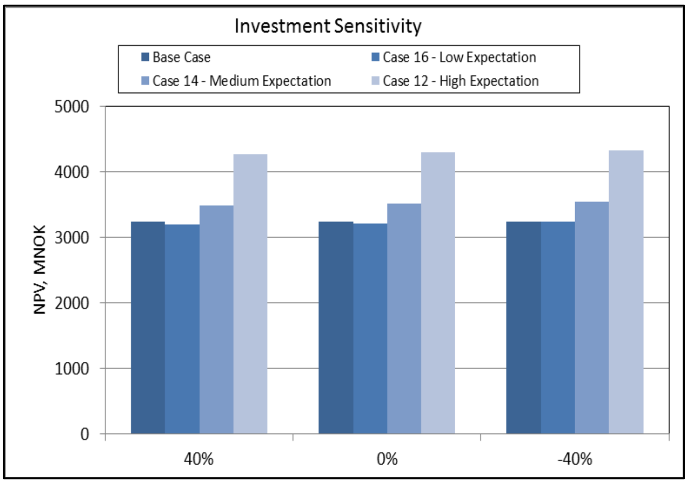

Figure 50 NPV variation with +/- 40% variation in the investment

CHAPTER 6 CONCLUSIONS

Abio gel as a permeability modifier is expected to increase the oil production of the H1 Segment of Gullfaks Main Field. In order to get better understanding of its effect in the reservoir, reservoir simulation has been done. Nineteen cases with 45 different combinations of sensitivity have been done and analyzed. All the cases showed that Abio gel as permeability modifier is able to increase the oil production and to decrease the water cut. Total oil production of the cases with Abio gel in the reservoir from January 2012 until 2025 also has been analyzed. The cases where Abio gel was injected showed 1-78% increase in oil produced compared to what can be produced from the base case.

By using the expectation curve, three cases have been chosen which represent the low, medium, and high expectations. Abio gel placement for these three cases is around 400-500 meters from the water injection well with different area which is shown by tracer concentration. A 60-70% permeability reducer is used for the low expectation case, 80-85% for the medium expectation case and 75-80% for the high expectation case. Those three cases show an increase in oil production compared to the base case. The recovery factor for the base case in 2025 is 63.26% whereas the recovery factor of low, medium and high expectation cases is 63.34%, 63.79% and 65.02% respectively.

The Net Present Value (NPV) of the base case is 3246.8 MNOK. An economic analysis shows that Low Expectation case gives lower NPV than the base case, which is 3230.7 MNOK. On the other hand, the medium and high expectation cases shows a higher NPV value than that of the base case, which are 3523.8 and 4313 MNOK respectively. From EOR value calculation, it shows that EOR value for low expectation case is negative, that means it is better not to apply the permeability reducer to the reservoir although the oil production increases. The EOR values for both medium and high expectation cases are positive. It means that the placement of the permeability reducer is preferable.

A sensitivity on the economic parameters: oil price, oil production and investment cost was applied to see the changes of the NPV. From this analysis, it was observed that the oil price is the most sensitive parameter.

The results of this project show that the application of Abio gel as a permeability reducer is able to increase the oil production and to decrease the water cut. Further analysis related to the placement of the Abio gel should be done in order to avoid a negative EOR value.

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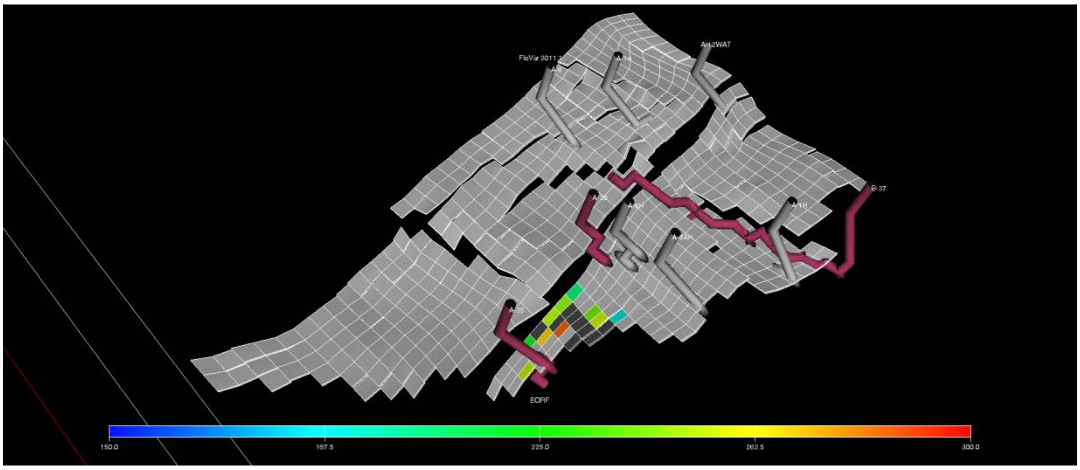
8. Jahn, F., Cook, M., and Graham, M. "Hydrocarbon Exploration and Production". page 179-182.
9. http://www.exchange-rates.org/Rate/USD/NOK

APPENDIX

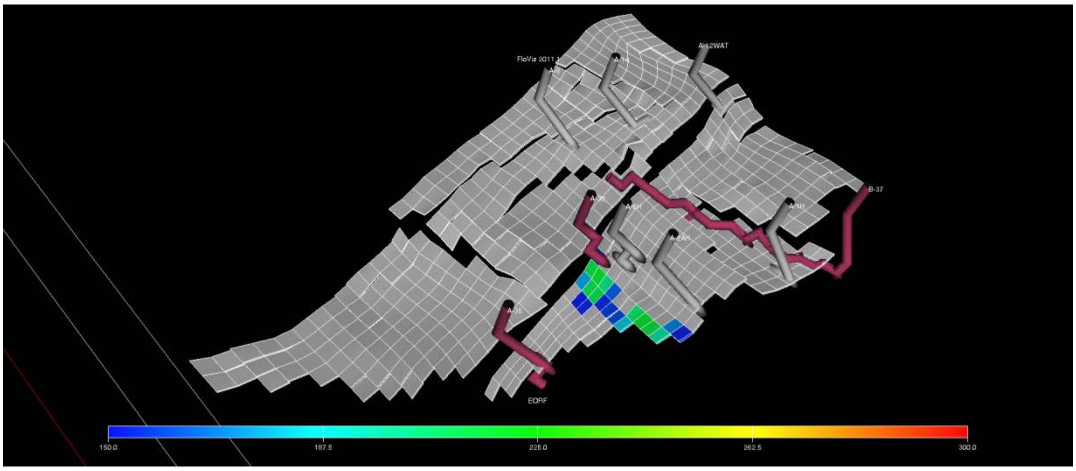
POSITION OF TRACER

Tracer Concentration 300-150

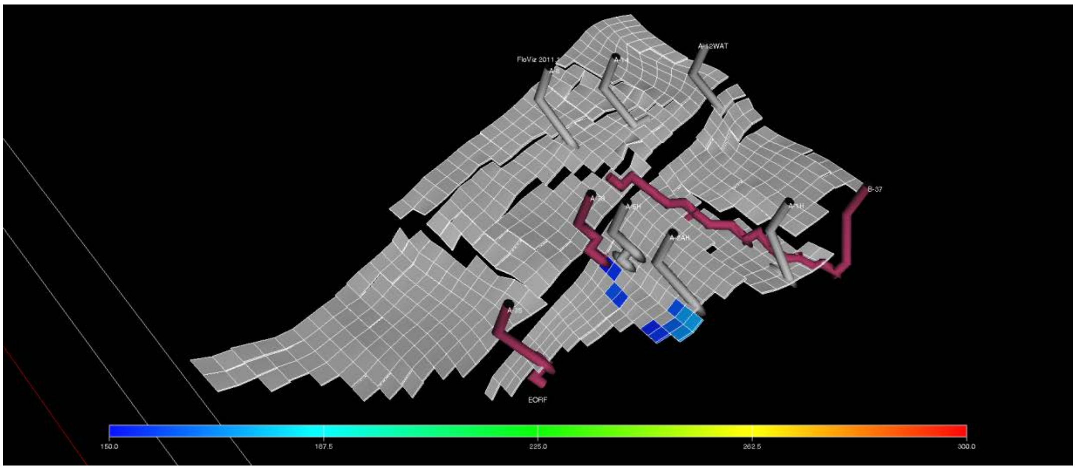
Layer 39: 1 June 2012



Layer 39: 1 January 2013

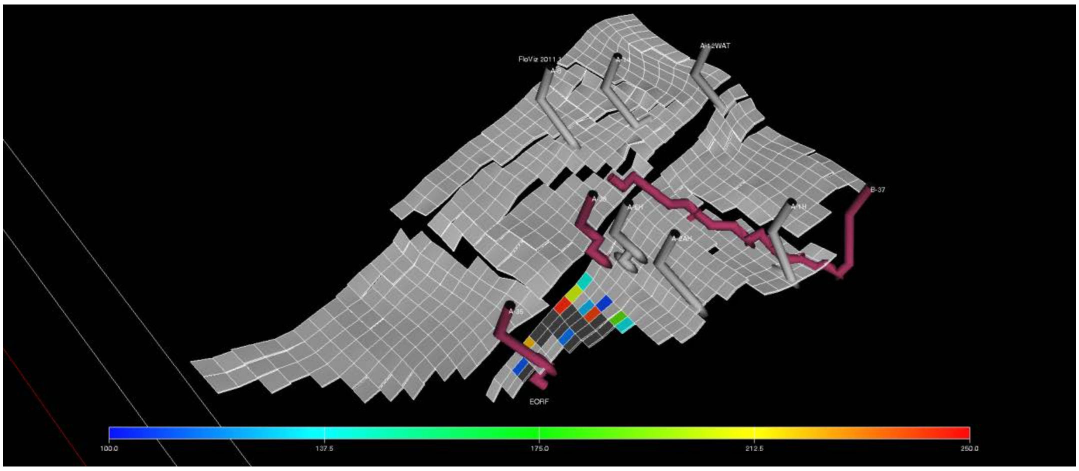


Layer 39: 1 June 2013

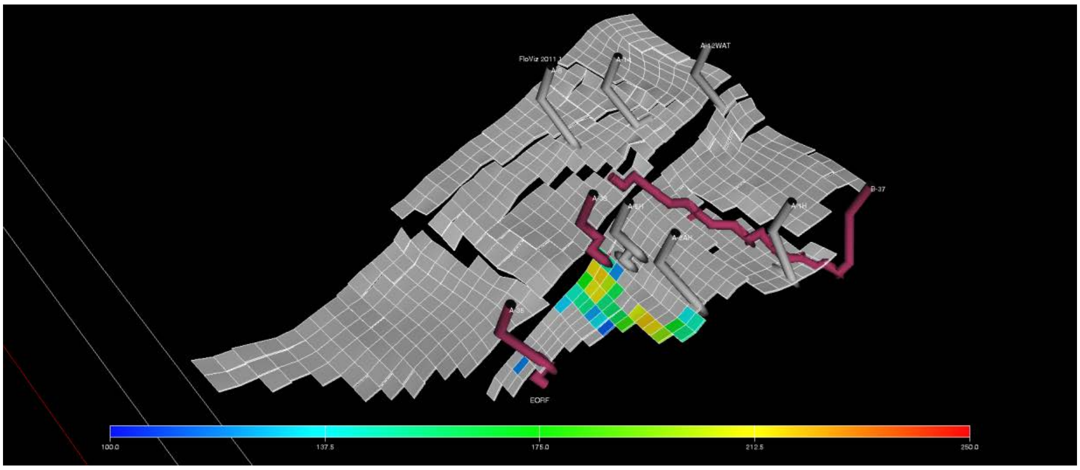


Tracer Concentration 250-100

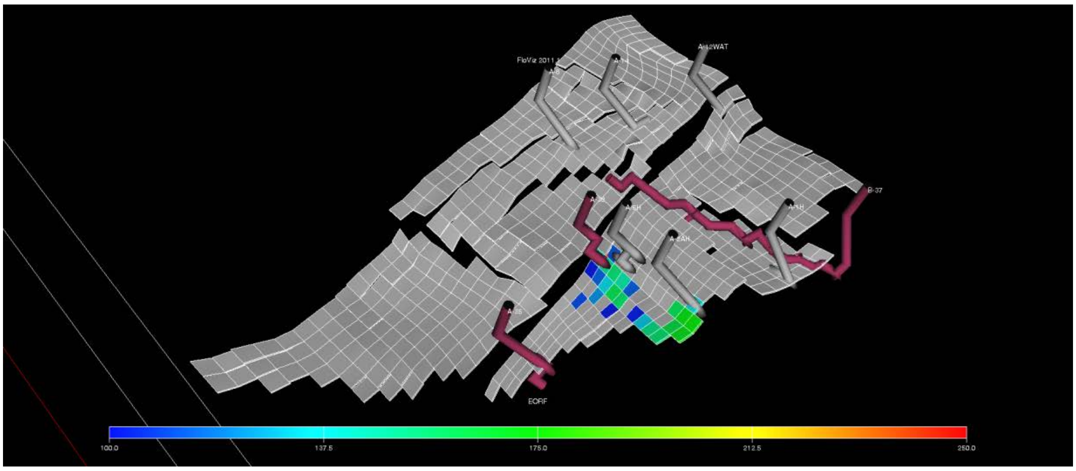
Layer 39: 1 June 2012



Layer 39: 1 January 2013

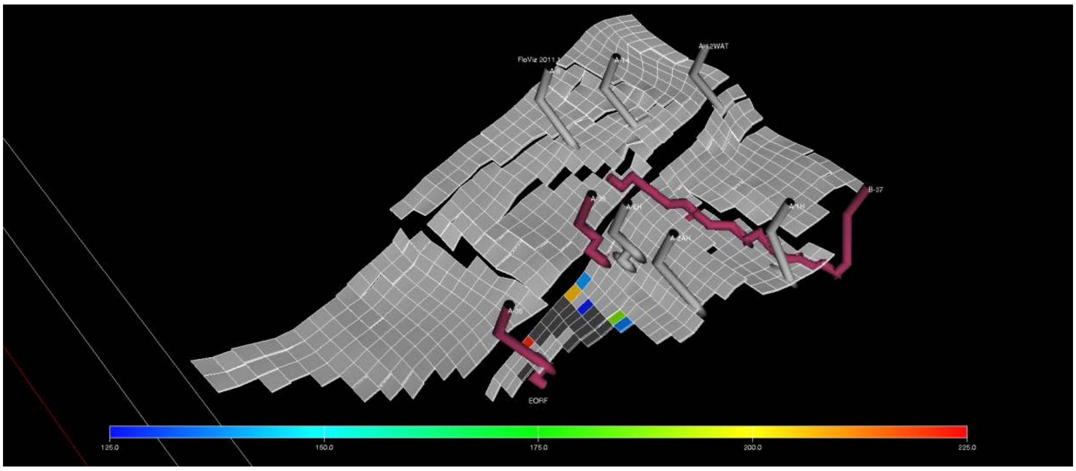


Layer 39: 1 June 2013

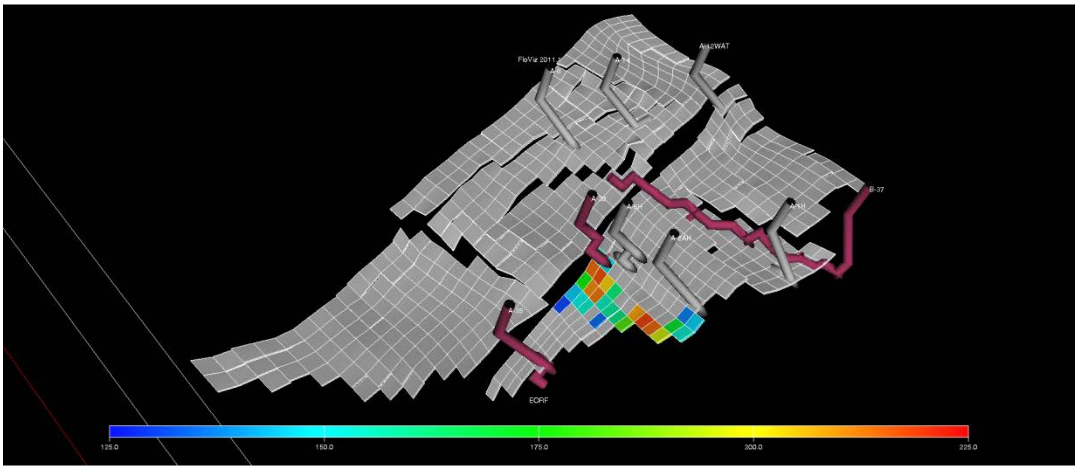


Tracer Concentration 225-125

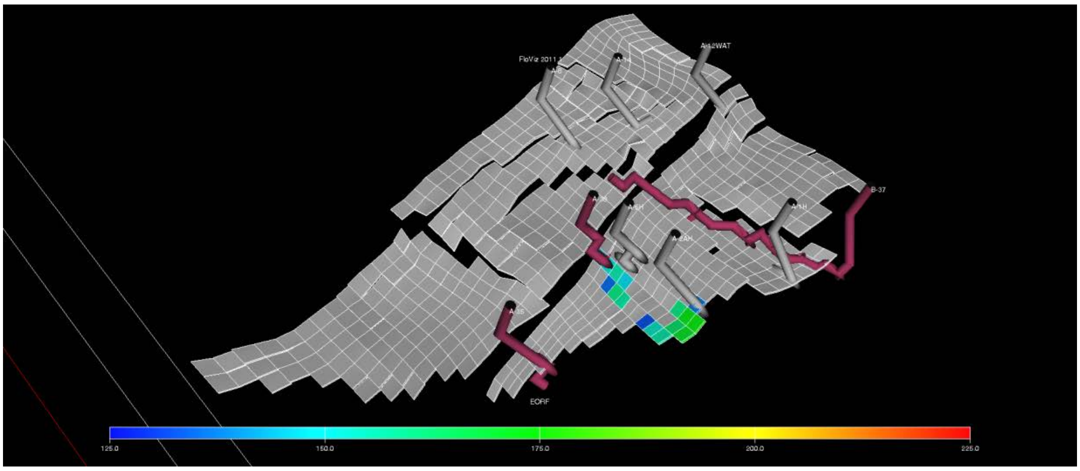
Layer 39: 1 June 2012



Layer 39: 1 January 2013

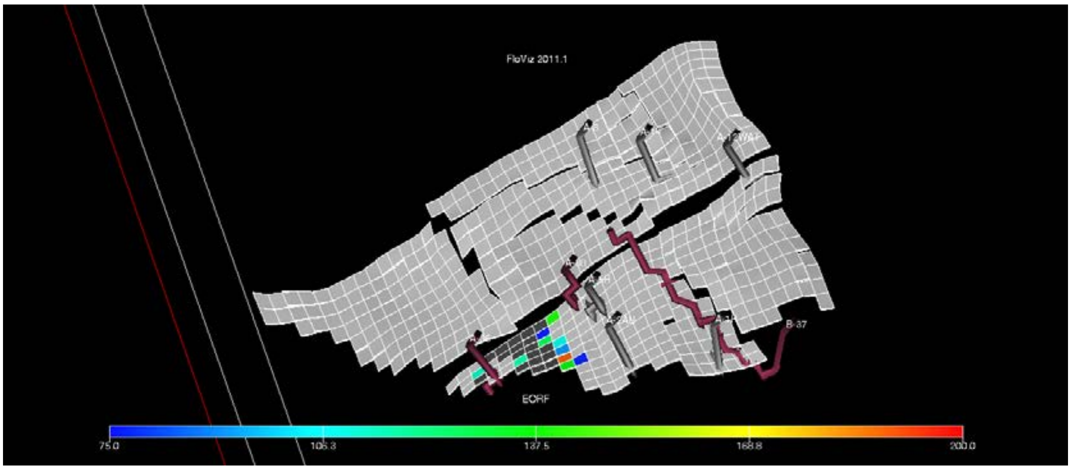


Layer 39: 1 June 2013

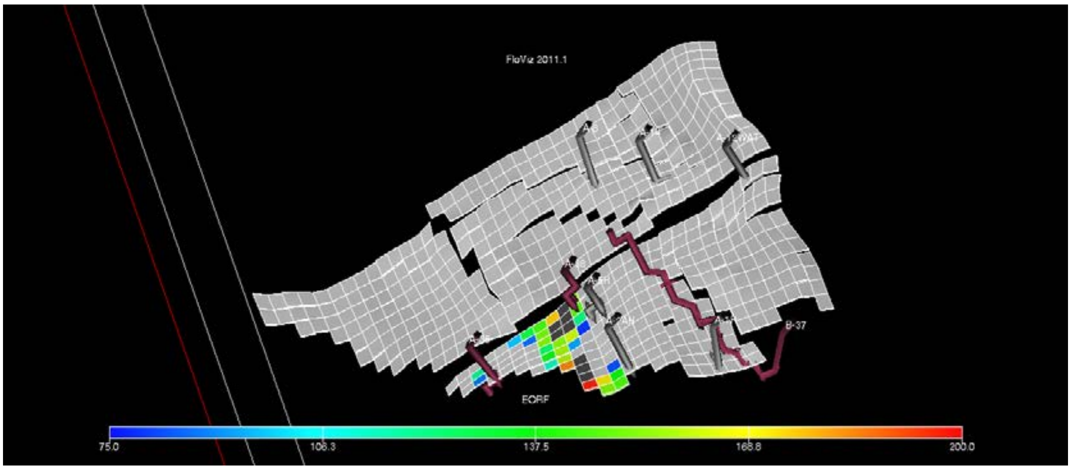


Tracer Concentration 200-75

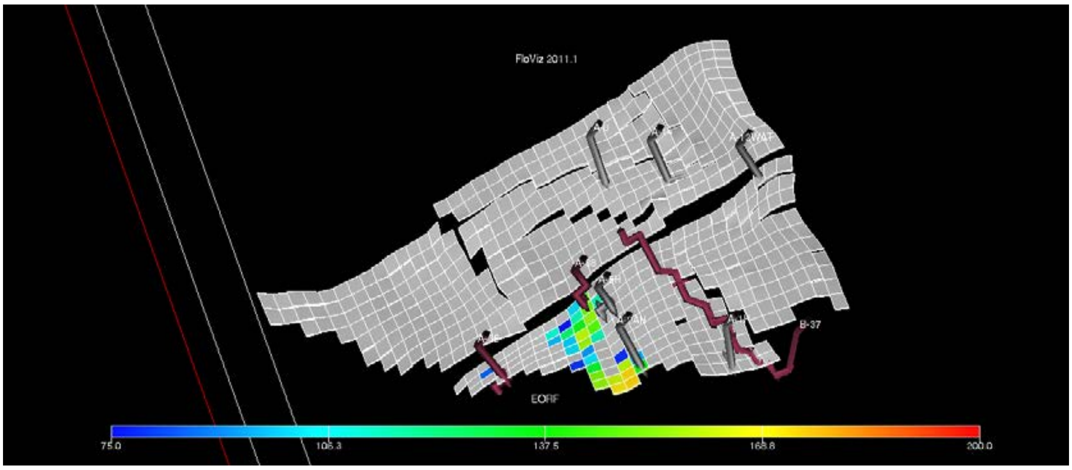
Layer 39: 1 June 2012



Layer 39: 1 Jan 2013

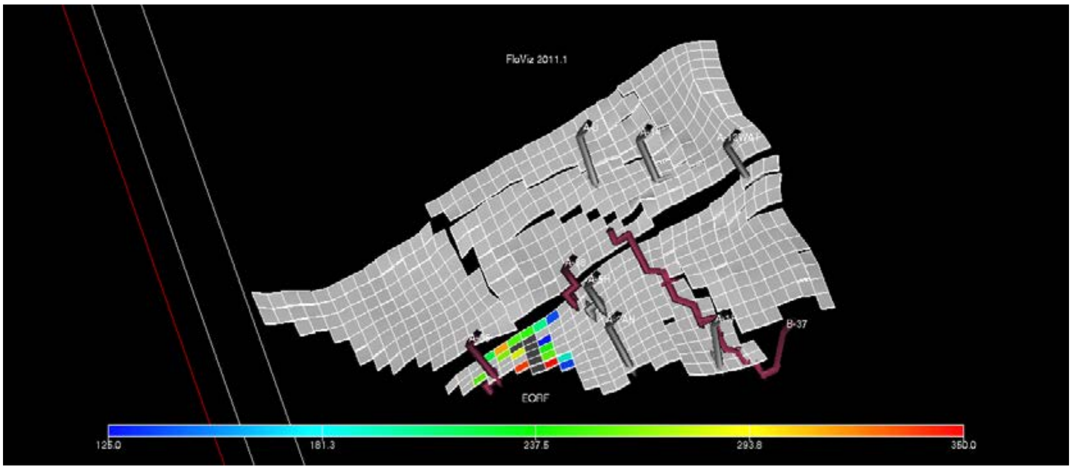


1 June 2013

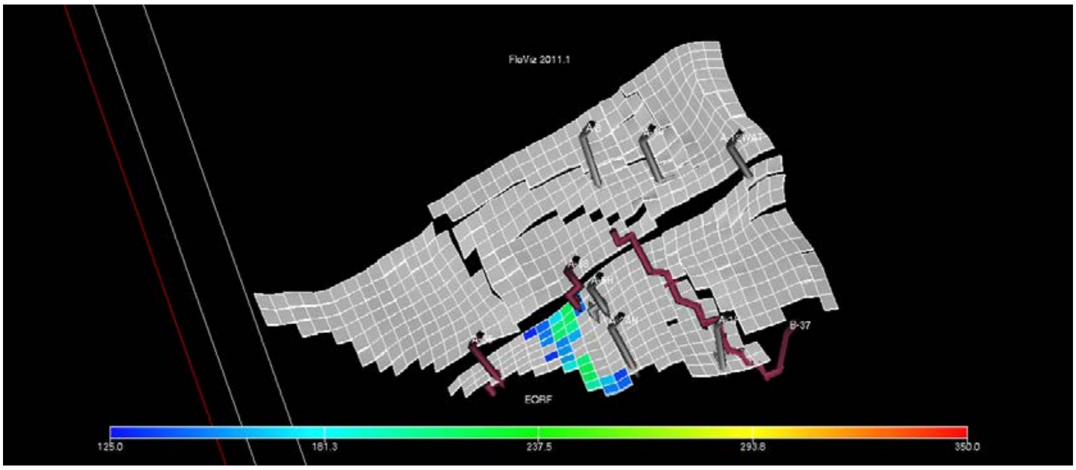


Tracer Concentration 350 - 125

Layer 39: 1 June 2012

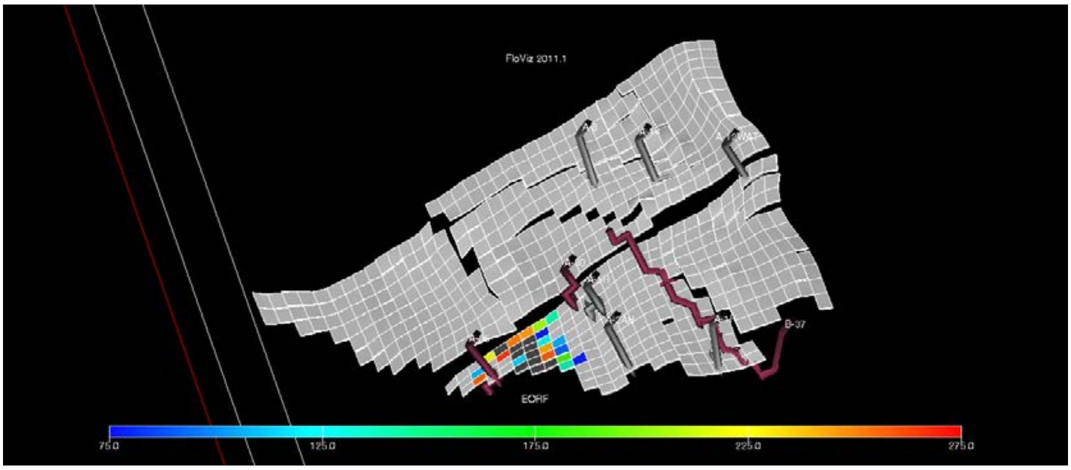


Layer 39: 1 January 2013

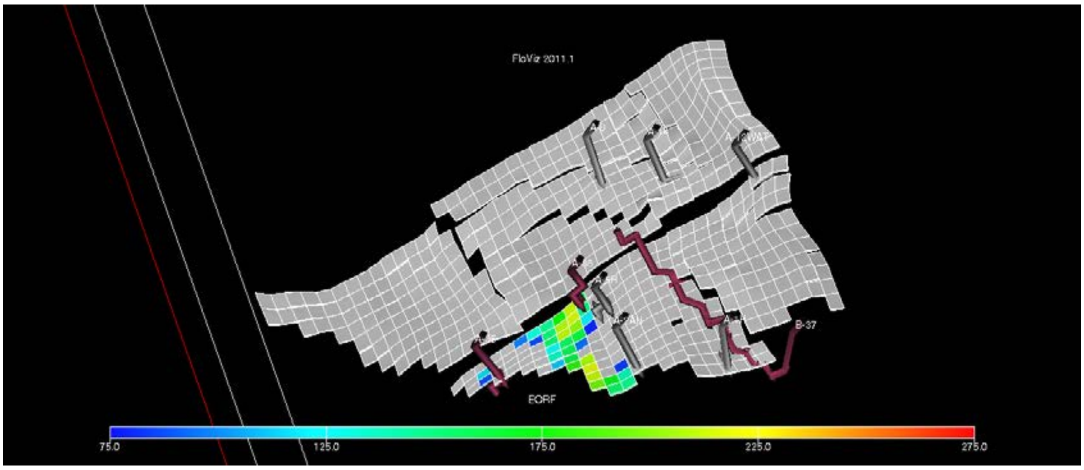


Tracer Concentration 275 - 75

Layer 39: 1 June 2012



Layer 39: 1 January 2013



SIMULATION RESULTS – Recovery Factor

Case	Tracer Concentration	Permeability modifier	Sensitivity		Difference in FOPT of 2025 (Sm3)	RF	Percentage of increasing
			Time step	Approximated distance of the placement of Abio gel			
1	300	0.15	1-Jun-12	< 400 m	114480	63.66%	9%
	300-150	0.2	1-Jan-13	400 - 500 m	28890	63.36%	2%
	150	1	1-Jun-13	> 500 m	11546	63.30%	1%
2	300	0.2	1-Jun-12	< 400 m	54346	63.45%	4%
	300-150	0.25	1-Jan-13	400 - 500 m	25530	63.35%	2%
	150	1	1-Jun-13	> 500 m	10166	63.29%	1%
3	300	0.3	1-Jun-12	< 400 m	11184	63.30%	1%
	300-150	0.4	1-Jan-13	400 - 500 m	17722	63.32%	1%
	150	1	1-Jun-13	> 500 m	6498	63.28%	1%
4	250	0.15	1-Jun-12	< 400 m	353294	64.48%	28%
	250-100	0.2	1-Jan-13	400 - 500 m	418758	64.71%	33%
	100	1	1-Jun-13	> 500 m	115234	63.66%	9%
5	250	0.2	1-Jun-12	< 400 m	233676	64.07%	18%
	250-100	0.25	1-Jan-13	400 - 500 m	287724	64.26%	23%
	100	1	-	-	-	-	-
6	250	0.3	1-Jun-12	< 400 m	61464	63.47%	5%
	250-100	0.4	1-Jan-13	400 - 500 m	66874	63.49%	5%
	100	1	-	-	-	-	-
7	225	0.15	1-Jun-12	< 400 m	244474	64.11%	19%
	225-125	0.2	1-Jan-13	400 - 500 m	154482	63.79%	12%
	125	1	-	-	-	-	-
8	225	0.2	1-Jun-12	< 400 m	152352	63.79%	12%
	225- 25	0.25	1-Jan-13	400 - 500 m	89236	63.57%	7%
	125	1	-	-	-	-	-
9	225	0.3	1-Jun-12	< 400 m	22620	63.34%	2%
	225- 25	0.4	1-Jan-13	400 - 500 m	22584	63.34%	2%
	125	1	-	-	-	-	-

10	200 200-75 75	0.1 0.15 1	1-Jun-12 1-Jan-13 1-Jun-13	< 400 m 400 - 500 m > 500 m	706298 991938 432960	65.71% 66.69% 64.76%	56% 78% 34%
11	200 200-75 75	0.15 0.2 1	1-Jun-12 1-Jan-13 1-Jun-13	< 400 m 400 - 500 m > 500 m	495268 727162 295714	64.97% 65.78% 64.28%	39% 57% 23%
12	200 200-75 75	0.2 0.25 1	1-Jun-12 1-Jan-13 1-Jun-13	< 400 m 400 - 500 m > 500 m	326930 507440 186398	64.39% 65.02% 63.90%	26% 40% 15%
13	200 200-75 75	0.3 0.4 1	1-Jun-12 1-Jan-13 -	< 400 m 400 - 500 m -	120870 182030 -	63.68% 63.89% -	10% 14% -
14	350 350-125 125	0.15 0.2 1	1-Jun-12 1-Jan-13 -	< 400 m 400 - 500 m -	205698 152916 -	63.97% 63.79% -	16% 12% -
15	350 350-125 125	0.2 0.25 1	1-Jun-12 1-Jan-13 -	< 400 m 400 - 500 m -	125012 88014 -	63.69% 63.56% -	10% 7% -
16	350 350-125 125	0.3 0.4 1	1-Jun-12 1-Jan-13 -	< 400 m 400 - 500 m -	13628 22196 -	63.31% 63.34% -	1% 2% -
17	275 275-75 75	0.15 0.2 1	1-Jun-12 1-Jan-13 -	< 400 m 400 - 500 m -	451124 672498 -	64.82% 65.59% -	35% 53% -
18	275 275-75 75	0.2 0.25 1	1-Jun-12 1-Jan-13 -	< 400 m 400 - 500 m -	307538 481518 -	64.32% 64.93% -	24% 38% -
19	275 275-75 75	0.3 0.4 1	1-Jun-12 1-Jan-13 -	< 400 m 400 - 500 m -	101562 157748 -	63.61% 63.81% -	8% 12% -