TPG-4851 Gullfaks Village

Spring Semester 2010

Experts in Team 2010

Improved Oil Recovery using BrightWater injection

Group 1

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Acknowledgement

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Abstract

This report is submitted as a group project in part fulfilment of the requirements to the course Experts in Team Gullfaks Multidisciplinary Village (TPG 4851).

Generally the objective of the project is to investigate the behaviour of the Statfjord formation in the Gullfaks Sør field, by applying an Eclipse 100 simulation model to the input data file of the Statfjord formation, provided by Statoil in Bergen. In this manner, first the behaviour of the field using a Statoil gas injection model was analyzed, and second the behaviour of the field was studied using a very specific IOR method called the "BrightWater injection model". In part A, recovery from Gullfaks Sør in the Statfjord formation was analyzed with a gas injection model. Accuracy of the model has been analyzed and proper improvements for history matching of water production were made. IOR of Gullfaks Sør using gas injection model is increasing oil recovery from 18% to 28%, but gives a high GOR, which is a problem for Gullfaks processing plant. Part B required converting Gullfaks Sør gas injection into water injection and then applying BrightWater to the reservoir. After 15 cases of water injection simulation, the most appropriate model, which would give approximately the same recovery as Gullfaks Extended gas injection case, was chosen for simulating BrightWater injection. Results showed that water injection case could potentially give 11% more recovery of oil than gas injection case. After 50 cases of BrightWater injection the best case gives 8% more recovery of oil than gas injection case. Charts and figures demonstrate the results of the simulation throughout this report. Due to environmental issues of BrightWater on the Norwegian Continental Shelf, lower predicted recovery and less economical benefit compared to the water injection, the use of BrightWater for Gullfaks Sør as IOR method is not recommended.

1 Geology and introduction

1.1 Gullfaks Sør Geological history:

1.1.1 Overview

The Gullfaks satellites include four fields, Gullfaks Sør, Rimfaks, Skinfaks and Gullveig. Both Gullfaks and the Gullfaks satellites are mainly located in block 34/10 on the west-flank of the Vikinggraben. Vikinggraben is a result of an extension regime within the northern North Sea basin. The northern North Sea is limited by the Norwegian mainland in east and the Shetland platform in the west, stretching from approx 58 ° to 62 ° N.

The next chapters will give the reader a short briefing on the structural and sedimentological history of the northern North Sea basin and the Vikinggraben.

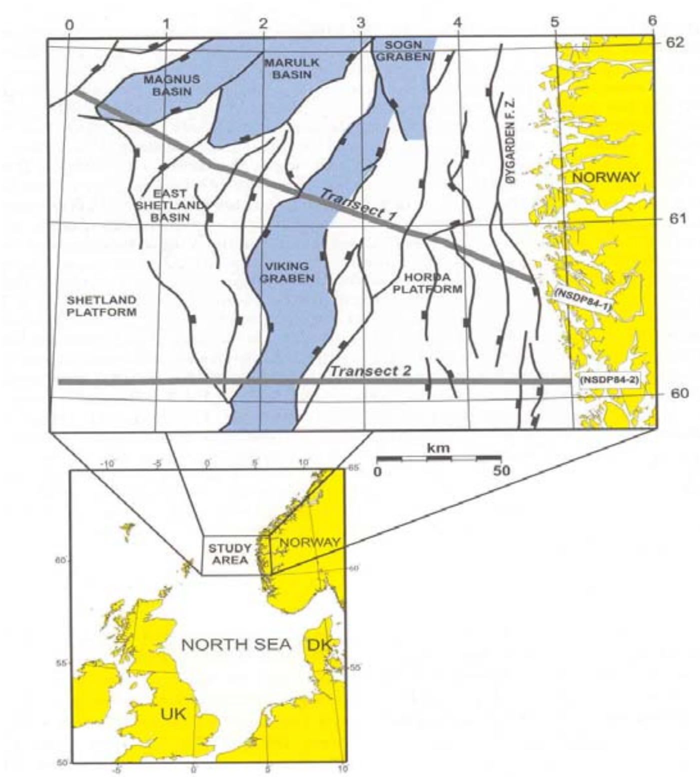


Figure 1-1 Vikinggraben and the surrounding structures. Grey areas are those affected by the rifting during Jurassic. From Odinsen et al. (2000)

1.1.2 Vikinggraben structural history

The Permian – Triassic and the Jurassic is considered to be the most interesting geological periods regarding the formation of the Vikinggraben. In Permian the western and central parts of Europe were a part of Pangea. During the transition between late Permian – early Triassic there was a shift from compression to extension, which resulted in a rift phase. Pangea started to crack, and in the northern North Sea the extension created huge tilted fault blocks limited by N-S trending fault zones. By the exit of Triassic there were created a 140-150 km wide basin in this area. During middle Jurassic until lower Cretaceous the area went through another phase of rifting. This rifting resulted in new N-S- and NNE-SSW-going listric faults and even higher subsidence of the basin floor. Vikinggraben is "an arm" in such a Jurassic rift system. The triple riftsystem consists of Vikinggraben, Sentralgraben and the Moray Firth Basin. Together with Sogngraben the system represents the area with the maximal extensions in the northern North Sea in the Jurassic. In the late Jurassic (kimmeridge-volg) a NE-SV trending fault regime is cutting the old N-S- zones creating a section of smaller, rhomboid fault blocks. The geometry of the faulting resulted in a rotation of the fault blocks towards the basins center. In Cretaceous and Tertiary the extension rate is falling and there is a subsidence due to thermal cooling and sediment loading.

1.1.3 Vikinggraben sedimentologic history

The assignment focuses on the Statfjord formation as the main reservoir rock and it also instructs to avoid drilling through the low-pressure BRENT group. Both the Statfjord formation and the BRENT group are deposited during the Jurassic period. A global transgression was ongoing in the early Jurassic period and the climate was changing from dry to a more humid climate. The northern part of the Vikinggraben was dominated by large river flats, and alluvial sequences such as the Statfjord formation were formed. Upon the Stafjord formation lays the BRENT group, which is interpreted as a regressive-transgressive clastic fan. The rifting in Jurassic led to a relative sea level rise and marine deposits became the dominant in the northern North Sea, with deposition of the organic rich Draupne- and Heater formation (source rocks). Subsidence combined with a sea level-rise led to a quick burial of the Triassic and

Jurassic sediments, and the relief made by the rotated fault blocks in the Vikinggraben was overfilled by sediments by the end of Cretaceous.

1.2 Gullfaks Sør structural geology

Gullfaks Sør is the deepest structure in the Gullfaks area, with top reservoir at 2860 m true vertical depth. Gullfaks Sør is divided into three main structural parts, see figure 1.2. The Domino system is positioned from west to east, the Accommodation area and the Horst complex. The Domino system is the most dominating part of Gullfaks Sør and occupies the western and central area. It consists of several rotated fault blocks tilted towards east. The Horst Complex is the easternmost part of the field and consists of horst blocks divided by easterly and westerly dipping faults. The Accomodation area is located in between these two main sections.This area has probably acted as a transition zone during the development of the faults between the easterly dipping faults in the Domino system and the westerly dipping faults in the Horst complex. The fact that this area had to adjust to the faulting processes developing on both sides, has probably made it the most complex of the three.

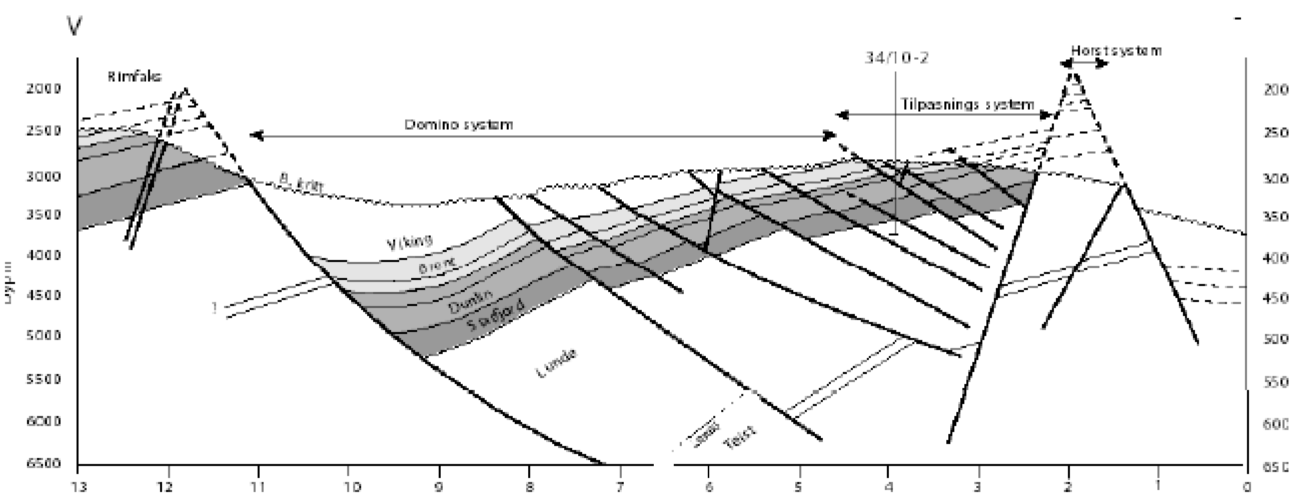


Figure 1-2 The structural geology of Gullfaks Sør. From RSP 2003, Statoil (2002)

The Statfjord reservoir lies underneath Brent, which can be found at around 2400m depth. Statfjord can be divided into an upper and a lower sequence and these sections can again be divided into different layers. The upper Statfjord consist of the two layers Nansen and Eiriksson-

2 and they are together about 70-80 m thick. The lower Statfjord is about 160-175m and consist of the two layers called Eiriksson-1 and Raude.

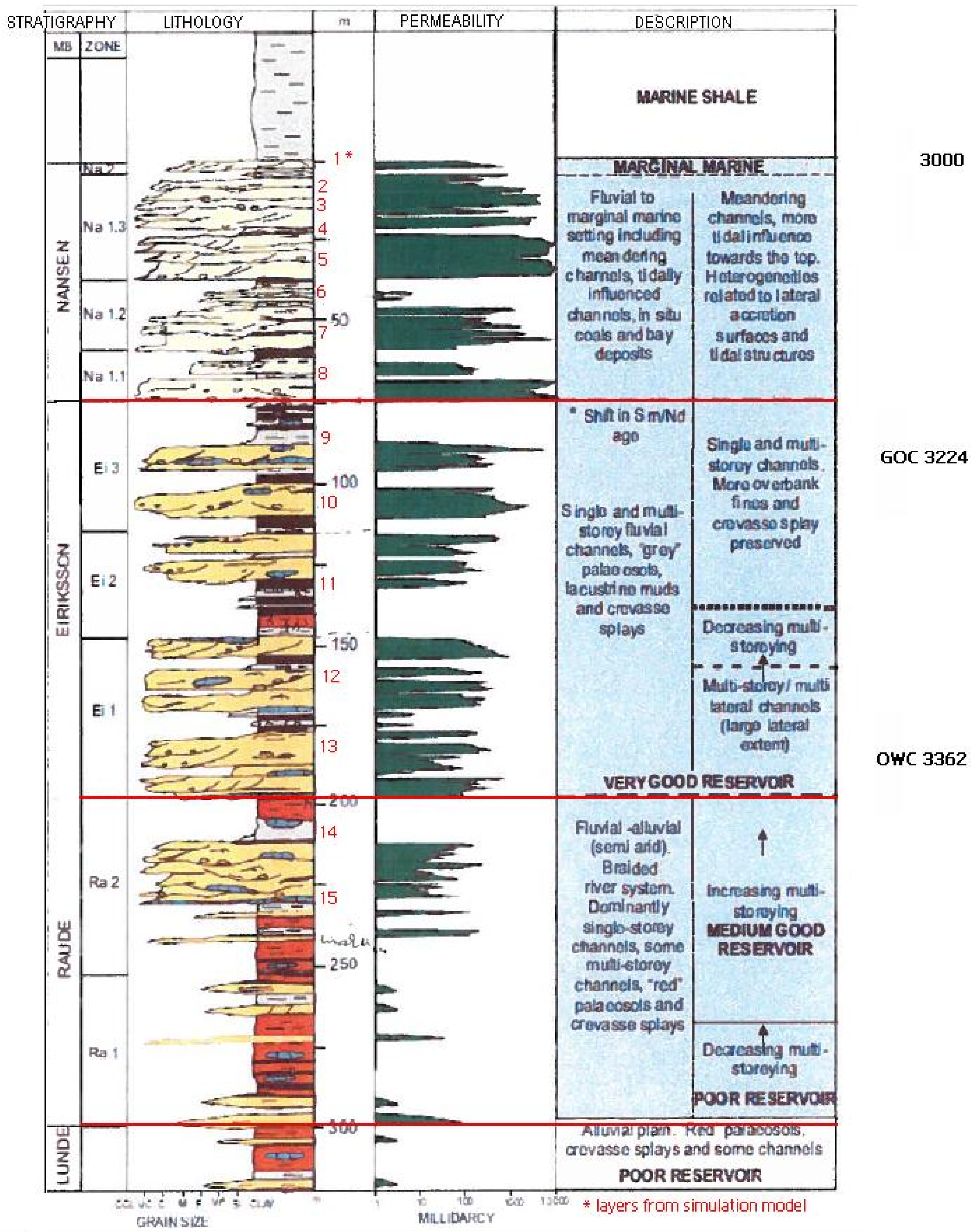


Figure 1-3 The stratigraphic column of the Statfjord formation at Gullfaks Sør. Provided by Karl Sigurd Årland

The reservoir rocks at Statfjord are sandstones from Lower Jurassic and Upper Triassic. The sands in Nansen and the two Eiriksson sections are massive, relatively homogeneous and high permeable (0.5-2D), but with some layers of shale and coal in between. This is shown in figure 1.3, where the lithology is on the far left and the permeability is in the middle. The lateral continuity in the sand in Nansen is especially good. Eiriksson-1 and Raude are characteristic by their alternating shales and sands of different thickness and quality. Raude has a high occurrence of red shales and sections with soil. The lower part of Statfjord has also a higher content of feldspar and kaolinite than the upper part.

As mentioned earlier the field is divided into several blocks separated with faults. Production has showed that the pressure drops relatively fast, which can be an indicator of poor communication between the different blocks. An important reason for this is deformation bands developed in association with the fault growth. These bands were generated by dissolution and recrystallization of quartz which reduces the permeability significantly, and even though they are very thin they affect the flow considerably.

1.2.1 Reservoir Heterogeneity

Due to the differences in depositional environment, diagenesis and tectonics the reservoir at Gullfaks Sør is very heterogeneous (see figure 1.3). Important reservoir parameters such as porosity, permeability and communication are all strongly affected by this heterogeneity.

When trying to inject water into the reservoir to sweep any remaining oilpockets, the water will travel toward the producers in the layers with the least resistance. High permeability layers will act as thiefzones for the water, stopping it from invading the zones where we initially wanted the water to sweep.

Studies of the stratigraphic column and reservoir models for Gullfaks Sør shows that layer 9, 12 and 13 is most likely to act as thiefzones for the injected water. These are layers consisting of high permeable sands deposited from rivers, both meandering and braided.

1.3 Petrophysic parameters

(The petrophysics figures can be found in the appendix)

1.3.1 Initial oil saturation:

As we see from figure 9.1 the oil saturation ranges from around 60-95% and it decreases from the gas-oil contact down towards the oil-water contact. In the gas cap and the water zone the saturation of oil is close to zero.

1.3.2 Initial gas saturation:

In figure 9.2 we see how the initial gas saturation is in the reservoir. Comparing this figure with figure 9.1 (all though they are from different angles) one observe that a gas cap exists at the top of the reservoir where the oil saturation is zero. Here the gas saturation is around 90-95%; while close to the oil-gas contact the saturation is 70-80% some places.

1.3.3 Porosity:

The initial porosity in Statfjord ranges from around 11-18% as showed in figure 9.3.
For most of the reservoir the porosity does not change gradually, but has alternating layers of low and higher porosity. This may be layers of sand with shale in between, which corresponds to what we see in figure 1.3. The porosity does usually not change much with production unless the compaction is high, due to a large pressure drop. In this model the porosity is assumed to be constant during the production time.

1.3.4 Net to Gross (NTG)

The net to gross values (figure 9.9) are ranging from 0.2 to 0.4 in the oil column. In the water zone and in the gas-cap it is generally higher (ranging from 0.2 to 0.8). The NTG for the Statfjord reservoir is overall stated to be 0.5. [1]

1.3.5 Permeability:

The paper "Reservoar styringsplan 2004" from Statoil states (shortened and translated):
‘Production experience from wells G-2 HT3 and F-4 AHT3 showed that the pressure fell

rapidly, and indicated limited communication. Deformation-bands in connection with faults were interpreted as the main cause of reduced communication.

Also dissolution and recrystallization of quartz nearby the deformation-bands has led to highly reduced permeability in the deformation zones.' [3]

From the figures we can see that the permeability in x-direction (Figure 9.3) varies from 0 mD to 200 mD, as suspected from the Statoil-paper. Such a trend can be explained by the geological conditions during deposition and burial (diagenesis). Statfjord formation consists of several different packages of sand and clay / shale, where reservoir-properties will vary accordingly. High permeable layers are often referred to as "highways", and these highways are in many cases the reason to a large water production, especially if the injector- and producer- wells are not placed correctly.

'In well D-4 H (drilled winter 1999/2000) the Statfjord formation was encountered dry approximately 60 m shallower than OWC from the existing fluid model (3362m TVD MHN). This shows that there exists sealing faults on the Statfjord level, and that the reservoir is significantly more complicated than originally assumed.' [3]

1.3.6 Relative Permeability

Relative permeabilities reflect the capability of the formation to produce a combination of oil, water or gas, more accurately than the absolute permeability, since the absolute permeability seldom reflects the in situ reservoir situation. For figures of the relative permeabilities see the appendix "Petrophysics figures", figure 9.6, 9.7 and 9.8.

Oil column: The relative permeability for oil is generally high (≈1) in the oil column, but with some areas where the majority of relative-permeabilities are rather low.

Gas cap: The relative permeability for gas is generally high (≈1) in the gas cap, but with some areas where the majority of relative permeabilities are rather low. The areas with low relative gas permeability are the mostly the same as those with low relative oil permeability, which may be caused by oil in solution with gas over a larger interval. This can also be seen in the saturation figures and is described in section 1.3.1 and 1.3.2.

Water zone: The relative permeability for water is close to 1 in the whole part of the water-zone.

1.3.7 Fluid Data

Oil viscosity: 1.2 cp

Oil gravity: 36.4 API

1.3.8 Resources

Field	Oil and Condensate (MSm^3)			Gas (GSm^3)		
	P90	Basis	P10	P90	Basis	P10
Statfjord	32	38	43	14	16	16
Brent	48	62	71	74	86	98
Lunde	17	24	31	3	5	7
Total	97	124	145	91	107	121

Table 1-1 Resources Gullfaks Sør [1]

1.3.9 In place volumes

STOOIP

38.5 MSm^3 totally in the Statfjord formation. [1]

Formation	STOOIP 2006 (MSm^3)
Nansen	16
Eiriksson	14,7
Raude	7,8
Total	38,5

Table 1-2 STOOIP Statfjord formation Gullfaks Sør[1]

Recovery factor: 0.14 (Figure 1.4) [1]

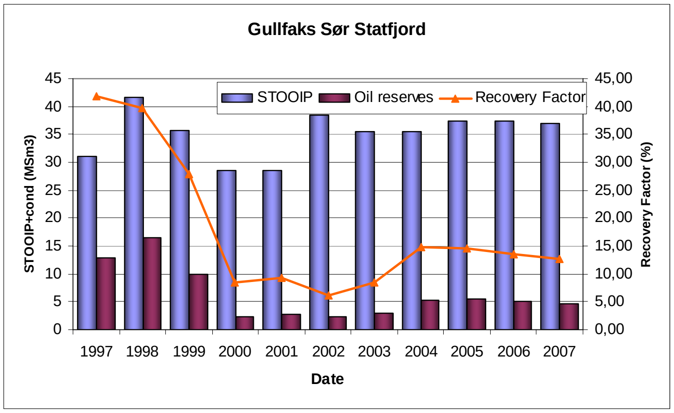


Figure 1-4 STOOIP, Reserves and Recovery factor, Statfjord formation Gullfaks Sør [1]
Figure 1-5 STOOIP, Reserves and Recovery factor, Statfjord formation Gullfaks Sør [1]

GIIP

9.7 MSm^3 totally in the Statfjord formation. [2]

Recovery factor: 0.12 (2)

The recovery factor for the gas-case is calculated by using the following formula,

$$RF(gas) = \frac{gas\ prod. - gas\ inject.}{GIIP - ass.gas} \quad [2]$$

which explains the rather low recovery factor in the gas-case.

2 Introduction to various recovery techniques

Oil recovery operations traditionally have been subdivided into three stages: primary, secondary and tertiary. Historically, these stages described the production from a reservoir in a chronological sense. Primary production, the initial production stage, resulted from the displacement energy naturally existing in a reservoir. Secondary recovery, the second stage of operation, usually was implemented after primary production declined. Traditional secondary recovery processes are water flooding, pressure maintenance and gas injection, although the term secondary recovery is now almost synonymous with water flooding. Tertiary recovery, the third stage of production, was that obtained after water flooding (or whatever secondary process was used). Tertiary processes used miscible gases, chemicals and/or thermal energy to displace additional oil after the secondary recovery process became uneconomical. The drawback to consideration of the three stages as a chronological sequence is that many reservoir production operations are not conduct in a specific order. A well-known example is production of the heavy oils that occur throughout much of the world. If the crude is sufficiently viscous, it may not flow at economic rates under natural energy drives, so primary production would be negligible. For such reservoirs, water flooding would not be feasible; therefore, the use of thermal energy might be the only way to recover a significant amount of oil. In this case, a method considered to be a tertiary process in a normal, chronological depletion sequence would be used at the first, and perhaps final, method of recovery. In other situations, the so-called tertiary process might be applied as a secondary operation in lieu of water flooding. For example, if a water flood before application of the tertiary process would diminish the overall effectiveness. Then the water flooding stage might reasonably be bypassed. Because of such situations, the term "tertiary recovery" fell into disfavour in petroleum engineering literature and the designation of "enhanced oil recovery" (EOR) became more accepted. Another descriptor designation commonly used is "improved oil recovery" (IOR), which includes EOR but also encompasses a broader range of activities, e.g., reservoir characterization, improved reservoir management and infill drilling. Because of the difficulty of chronological oil-production classification, classification based on process description is more useful and is now the generally accepted approach, although the naming of the processes still incorporates the earlier scheme based on chronology. Oil recovery processes now are classified as primary, secondary, and EOR processes. A classification scheme is clearly useful in that it establishes a basis for communication among technical persons. However, it also has a pragmatic utility in the implementation of tax laws and accounting rules. Primary recovery results from the use of natural energy present in a reservoir as the main source of energy for the displacement of oil to producing wells. These natural energy sources are solution- gas drive, gas-cap drive, natural water drive, fluid and rock expansion, and gravity drainage. The particular mechanism of lifting oil to the surface, once it is in the wellbore, is not a factor in the classification scheme. Secondary recovery results from the augmentation of natural energy through injection of water or gas to displace oil toward producing wells. Gas injection, in this case, is either into a gas cap for pressure maintenance and gas-cap expansion or into oil-column wells to displace oil immiscibly according to relative permeability and volumetric sweep out considerations. Gas processes based on other mechanisms, such as oil swelling, oil viscosity reduction, or favourable phase behavior, are considered EOR processes. An immiscible gas displacement is not as efficient as a water flood and is used infrequently as a secondary recovery process today. (Its use in earlier times was much more prevalent.) Today, water flooding is almost synonymous with the secondary recovery classification. EOR results principally from the injection of gases or liquid chemicals and/or the use of thermal energy. Hydrocarbon gases, CO2, nitrogen, and flue gases are among the gases used in EOR processes. A number of liquid chemicals are commonly used, including polymers, surfactants, and hydrocarbon solvents. Thermal processes typically consist of the use of steam or hot water, or rely on the in-situ generation of thermal energy through oil combustion in the reservoir rock. EOR processes involve the injection of a fluid or fluids of some type into a reservoir. The injected fluids and injection processes supplement the natural energy present in the reservoir to displace oil to a producing well. In addition, the injected fluids interact with the reservoir rock/oil system to create conditions favourable for oil recovery. These interactions might, for example, result in lower IFT's, oil swelling, oil viscosity reduction, wettability modification, or favourable phase behaviour. The interactions are attributable to physical and chemical mechanisms and to the injection or production of thermal energy. Simple water flooding or the injection of dry gas for pressure maintenance or oil displacement is excluded from the definition. EOR processes often involve the injection of more than one fluid. In a typical case, a relatively small volume of an expensive chemical (primary slug) is injected to mobilize the oil. This primary slug is displaced with a larger volume of a relatively inexpensive chemical (secondary slug). The purpose of the secondary slug is to displace the primary slug efficiently with as little deterioration as possible of the primary slug. In some cases, additional fluids of even lower unit cost are injected after a secondary slug to reduce expenses. In such a case of multiple fluid injections, all injected fluids are considered to be part of the EOR process, even though the final chemical slug might be water or dry gas that is injected solely to displace volumetrically the fluids injected earlier in the process. EOR processes can be classified into five categories: mobility-control, chemical, miscible, thermal and other processes such as microbial EOR. [4]

In this report two secondary stage IOR techniques and one tertiary stage IOR technique will be used; water injection and gas injection models in secondary stage and BrightWater injection model (a chemical additive) in tertiary stage.

3 Reservoir Simulation Analysis

3.1 Analysis of history matching

In this chapter the results from history matching is discussed and the reference case of production and new IOR plan are compared. The chapter is supported with figures and discussion of the results.

The main results of history match between simulation model and data are shown below:

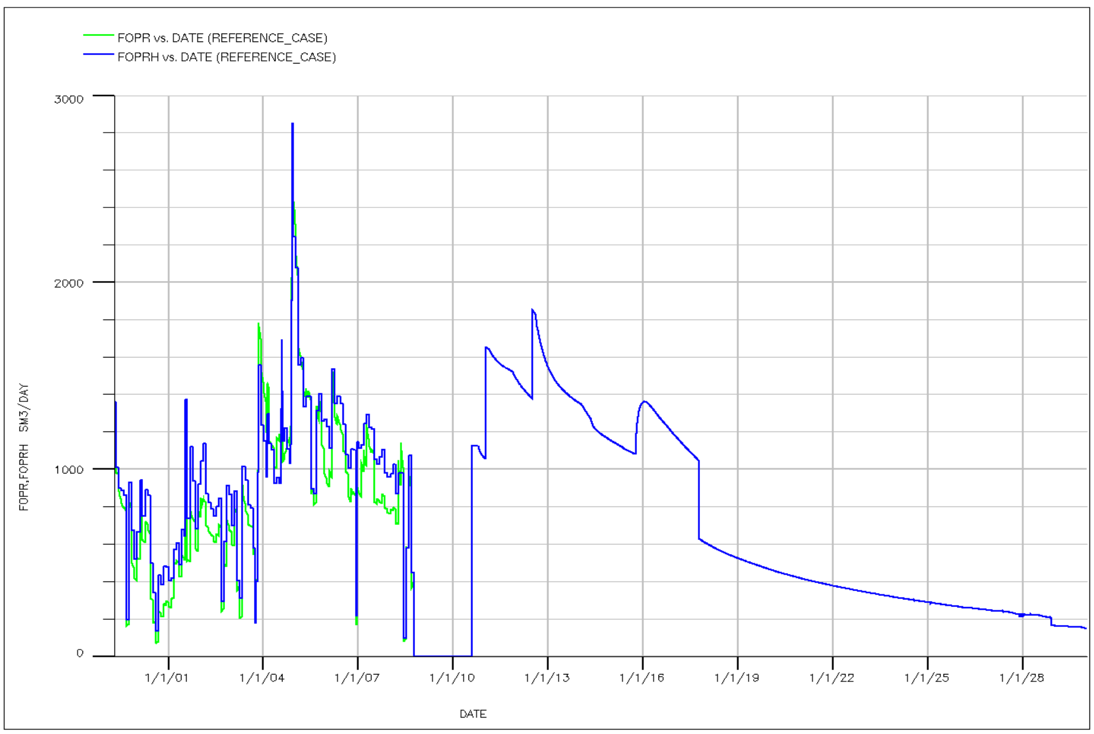


Figure 3-1 Field Oil Production rate history vs. simulation model

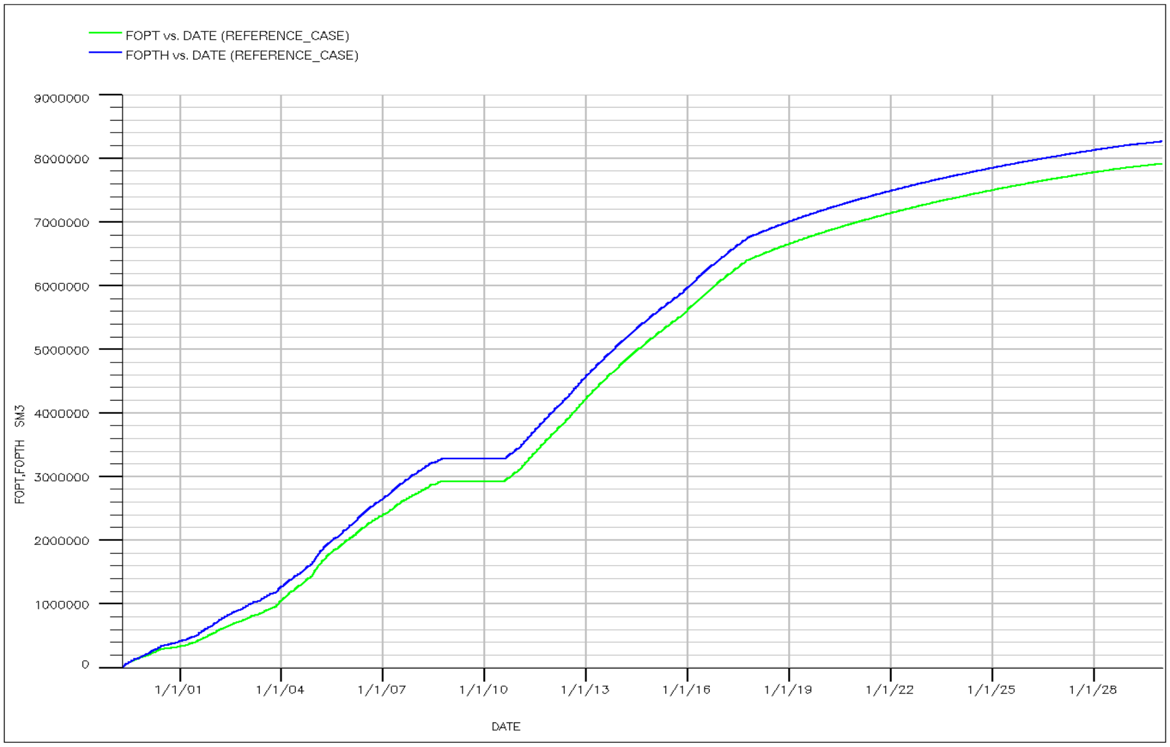


Figure 3-2 Field Cumulative oil production vs. simulation model

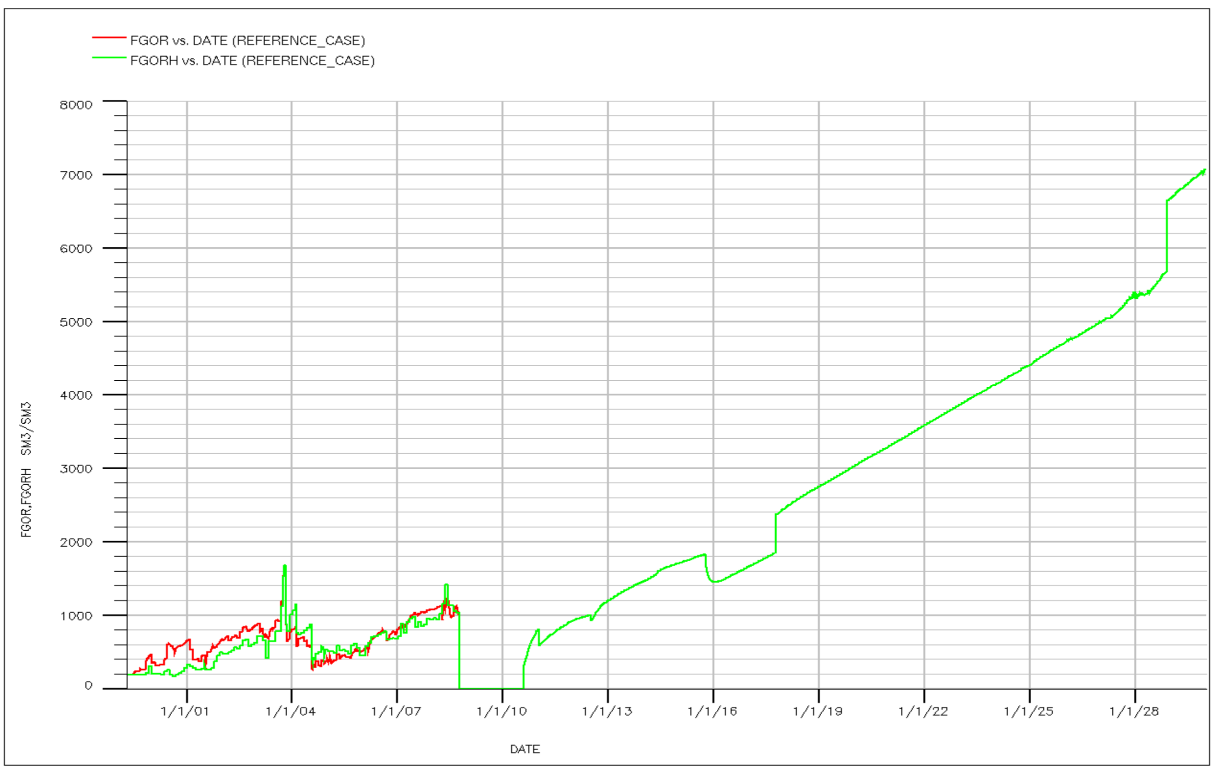


Figure 3-3 Field Gas Oil Ratio history vs. simulation model

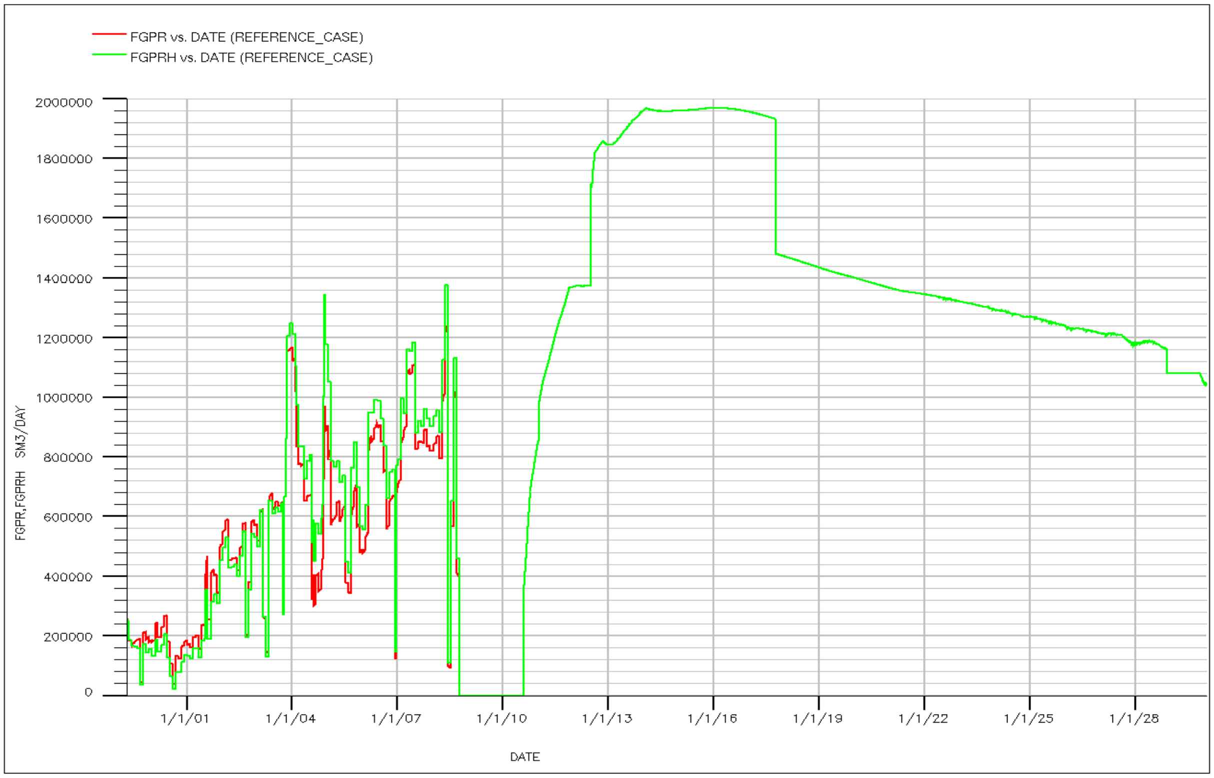


Figure 3-4 Field gas production rate history vs. simulation model

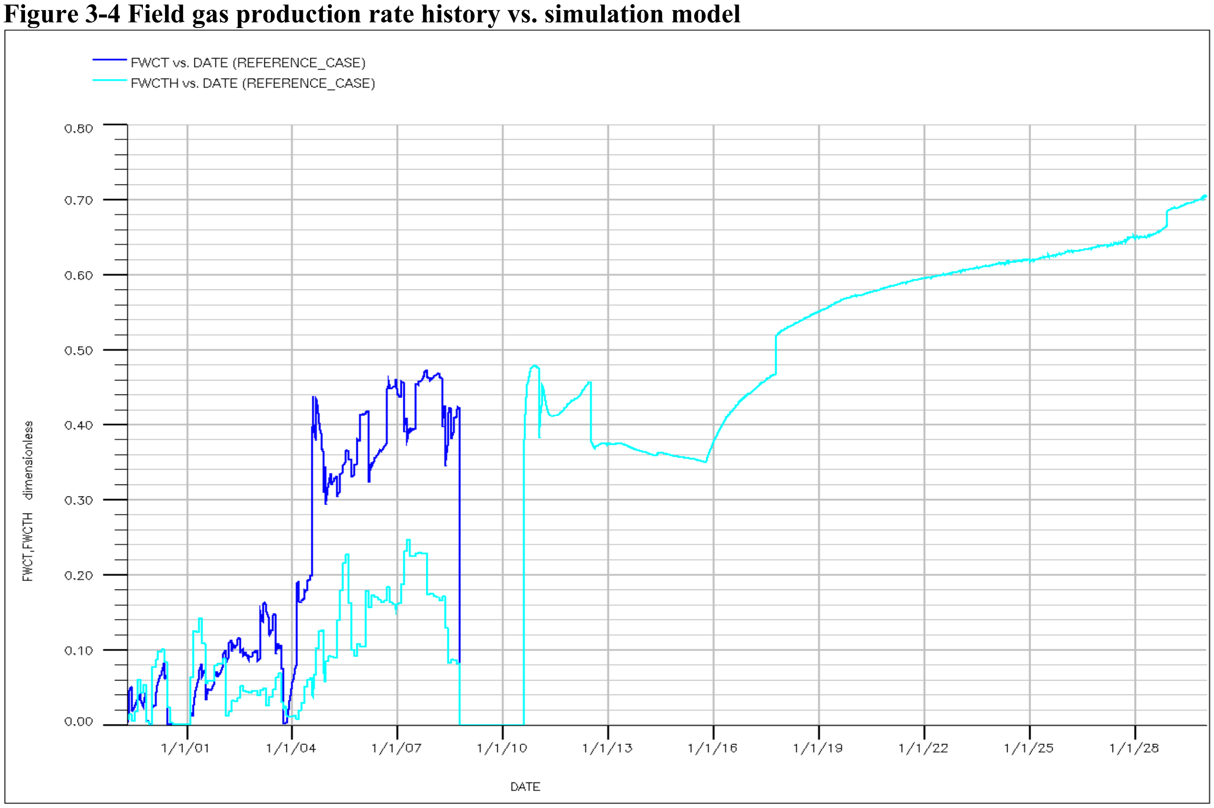


Figure 3-5 Field Water-cut history vs. simulation model

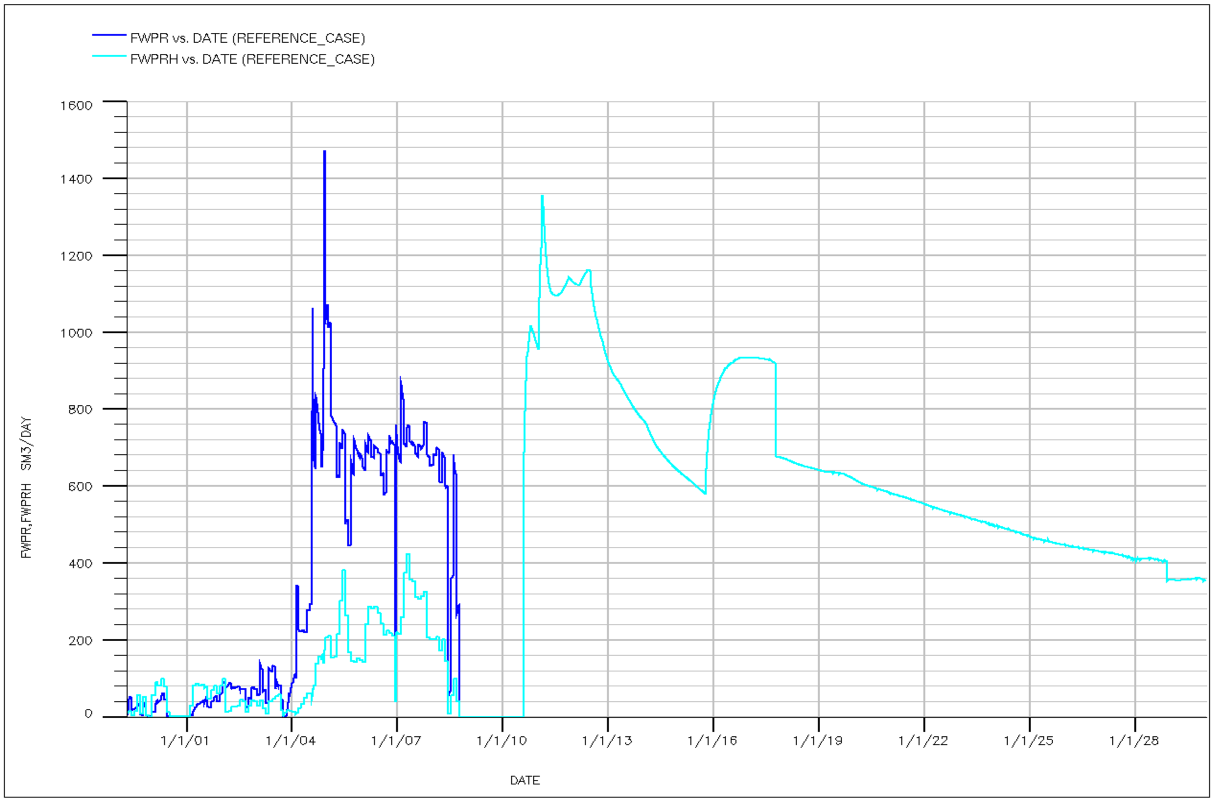


Figure 3-6 Field Water Production rate history vs. simulation model

3.1.1 Discussion of the results from History matching

The main conclusion that we can draw from the simulation match is that in all main operational components of the field (FOPR, FGOR, FGPR) we get perfect match except field indications regarding water production. Simulation indicates a lot bigger number than history. The main reason for this could be found if we take a more individual approach to every well existing in the field.

F2_ML

After careful investigation, our group found the well that is disturbing a fine match of model to history. It is well F2_ML:

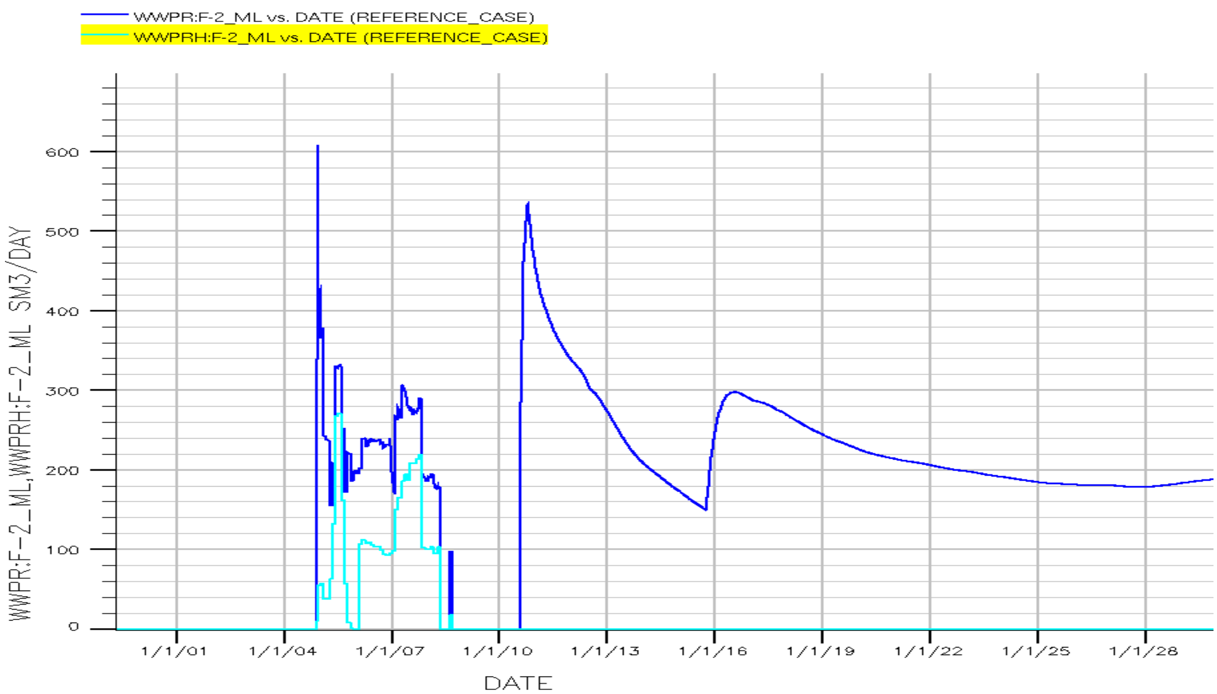


Figure 3-7Well water production rate for F-2_ML Eclipse vs. History

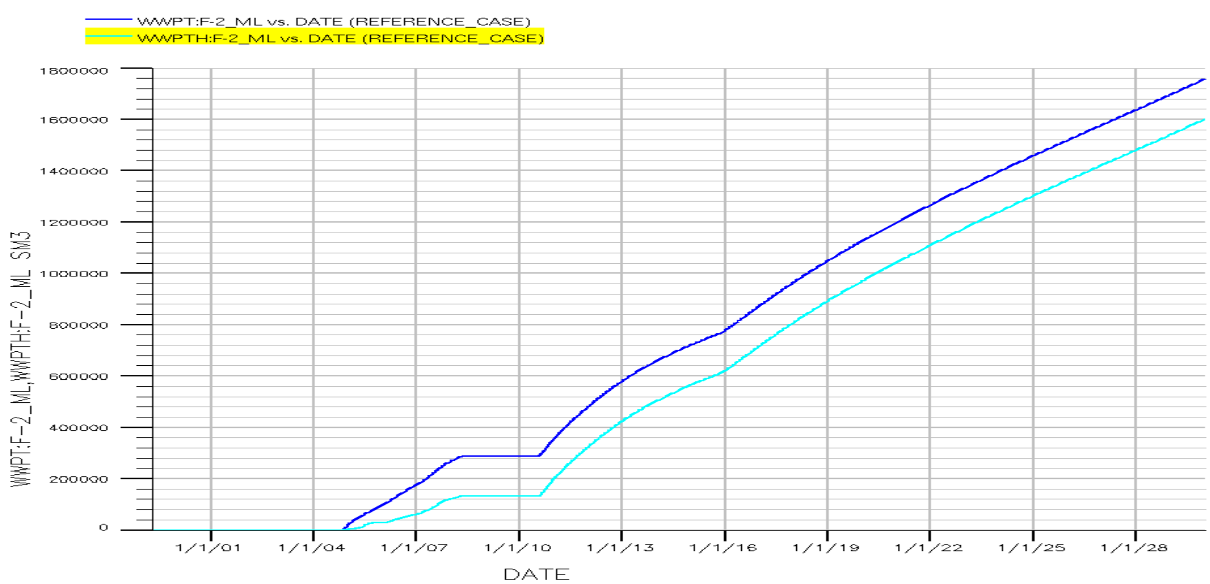


Figure 3-8 Cumulative water production volume for F-2_ML Eclipse vs. History

As we can see the Eclipse model produces more water than actual history. We get 156311 Sm^3 more water than history data from Field Total Water produced. The model can be tuned to actual history by introducing permeability multipliers for high water producing zones in Grid files.

3.2 Analysis new IOR plan with existing reference case of production

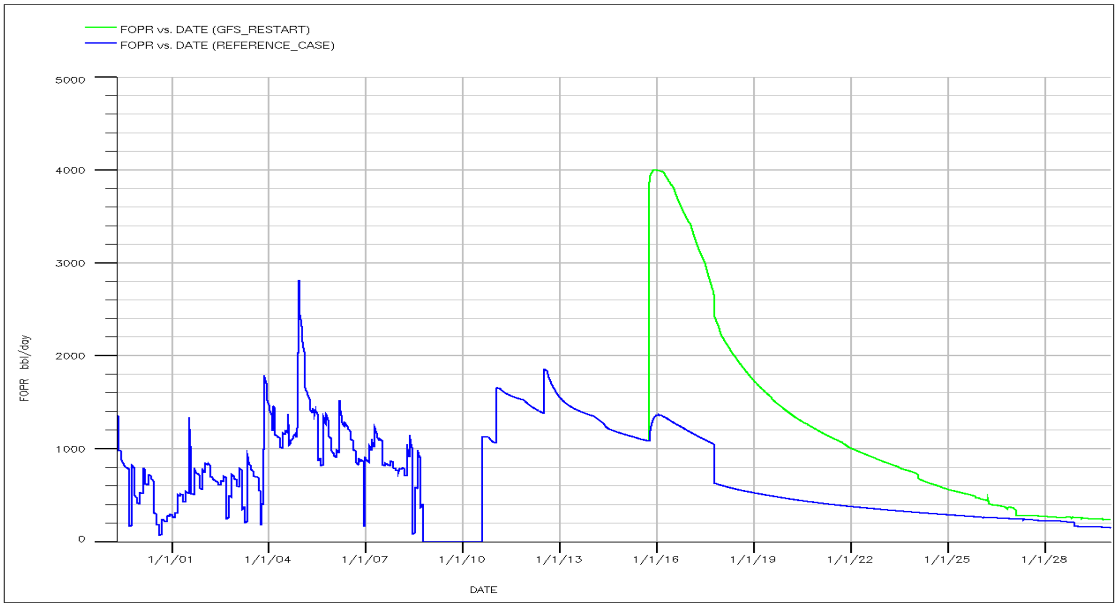


Figure 3-9 Comparison of Reference case and IOR plan of Statoil- Field Oil production rate

Statoil decided to drill 6 new wells: 2 gas injectors (GI-2, GI-4) and 4 producers (W1, W2W3, W4W5, W6W7). The given figures show the comparison between existing reference case with new IOR plan of Statoil:

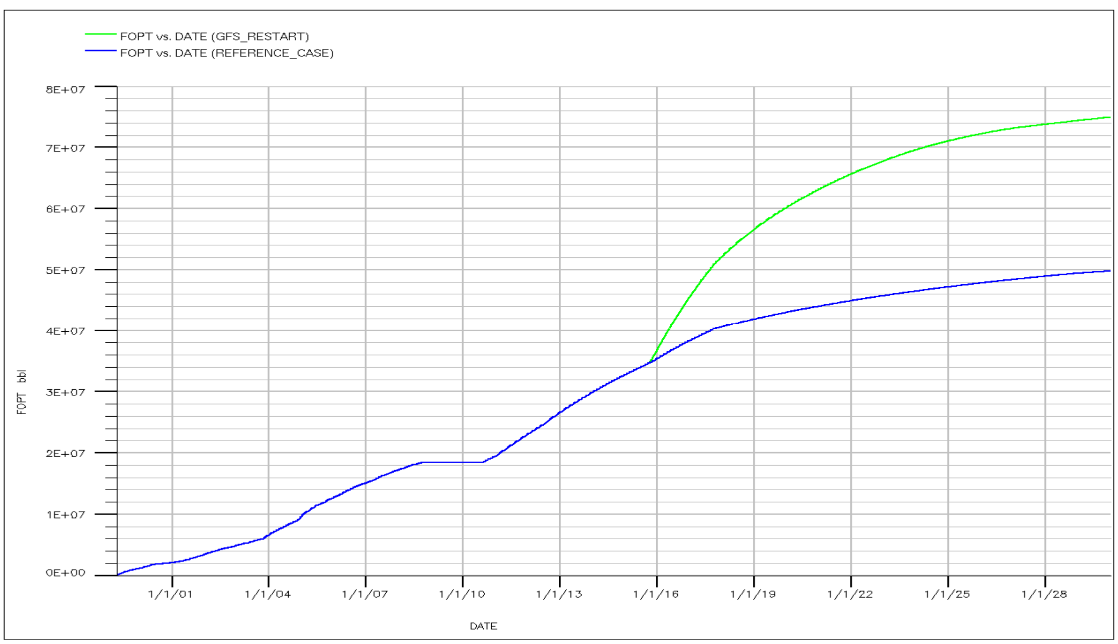


Figure 3-10 Cumulative Oil production comparison

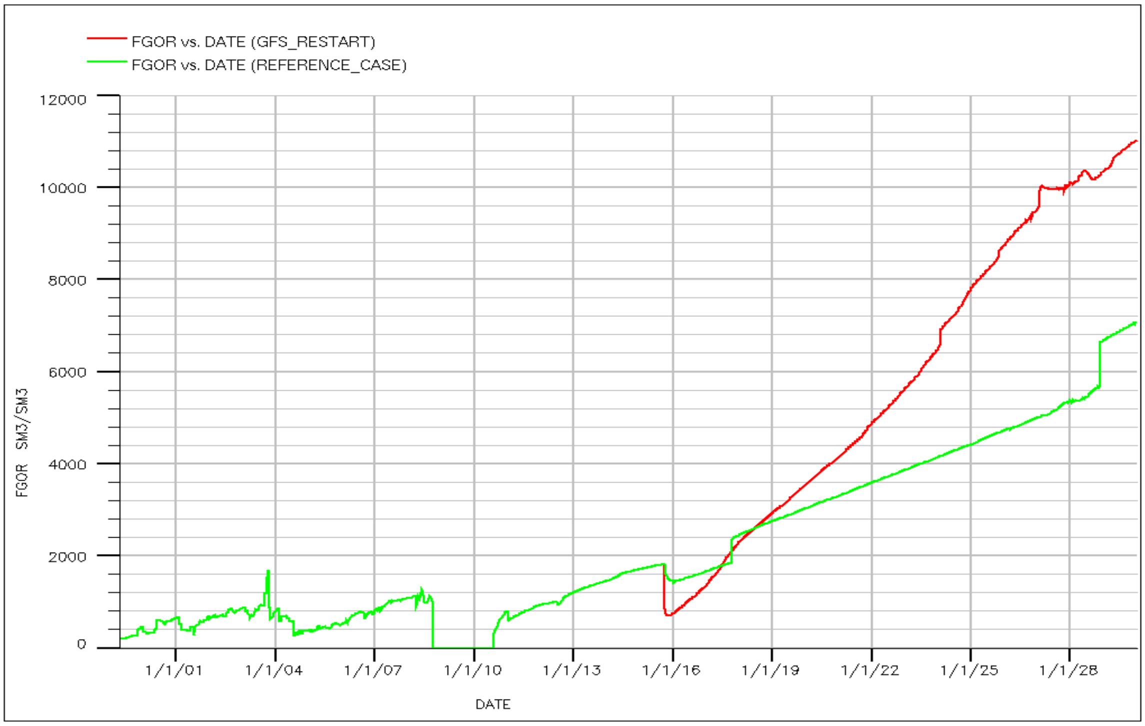


Figure 3-11 Field GOR comparison

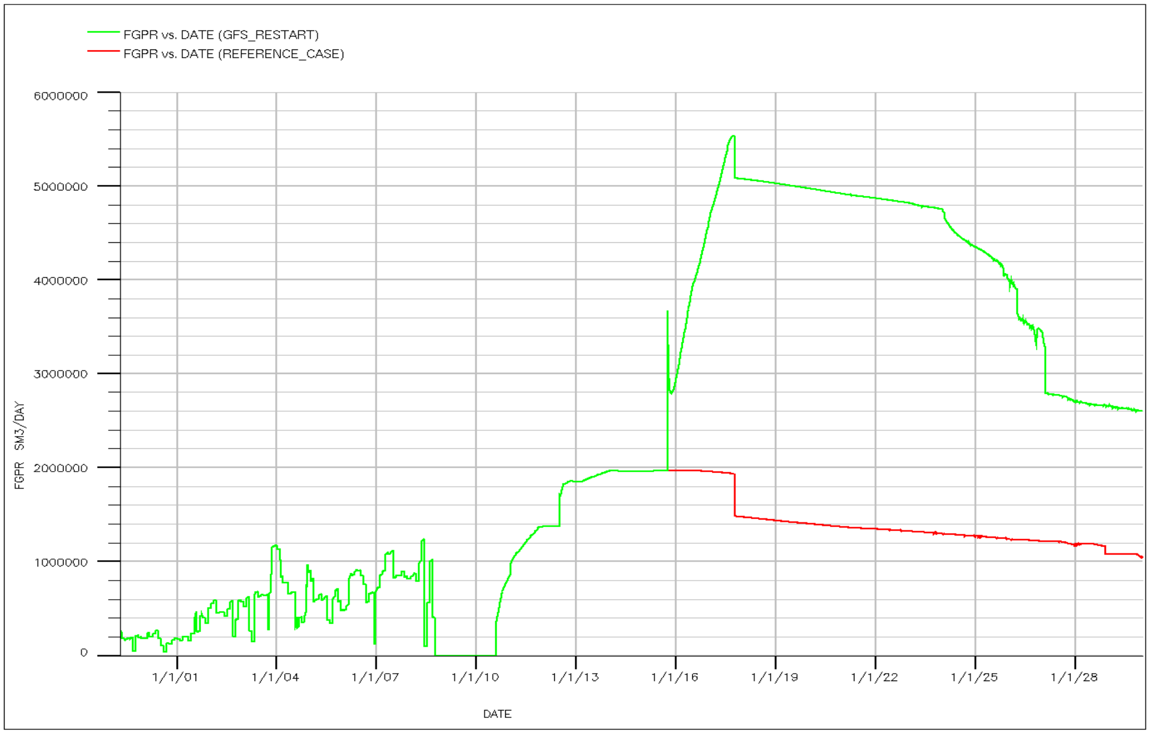


Figure 3-12 Field Gas production rate

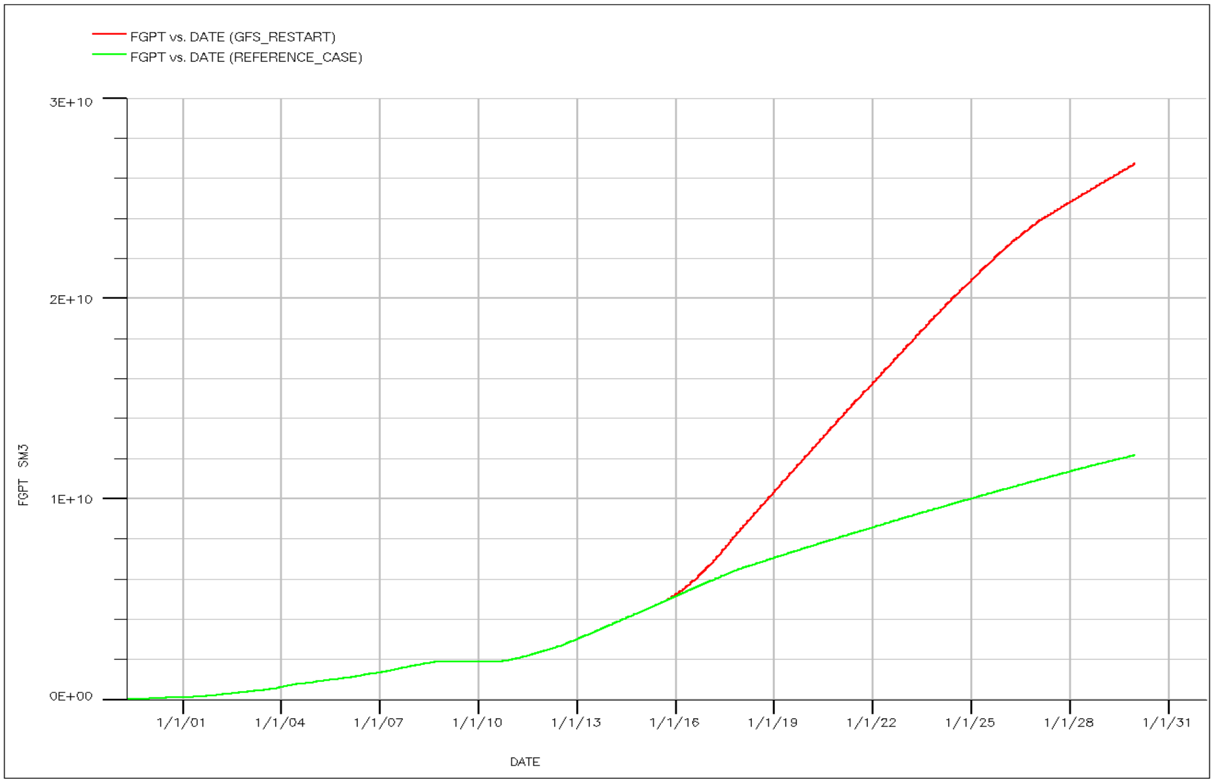


Figure 3-13 Field gas production total

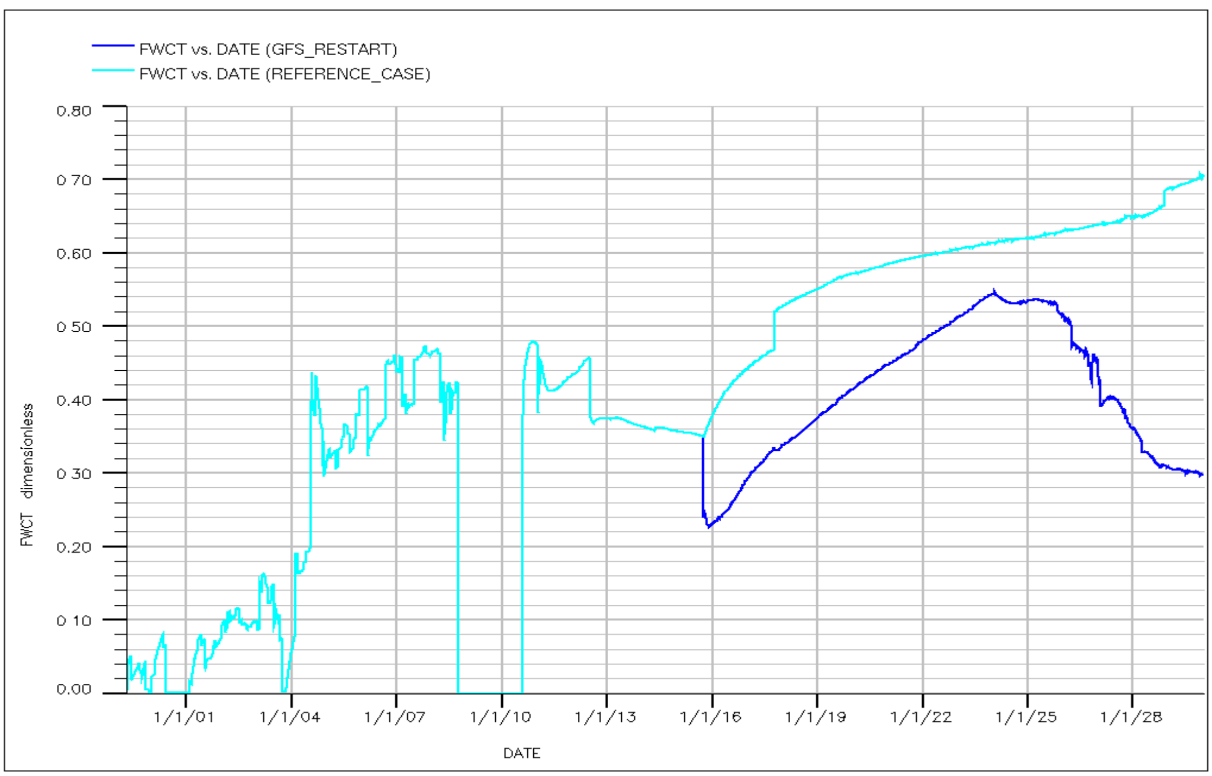


Figure 3-14 Field water cut

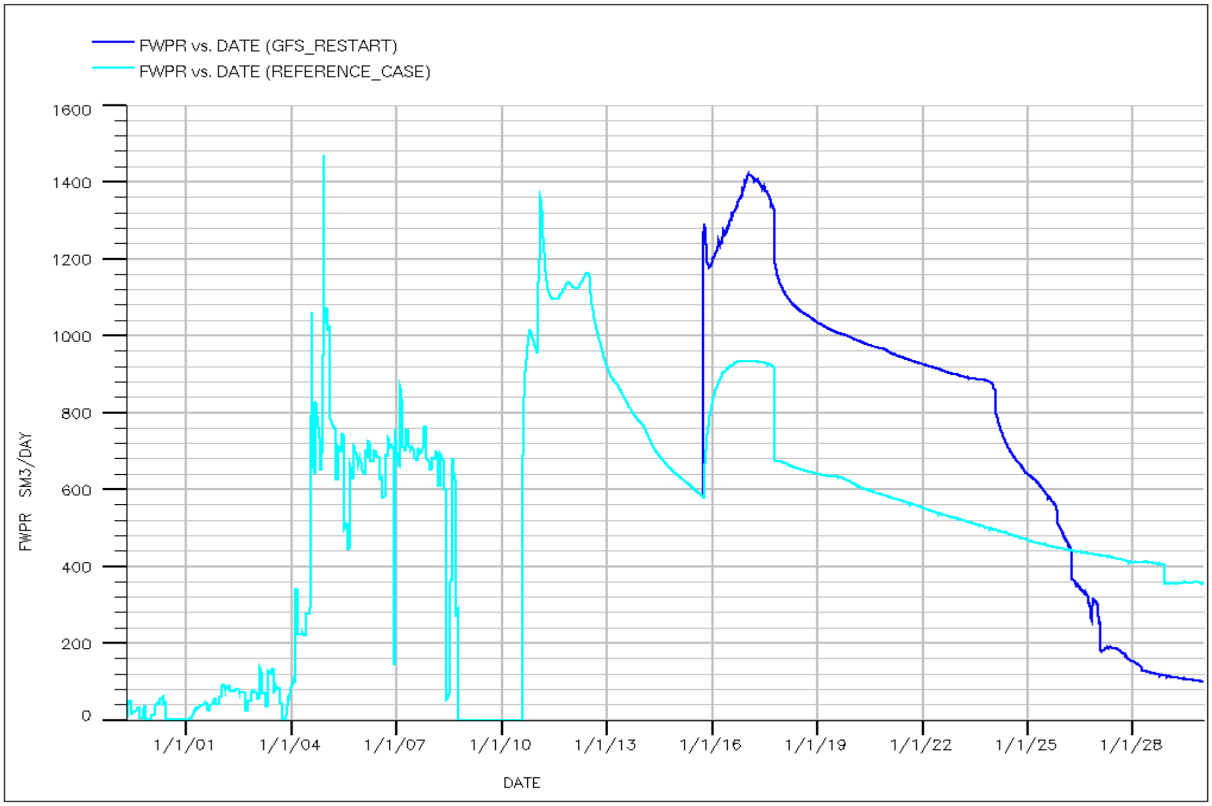


Figure 3-15 Field water production rate

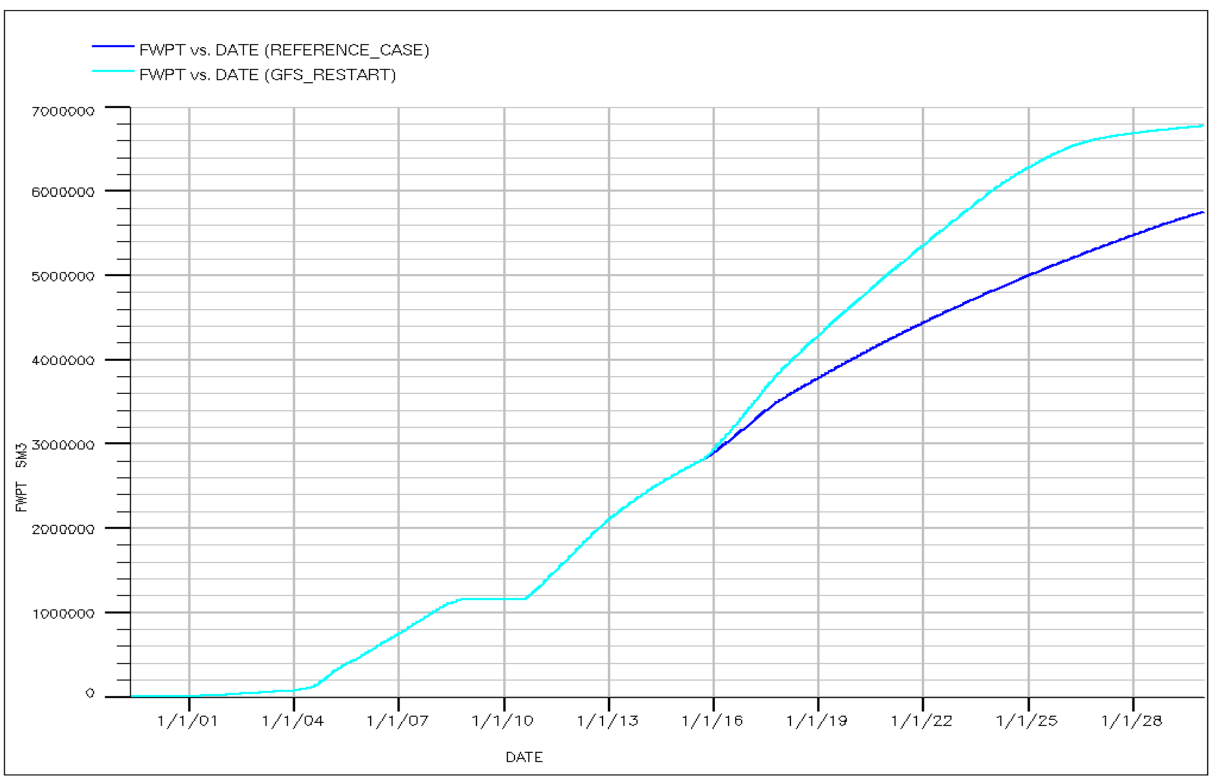


Figure 3-16 Field water cumulative production volume

3.2.1 Discussion of comparison between reference case and new IOR plan

As it can be seen from figure 3.1 new wells are giving increase in Field Oil production rate, but this increase does not last for a very long time. GOR analysis of the field (figure 3.3) shows in the first 2 years of injection that the GOR decreases, while after that it suddenly surpasses the GOR profile of the field with reference case without any new wells. It can be seen from 3.4 and 3.5 that gas production of new IOR plan is much higher than that of the reference case. Looking at figures of water cut, water production rate and cumulative water production, we can conclude that new plan gives higher production of water than reference case plan. The higher production water and sudden increase of gas production could be one of the reasons for not a consistent field oil production rate. Since reservoir management plan of Gullfaks Sør does not give enough information about pressure communication between the segments, it becomes hard to say which wells are contributing to this production profile of the field. Therefore individual well performance analysis should be made before any conclusion is drawn.

3.3 Comparison of individual new production wells

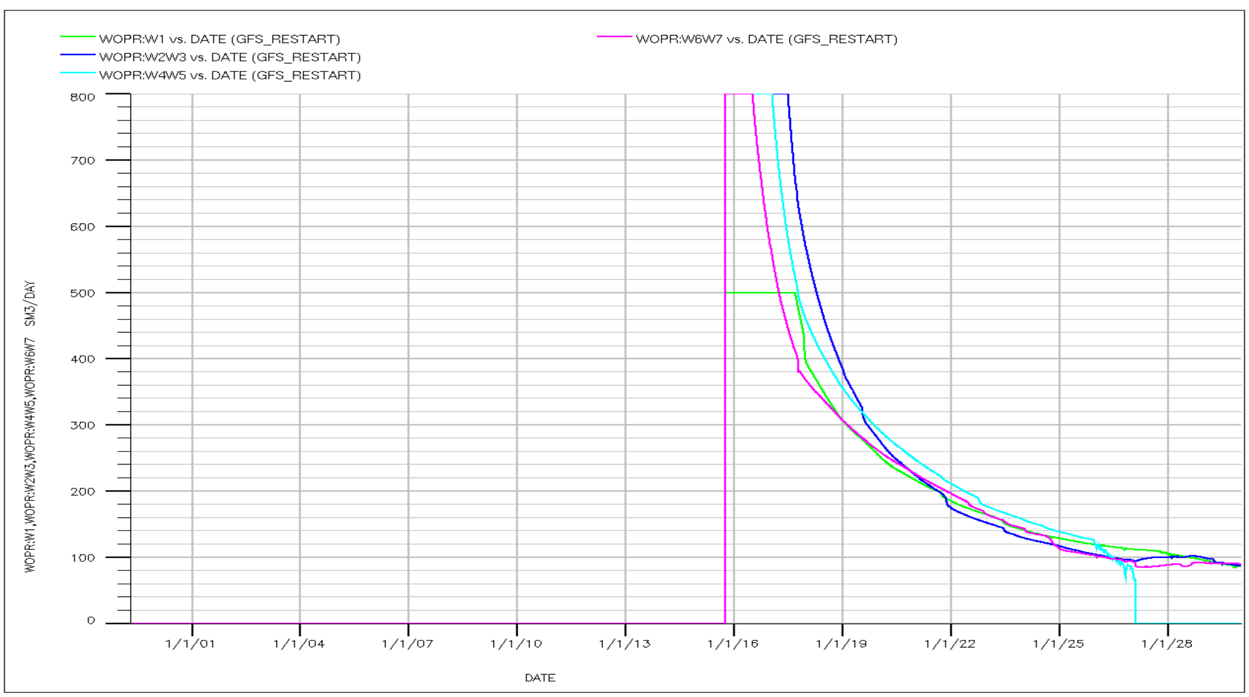


Figure 3-17 Field Oil production rate comparisons of new wells

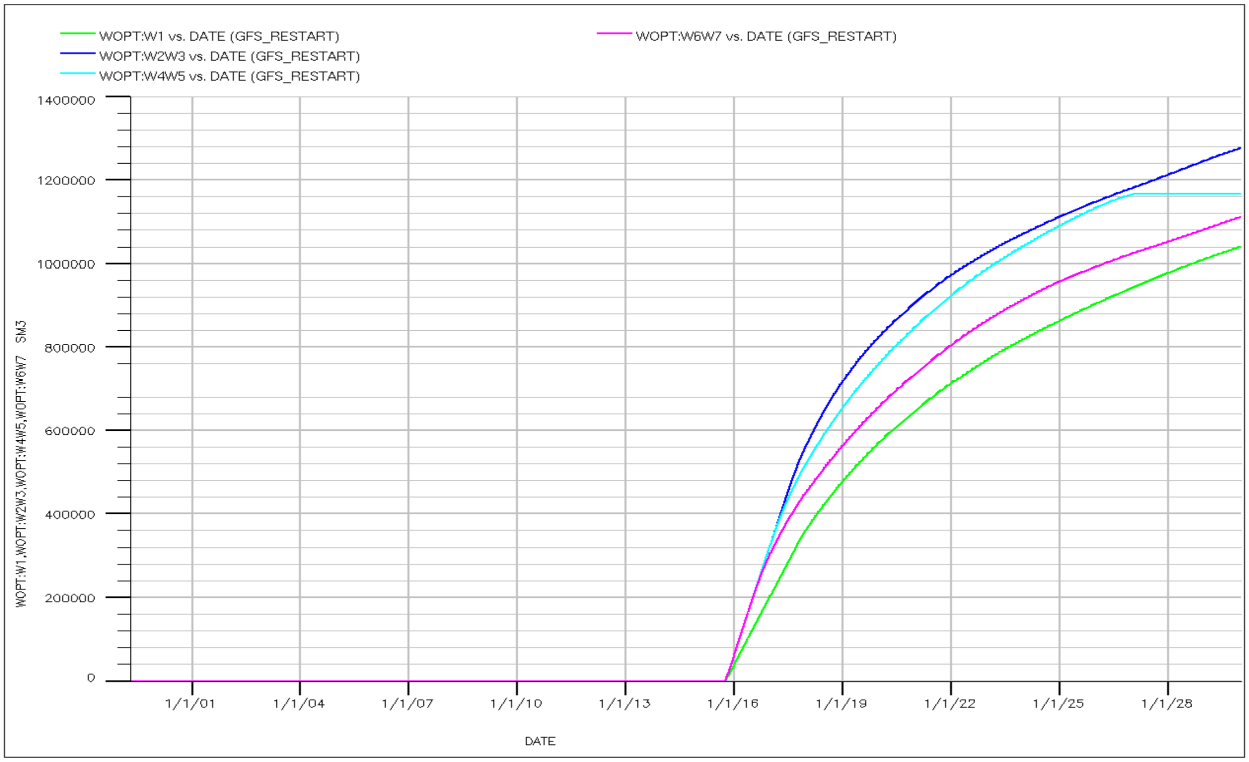


Figure 3-18 Field Cumulative oil production of new wells

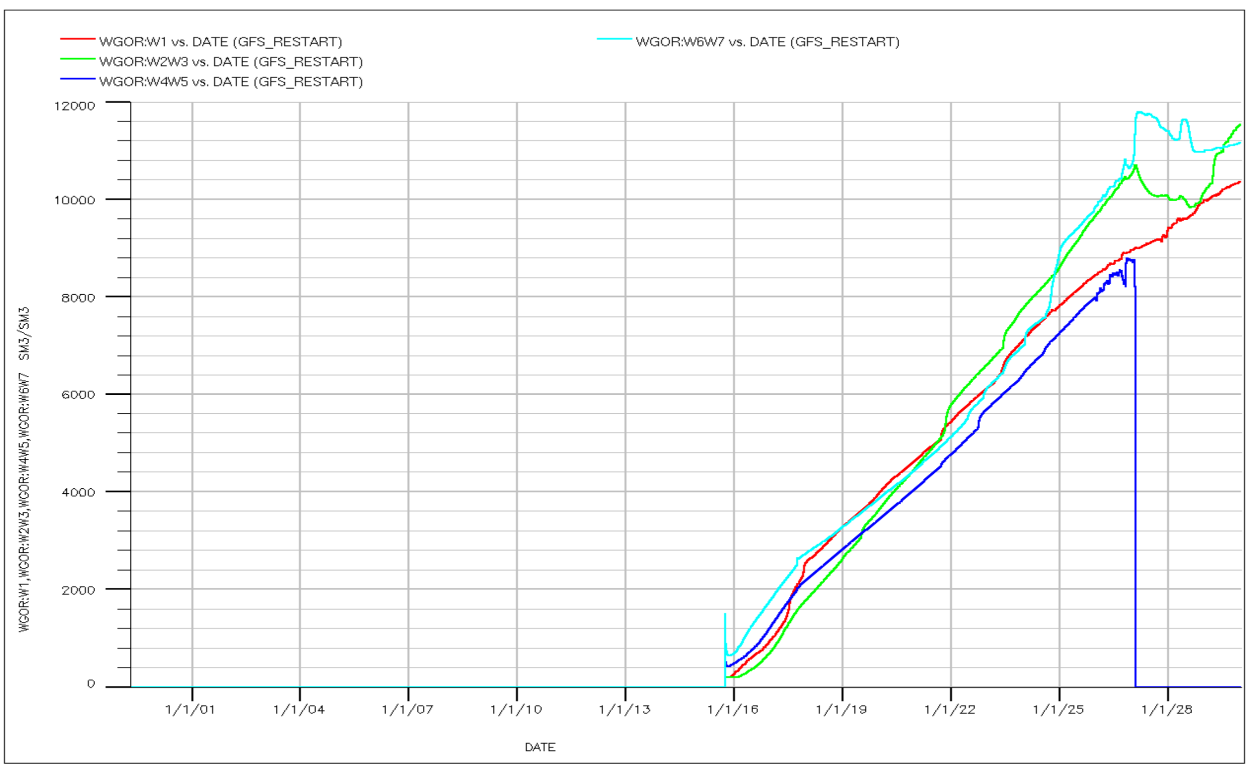


Figure 3-19 Field GOR comparison of new wells

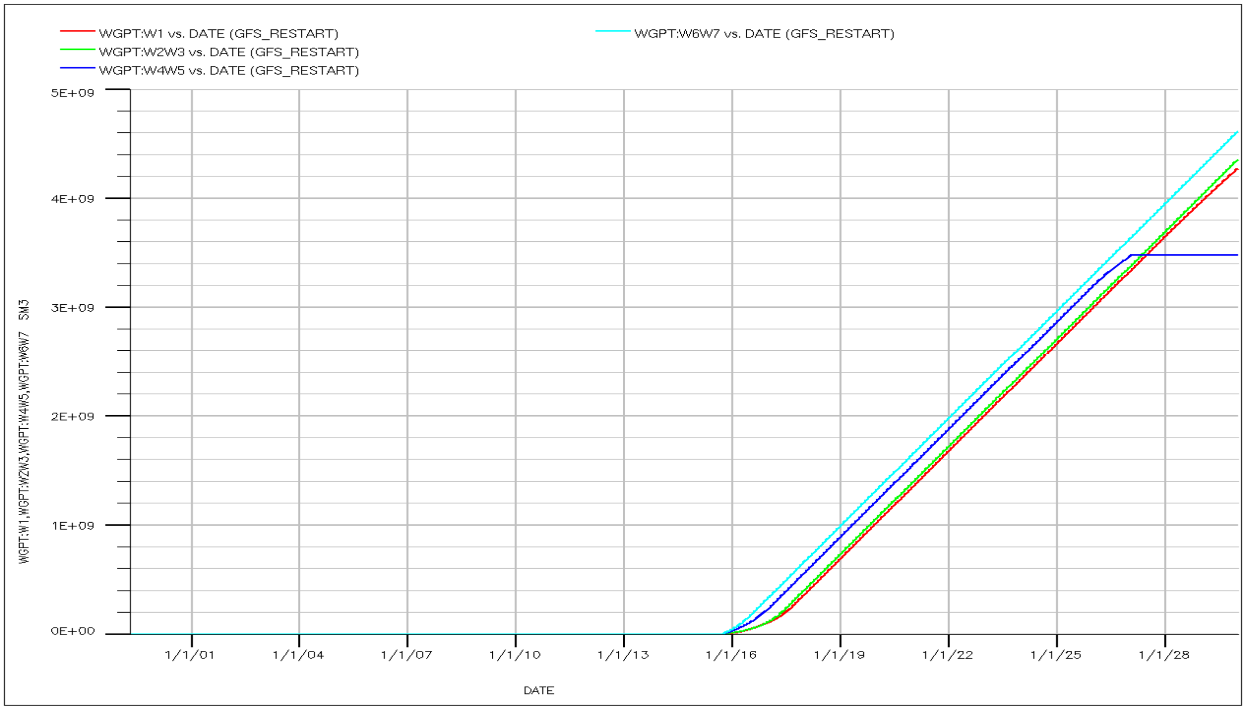


Figure 3-20 Field cumulative gas production comparison of wells

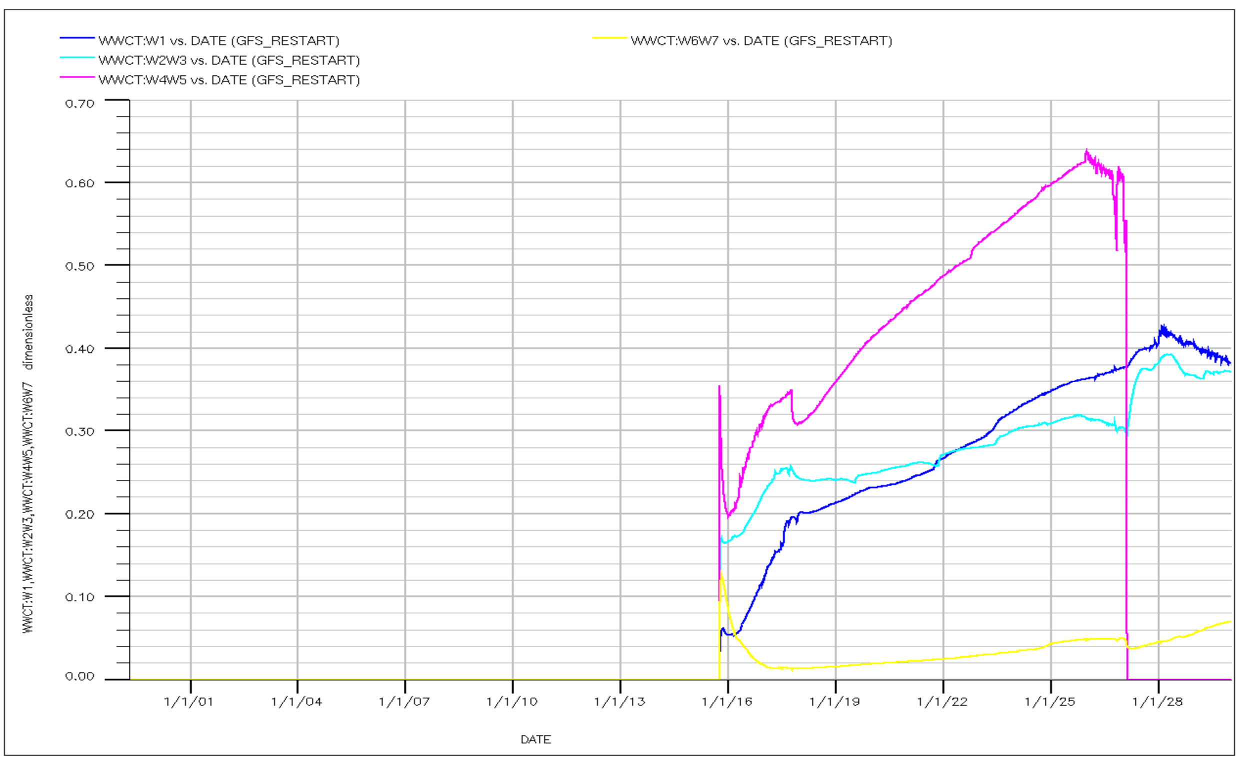


Figure 3-21 Field water cut comparison of new wells

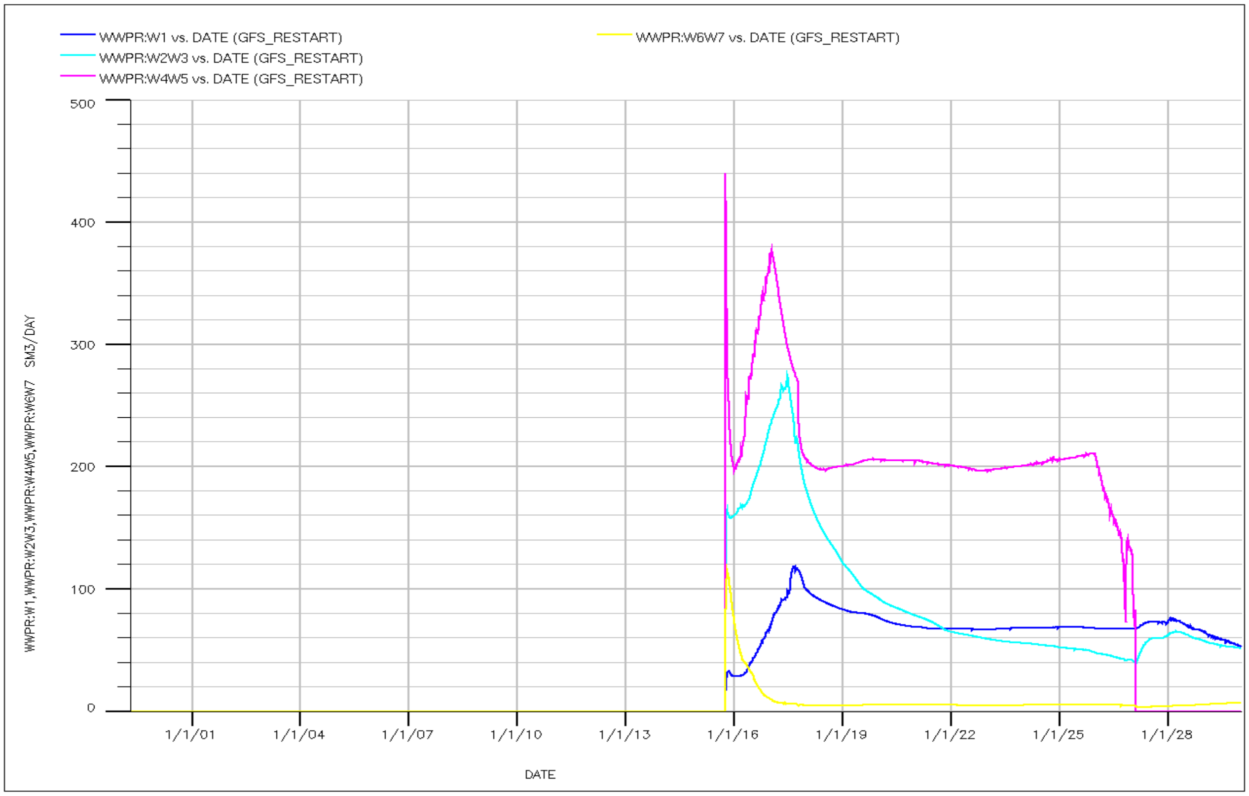


Figure 3-22 Field water production comparison from new wells

3.3.1 Discussion of results:

The information shows that well W1 gives less production than other wells. The results also reveal that well W4W5 stops production before the other well. And this well gives the most water production, but it gives the lowest GOR. The GOR gaps among individual wells are very low; therefore it is hard to say which well contributes the most to the sudden increase in gas production. Concluding from the figures given, for more detailed analysis we need more information about the level of communication and pressure connectivity between the segments. After enough information we can say if there is a case of unstable displacement or possible coning effects.

4 Economic Evaluation

4.1 Objectives

Using Net Present Value (NPV) technique in order to:

- Economical analyzing between two oil and gas production alternatives: Fixed platform and subsea development in Gullfaks Sør Statfjord

- Economical analyzing between Reference and extended models for improved oil recovery in Gullfaks Sør Statfjord.

4.2 Assumptions

Statoil's estimation and suggested data for economical evaluation have been used in this report which is as following:

- Oil Price: 400 NOK/bbl increasing 3% p.a.
- Gas Price: 200 NOK/bbl oe increasing 3% p.a.
- IRR: 6%
- Sensitivities:
  - Oil and Gas prices increasing 5% p.a. / decreasing 2% p.a.
  - OPEX +/- 30%
  - CAPEX +/- 40%
- Fixed platform
  - CAPEX
    - ➢ Wellhead platform with 15 slots: 4000 MNOK
    - ➢ Statoil drilling rig 150 MNOK /Well

      (Drilling 4 wells per year is possible)

      Extra branch drilling 50 MNOK/Branch
    - ➢ Plugging and abandonment 300 MNOK
  - OPEX
    - ➢ Operations jack-up(Omega) 80 NOK/bbl oe
    - ➢ Operations (Gullfaks) 10 NOK/bbl oe
    - ➢ Transportation (Gullfaks) 1 NOK/bbl oe
- Subsea development

- CAPEX
  - ➢ Two four slot template with all pipelines: 2500 MNOK (+1000MNOK/Template)
  - ➢ Statoil drilling rig 150 MNOK/Well

    (Drilling 4 wells per year is possible)

    Extra branch drilling 50 MNOK/Branch
  - ➢ Plugging and abandonment 200 MNOK
- OPEX
  - ➢ Operations Sub-sea(Omega) 100 NOK/bbl oe
  - ➢ Operations (Gullfaks) 10 NOK/bbl oe
  - ➢ Transportation (Gullfaks) 1 NOK/bbl oe

- Due to uncertainty, three possible cases are assumed for each alternative :
  - ➢ Base case: Prices and costs will be remained in most likely level
  - ➢ Worst case: oil & gas Prices -2% , OPEX +30% , CAPEX +40%
  - ➢ Best case: oil & gas Prices +5% , OPEX -30% , CAPEX -40%
- In Extended model, amount of gas which should be reused for gas injection has been subtracted from each year gas production.
- Economical analysis method: Using NPV for comparing two models (e.g. reference and extended models) to each others. NPV is calculated for difference of produced oil & gas in the new model and previous one. So, if the NPV will be positive, it means that the new model is more economic and beneficial than previous one.

4.3 Economical Analysis of two given alternatives for extended model compared to reference model

4.3.1 NPV calculation

By using any of the two given alternatives (fixed platform or subsea development), both FOPT and FGPT could be increased by extended model compared to reference model:

– FOPT Increasing = +50.56%

– FGPT Increasing = +119.87% - 77.12% (Reused for gas injection) = +42.74%

But the question is: By considering the needed CAPEX and OPEX costs for extended model, will extended model be economic or not? For answering this question, the total NPV should be calculated for each alternative.

As the details of calculation are shown and tabulated in attachment1, the following final results for total NPV have been obtained:

Alternative1 – Fixed platform		Alternative2 – Subsea development	
Total NPV for Base Case	-412.86 Million NOK	Total NPV for Base Case	-480.77 Million NOK
Total NPV for Worst Case	-4391.18 Million NOK	Total NPV for Worst Case	-4235.56 Million NOK
Total NPV for Best Case	3762.71 Million NOK	Total NPV for Best Case	3583.4 Million NOK

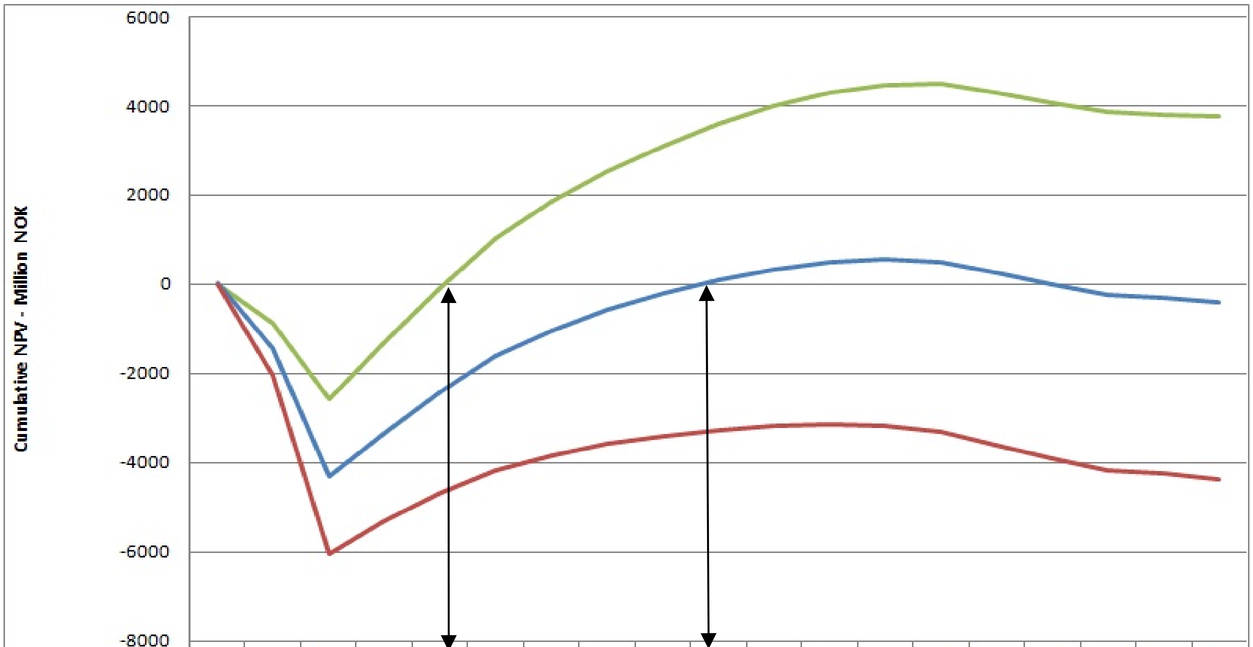
These results imply that in two possible cases (Base case and Best case), alternative 1 (fixed platform) will be more beneficial than alternative 2 for investment. In both the alternatives the total NPVs becomes positive only for the best cases. So, even though the extended model will increase both FOPF and FGPT, it is not recommended from an economical point of view. By considering the following figures, the possibility for more detailed analysis will be provided. The earned NPV for each year also the cumulative NPV between 2012 and January 1st 2030, are depicted as following figures;

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
BEST NPV	0	-872	-1721	1261	1264	1091	832	677	576	484	413	295	182	28	-187	-242	-206	-51
BASE NPV	0	-1454	-2869	975	941	787	574	450	371	301	247	154	66	-56	-231	-273	-239	-58
WORSE NPV	0	-2035	-4016	737	638	508	337	243	185	134	97	26	-41	-137	-278	-309	-275	-67

Figure 4-1 Alternative 1- Fixed platform

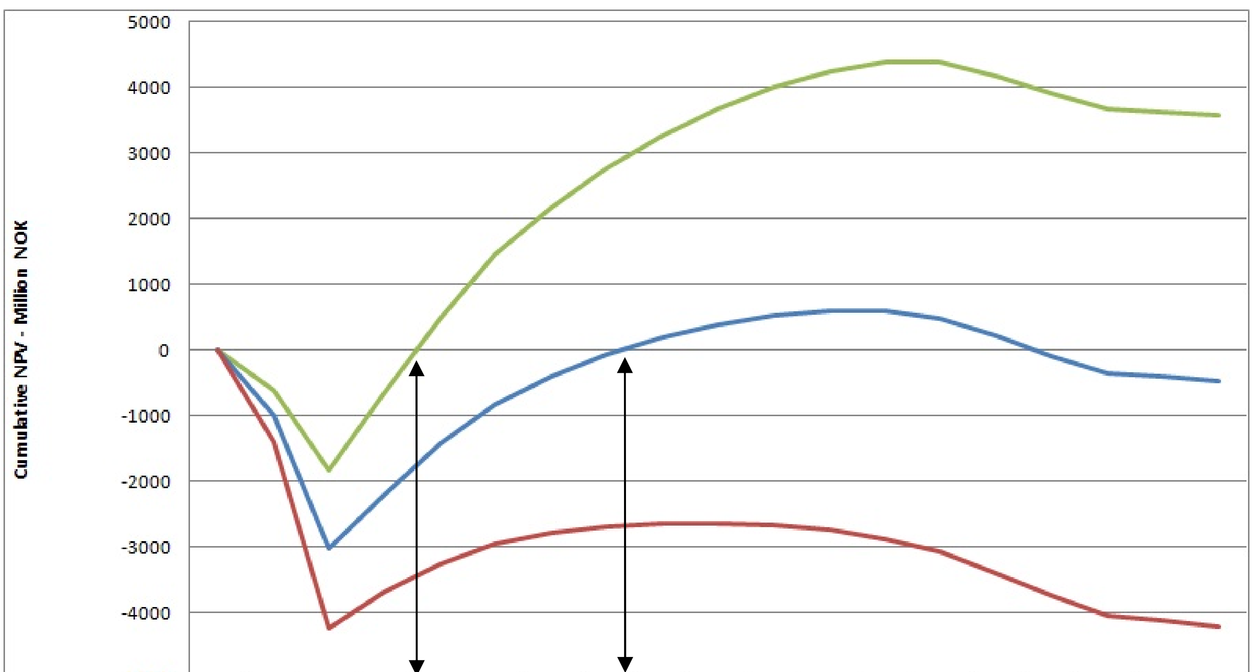
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
BEST NPV	0	-605	-1217	1157	1142	975	731	587	494	410	345	236	133	-10	-212	-262	-226	-56
BASE NPV	0	-1009	-2029	825	767	621	430	322	255	195	151	71	-5	-111	-266	-301	-266	-65
WORSE NPV	0	-1412	-2841	543	444	314	166	87	43	4	-22	-78	-131	-207	-323	-345	-311	-75

Figure 4-2 Alternative 2-Subsea



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BEST NPV	0	-872	-259	-133	-68	1023	1855	2532	3108	3591	4004	4299	4481	4509	4322	4079	3873	3822	3763
BASE NPV	0	-145	-432	-334	-240	-162	-104	-596	-224	76	324	478	544	488	257	-17	-255	-314	-413
WORSE NPV	0	-203	-605	-531	-467	-416	-383	-358	-340	-326	-317	-314	-318	-332	-360	-391	-418	-425	-439

Figure 4-3 Alternative 1- Fixed platform



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BEST NPV	0	-605	-182	-666	476	1451	2182	2770	3264	3674	4019	4256	4388	4378	4166	3904	3679	3623	3583
BASE NPV	0	-100	-303	-221	-144	-824	-394	-72	183	378	529	600	595	484	218	-83	-350	-415	-481
WORSE NPV	0	-141	-425	-371	-326	-295	-278	-269	-265	-265	-267	-275	-288	-309	-341	-375	-406	-414	-423

Figure 4-4: Alternative 2- Subsea

As it is shown in figure 4.1 and 4.2, in 2013 and 2014 there are negative numbers in all three cases and in two alternatives, which due to investment costs (CAPEX) is expected. The negative numbers from the last years are caused by the decrease in oil and gas recovery, and the OPEX costs could exceed the incomes of oil and gas revenues. Hence, this would be the time shutting down the field and stop producing oil and gas, even if the best cases of the extended model are selected for IOR in Gullfaks Sør Statfjord.

Moreover, as it is shown in figure 4.3 and 4.4; The "***Break-even-points***" for Base and Best cases could be resulted as following: (there is no Break-even-point for Worst cases in both alternatives, because they are always negative).

Alternative1 – Fixed Platform		
Best case: End of 2016	Base case: End of 2020	Worst case: -
Alternative2 - Subsea		
Best case: End of 2015	Base case: End of 2019	Worst case: -

4.3.2 Sensitivity Analysis:

Due to uncertainty, there are five variables that might be varied as it was mentioned in the assumptions:

• **Oil price**	• **Gas price**	• **CAPEX cost**
• **OPEX cost (Oil OPEX and Gas OPEX)**		

These variables could effect on NPV's value, Sensitive analysis shows that how much the total NPV is sensitive by changing each these five variables

Alternatine 1 (Fixed platform)				Alternatine 2 (Subsea development)			
Oil Price	**Low**	**Base**	**High**	**Oil Price**	**Low**	**Base**	**High**
% Change	-2.00%	0%	5.00%	**% Change**	-2.00%	0%	5.00%
NPV (MNOK)	-560	-413	-45	**NPV (MNOK)**	-628	-481	-113
% Change	-35.62%	0%	89.05%	**% Change**	-30.6%	0%	76.47%
Gas Price	**Low**	**Base**	**High**	**Gas Price**	**Low**	**Base**	**High**
% Change	-2.00%	0%	5.00%	**% Change**	-2.00%	0%	5.00%
NPV (MNOK)	-472	-413	-265	**NPV (MNOK)**	-540	-481	-333
% Change	-14.34%	0%	35.85%	**% Change**	-12.31%	0%	30.78%
Oil OPEX	**Low**	**Base**	**High**	**Oil OPEX**	**Low**	**Base**	**High**
% Change	-30.00%	0%	30.00%	**% Change**	-30.00%	0%	30.00%
NPV (MNOK)	52	-413	-990	**NPV (MNOK)**	86	-481	-1048
% Change	112.61 %	0%	-139.77%	**% Change**	117.96 %	0%	-117.96%
CAPEX	**Low**	**Base**	**High**	**CAPEX**	**Low**	**Base**	**High**
% Change	-40%	0%	40.%	**% Change**	-40.00%	0%	40.00%
NPV (MNOK)	1356	-413	-2181	**NPV (MNOK)**	761	-481	-1722
% Change	428.4%	0%	-428.37%	**% Change**	258.24 %	0%	-258.24%
Gas OPEX	**Low**	**Base**	**High**	**Gas OPEX**	**Low**	**Base**	**High**
% Change	-30%	0%	30%	**% Change**	-30%	0%	30.00%
NPV (MNOK)	1014	-413	-1839	**NPV (MNOK)**	1259	-481	-2221
% Change	345.5%	0%	-345.5%	**% Change**	361.9%	0%	-361.9%

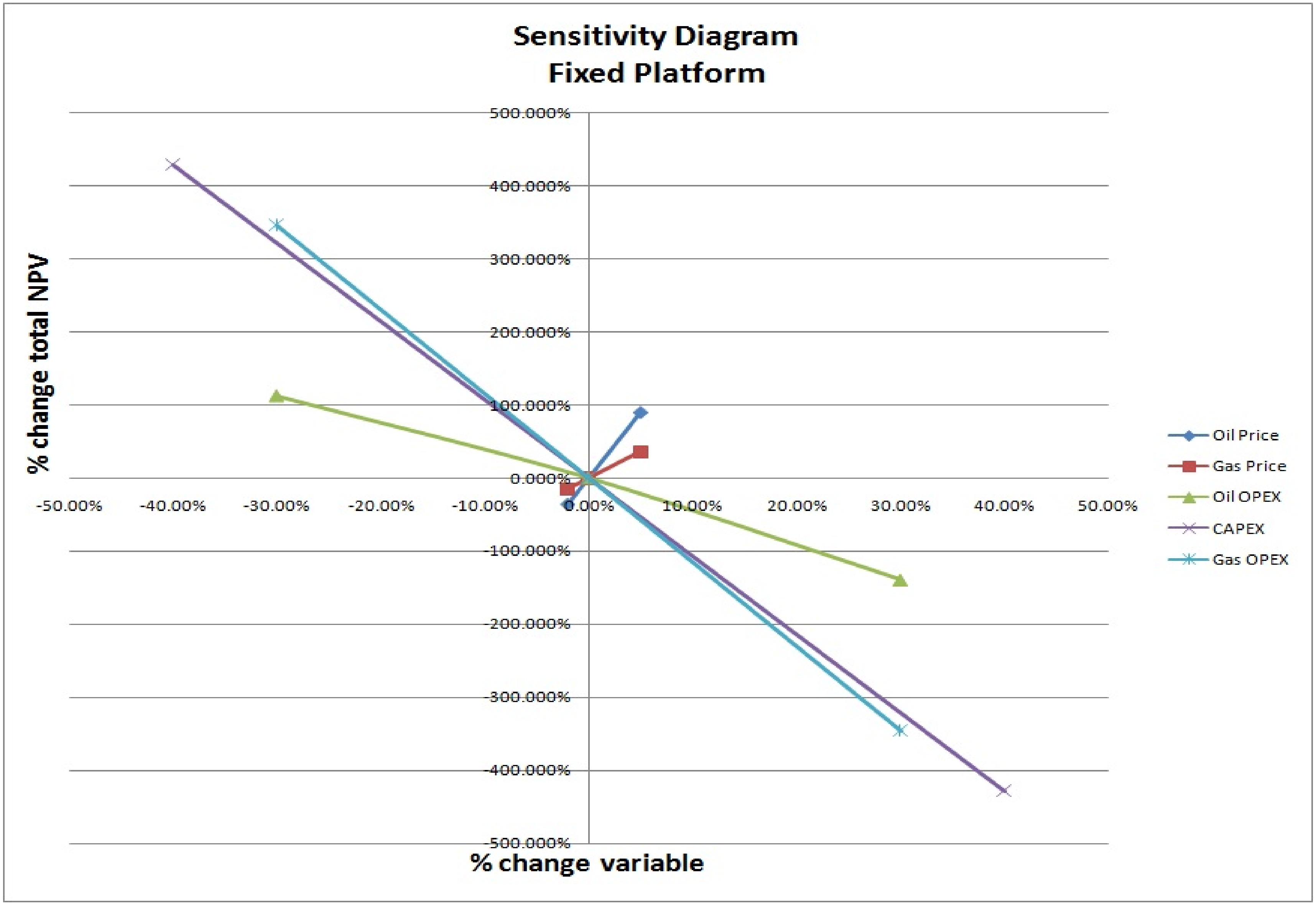


Figure 4-5 Sensitivity diagram Fixed platform

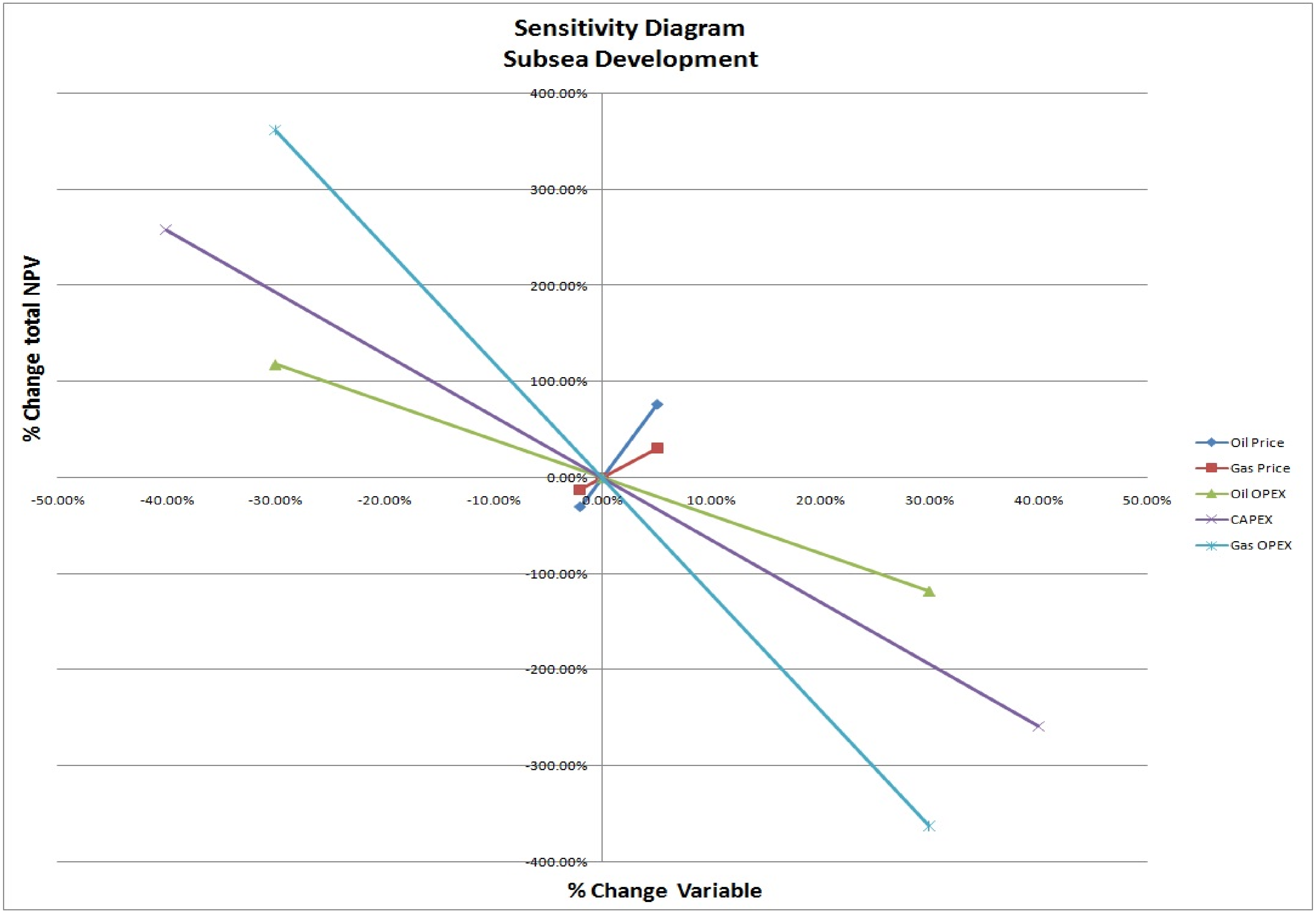


Figure 4-6 Sensitivity diagram Subsea development

As it is shown in figure 4.5, for alternative1 (fixed platform), the sensitivity of the total NPV is depending on (ranged in manner of influence) CAPEX, Gas OPEX, Oil OPEX, Oil price and Gas price. And for alternative 2 (Subsea development), as it is shown in figure 4.6, for alternative 1 (fixed platform), the sensitivity of the total NPV is depending on (ranged in manner of influence) CAPEX, Gas OPEX, Oil OPEX, Oil price and Gas price

In conclusion, by choosing fixed platform instead of subsea development, reaching to more NPV would be expected. So, fixed platform alternative would be more economical than subsea development alternative in extended model.

Also, as an economical point of view, extended model could be remained as an economical model just until:

In Fixed platform alternative: End of 2025, end of 2024 and end of 2023 for BEST, BASE and WORST cases respectively. (As it shown in figure 4.1)

In Subsea development alternative: End of 2024, End of 2023 and End of 2021 for BEST, BASE and WORST cases respectively. (As it's shown in figure 4.2)

So, maybe there are some better models than extended model for IOR (Improved oil recovery) in Gullfaks Sør Statfjord, which should be tried. This possibility by selecting two “Water injection” and “BrightWater injection” models in Part B will be experienced.

5 BrightWater

5.1 Introduction

Getting as much oil as possible out of reservoir has always been the industries' primary goal. When the reservoir pressure has dropped, this often involves using water as a means of flushing out oil. However such methods only works to certain extent, as water follows the path of least resistance, leaving tougher areas unswept [5]. Within any reservoir permeability variation, either vertical or aerial, stimulate the variation of water pathways. Once a continuous outlet exists there is less attraction for the injected water to follow the alternative route. Consequently, the water injected to push the remaining oil from reservoir [6].

After second recovery it has been a concerted effort to improve the recovery of oil by mobility control using polymers and polymer derived gels. The polymer flooding process has some strength, but also a number of weaknesses. In particular the polymers are sensitive to salinity, temperature, shear and biological degradation to differing degrees. The better performing polymers tend to use more expensive monomers or production processes. There are also limitations related to the reservoir flooding process. High viscosity of the polymer flooding solution limits the injection rate at any given injection pressure. The maximum usable viscosity is typically limited to between three and ten times that of the injection water (RF maximum of 10). There are added risks of the injector fracturing and of polymer shear degradation. Unfortunately, the effectiveness of the process is reduced at low viscosity, and overall this severely restricts the range of viable applications [6].

The more cost effective method for improving sweep efficiency in oil reservoirs is achieved by injecting a low viscosity material, which subsequently triggered to form a highly viscous or blocking phase. Concentrating on the permeability reduction element of the water flood modification should result most of the injected materials to produce a lasting effect [6].

5.2 About BrightWater

BrightWater is dispersed in hydrocarbon, comprising a tightly bound, thermally activated particle sub micron in size [5]. Chemically BrightWater is highly cross linked, sulfonate containing polyacrylamide micro particle in which the conformation is constrained by both labile and stable internal crosslinks [6]. When subject to elevated temperature, the rate of decrosslinking of the labile crosslinker accelerates. This reduces the crosslink density of the particle and allows the particle to expand by absorbing the surrounding water. The particles are applied in constrained state - called kernel particles for convenience. After heating these are able to swell to adapt a much expanded configuration called popcorn as shown in fig. 4.1[6].

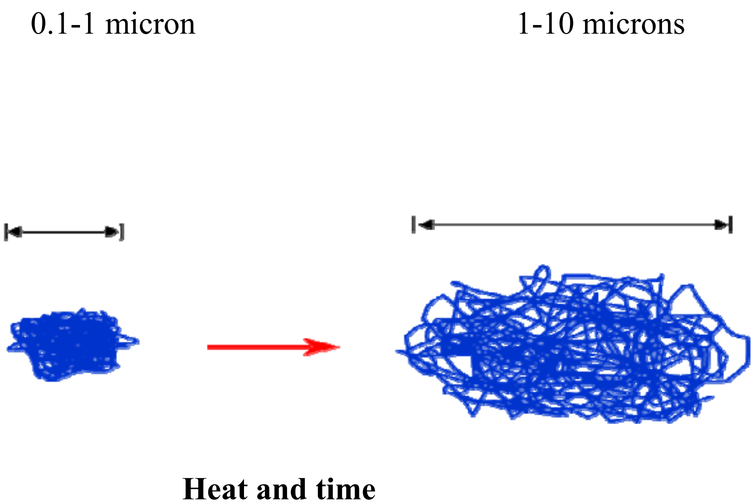


Figure 5-1: BrightWater expansion [10]

The particles would move freely through the matrix rock until a reservoir trigger causes the particles to increase in size to block thief zone pore throats [9]. The reduction in reversible crosslink density is also time dependent and can be affected by the pH of the fluid. Different labile crosslinkers have different rates of bond cleavage at different temperatures. The temperature required and the mechanism of bond dissociation depends on the chemical structure of the crosslinker. Proper selection of crosslinker can give particles with different activation temperature. The presence of stable crosslinker gives conformational integrity to particles, especially after popping [6].

5.2.1 History and applications

The development of BrightWater is a story of technological excellence, coupled with unusual personal dedication and perseverance. BrightWater, was a BP project, started in 1997. It was considered as a speculative, but high reward project, and was proposed as a Joint Venture project to the “MoBPTeCh” consortium which has now disbanded. After two years of sample development and evaluation in the labs it was rewarded in January 2000, when the chemical and technical potential of a product, which became known as BrightWater was proved in a laboratory environment. Initial trial was carried out in Chevron Minas field in Indonesia in 2001. The field where it has been applied is given below along with year of implementation [10]

- Minas, Indonesia (Chevron, 2001)
- Arbroath, North Sea, UK (BP, 2002)
- Milne Point and Prudhoe Bay, Alaska, USA (BP) (several, 2004-5)
- Strathspey field, North Sea, UK (Chevron, 2006)
- Argentina (several, 2006)
- Pakistan (BP, 2006-7)
- Alaska (several, 2007)
- Being considered: more treatments in Indonesia Australia, Alaska and Gulf of Mexico, USA [10]

5.2.2 How it works

When dispersed into injection water using an added surfactant the particles can propagate through matrix rock until the temperature rises, or enough time has passed at any given temperature. They then expand in diameter ("pop" rather like popcorn but a lot slower), form associations and block rock pores. This enables a flow resistant block to form in thief zones, diverting chase water to displace previously unswept oil in adjacent zones as exemplified by the drawing shown in Figure 5.2 where the middle zone is taken to be the most permeable. The ability of the chase water to divert between the blocked "patches" and create a pressure drop across unswept oil is crucial to this technology. For a given particle grade, the block point will be further away from the well if the temperature is cooler, or if the injection rate is faster, or if the water flows primarily through a thinner zone or narrow channel. If required, the block can be formed closer to the well by choosing a faster reacting grade or further away with a slower reacting one.

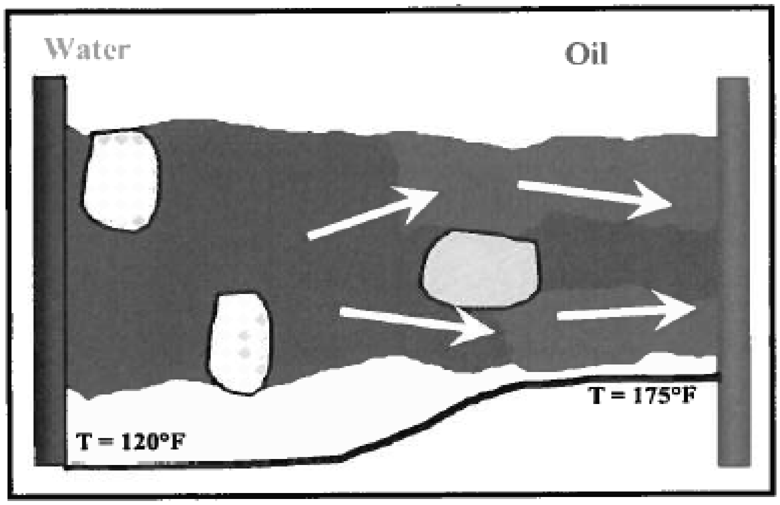


Figure 5-2 BrightWater Mechanism [11]

The thermally reactive particles used in the sweep improvement process are predominantly spherical and distributed in the size range 0.1 to 1 micro meter. They are supplied as 30 weight percent active concentrates in light mineral oil. This is slipstreamed into the injection water downstream of where a surfactant is added to disperse the particles and emulsify the carrier oil. Different type of surfactant can be used along with BrightWater and it is readily available:

1. The temperature is that of the injection water and should be relatively low, typically 50 to 120°F. The particles are submicron diameter and inert when injected. This allows them to enter the formation without causing loss of injectivity.
2. The propagation phase is when the particles, still small and inert, are pushed by the normal waterflood and move through the pore structure far into the reservoir at geometrically reducing velocity and increasing temperature gradient between the injection water and the reservoir temperature.
3. "Popping" when the particles reach temperatures between 120 and 170°F, internal crosslinks break and the particles absorb water and grow with time and temperature; they react with water, expand and become interactive. They can then block the pore system they are traveling through. Isothermal application is also possible with the correct grade selection [11].

The following points should be considered when evaluating a potential candidate for BrightWater, preferred target properties [14]:

1. Available movable reserves
2. Early water break through to high water-cut
3. Problem with high permeability contrast (thief zone at least 5 times the unswept zone)
4. Porosity of highest permeability zone >17%
5. Permeability of thief zone >100 md
6. Minimal reservoir fracturing
7. Temperature from 50 to 150 ºC
8. Expected injector-producer transit time >30 days
9. Injection water salinity under 70000 ppm

5.2.3 Benefits of BrightWater

Listed below are the benefits of BrightWater. [14]

1. Restricts flow of water into high permeability thief zones
2. Reduces unwanted costly water production
3. Improves sweep efficiency
4. Improves reservoir oil recovery by up to 10 percent
5. Can be deployed with conventional chemical injection equipment and existing water injection systems
6. Water miscible solution
7. Poses no risk to your reservoir or the environment
8. No shutdowns required

5.3 Arrangement for injecting BrightWater

A general arrangement for BrightWater injection is shown in figure 5.3:

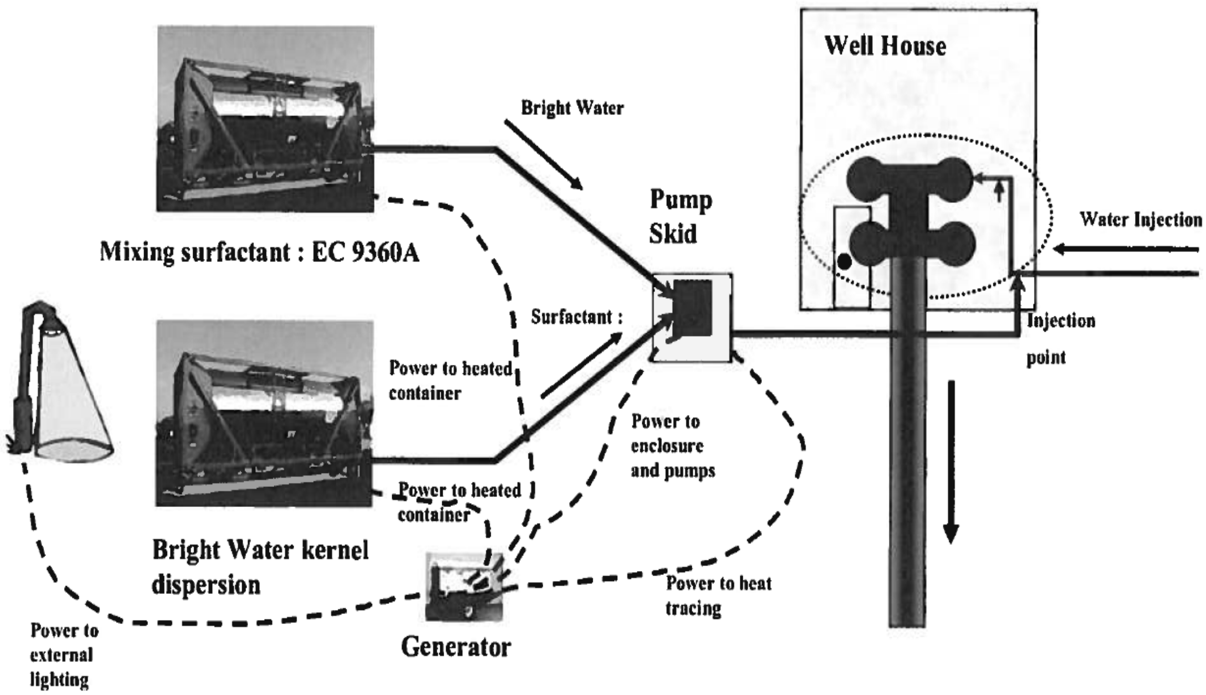


Figure 5-3: general arrangements for pumping the particulate system [14]

The arrangement consists of two containers, in one container BrightWater is placed and in the second container surfactant is placed. The power is required for heating the containers in order to maintain temperature within the containers. Both surfactant and BrightWater are pumped in appropriate proportion to the water injection line. The discharge pressure of the injecting pump should be greater than the water pressure in the injectors.

The equipments for injecting BrightWater [14]:

1) Two containers for the surfactant and polymer in a temporary containment area.
2) Two positive displacement piston pumps in a temporary containment area (shown in Figure 5.3).
3) A generator

5.4 Environmental and health impact of chemicals on human health

Hazardous chemicals enter the body via the air inhalation, food and water ingestion, or by direct contact with the skin. Chemicals may cause acute poisoning or burns, chronic health problems, or have long-term effects such as cancer, fatal damage and reduced fertility. It is easiest to quantify acute effects, because the injury appears so rapidly after exposure. The products that cause most of the poisonings and chemical burns among ordinary consumers are household chemicals, tobacco and pesticides. In general, people are more likely to be repeatedly affected by small doses of chemicals than to suffer acute injury. We know less about the damage caused by long-term exposure than we know about the acute effects of high single doses. This is because it is difficult to prove the connection between exposure and effects when the effects may take years to appear. The fact that everyone is exposed to a number of different substances, and that we know not enough about their combined effects, this complicates the picture further [10].

5.4.1 Impacts on the environment

Chemicals can cause higher mortality, slow down growth or disturb reproductive processes in plants, animals and microorganisms. Many hazardous substances are persistent, meaning that they break down very slowly in the environment. They therefore enter food chains, being transferred from one species to another and becoming more concentrated in the process. There is a serious risk that environmental concentrations of some pollutants may reach levels that make it difficult to repair the damage before their effects are detected. And the damage does not stop here. In mammals, hazardous chemicals are transferred from mother to offspring through the placenta, or to infants through the mother's milk. Future generations may suffer the impacts of pollution if chemicals damage the genetic material in sperm and egg cells. Nowadays we are using more chemicals than before, in a wider variety of products. Even though we have reduced the levels of some dangerous substances in the environment, new dangerous substances are constantly discovered in our surroundings. In some places pollution from earlier industrial and mining activities is still causing problems. Some chemicals can cause cancer, mimic hormones or in other ways disrupt hormones, disturb reproduction or cause acute poisoning. Persistent substances accumulate in the environment and in food chains, and the impacts on people can be very serious [10].

5.5 SFT list

Norwegian authorities have drawn up three hazardous chemical lists.

5.5.1 The list of Priority Substances

The authorities have drawn up a priority list of hazardous chemicals, and set targets for when emissions of these substances should be substantially reduced or completely eliminated.

5.5.2 The Observation list

The Observation list includes substances that are particularly hazardous to health or the environment and are used so widely or in such amounts that they may represent special problems at national level.

5.5.3 The list of Dangerous Substances

Approximately 3500 substances are included in the Norwegian list of Dangerous Substances.

As we discussed above BrightWater is a highly cross linked, sulfonate containing polyacrylamide micro particle and it is in SFT red list/observation list.

5.6 MSDS of Polyacrylamide

Akrylamide

Index number	616-003-00-0		
CAS number:	79-06-1		
EC number:	201-173-7		
Classification			
	Carcinogenic R45		
	Mutagenic R46		
	Harmful for reproduction		
	Toxic R25-48/23/24/25		
	Harmful R20/21		
	Irritant R36/38		
	R43		
Indication of danger		Toxic	
R-phrase:		45-46-20/21-25-36/38-43-48/23/24/25-62	
S-phrase:		S-53-45	
	Number	Concentration	Effect
	1	>=25%	T;R45-46-20/21-25-36/38-43-48/23/24/25-62
	2	20 % <= C < 25 %	T;R45-46-22-36/38-43-48/23/24/25-62
	3	10 % <= C < 20 %	T;R45-46-22-43-48/23/24/25-62
	4	5 % <= C < 10 %	T;R45-46-22-43-48/20/21/22-62
	Effects of various concentration of acrylamide (4)		

S-phrase Safety phrase

R-phrase Risk phrase

R45 May cause cancer.

R46 May cause heritable genetic damage.

R62	Possible risk of impaired fertility.
R20/21	Harmful by inhalation and in contact with skin.
R36/38	Irritating to eyes and skin
R43	May cause sensitization by skin contact.
R25	Toxic if swallowed
S53	Avoid exposure, obtain special instructions before use.
S45	In case of accident or if you feel unwell, seek medical advice immediately

R48/20/21/22 Harmful: danger of serious damage to health by prolonged exposure through inhalation, in contact with skin and if swallowed.

R-48/23/24/25 Toxic: danger of serious damage to health by prolonged exposure through inhalation, in contact with skin and if swallowed [7].

From the above table it is clear that acrylamide is toxic chemical but it is more toxic when it has higher concentration but it is less harmful and toxic as its concentration reduces. Up to 100ppm it is carcinogenic but below than 100ppm there is no issue with it and it is allowed to use [3]. If polyacrylamid content forms "free" acrylamide 0.01% or more, the health marking has "May cause cancer" -and "Poison" symbol. This will affect the content of the safety data sheet for such products, and use of the products. But if the concentration is less than 100ppm then it is not harmful and there is no need to label it as toxic or carcinogenic chemical [12]. More details polyacrylamide MSDS is given in appendix.

5.6.1 Physical and chemical properties [12]

Condition Form	Powder
Odour	None
Colour	White
Solubility in water	completely soluble
Gravity Value:	0.75 g/cm3
PH (solution) Value:	3.5
Comments:	1% solution
Flash Point Value:	> 100 ° C

5.7 Polyacrylamide in reservoir

Polyacryamide is injected along with water, blocks the thief zones and stays inside. Concentration on the permeability reduction element of the water flood modification should result in systems that use most of the injected material to produce a lasting effect. It would also ensure that injected material was never subsequently produced with the water from the field. Field trials and commercial applications of gel systems intended to achieve this have been reported [6].

5.8 Techniques for degrading Polyacrylamide in reservoir

As mentioned above there was no observation of polyacrylamide along with water in the producer but Polyacrylamide is not biodegradable in nature however its degradation can take place under the separate or combined action of heat, light, ionizing radiations, mechanical effects and biological factors [15].

Different methods are available to degrade PAM these are explained below

5.8.1 Chemical degradation

The chemical degradation of polyacrylamides involves a variety of chemistries. There are innumerable reaction conditions and possible products, and in this review we have not attempted to cover every possible situation but have endeavored to give the reader a feel for the types of chemistries involved. There is however one generality from all the literature examined that PAM behaves as a typical monosubstituted vinyl monomer, and no studies have shown release of acrylamide upon chemical degradation. The different chemical degradation techniques are available i.e hydrolysis of polyacrylamide cross-linked gels, Hoffman Degradation of Polyacrylamides and Chemically Induced Free Radical Degradation of Polyacrylamide[18].

5.8.2 Mechanical degradation

Irreversible damage in the polymer structure can happen during preparation, injection and polymer movement through the porous medium. Shear degradation is dependent upon polymer concentration and that the degree of degradation is dependent on the polymer stretch rate, the flow-path length, and polymer molecular weight. Mechanical degradation effects shown, that it increases with decreasing concentration. The higher-concentration polymer solutions, therefore, would be expected to show the least change in measured flow properties [16].

5.8.3 Thermal degradation

Increase temperature can accelerate the degradation rate of polymers, which causes the degradation of polymer. The degradation of PAM starts at 200 °C. It has been experimentally observed that at 340°C, the polymer degrade completely [17].

5.8.4 Biological degradation within reservoir

Study has been carried out in China regarding Polyacrylamide (PAM) degradation. Compared with the physico-chemical degradation of PAM, there is no acrylamide monomer, which causes peripheral neuropathy, released in the process of biodegradation. Unfortunately, few microorganisms have been isolated which can degrade PAM. Two PAM-degrading bacterial strains, named HWBI and HWBII, were isolated from the activated sludge and soil in an oil field that had been contaminated by PAM for an extended period. These were subsequently identified as Bacillus cereus and Bacillus flexu, respectively. Although both strains degraded PAM in different rates, it was observed that 72 h cultivation more than 70% of the PAM was consumed. This degradation efficiency was much higher than previous studies. Both strains degraded a determinate proportion of PAM when 50–1000mgL−1 of the initial PAM was supplied [13].

5.9 Discussion/recommendation

I njection of BrightWater is an environmental issue in Norway even if it has been used in other parts of the world, such as in the North Sea British sector in 2002 and 2006. It has been applied to many fields and it has never been observed along with water from the producer side, so it is confirmed that it remains inside. A lot of techniques are available to degrade it within the reservoir as mentioned above. Especially its biological degradation, which is the latest research and it degrade about 70% of PAM. Another option is to use water, which is producing from the producer and inject it back.

Overall if BrightWater gives a lot of recovery, then there is no harm to use it for reservoir recovery. It remains inside for a few years and by using any degradation method after recovering oil, especially biological degradation method makes the reservoir free of polyacrylamide. It is a very viable technique, which gives huge recovery, and few environmental impacts that can be easily managed if you get enough profit.

6 Simulation Part

Implication: Adding a chemical called “BrigthWater” to the injection water may increase oil recovery by improved volumetric sweep. However, the chemical is classified as red according to SFT’s regulations.

Task: Use the WI-model developed by Group 5 and find a way to model ”BrightWater”. Discuss possible improvements necessary in Eclipse to fully account for the properties of this chemical.

6.1 Software information

Our group used Eclipse 100 for the simulation of BrightWater injection to Gullfaks Sør. ECLIPSE is an oil and gas reservoir simulator originally developed by ECL (Exploration Consultants Limited) and currently owned, developed, marketed and maintained by SIS (formerly known as GeoQuest), a division of Schlumberger. Eclipse has 3 editions

1. Eclipse 100(Black Oil Simulator)
2. Eclipse 300(compositional simulator)
3. Eclipse 500(Thermal Simulator).

Ceetron GLview Pro, GLview Inova and Eclipse Office have been used for visualizing and monitoring sweep efficiency.

We have learned a new programming-based software called ECLpost in the process of simulation. ECLpost reads input and output files from Eclipse, and offers several options for interpreting and processing the data.

The main benefits of Eclpost are:

- When using Eclpost for data mining, engineers will save time and reduce errors in input and output data from reservoir simulations

- Eclpost is faster and more flexible than other tools. It has an easy macro language to use for repetitive task.

It is also possible to use IPM Resolve simulator to simulate the process of BrightWater injection and it can import data from Eclipse 100.

6.2 Workflow of BrightWater simulation

As the assignment told, the simulation of BrightWater injection has been completed in 2 stages:

1. Developing appropriate water injection model

To get the best water injection model we simulated 15 cases of water injection system.

2. Taking water injection model for developing appropriate BrightWater injection model

To get the best BrightWater injection model possible for Gullfaks Sør we simulated 50 cases of BrightWater system.

Figure 6.1 show the workflow of the sensitivity analysis:

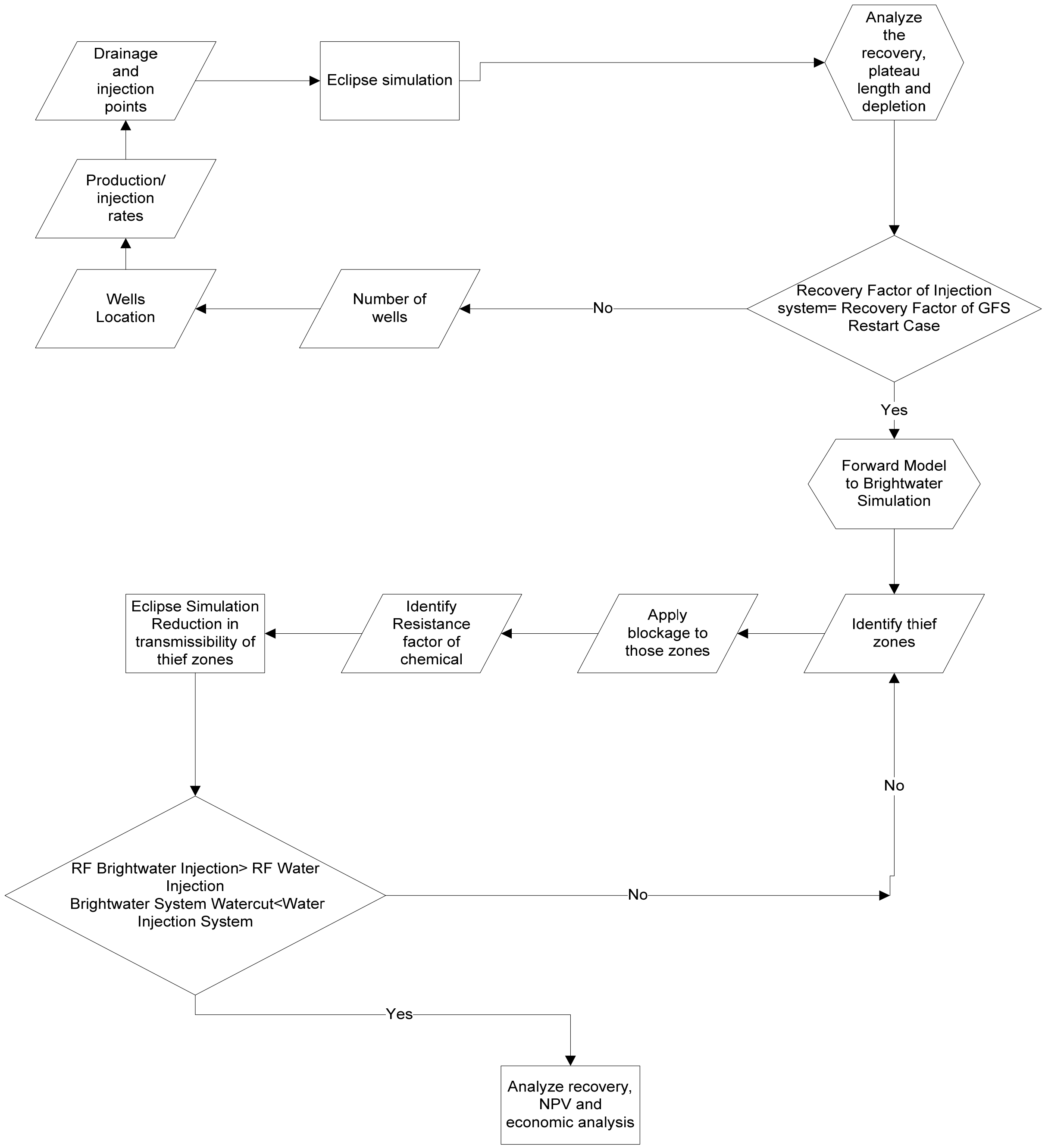


Figure 6-1 Workflow of simulation sensitivity analysis

Experience with Eclipse showed that appropriate water injection model is the most vital aspect for success with BrightWater injection. On this process to decide the number of wells needed to drain the reservoir, oil saturated zones efficiently consumed many time. We concentrated to get more residual oil with less number of wells from the segments with good lateral communication

(MULTX, MULTY), whereas we tried to treat individually segments with low lateral communication to the rest of the field. Also we prioritized layers (table 5.1) and segments according to Fluid in Place volumes.

Case GO-DG0-07

Segment	FIPNUM	Initial Oil in Place [MSm3]	Remaining Oil in Place [MSm3]	Recovery
A1	70	1.8	1.4	0.22
A2	60	9.7	5.7	0.41
A3	30	8.8	6.8	0.23
A4	20+10	5.1	4.2	0.18
A5	120+130	10.9	7.9	0.28
A6	140+150	2.8	2.4	0.15
		39.1	**28.4**	**0.27**

Table 6-1 Fluid -in-place numbers of Gullfaks Sør Statfjord [19]

Well locations mainly started from high oil saturated layers of segments crossing the faults that have transmissibility 0.5 or less. This decision has been taken to optimize the system for the ultimate efficiency with the less number of wells.

Production/injection rates were one of the main factors of sensitivity analysis of injection system. Process showed that to obtain lower cut, the reservoir should be depleted at lower rates (max 400 Sm^3/d for one branch slanted/directional well, 800 Sm^3/d max for horizontal 2 branched wells).

Production and injection targets are probably the most important factors affecting the shape Field Oil Production Rate, Field Oil Cumulative Production and Recovery factor. From observation we saw that Nansen in the North part and Nansen and Eiriksson in Southern part of the field are much suitable for drainage.

After every simulation we analysed the results of following parameters:

- Field Oil Production Rate, Sm^3/d
- Field Oil Production Cumulative, Sm^3
- Field Oil Recovery, %
- Residual Oil Saturation

- Field Water Cut
- Individual well production performances

Our group also partly worked with group 5, helping them to develop a better model of water injection. After fifteen cases of simulation with water flooding group 5 decided that Case11 of water injection was the best model achieved. However after analysing Case11 Water Injection model, we decided that this model may not be to appropriate for BrightWater injection application, as we needed at least one month injector-producer water transit time. So we modified the Case11 model by changing the location of injectors and by adding one more producer. Here you can see the trajectories and configuration of wells for Case11 and Water injection model proposed by group 1:

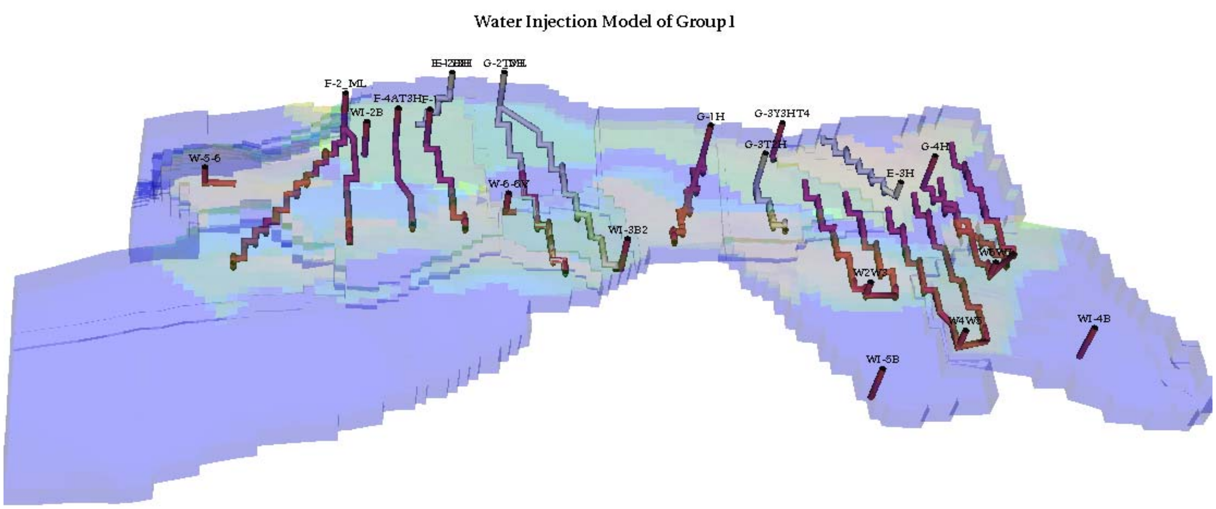


Figure 6-2 Water injection model suggested by Group 1

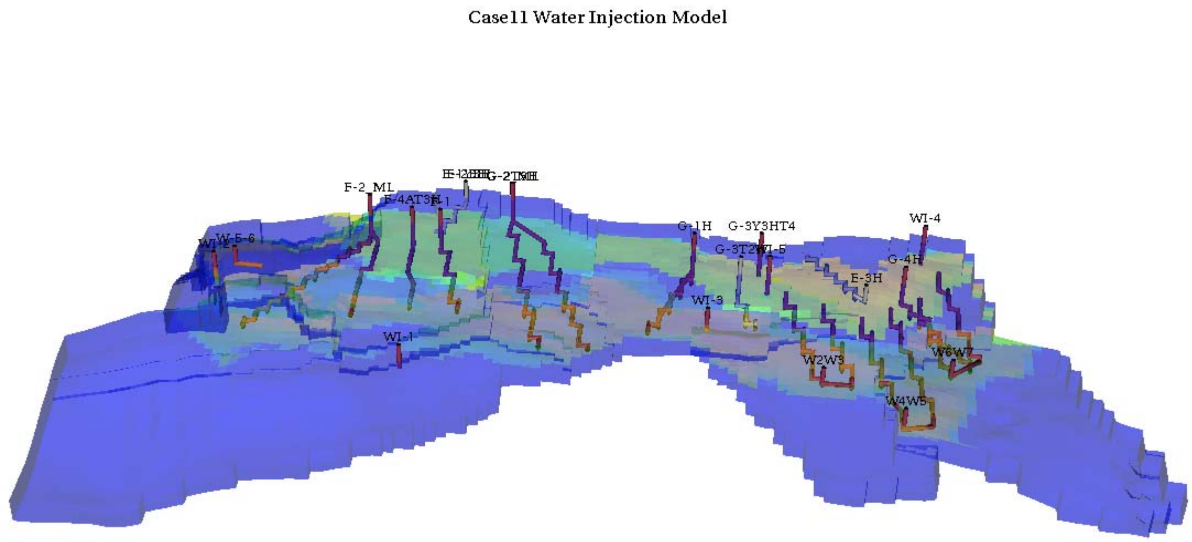


Figure 6-3 Water injection model CASE11

6.3 Analysis of water injection models and communication between segments:

According to model description in Grid files, there is a good lateral communication between A1, A2, and A3. However A4 and A5 are not in full communication with the rest of the field as shown in figure 6.4, 6.5.

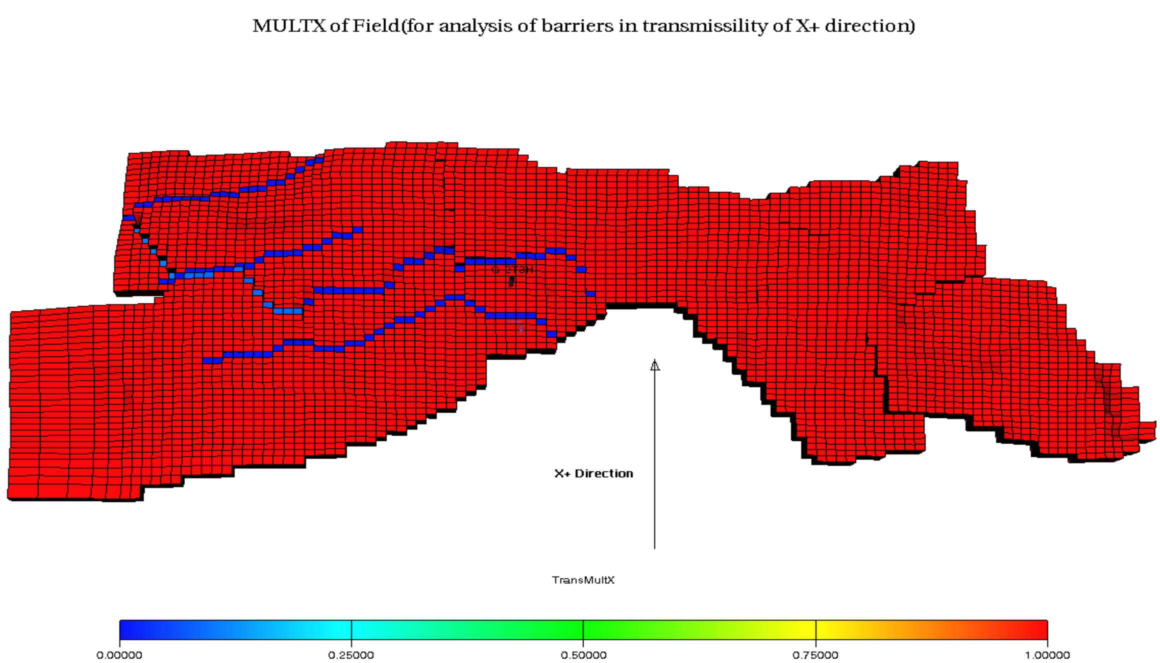


Figure 6-4 Transmissibility in X+ direction

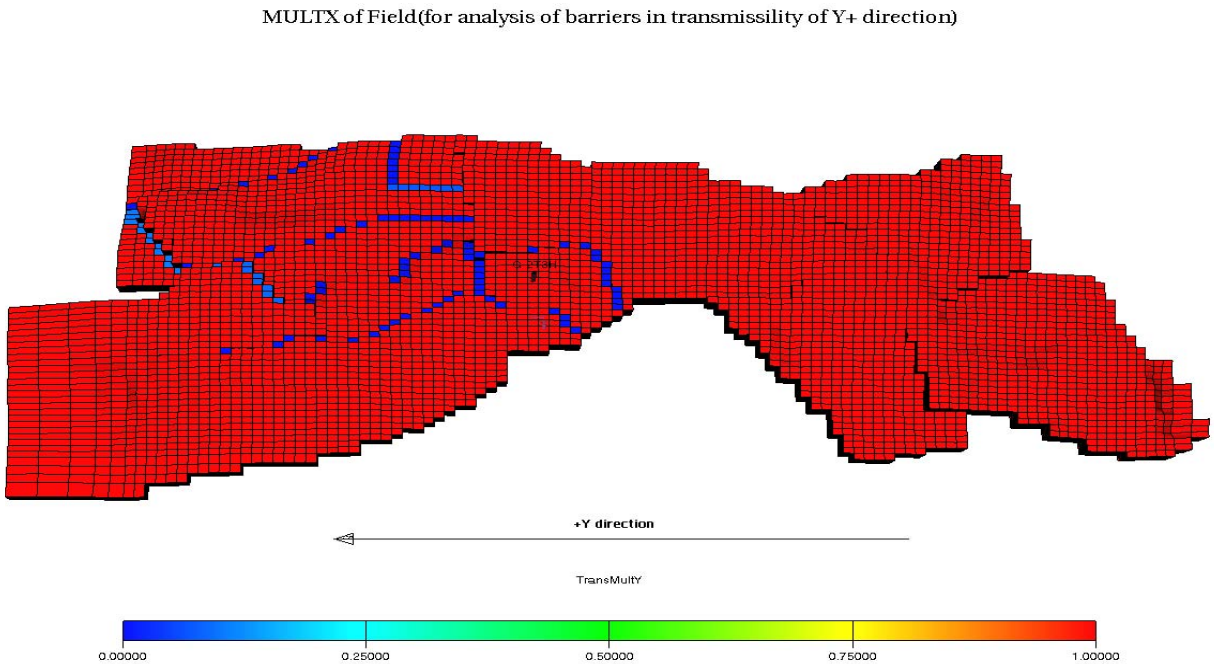


Figure 6-5 Transmissibility Y+ direction

After analysing the system communication, we decided that treating A1, A2 and A3 as one segment, but treating A4 and A5 as separate segments would give better results in injection strategy. Five injectors have been added to Case11 system: WI-1, WI-2, WI-3, WI-4 and WI-5, whereas Water Injection model Group 1 includes four injectors: WI-5B, WI-4B, WI-3B2 and WI-2B. As can be seen, both of the models include W2W3, W4W5 and W6W7 (proposed by Statoil) and horizontal W-5-6 (draining from A5). Plus, Water Injection model Group 1 includes one more slanted producer- W-6-6V in A4 segment. We did not change the locations of W2W3, W4W5 and W6W7, as the proposed location of these wells was already giving good results.

Wells information:

Results of simulation for selection of water injection model figure 6.6:

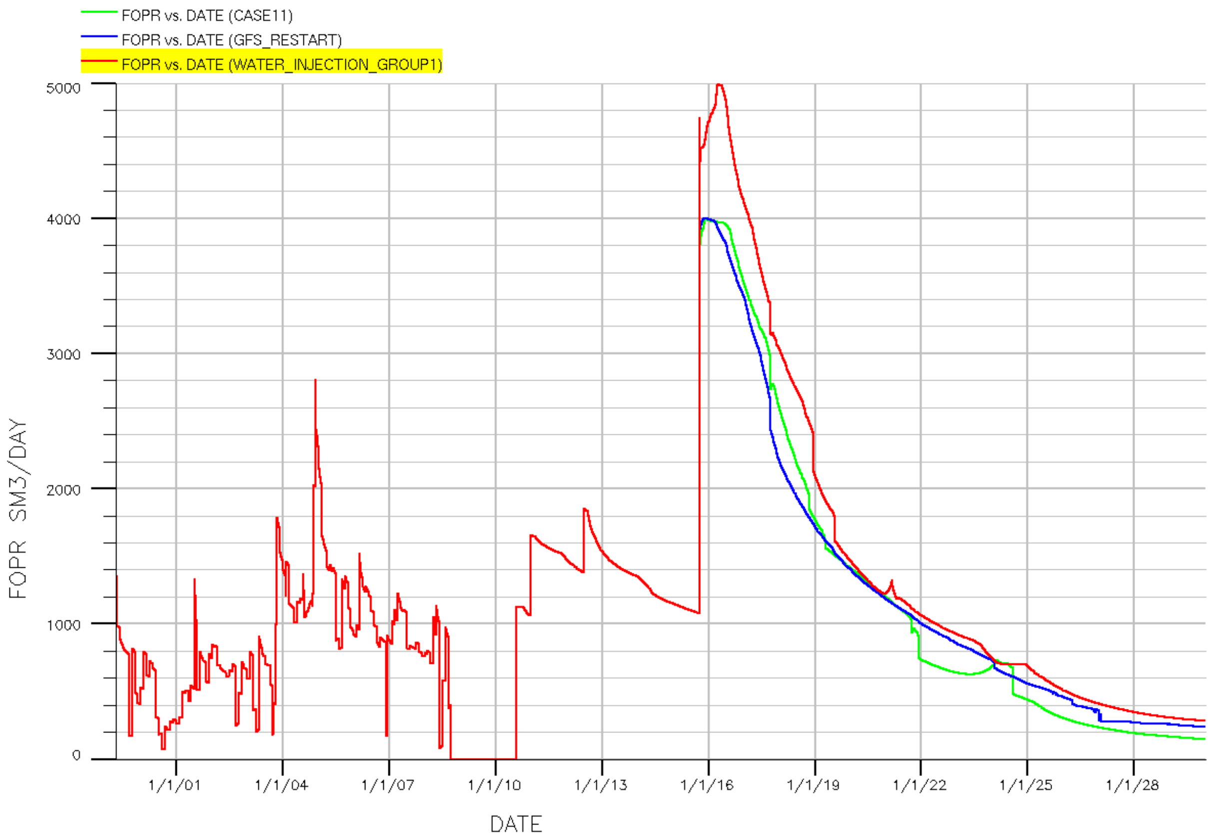


Figure 6-6 Field oil production rate comparison of CASE11, GFS_RESTART and WATER_INJECTION_GROUP1

Water injection model proposed by group 1 gives increased production rate compared to Case11 water injection model and GFS_RESTART Case (figure 6.6). It gets the maximum value of 4981 Sm^3/d on April 5th 2016, whereas Case11 gets maximum value of 3969 Sm^3/d on May 10th 2016 and GFS restart Case gets 3996 Sm^3/d on November 22nd 2015. Although Group1 Water injection model does not have a stable plateau period, throughout the production period it produces at higher rates than GFS Restart Case and Case11, which already implies higher cumulative oil and thus recovery than GFS Restart and Case11 (figure 6.7):

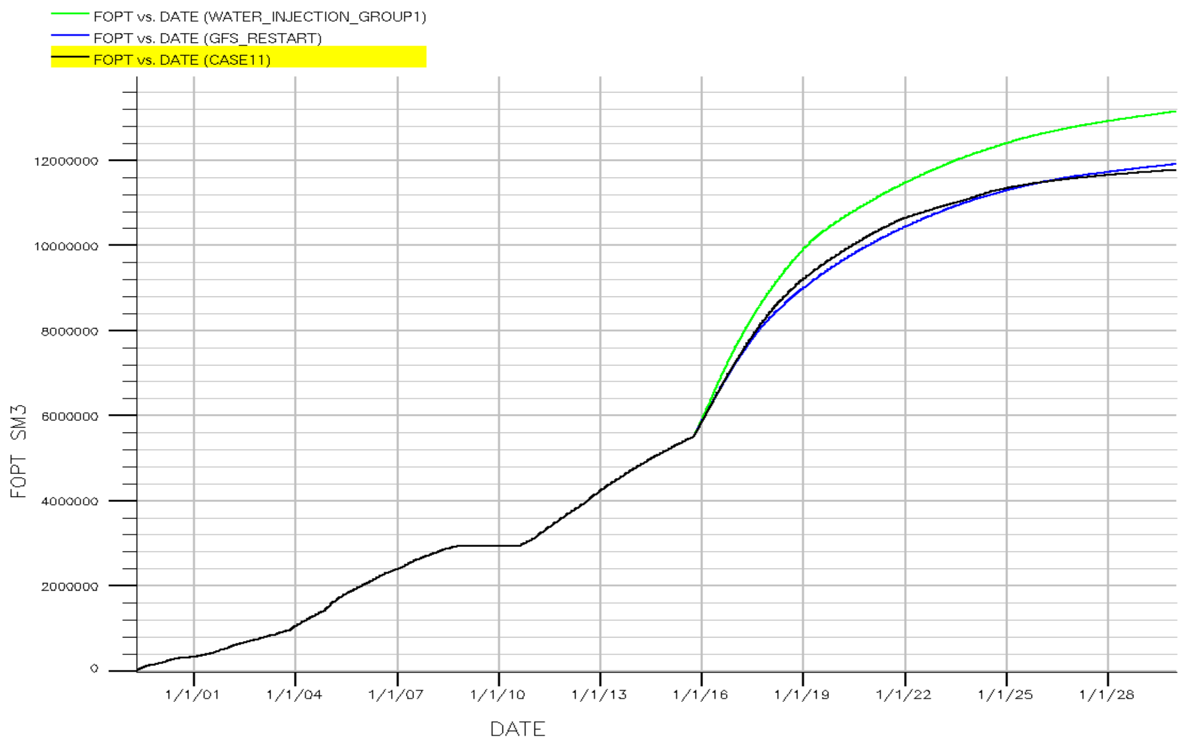


Figure 6-7 Cumulative oil produced comparison of CASE11, GFS_RESTART and WATER_ INJECTION_GROUP1

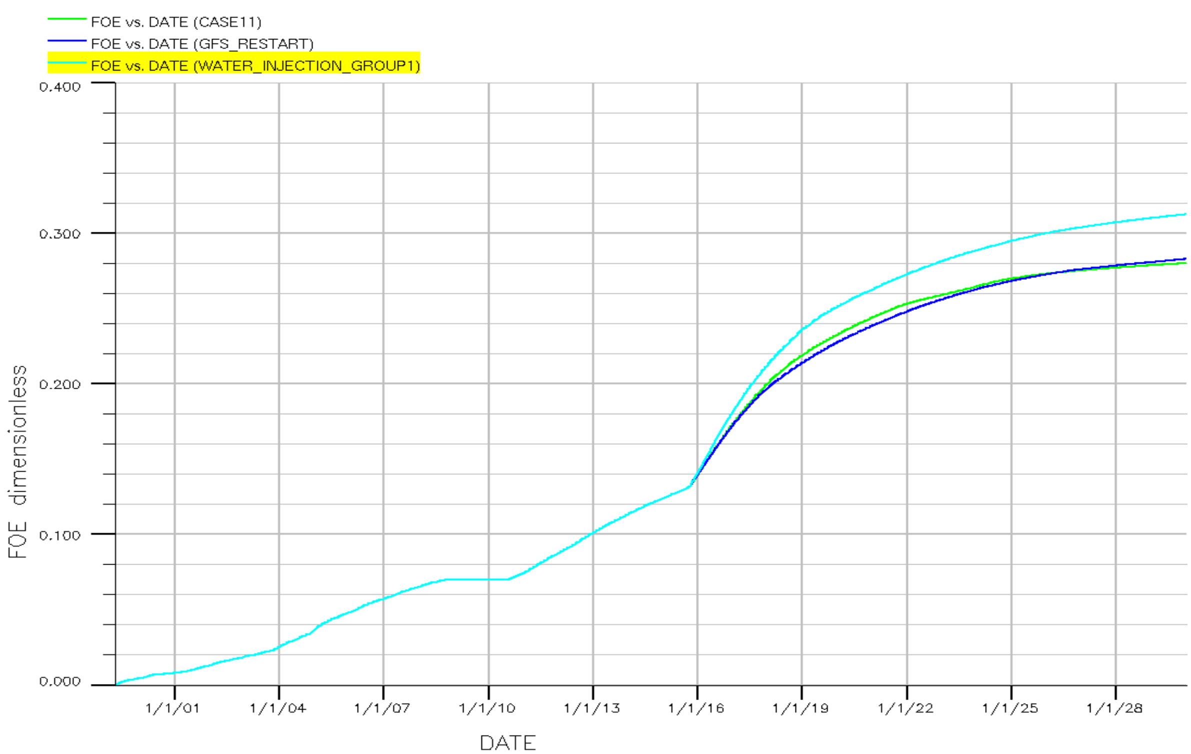


Figure 6-8 Field oil recovery comparison CASE11, GFS_RESTART and WATER_INJECTION_GROUP1

As it can be seen from figure 6.7, water injection model by Group1 is giving much better cumulative produced oil than Case11 and GFS restart model. Cumulative oil produced on January 1st 2030 equals to 13148785 Sm^3, but GFS restart gives 11912783 Sm^3 and Case11 gives 11776083 Sm^3. Field oil recovery for group1 water injection is 32% but for GFS restart 28% and for Case11 28% figure 6.8. The main issue for both Case11 and Group1 water injection is high watercut as shown in figure 6.9, 6.10 and 6.11.

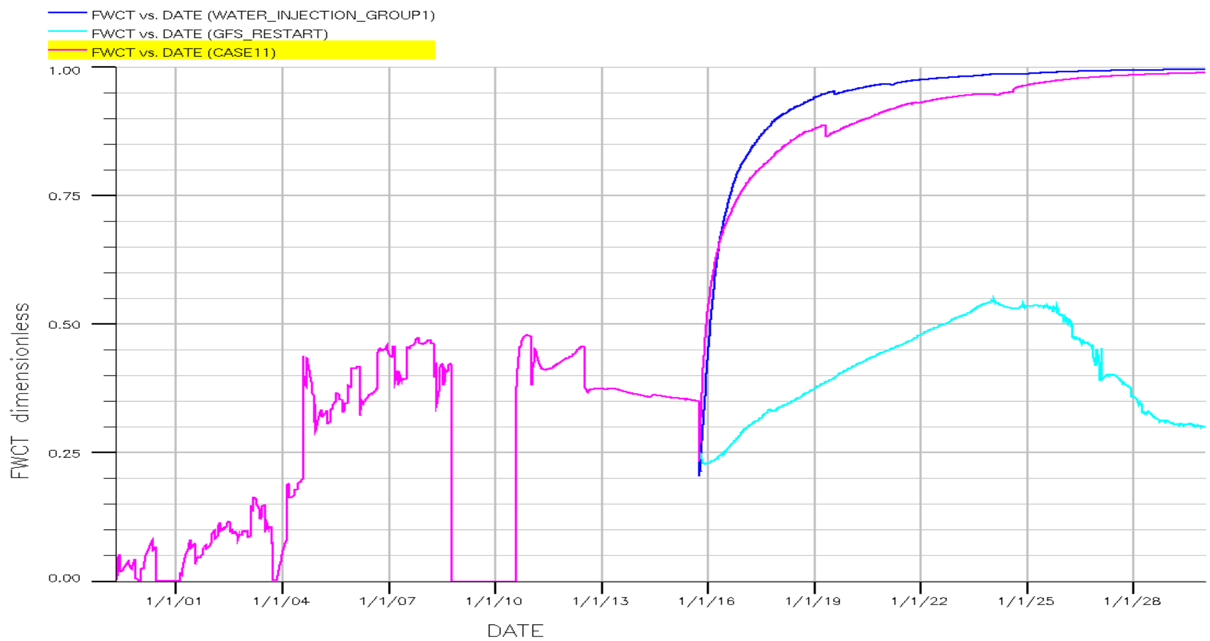


Figure 6-9 Field watercut comparison of WATER_INJECTION_GROUP1, GFS_RESTART and CASE11

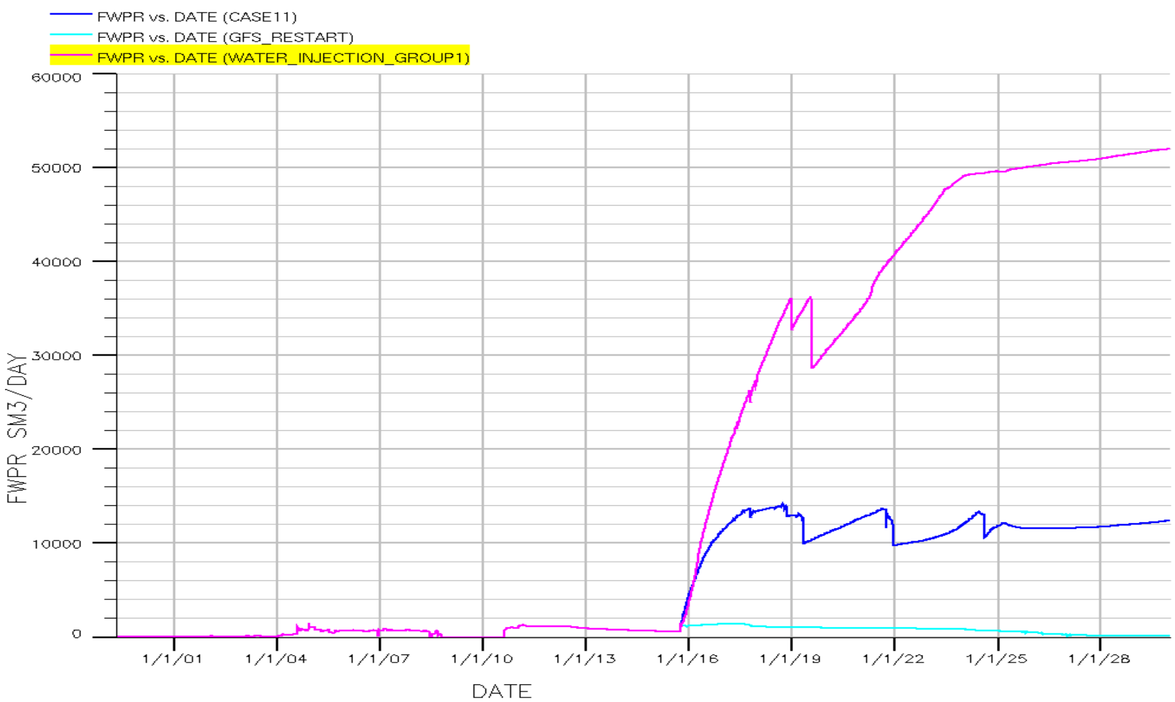


Figure 6-10 Field watercut production of WATER_INJECTION_GROUP1, GFS_RESTART and CASE11

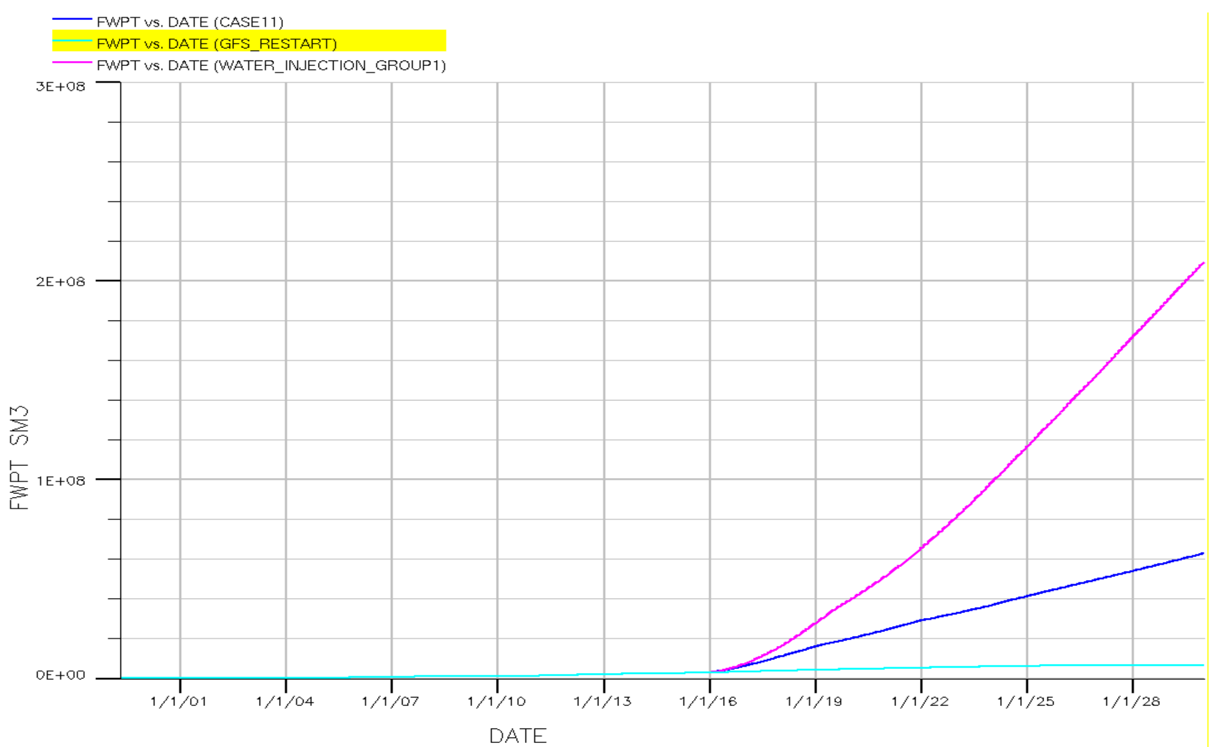


Figure 6-11 Field cumulative water production comparison of WATER_INJECTION_GROUP1, GFS_RESTART and CASE11

As we can see from the figure of water production curves, water production for Group 1 water injection rises up more rapidly than Case11 and GFS restart. Watercut for Group 1 water injection model and Case11 is 97% and this is 72% more than GFS restart Case in the year of 2030.

Conclusion on selection on water injection model:
Above the two best models of water injection for application of BrightWater injection system is discussed. After careful review of the results, our group decided that applying Group1 water injection model for BrightWater simulation is reasonable because of high recovery of oil.

6.4 Procedure of BrightWater implementation into eclipse water injection model

There are 3 different ways to implement BrightWater model into eclipse. The methods are listed in the order of complexity and data input:

1. Define a box in the water flooded region and reduce the permeability by using MULT-key word for modification of permeability through the region of thiefzone.
2. Inject a tracer and reduce the permeability in the regions with highest tracer concentration at a preselected time. The permeability reduction could be made proportional to the tracer concentration if one wants to refine the procedure.
3. Use the POLYMER option and let the amount of adsorbed polymer govern the permeability reduction, while eliminating the viscosifying effect of the polymer.

Our group used method 1 since it is the easiest one to implement. We have to use **MULT** keywords after the preselected date of water injection in the schedule file of simulation data (figure 6.12):

```
DATES
 1 'JAN' 2016 /
/

-------- IX1-IX2 JY1-JY2 KZ1-KZ2
BOX
          45  60 20  24   9   9 /
MULTY
 80*0.01 /
ENDBOX
/
-------- IX1-IX2 JY1-JY2 KZ1-KZ2
BOX
          45  60 20  24   12   12 /
MULTY
 80*0.01 /
ENDBOX
/
-------- IX1-IX2 JY1-JY2 KZ1-KZ2
BOX
          45  60 20  24   13   13 /
MULTY
 80*0.01 /
ENDBOX
/
```

Figure 6-12 Source code: Eclipse 100, BrightWater_Case38.SCHEDULE (partly)

The box containing X(45:60) and Y(20:24) in the layer 9 will have reduced permeability by factor of 0.01 in the first usage of MULTY. During the use of this method we cannot control the amount of injected BrightWater chemical; instead we simulate just the effect of BrightWater on the reservoir. As the first step to this we identify thiefzones as shown in figures 6.13 and 6.14:

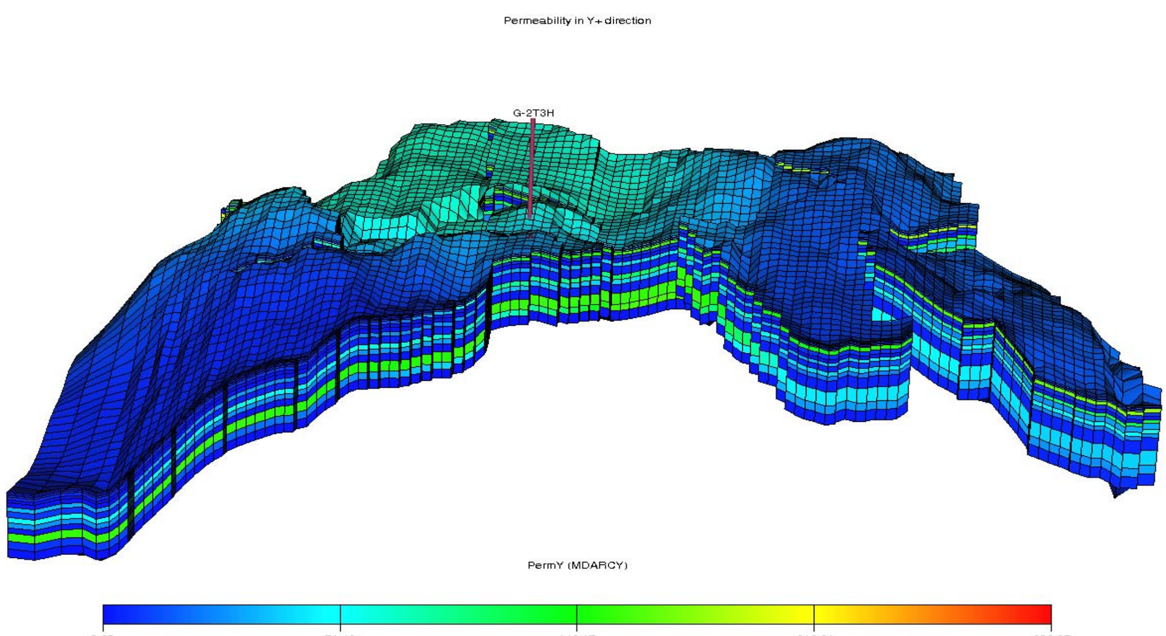


Figure 6-13 PERMY of Gullfaks Sør

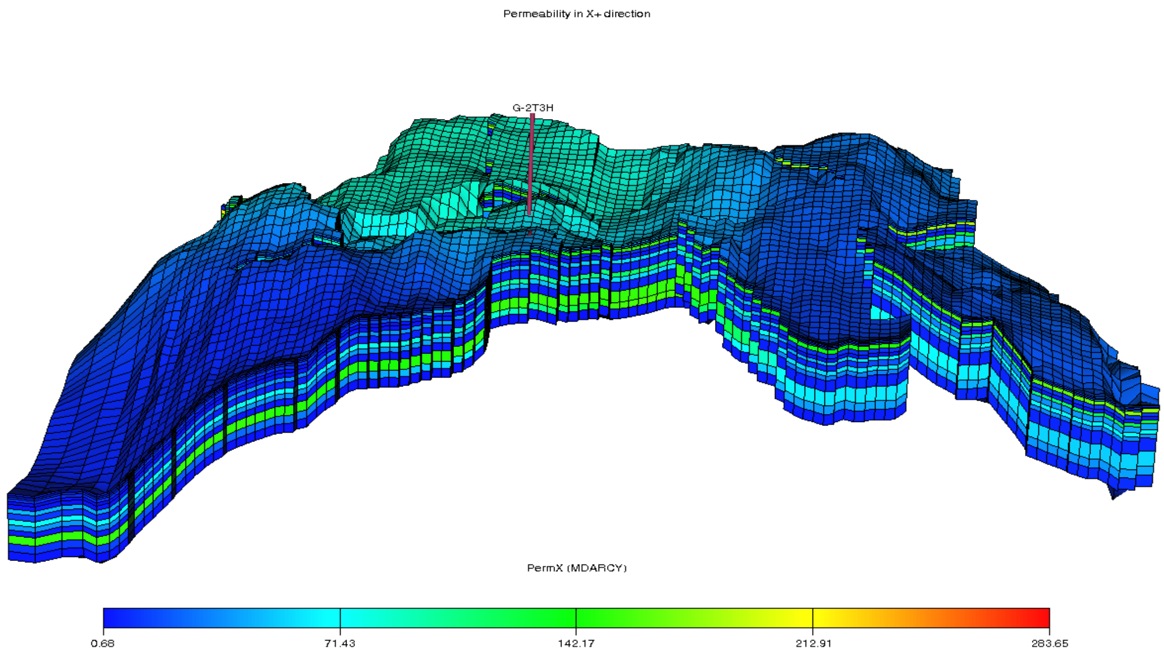


Figure 6-14 PERMX

Permeability figures of field shows that possible layers for blocking are 9, 12 and 13. Therefore we applied blockage to 9, 12 and 13 in different parts of reservoir shown in figure 6.15.

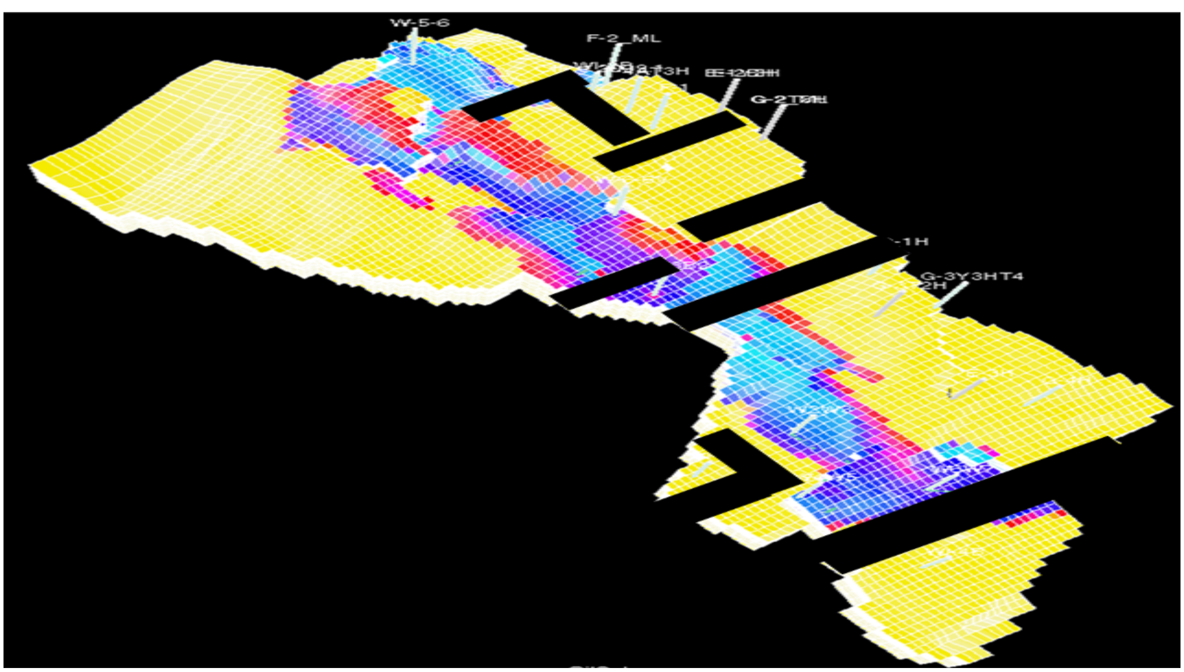


Figure 6-15 Blockage stragety on layers 9, 12 and 13

6.5 Assumptions for simulation:

I. We assume that there is enough transit time for BrightWater to activate popping mechanism between injector and producer.

II. Since reservoir temperature is 128°C and the water injected is 0°C (default Eclipse feature), we assume that there is good lateral temperature gradient for BrightWater to show its popping effect.

6.6 Simulation and discussion of results:

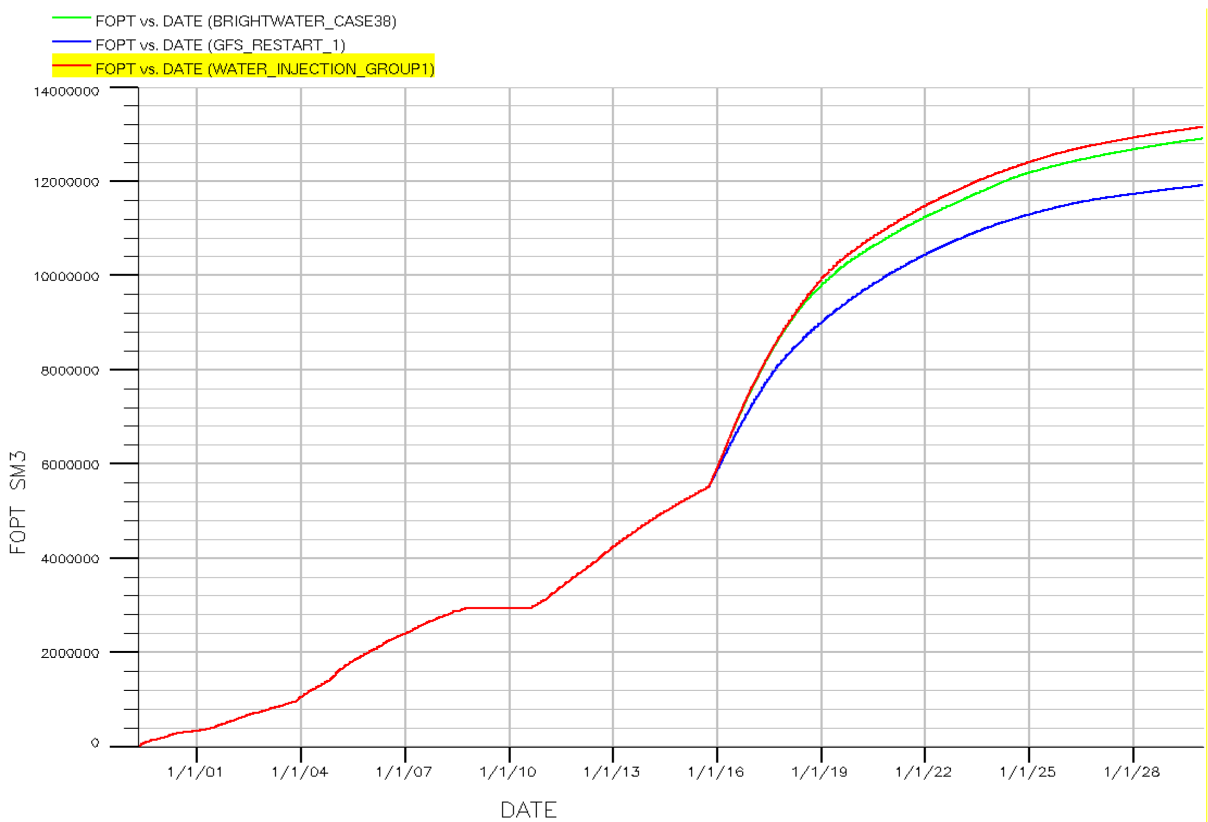


Figure 6-16 Cumulative oil production comparison of BRIGHTWATER INJECTION, GAS INJECTION and WATER INJECTION

Application of BrightWater injection into the field declines cumulative oil production by 243553 Sm^3 of oil from water injection model of Group1. But it gives 992449Sm3 more oil than GFS restart (figure 6.16). Application of BrighWater must show its affect in terms of decrease in watercut. However, as we can see from figure 6.17, it did not affect watercut as we supposed.

Despite of multiple sensitivity cases by application of BrightWater to different layers, with different resistance factors and with different fronts, it did not get any better than in figure 6.17 in terms of reduction in watercut.

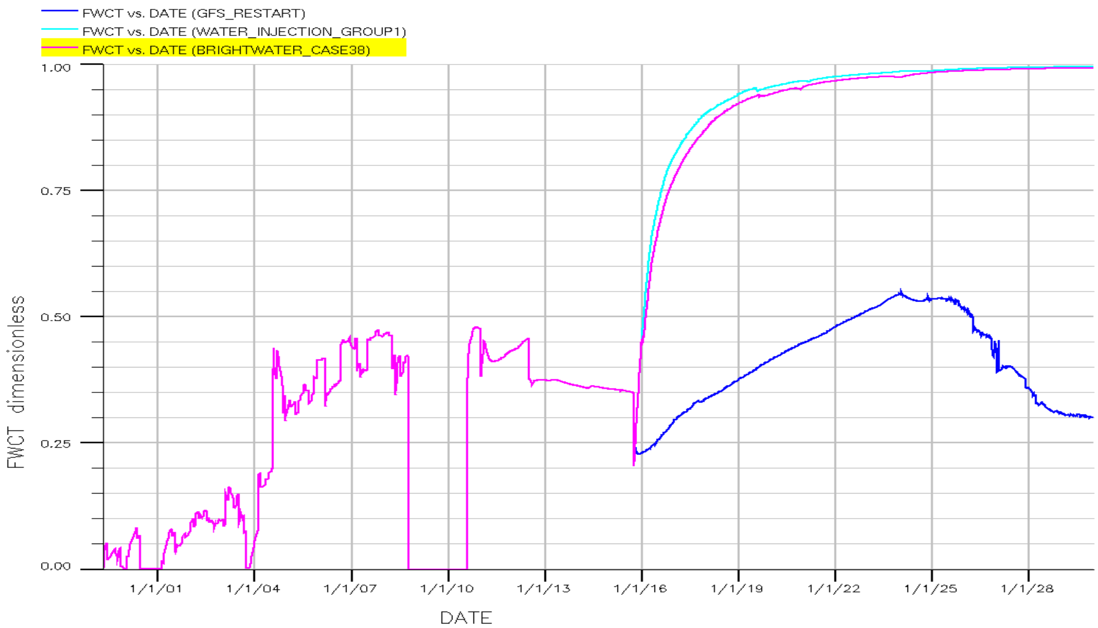


Figure 6-17 Watercut comparison of BRIGHTWATER INJECTION, GAS INJECTION and WATER INJECTION

Figure 6-18 Field water production rate comparison of BRIGHTWATER INJECTION, GAS INJECTION and WATER INJECTION

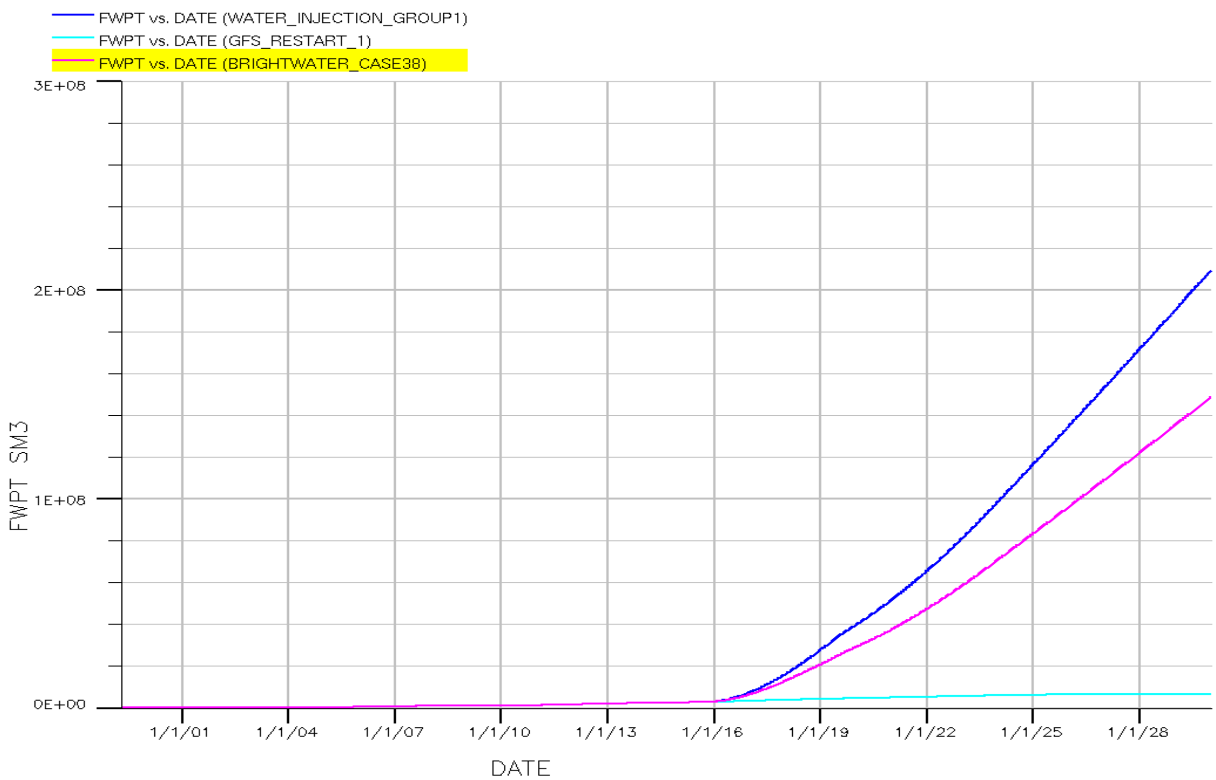


Figure 6-19 Field cumulative water production comparison of BRIGHTWATER INJECTION, GAS INJECTION and WATER INJECTION

The only change in terms of water production can be seen by looking at field water produced total from figure 6.19 and field water production rate from figure 6.18. The total reduced water production because of the BrightWater injection equals to 0.613E8 Sm^3.

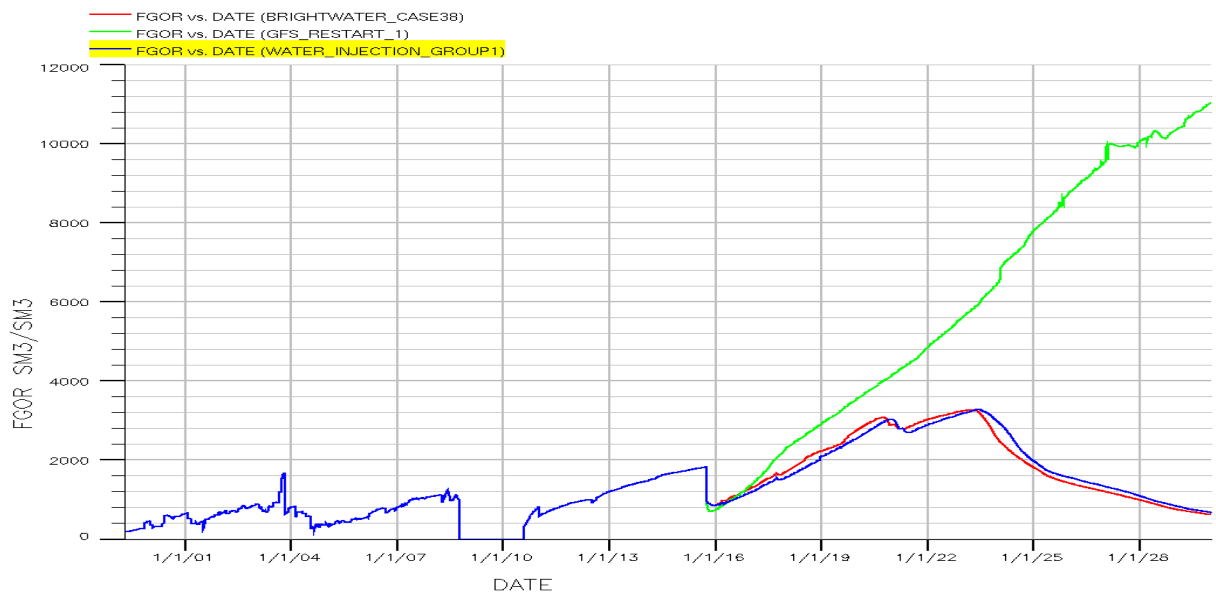


Figure 6-20 Field gas-oil ratio comparison of BRIGHTWATER INJECTION, GAS INJECTION and WATER INJECTION

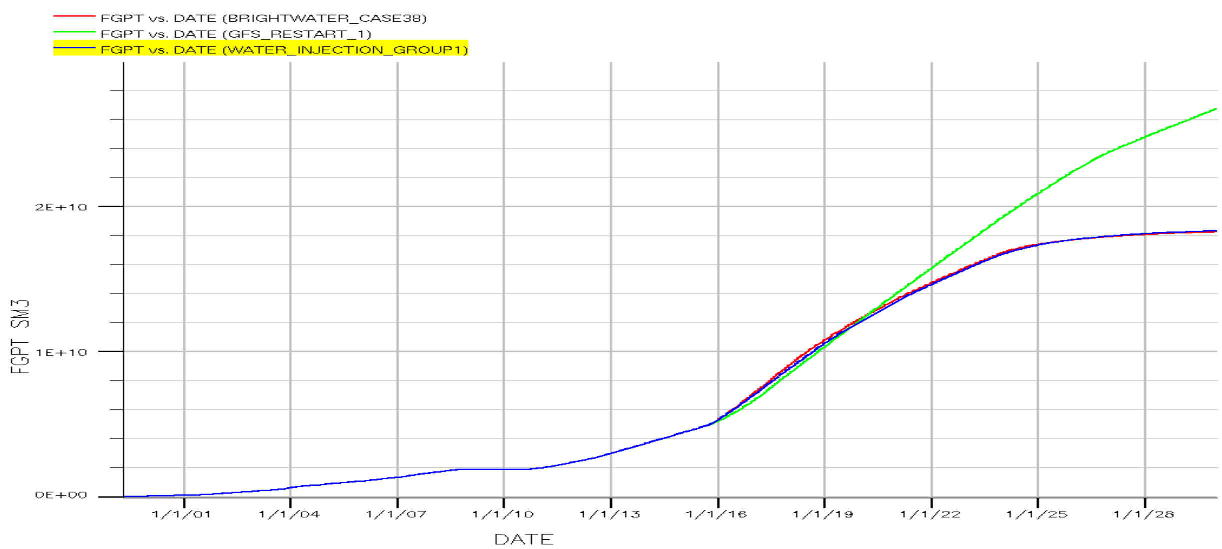


Figure 6-21 Field cumulative gas produced comparison of BRIGHTWATER INJECTION, GAS INJECTION and WATER INJECTION

Field GOR from figure 6.20 shows that GFS gas injection produces more gas than BrightWater and water injection models. The total gas produced from GFS Restart Case is 0.85E10 Sm^3 more than BrightWater Case (figure 6.21).

7 Economic Evaluation

7.1 Objectives

Using Net Present Value (NPV) technique in order to:

- Economical analyzing between two Oil and Gas production alternatives: Fixed platform and subsea development in Gullfaks Sør Statfjord

- Economical analyzing between Reference, Water injection and BrightWater injection models for improved oil recovery in Gullfaks Sør Statfjord.

7.2 Assumptions

All assumptions are completely as the same of economical evaluation's assumptions in part A plus two following items for CAPEX in BrightWater injection model:

- Active BrightWater 10 $/liter
- Surfactant active component 2 $/liter

7.3 Economical Analysis of the difference injection models

Subsea alternative and platform alternative for the water injection model and the BrightWater injection model when compared to the reference model.

7.3.1 NPV calculation

By using any of two given alternatives (fixed platform or subsea development), Both FOPT and FGPT will be increased by Water injection model and BrightWater injection model in compared to reference model:

By Water injection model:

- FOPT Increasing = +66.19%

- FGPT Increasing = +50.65 %

By BrightWater injection model:

- FOPT Increasing = +63.12%

– FGPT Increasing = +50.11 %

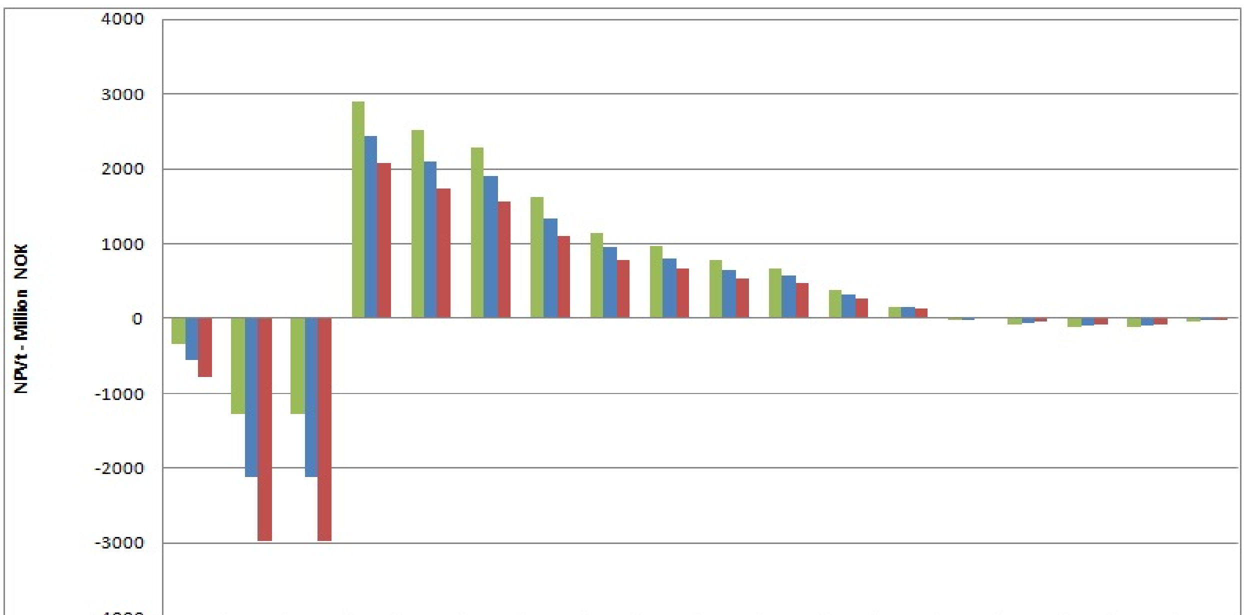
But like part A, the question is: By considering the needed CAPEX and OPEX costs for these two models, will Water injection or BrightWater injection models be economic or not? For answering this question, the total NPV should be calculated for each alternative.
As the details of calculation are shown and tabulated in attachment1, the following final results for total NPV have been obtained:

Water injection model			
Alternative1 – Fixed platform		Alternative2 – Subsea development	
Total NPV for Base Case	6036.94 Million NOK	Total NPV for Base Case	3707.41 Million NOK
Total NPV for Worst Case	2256.39 Million NOK	Total NPV for Worst Case	-758.38 Million NOK
Total NPV for Best Case	10135.46 Million NOK	Total NPV for Best Case	8637.74 Million NOK
BrightWater injection model			
Alternative1 – Fixed platform		Alternative2 – Subsea development	
Total NPV for Base Case	5607.62 Million NOK	Total NPV for Base Case	3295.98 Million NOK
Total NPV for Worst Case	1849.17 Million NOK	Total NPV for Worst Case	-1150.70 Million NOK
Total NPV for Best Case	9678.57 Million NOK	Total NPV for Best Case	8193.38 Million NOK

These results imply that both water injection model and BrightWater injection model in any possible cases (except worst cases in alternative 2) will be economic. Water injection model could reach a better total NPV and also a higher FOPT and FGPT. So, Water injection model would be more economic compared to reference, extended and BrightWater injection models for IOR (improved oil recovery) in Gullfaks Sør Statfjord.

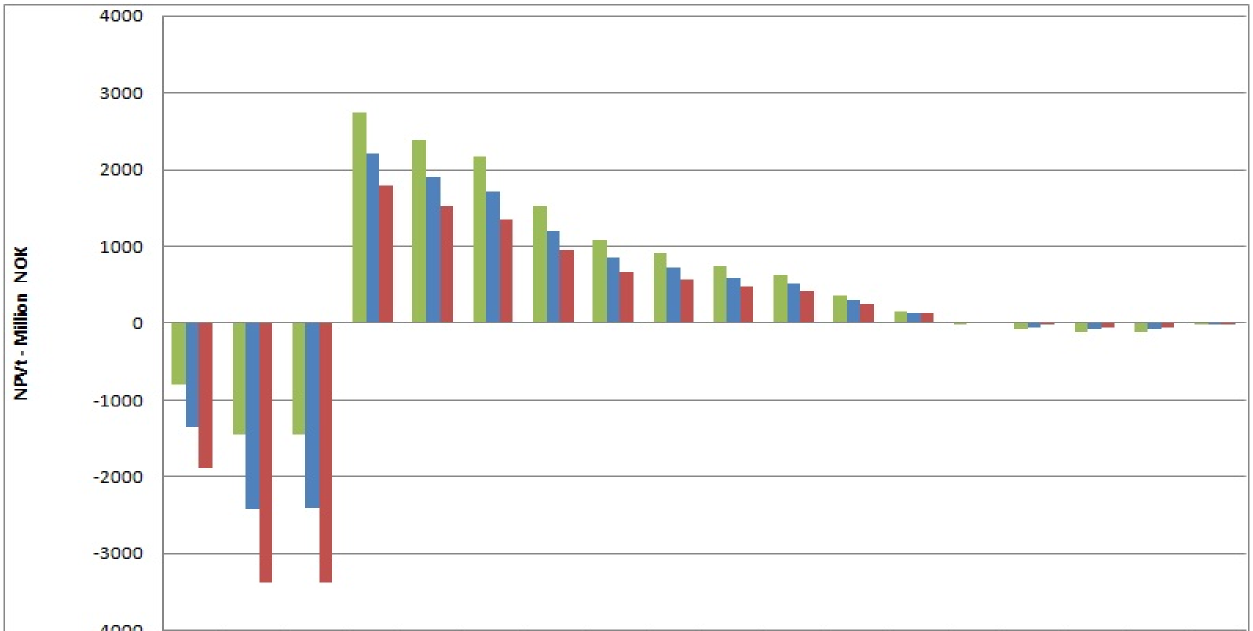
Moreover, as in extended model in part A, fixed platform alternative for producing oil and gas could reach higher total NPV, so it would be more beneficial for both water injection and BrightWater injection model as well.

By considering the following figures, the possibility for more detailed analysis will be provided. The earned NPV for each year and the cumulative NPV between 2012 and January 1st 2030 are depicted in figures below;



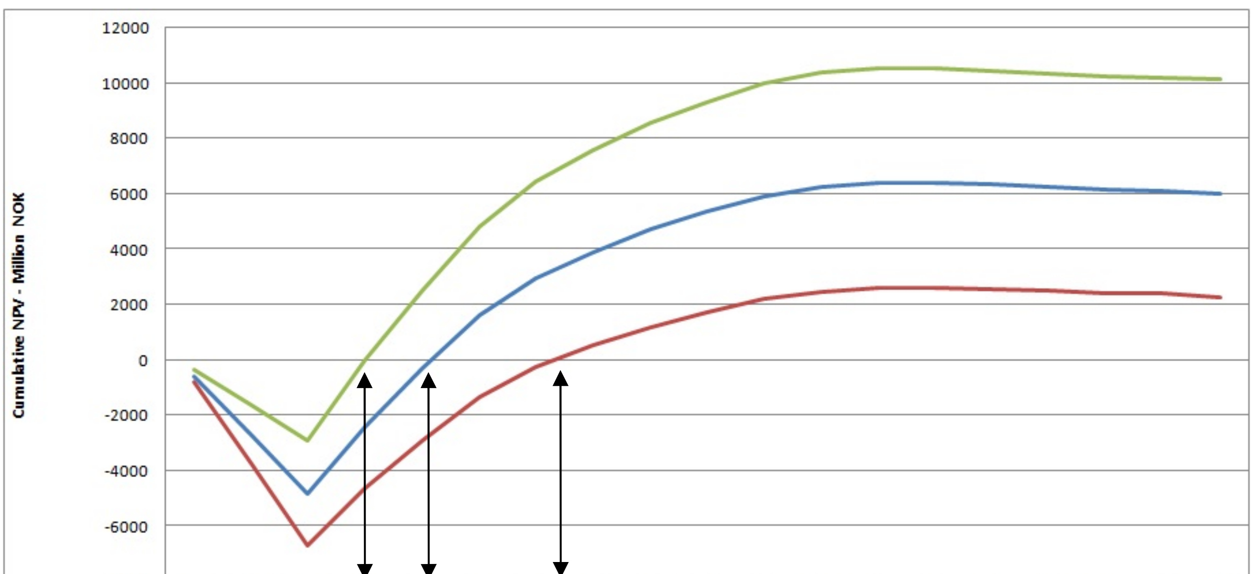
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
BEST NPV	-336	-1270	-1273	2895	2523	2292	1613	1143	970	776	673	375	161	0	-79	-123	-115	-29
BASE NPV	-561	-2116	-2122	2430	2103	1904	1335	945	805	648	563	320	145	9	-59	-97	-91	-23
WORSE NPV	-785	-2963	-2971	2067	1730	1565	1096	775	665	539	471	274	131	15	-43	-77	-73	-19

Figure 7-1: Alternative 1 – Fixed platform - Water injection model



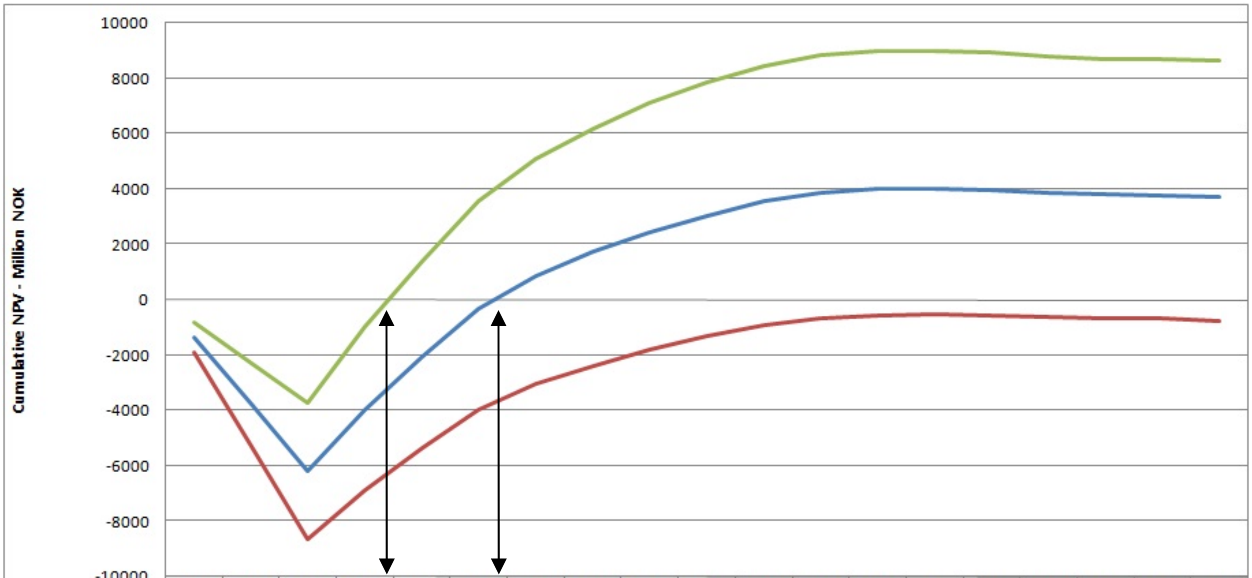
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
BEST NPV	-808	-1448	-1441	2744	2385	2163	1520	1077	915	734	637	358	157	4	-71	-114	-107	-27
BASE NPV	-1347	-2413	-2402	2214	1905	1721	1203	849	726	588	512	295	140	15	-48	-84	-79	-20
WORSE NPV	-1886	-3378	-3363	1786	1515	1360	944	664	573	469	411	246	127	25	-28	-59	-55	-14

Figure 7-2: Alternative2-Subsea-Water injection model



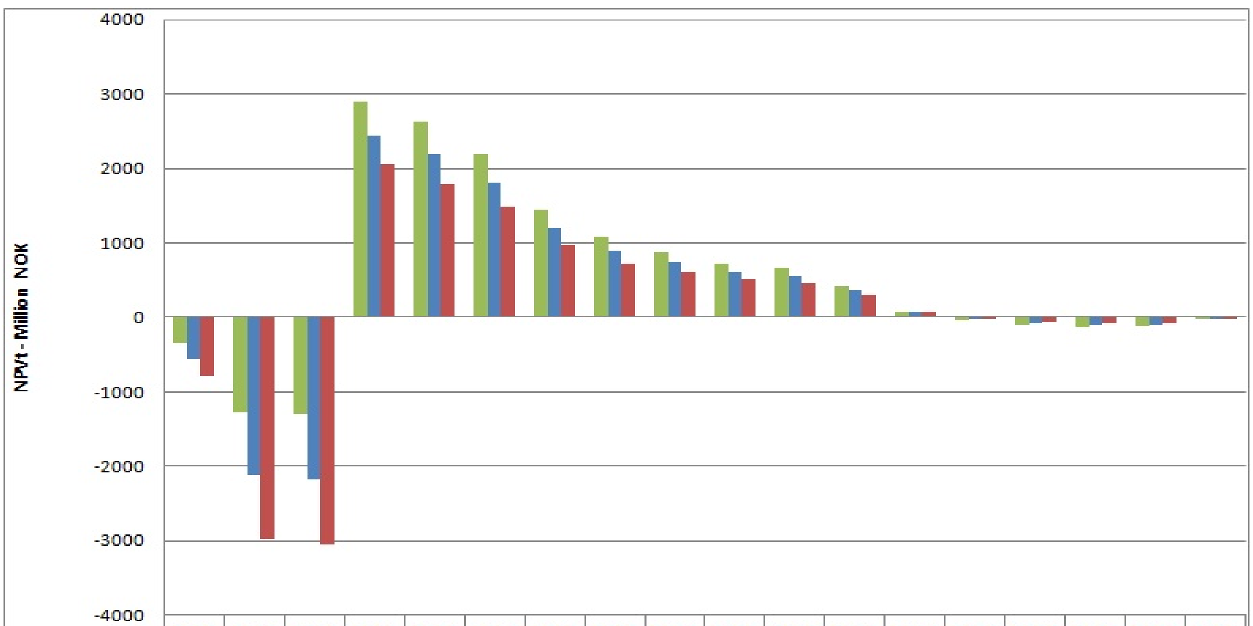
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BEST NPV	-336	-1606	-2880	15	2539	4830	6443	7587	8556	9333	10005	10380	10541	10541	10462	10339	10224	10195	10135
BASE NPV	-561	-2677	-4799	-2370	-267	1637	2973	3917	4722	5370	5933	6253	6398	6407	6348	6250	6159	6136	6037
WORSE NPV	-785	-3748	-6719	-4652	-2923	-1358	-262	513	1177	1717	2188	2461	2592	2607	2564	2486	2414	2395	2256

Figure 7-3: Alternative 1-Fixed platform-Water injection model



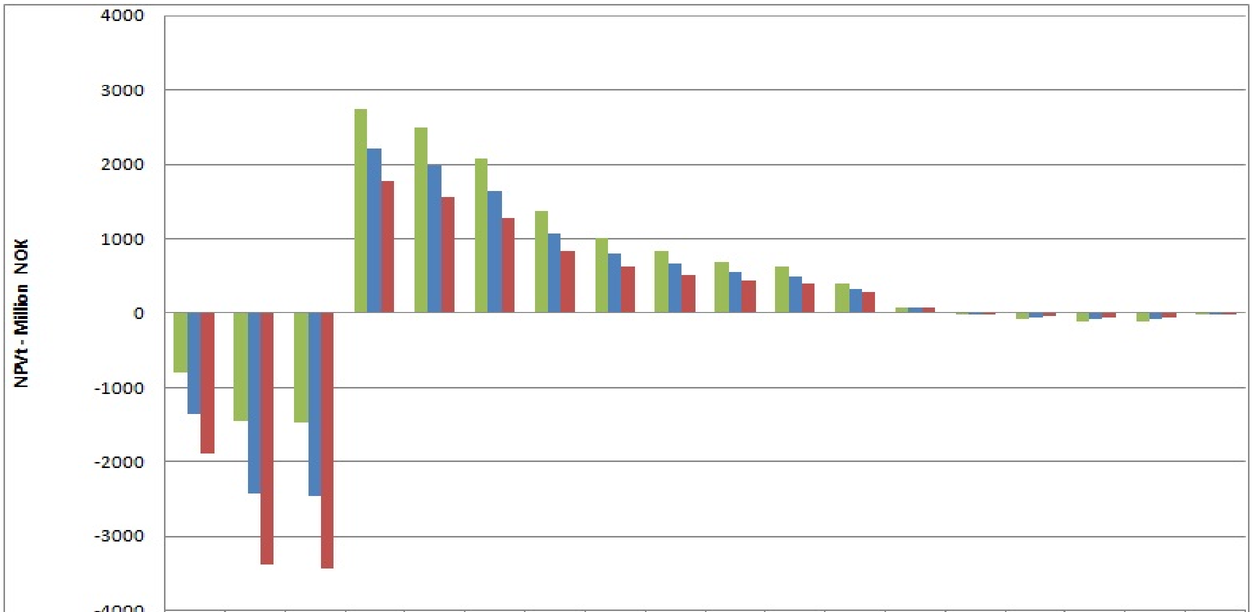
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BEST NPV	-808	-2256	-3697	-954	1431	3594	5115	6192	7106	7841	8477	8835	8992	8996	8925	8811	8704	8677	8638
BASE NPV	-1347	-3760	-6162	-3948	-2044	-323	880	1730	2456	3044	3555	3851	3990	4005	3957	3873	3794	3774	3707
WORSE NPV	-1886	-5264	-8627	-6841	-5326	-3966	-3022	-2358	-1785	-1317	-906	-660	-533	-508	-537	-596	-651	-666	-758

Figure 7-4: Alternative 2-Subsea-Water injection model



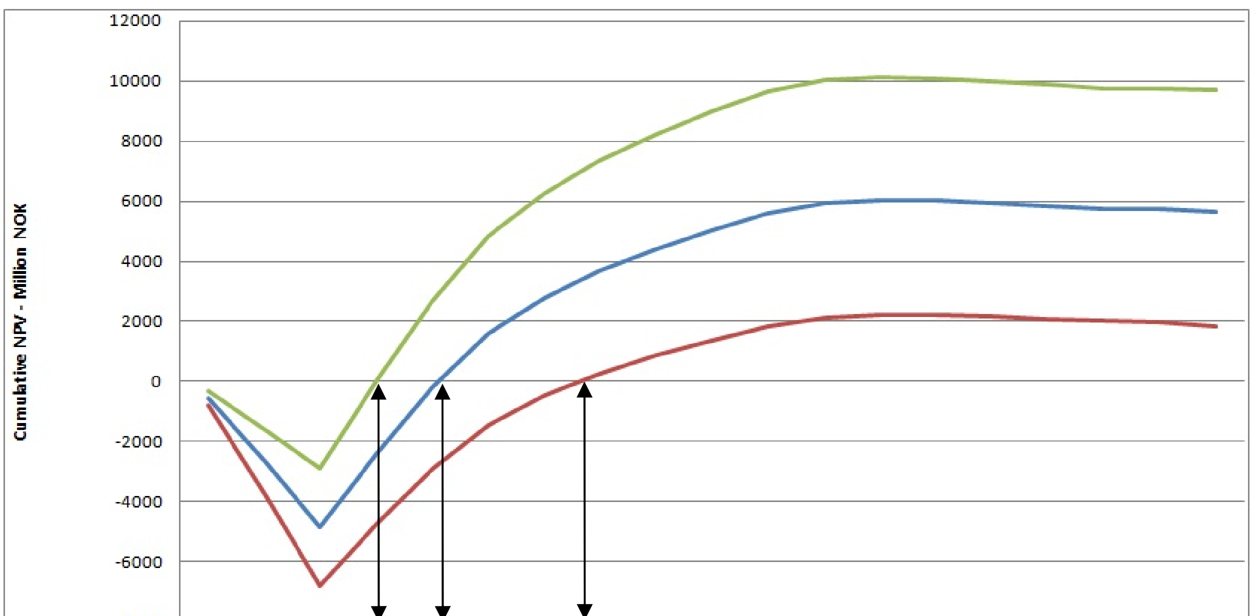
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
BEST NPV	-336	-1270	-1303	2901	2635	2197	1449	1081	884	733	660	414	82	-31	-90	-124	-114	-28
BASE NPV	-561	-2116	-2172	2429	2187	1818	1197	890	734	611	553	355	78	-17	-68	-98	-90	-23
WORSE NPV	-785	-2963	-3041	2061	1791	1487	979	728	606	507	463	305	74	-7	-51	-78	-71	-18

Figure 7-5: Alternative 1-Fixed platform-BrightWater injection model



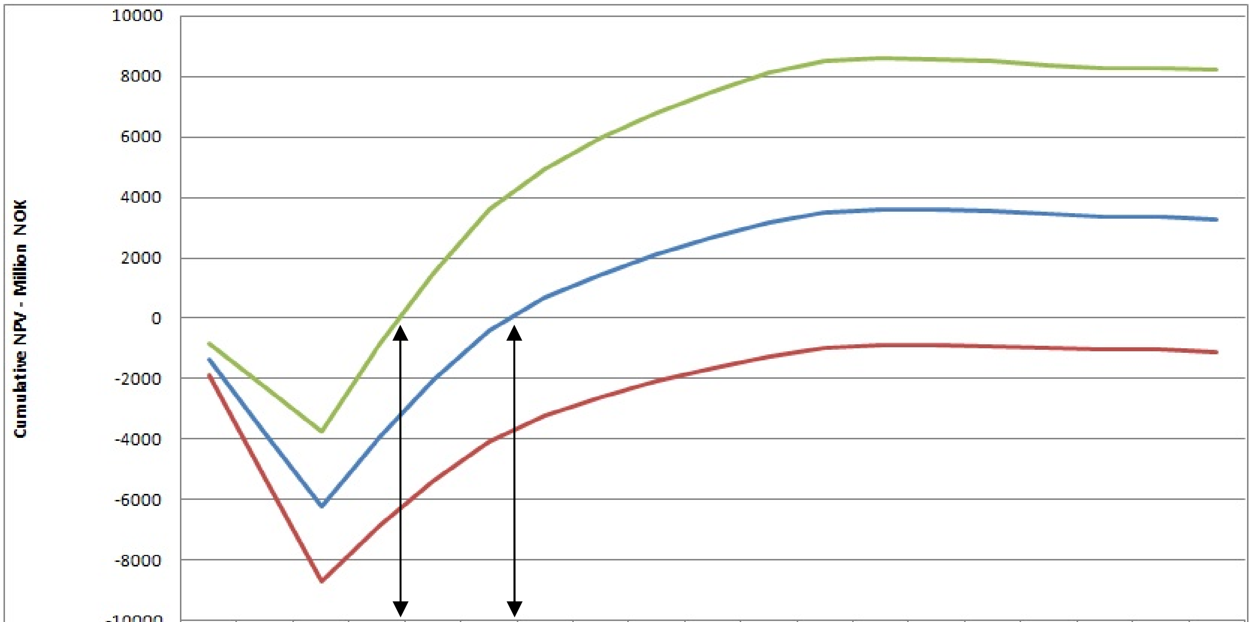
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
BEST NPV	-808	-1448	-1471	2747	2486	2070	1364	1016	834	693	625	396	82	-25	-82	-115	-105	-26
BASE NPV	-1347	-2413	-2452	2210	1974	1637	1076	798	662	553	503	329	79	-9	-56	-85	-77	-20
WORSE NPV	-1886	-3378	-3433	1775	1557	1284	839	619	522	440	404	277	77	6	-34	-59	-54	-14

Figure 7-6: Alternative 2-Subsea-BrightWater injection model



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BEST NPV	-336	-1606	-2909	-9	2626	4823	6272	7353	8237	8970	9631	10044	10126	10095	10005	9881	9766	9738	9679
BASE NPV	-561	-2677	-4849	-2420	-233	1585	2782	3672	4406	5016	5569	5924	6003	5985	5917	5819	5729	5707	5608
WORSE NPV	-785	-3748	-6789	-4728	-2937	-1449	-471	257	863	1370	1833	2138	2213	2206	2155	2077	2006	1988	1849

Figure 7-7: Alternative 1-Fixed Platform-BrightWater injection model



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BEST NPV	-808	-2256	-3727	-980	1506	3576	4941	5957	6792	7484	8109	8505	8587	8562	8480	8365	8259	8233	8193
BASE NPV	-1347	-3760	-6212	-4002	-2028	-391	685	1483	2145	2698	3201	3531	3609	3600	3544	3459	3382	3362	3296
WORSE NPV	-1886	-5264	-8697	-6921	-5364	-4081	-3242	-2622	-2100	-1661	-1257	-980	-902	-897	-931	-990	-1044	-1058	-1151

Figure 7-8: Alternative 2-Subsea-BrightWater injection model

As it is shown in figure 7.1, 7.2, 7.5 and 7.6; in 2012, 2013 and 2014 there are negative numbers in all three cases and in both alternatives, which obviously is due to investment cost (CAPEX) and is expected. However, the negative numbers at the last years are because of decreasing in oil and gas recovery and the OPEX costs could exceed to the incomes of oil and gas revenues. Hence, it would be the time for stopping producing oil and gas if water injection model or BrightWater injection model was selected for IOR in Gullfaks Sør Statfjord.

Moreover, as shown in figure 7.3, 7.4, 7.7 and 7.8; The "***Break-even-points***" for all possible cases, for the two alternatives, for both water injection model and BrightWater injection model could be resulted as in the following table:

Water injection model		
Alternative1 – Fixed Platform		
Best case: End of 2014	Base case: End of 2016	Worst case: End of 2018
Alternative2 – Subsea		
Best case: End of 2015	Base case: End of 2017	Worst case: -

BrightWater injection model		
Alternative1 – Fixed Platform		
Best case: End of 2015	Base case: End of 2016	Worst case: End of 2018
Alternative2 – Subsea		
Best case: End of 2015	Base case: End of 2017	Worst case: -

7.3.2 Sensitivity Analysis:

Due to uncertainties, there are five variables that might be varied as it was mentioned in the assumptions:

• **Oil price**	• **Gas price**	• **CAPEX cost**
• **OPEX cost (Oil OPEX and Gas OPEX)**		

These variables could effect on NPV's value, Sensitivity analysis shows that how much the total NPV is sensitive by changing each these five variables.

Water injection model							
Alternatine 1 (Fixed platform)				Alternatine 2 (Subsea development)			
Oil Price	**Low**	**Base**	**High**	**Oil Price**	**Low**	**Base**	**High**
% Change	–2.00%	0%	5.00%	**% Change**	–2.00%	0%	5.00%
NPV (MNOK)	5844	6037	6519	**NPV (MNOK)**	3515	3707	4189
% Change	–3.194%	0%	7.986%	**% Change**	–5.20%	0%	13.00%
Gas Price	**Low**	**Base**	**High**	**Gas Price**	**Low**	**Base**	**High**
% Change	–2.00%	0%	5.00%	**% Change**	–2.00%	0%	5.00%
NPV (MNOK)	5920	6037	6329	**NPV (MNOK)**	3591	3707	4000
% Change	–1.94%	0%	4.84%	**% Change**	–3.15%	0%	7.88%
Oil OPEX	**Low**	**Base**	**High**	**Oil OPEX**	**Low**	**Base**	**High**
% Change	–30.00%	0%	30.00%	**% Change**	–30.00%	0%	30.00%
NPV (MNOK)	6648	6037	5279	**NPV (MNOK)**	4453	3707	2962
% Change	10.12%	0%	–12.55%	**% Change**	20.10%	0%	–20.10%
CAPEX	**Low**	**Base**	**High**	**CAPEX**	**Low**	**Base**	**High**
% Change	–40.00%	0%	40.00%	**% Change**	–40.00%	0%	40.00%
NPV (MNOK)	7996	6037	4078	**NPV (MNOK)**	6199	3707	1216
% Change	32.46%	0%	–32.46%	**% Change**	67.20%	0%	–67.20%
Gas OPEX	**Low**	**Base**	**High**	**Gas OPEX**	**Low**	**Base**	**High**
% Change	–30.00%	0%	30.00%	**% Change**	–30.00%	0%	30.00%
NPV (MNOK)	6791	6037	5283	**NPV (MNOK)**	4627	3707	2788
% Change	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]

BrightWater injection model

Alternatine 1 (Fixed platform)

Oil Price	Low	Base	High
% Change	–2.00%	0%	5.00%
NPV (MNOK)	5424	5608	6067
% Change	–3.279%	0%	8.199%
Gas Price	**Low**	**Base**	**High**
% Change	–2.00%	0%	5.00%
NPV (MNOK)	5491	5608	5899
% Change	–2.08%	0%	5.20%
Oil OPEX	**Low**	**Base**	**High**
% Change	–30.00%	0%	30.00%
NPV (MNOK)	6190	5608	4887
% Change	10.39%	0%	–12.86%
CAPEX	**Low**	**Base**	**High**
% Change	–40.00%	0%	40.00%
NPV (MNOK)	7587	5608	3628
% Change	35.30%	0%	–35.30%
Gas OPEX	**Low**	**Base**	**High**
% Change	–30.00%	0%	30.00%
NPV (MNOK)	6365	5608	4850
% Change			

Alternatine 2 (Subsea development)

Oil Price	Low	Base	High
% Change	–2.00%	0%	5.00%
NPV (MNOK)	3112	3296	3756
% Change	–5.580%	0%	13.949%
Gas Price	**Low**	**Base**	**High**
% Change	–2.00%	0%	5.00%
NPV (MNOK)	3179	3296	3587
% Change	–3.54%	0%	8.84%
Oil OPEX	**Low**	**Base**	**High**
% Change	–30.00%	0%	30.00%
NPV (MNOK)	4007	3296	2585
% Change	21.57%	0%	–21.57%
CAPEX	**Low**	**Base**	**High**
% Change	–40.00%	0%	40.00%
NPV (MNOK)	5807	3296	785
% Change	76.19%	0%	–76.19%
Gas OPEX	**Low**	**Base**	**High**
% Change	–30.00%	0%	30.00%
NPV (MNOK)	4220	3296	2372

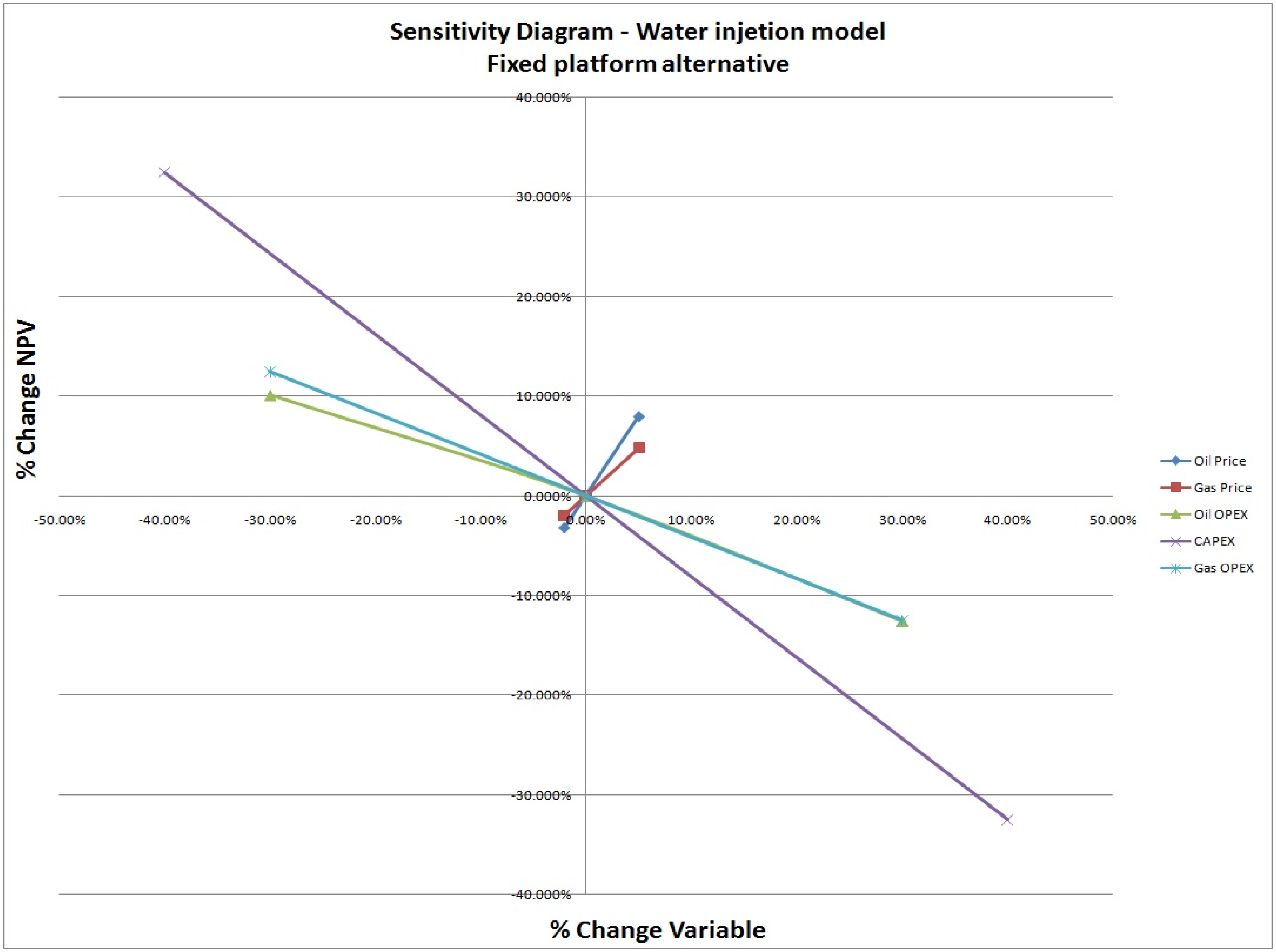


Figure 7-9 Sensitivity Diagram-Water injection model-Fixed platform alternative

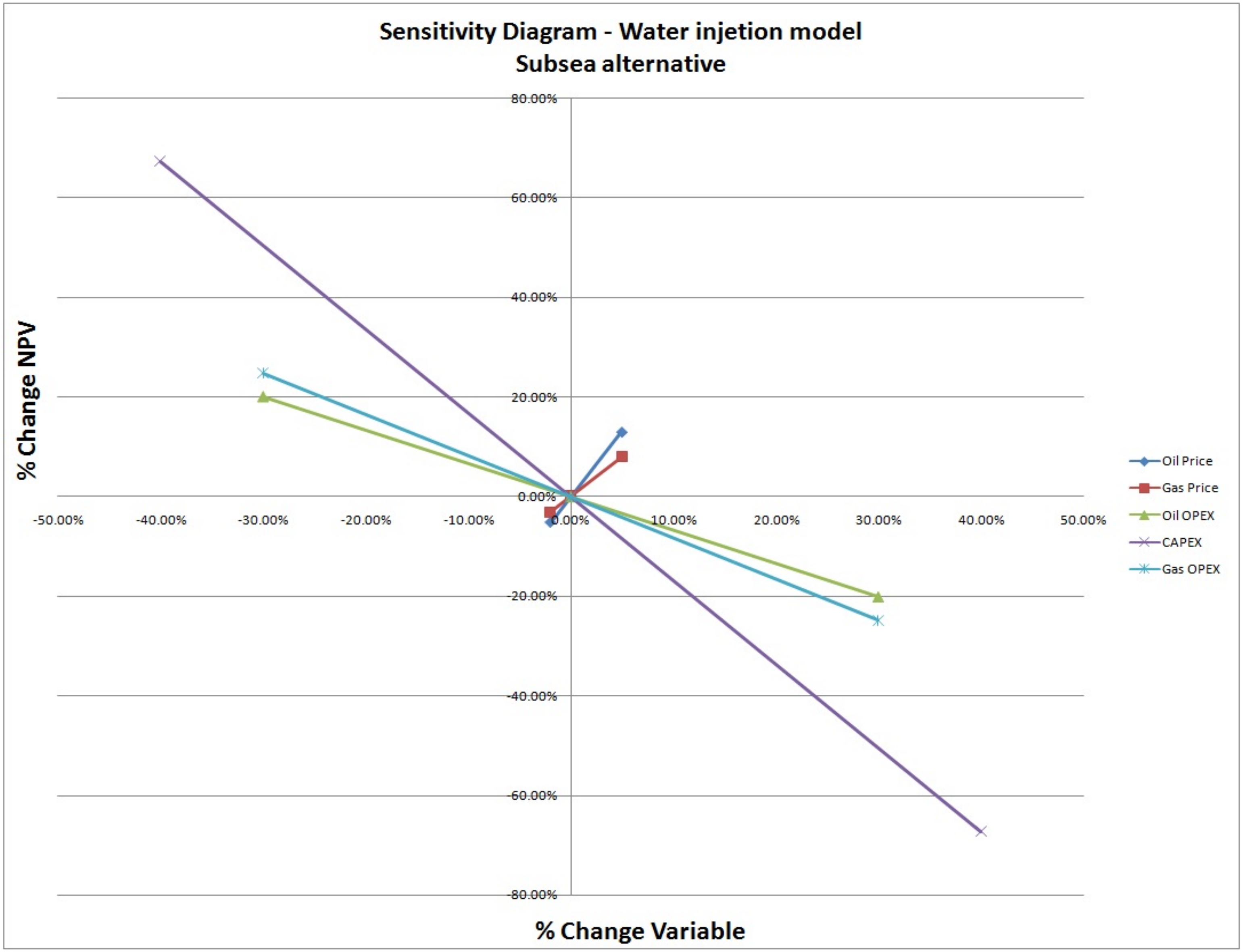


Figure 7-10 Sensitivity Diagram-Water injection model-Subsea alternative

Figure 7-11 Sensitivity Diagram-BrightWater injection model-Fixed platform alternative

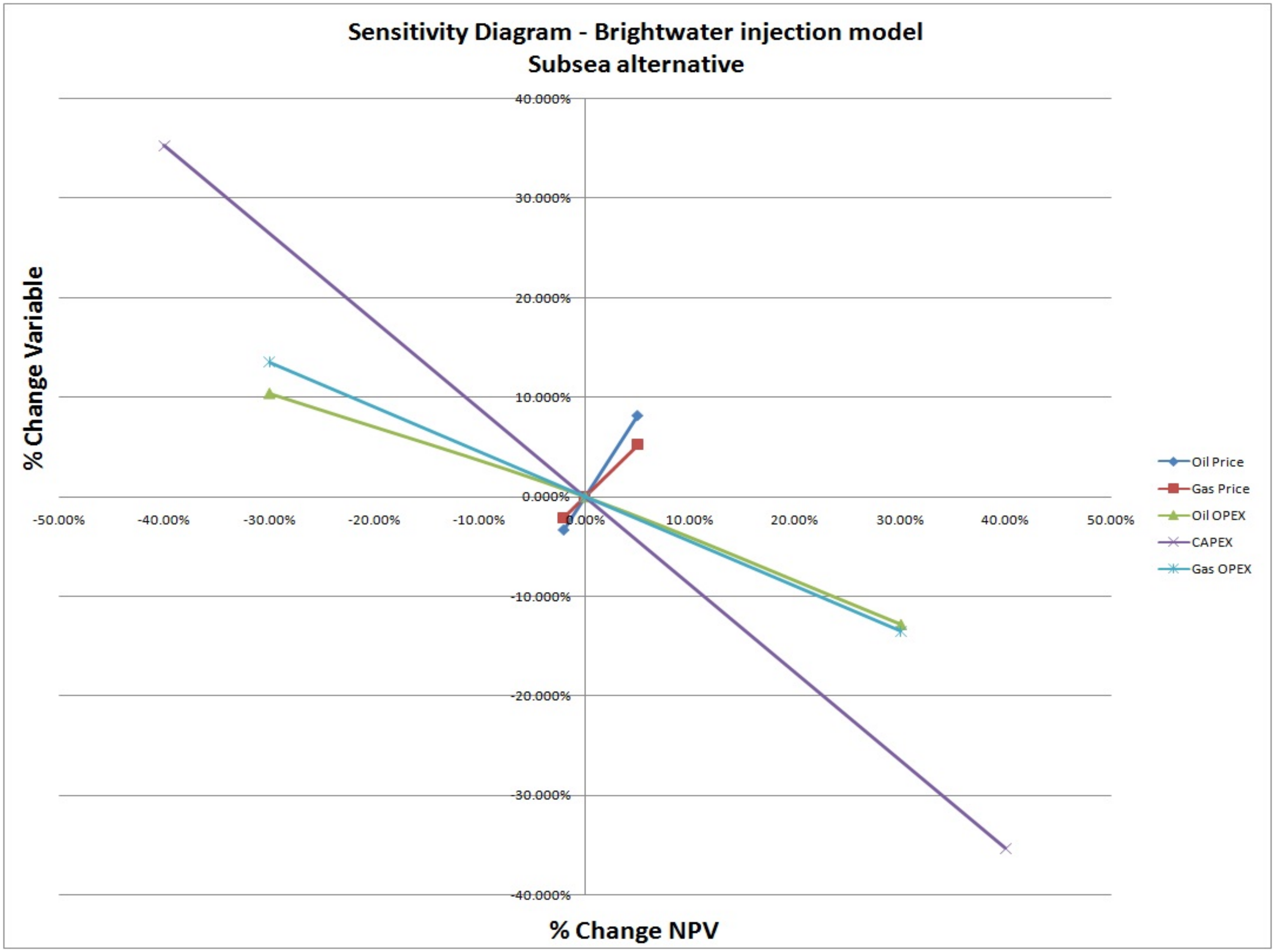


Figure 7-12 Sensitivity Diagram-BrightWater injection model-Subsea alternative

As it is shown in figures 7.9, 7.10, 7.11 and 7.12 in both the water injection and the BrightWater injection models and for both alternative1 (Fixed platform) and alternative2 (Subsea), the sensitivity of the total NPV is depending on (ranged in manner of influence) CAPEX, Gas OPEX, Oil OPEX, Oil price and Gas price.

8 Conclusion

Now it is possible to compare these different IOR models in part A and part B (Extended, water injection and BrightWater injection models) to each other and even with Refrence model in all possible cases (Base, Best and Worst cases) and with the two given alternatives (Fixed platform and Subsea development).

Water injection model gives an oil recovery of 33 Million bbl (66%) more than reference model and 8 million bbl (11%) more than extended model. In addition it gives a gas recovery of 39000 Million bbl (51%) more than the reference case and 21000 Million bbl (23%) more than the extended case.

BrightWater injection model gives an oil recovery of31 Million bbl (63%) more than the reference model and 6 million bbl (8%) more than the extended model. The gas recovery is 38000 Million bbl (50%) more than reference model and 21000 Million bbl (23%) more than extended model.

Moreover, Water injection model would reach a better total NPV compared to the other models.

Furthermore, between two given alternatives for producing oil and gas, the fixed platform gives better total NPV.

Hence, water injection model by using fixed platform producing method could be selected such a best option for IOR in Gullfaks Sør Statfjord as an economical point of view in this report.

It should be taken into consideration that as it is shown in figure 7.1, water injection model by using fixed platform producing method could be remained as an economical model just until end of 2025 for all possible cases (Base, Best and worst cases).

Possible reasons for the increase in oil recovery of Brightwater injection compared to extended model appear to be due to successful well placement strategy. A possible reasons for BrightWater not being as effective as it was in US and UK could be because of less injector to producer transit time. After 50 cases of BrightWater and 15 cases of water injection, our suggestion is that BrightWater system should be more investigated before application to Gullfaks Sør. As result we see that field recovery could be because of better well placement during water injection. Another reason for BrightWater not being as successful as it was supposed to is that, it might be limiting the water sweep energy from water zones of potential producing zones. But real effect of BrightWater –decrease of watercut – was not observed. For getting more efficiency with BrightWater injection more investigation should be put to injection-producer transit time. Accurate front position should be determined for better and more recovery from layers.

9 Appendix

9.1 Gullfaks Sør Petrophysic Figures

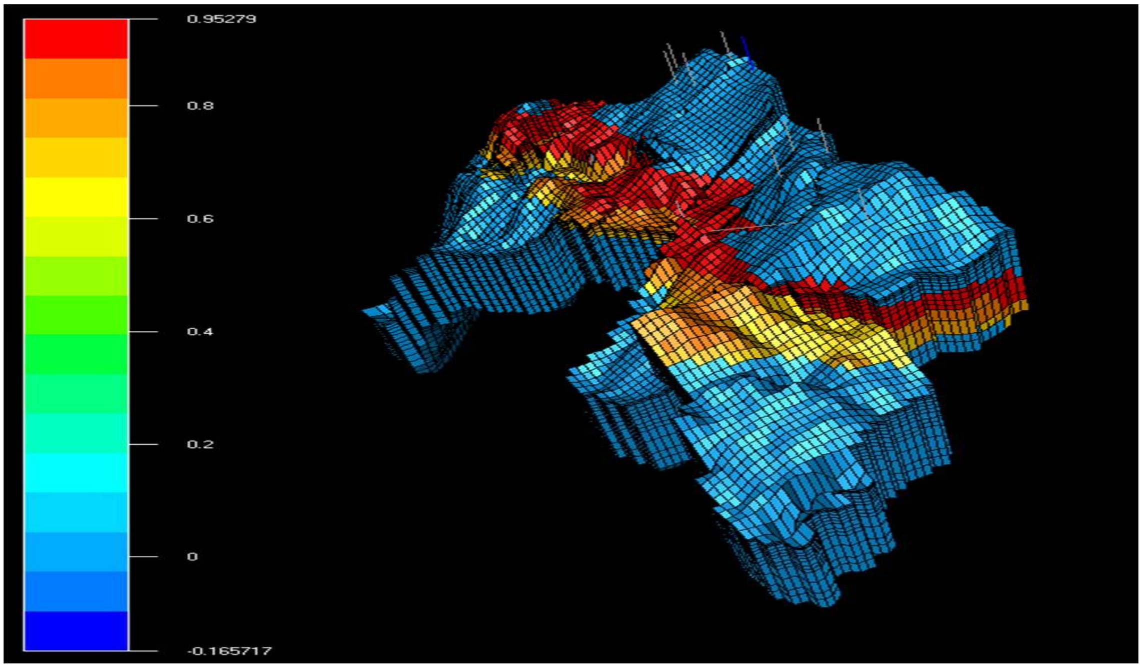


Figure 9-1 Initial oil saturation (fraction) in the reservoir

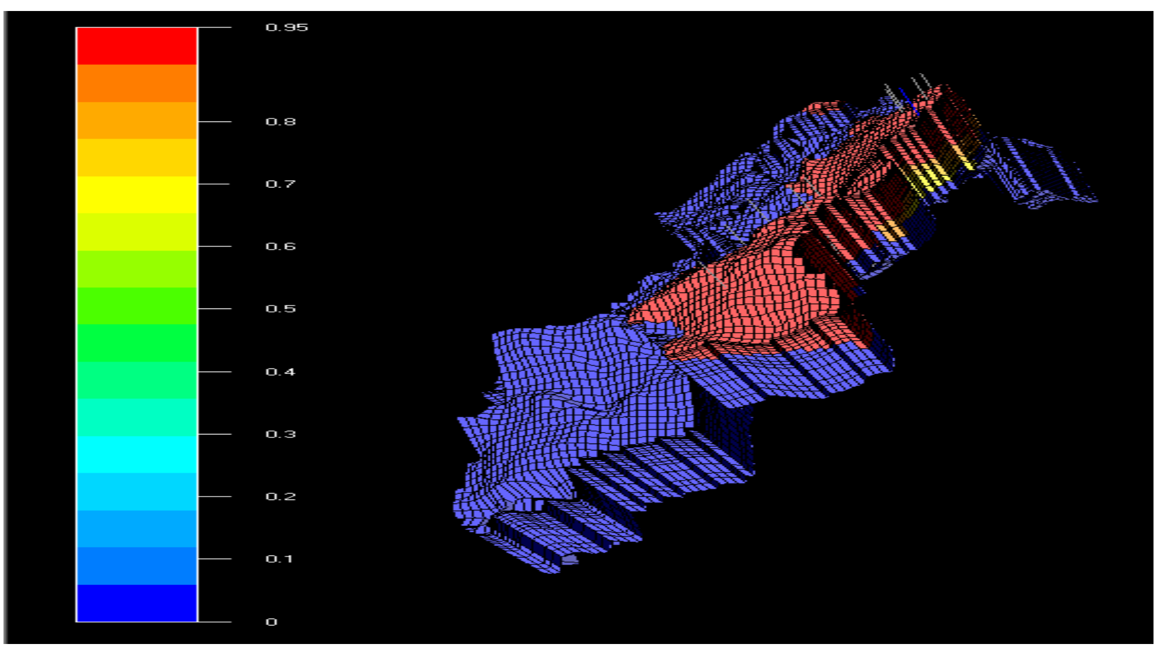


Figure 9-2 Initial gas saturation (fraction) in the reservoir

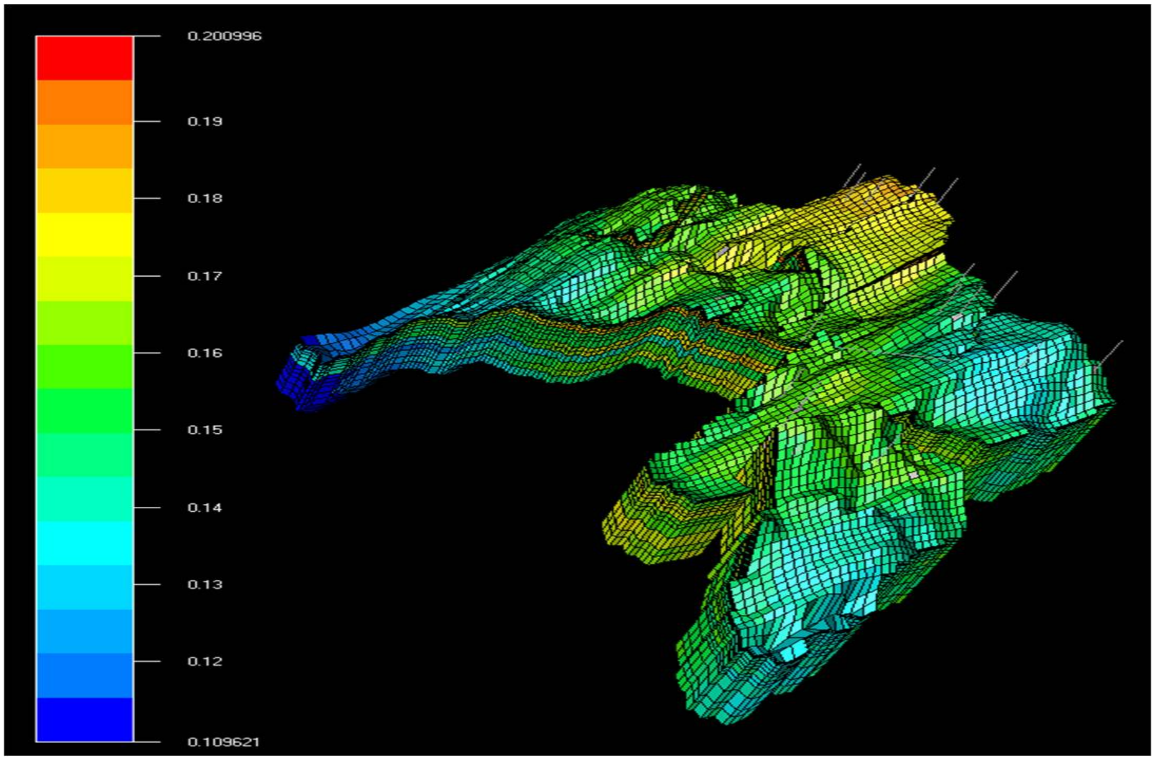


Figure 9-3 Initial porosity (Φ) in the reservoir

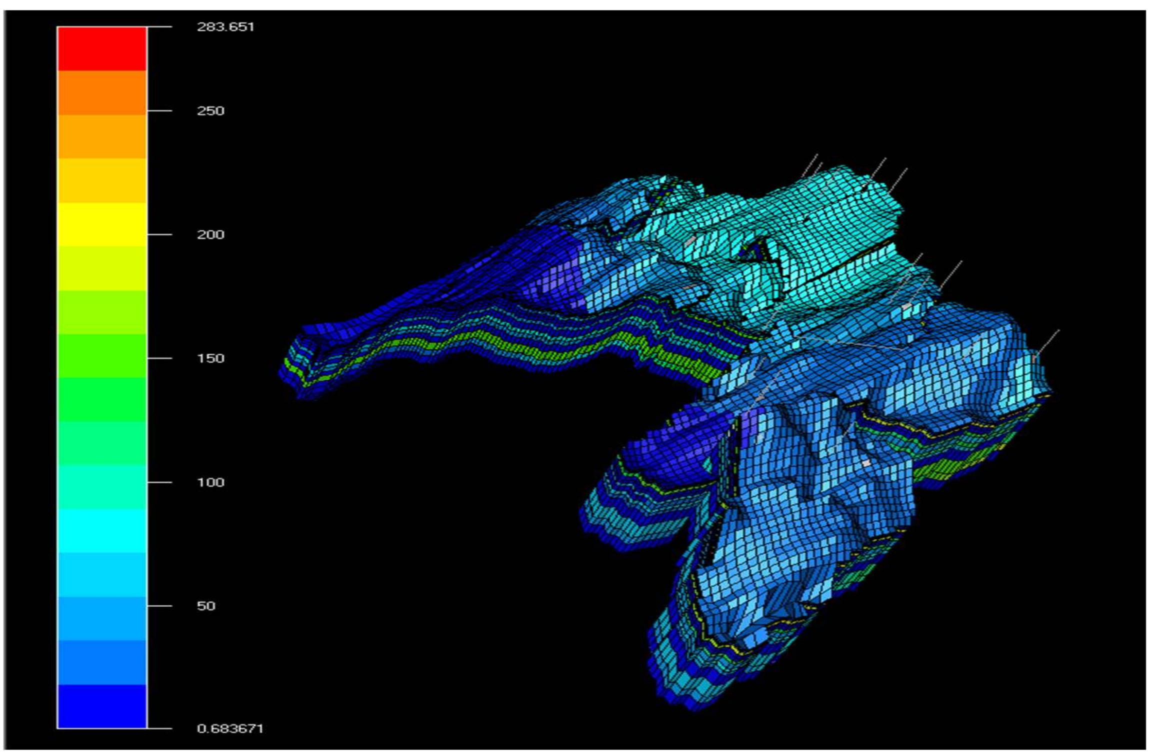


Figure 9-4 Initial permeability (mD) in x-direction in the reservoir

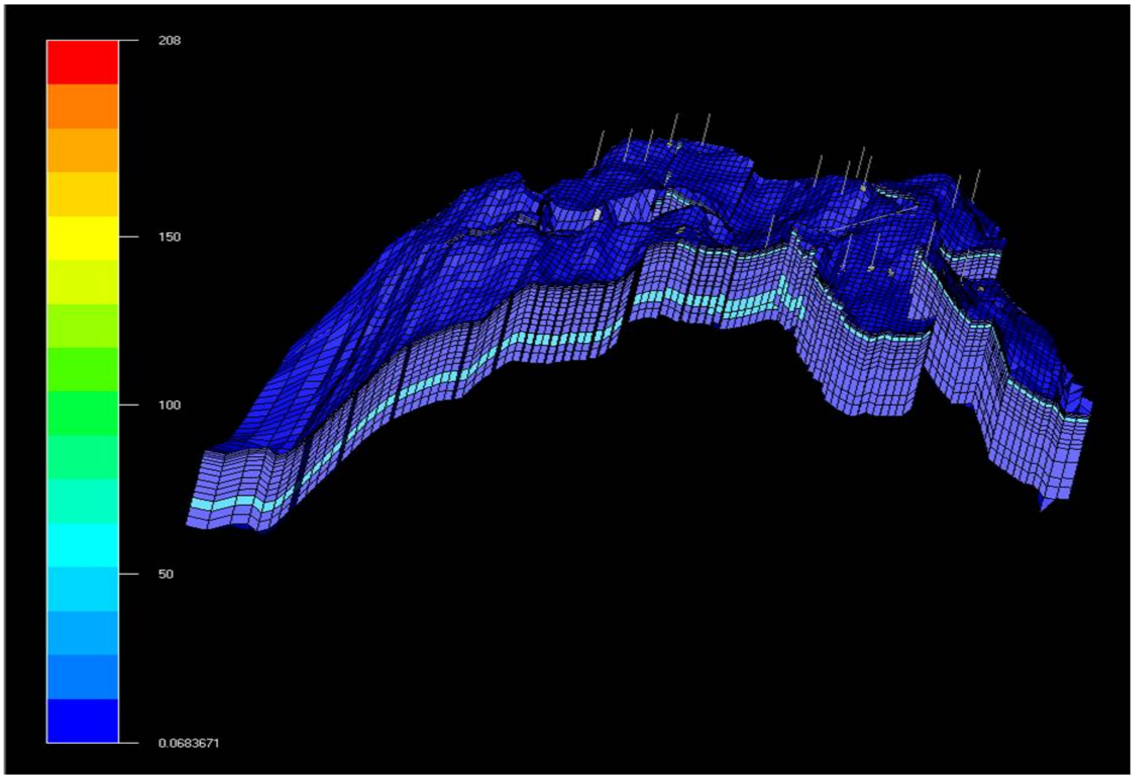


Figure 9-5 Initial permeability (mD) in z-direction in the reservoir

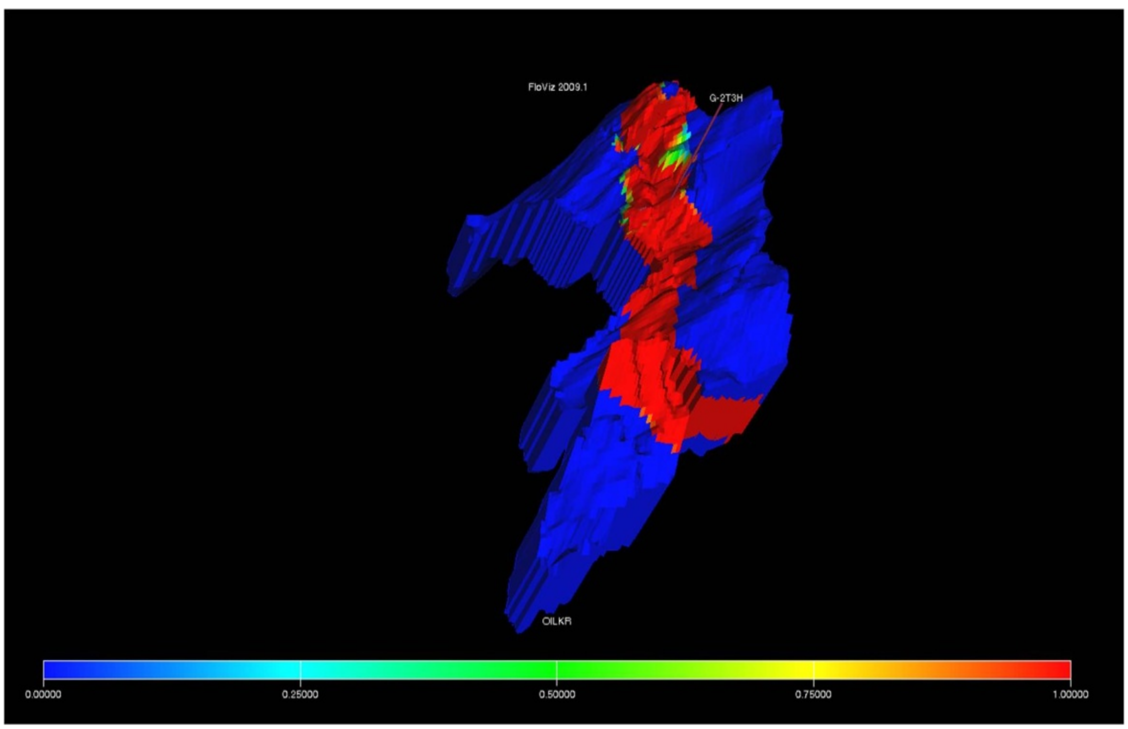


Figure 9-6 Relative permeability (fraction) OIL (Kro)

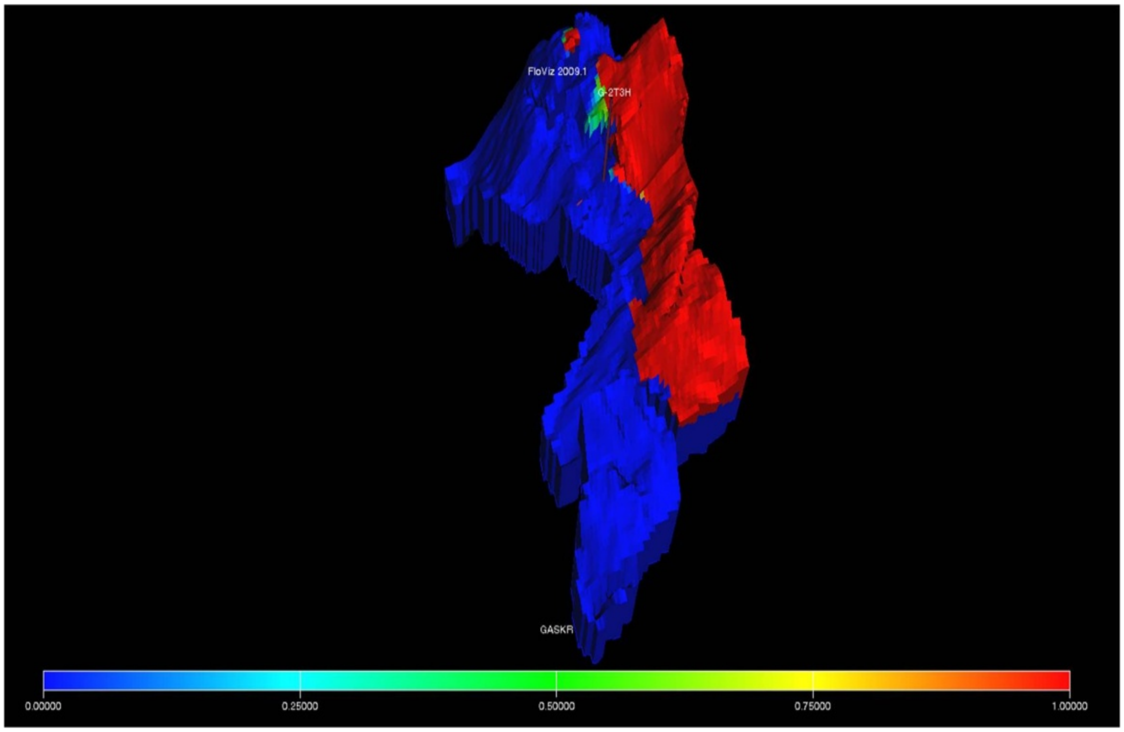


Figure 9-7 Relative permeability (fraction) GAS (Krg)

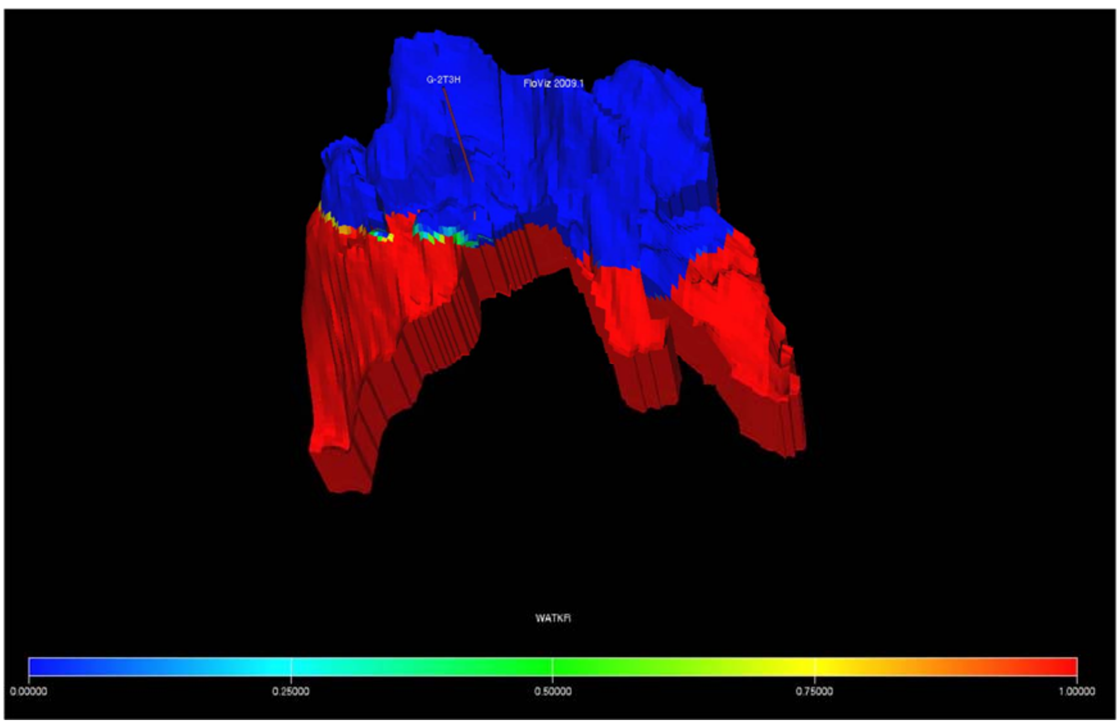


Figure 9-8 Relative permeability (fraction) WATER (Krw)

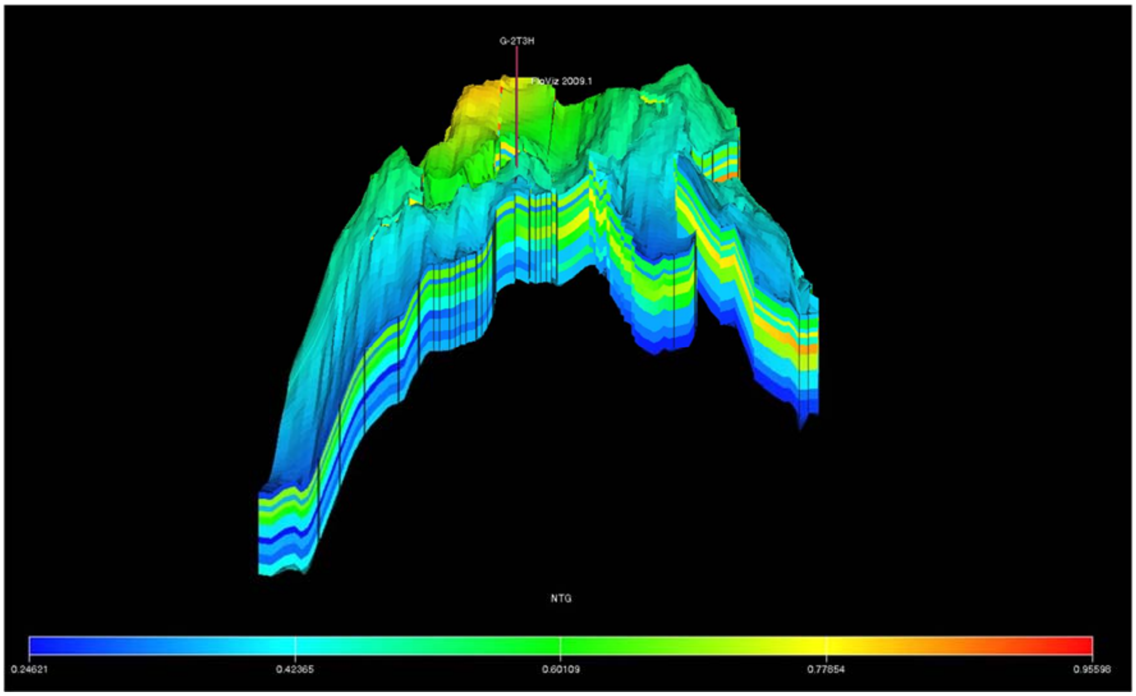


Figure 9-9 Net To Gross (NTG)

9.2 MSDS of polyacrylamide details

9.2.1 First aid measures [20]

Eyes**:** Flush eyes with plenty of water for at least 15 minutes, occasionally lifting the upper and lower eyelids. Get medical aid.
Skin**:** Flush skin with plenty of water for at least 15 minutes while removing contaminated clothing and shoes.
Ingestion**:** If victim is conscious and alert, give 2-4 cupfuls of milk or water. Never give anything by mouth to an unconscious person. Get medical aid immediately.
Inhalation**:** Remove from exposure and move to fresh air immediately. If not breathing, give artificial respiration. If breathing is difficult, give oxygen. Get medical aid if cough or other

symptoms appear.

Notes to Physician**:** Treat symptomatically.

9.2.2 Fire-fighting measures

Suitable extinguishing media; powder / water / foam / carbon dioxide

Other Information; Wet product can cause very slippery surfaces.

9.2.3 Accidental Release Measures/Precautions

Safety precautions personnel	Wet Products cause very slippery floors
Safety precautions environment	Prevent release to drains
Methods for cleaning up dry product	Flush contaminated area with water

9.2.4 Handling and storage

Handling:	Spill causes slippery surfaces. So avoid spillage
Storage:	Store in a dry place at normal temperature

9.2.5 Exposure control

Occupational exposure workplace: Use ventilation to extraction of potentially dust formation.

Hand protection:	Risk of direct contact so use gloves PVC or rubber.
Respiratory protection:	Filters

9.2.6 Stability and reactivity

Reactivity:	Keep away from strong acids and bases due to reactivity
Stability:	Stable under normal conditions [16]

10 References

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