Improved Oil Recovery with Water Injection

EiT - Gullfaks Village 2011

Norwegian University of Science and Technology

In cooperation with

Statoil ASA

Project Group 6

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Abstract

The project is focused on the issue of water injection in Beta Ridge in the Gullfaks Field, offshore Norway. The main task was:

- To determine the amount of injected water needed to stabilize the reservoir pressure decline.
- To estimate the costs of drilling the required well(s).
- To make an estimate of the additional recovery the water injection would give,
- To make a recommendation based on the economics of the project.

Eclipse simulations, knowledge about geology and reservoir communication, and economics were used in conjunction with one another to help determine a final recommendation. We determined that perforating and injecting into the Etuve/Rannoch Formations (layer 7 of our model) gave the best results for reservoir pressure maintenance.

Three simulations were run with a well placed on the east side of the main fault, a well on the west side of the fault, and a well on either side of the fault. The results showed that the amount of water injection necessary was nearly the same in all cases, with the two well scenario simply splitting the total volume needed between the two wells. Sensitivities were run based on the well placement and well orientation (i.e., vertical vs. horizontal), and it was determined that there was little change in the volume of injected water needed in both cases.

Simulations were run to test the formation pressure after injection, and the effects on the BHP. It was determined that a slight reduction of both formation pressure and BHP was seen in the two-well scenario, but as we were well below the fracture pressure of the formation, the results were not a deciding factor in the final recommendation.

The amount of additional oil recovery in each case was calculated, with injection in the east well giving us the greatest results with an additional oil recovery of 1.1%. The economics for the project were based on this one well scenario, but were also run in the two-well scenario to show that the project was still profitable even with the higher costs of drilling two wells. It would be beneficial to drill two wells as a safety measure (i.e., in case one well were to fail), and also in situations where we are near the fracture pressure of the formation. Statoil provided the assumptions used in the economics, with results based on sensitivities to OPEX, CAPEX, and the price of oil. It was determined that even in a worst case scenario with cost overruns in drilling, and low oil price, the project would still be highly profitable for Statoil. Based on the simulations run, sensitivities tested, and economics, the group recommends that Statoil proceed with a single water injector placed on the eastern side of the main fault in Beta Ridge.

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1 Introduction

As a part of the Experts in Team (EiT) program at The Norwegian University of Science and Technology, the Department of Petroleum Engineering & Applied Geophysics has an arrangement with Statoil ASA ('Statoil') that results in three "Villages". Among these, is the Gullfaks Village. The main focus areas in this village, in addition to team related training, are the issues related to the Gullfaks Sør field operated by Statoil. The groups are faced with real life challenges and are provided with the necessary tools to overcome and find the best solutions. The following report is written as a result of the work done by Group 6 in the Gullfaks Village 2011. All work has been done in close collaboration with Statoil, and its office in Bergen.

The report consists of two parts, Part A and Part B, each addressing issues related to the Gullfaks satellite fields in the Vestlig Provins.

The main purpose of Part A was to demonstrate an understanding of the challenges related to production with pressure depletion and aquifer support. A material balance calculation was used as a basis for analyzing production and pressure behavior. The main focus from the results was the question regarding communication within the reservoir as well from field to field.

The primary goal for Part B was to find a solution to the challenge of stabilizing the reservoir pressure decline to improve the recovery factor. To achieve this goal, Statoil has provided a model of the Vestlig Provins, which was used for studying the effects of water injection (WI) in the formations along the Beta Ridge.

Part B starts off with a brief introduction to the aspects related to the geology in the Vestlig Provins in Chapter 8. In the chapter "Reservoir Model Description", details around the model being used are mentioned, followed by sections discussing issues related to drilling.

The main task of the project is being addressed in Chapter 12. The chapter answers a number of questions, including, the additional amount of injected water that is required to achieve pressure maintenance along Beta Ridge. Having answered this question, aspects regarding the sensitivity of these results are studied in more detail.

A final recommendation and conclusion is given based on the results from the sensitivity analysis, as well as the estimates done for recovery and an economical analysis. The latter two are addressed in Chapters 15 and 17, respectively.

Part I
Project Part A

2 Introduction Part I

2.1 Objective

This report has several main objectives:

- To give a briefhistory of the field, and a short geological description of the Brent Formation and associated structural configuration.
- To calculate the average reservoir pressure depletion in Beta Ridge.
- To compare the average reservoir depletion with wells A-32 and discuss any differences that may be present.
- Evaluate the recovery factor for the various fields to date, and answer questions such as: how the fields interfere with each other, the expected recovery factors over the full production of the life of the fields, and why there could be differences in the recovery factors calculated between the fields.

2.2 Field History – Gullfaks Area

The Gullfaksfield, as seen in Figure 1, comprises two field areas, namely Gullfaks, and the Gullfaks Satellites (GF SAT). The latter refers to the collection of smaller fields that surround Gullfaks, and include those fields in Beta Ridge that are included in this report – Tordis, Vigdis, Gullfaks Vest, Gullveig, and Gulltopp, and Skinfaks. Beta Ridge is outlined in Figure 1.

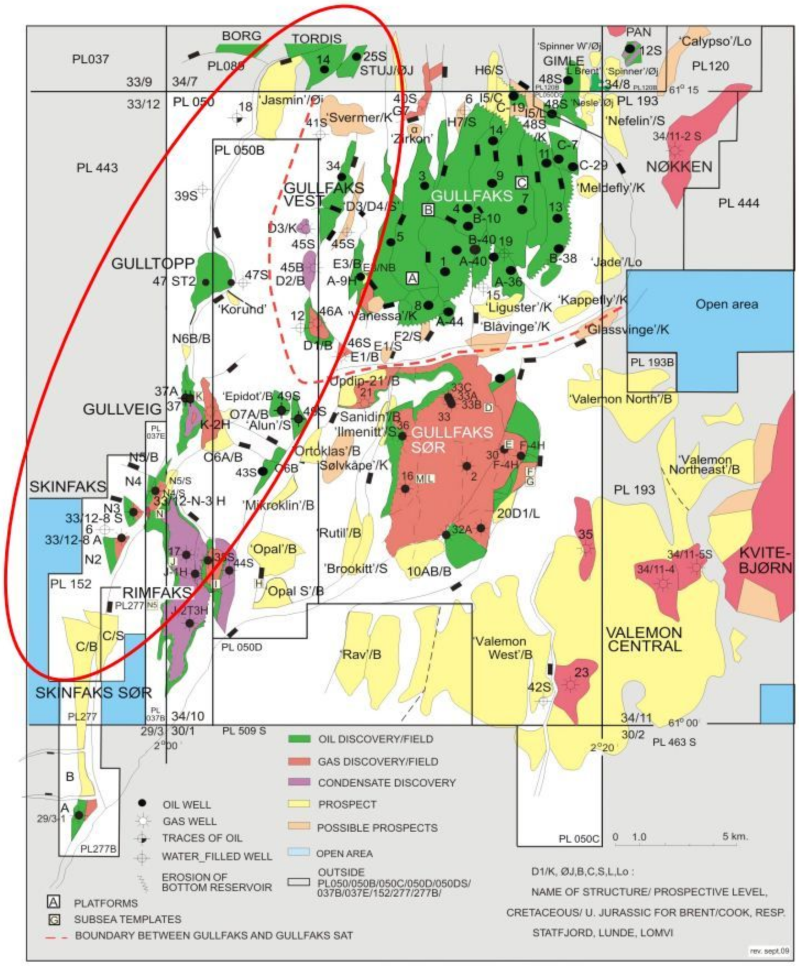

Figure 1: Fields and discoveries in the Gullfaks area with the Beta ridge marked.

Statoil and Petoro jointly own the Gullfaks field, with the former holding 70% working interest and operatorship, and the latter holding the remaining 30%.The main Gullfaks field was discovered in 1978 by well 34/10-1, with production beginning on the Gullfaks A, B, and C platforms beginning in December 1986, February 1988, and January 1990, respectively.

From the period shortly after the 34/10-1 discovery until 2002, a total of 12 explorationwells were drilled in the GF SAT fields. Production from these satellite fields (which includes Gullfaks South) commenced in 1998, and as of June 30, 2007, has produced 60.5% of the proven reserves.

2.3 Geology

The geology of the Gullfaks area is quite complex, and will be simplified in this report for the purposes of brevity. The target formation is the middle Jurassic Brent Formation, with the following formations listed from oldest to youngest: Broom, Rannoch, Etive, Ness, and Tarbert. Overlying shalesof the Heather Formation provide a seal for the reservoir. In addition to the producing Brent Formation, other underlying producing formations include: Cook Formation, Statfjord Formation, Lunde Formation, and Krans Formation, but will not be further discussed in this report.

The Broom, Rannoch, and Etive Formations (lower Brent Group) represent the progradational phase of the delta complex, while the Ness and Tarbert Members represent the retrogradational phase. The Tarbert Formation contains various packages of sediments that represent facies encountered in a retreating delta front. These include:

- Bay in-fill sediments, which are capped by pervasive coal deposits that facilitate correlation of units
- Tidal surfaces and coastal plains
- Fluvial channels - some of which contain excellent reservoir properties (e.g. Silky Sand)
- Shoreface deposits, which are encountered in the uppermost part of the formation, and are thought to represent the final pulse of the delta prior to drowning.

The upper reservoir units in the Tarbert are dominantly homogeneous, with permeability values between 3 and 10 Darcy encountered. The lower portion of the reservoir, however, contains several heterogeneities that include: mudstones, coal layers, and calcite cementation.

The Ness Formation is highly heterogeneous formation that was interpreted to have been deposited at the top of the Brent delta. Two main facies dominate this section, namely: floodplain sediments, and crevasse splay complexes with minor mouth bar deposits.

The lower Brent Group represents the deposits of delta progradation. The lowermost Broom Formation consists of prodelta mudstones, and is not of any interest in reservoir development. Overlying the Broom Formation is the Rannoch Formation, which consists of heterolithic cross-stratified sandstones. The upper part of the Rannoch is generally homogeneous with good reservoir properties, while the lower contains more heterogeneities, including calcite cementation and high clay content. These are barriers to flow within the reservoir, but are not correlable from well to well. The Etive Formation contains the best reservoir of the lower Brent Group, consisting of massive cross-stratified sands, with few heterogeneities that could hinder fluid movement.

In addition to the complex geology seen through the Brent Formation, the region has been influenced extensively by regional tectonics. The Gullfaks region lies in a structurally high area to the west of the Viking Graben, with current structural configuration due to rifting during late Jurassic/early Cretaceous time. The most important part of the Gullfaksfield lies within the westerly domino system of westward dipping rotated fault blocks. The main faults are oriented in a north-south direction, with fault throwsof 50 and 250 metres. Three main structural regimes exist across the Gullfaks area, namely: the domino system, the accommodation zone, and the horst complex. The important parts of the Gullfaks field lie within the domino system, where the Brent group hasn't been eroded away (as is seen in the horst complex). As the Brent Formation is located near the top of the stratigraphic section, it has experienced intense tectonic deformation, with numerous faults that can aid or hinder fluid movement throughout the reservoir.

The Gullfaks satellite fields have undergone similar tectonic deformation, but are located on a structural high to the west of the main Gullfaks field.

3 Theory

The equation we will use in order to calculate volume changes in the reservoir is:

$$\triangle V = V_1 C_{tot} \triangle P$$

which is a variation of a part of the material balance equation listed below:

$$V_2 = V_1(1 + C_{tot} \triangle P$$

In this equation we have used the following parameters:
$\triangle V = V_2 - V_1$
V_2 = Reservoir volume, after depletion
V_1 = Reservoir volume, before depletion

This change in volume is the amount of oil produced at the surface, and the recovery factor is therefore given by $\Delta V/V_1$. After petroleum is produced for a little bit of time, we will see reduction in the reservoir pressure. This can be problematic as the primary driving mechanism when producing petroleum is the pressure difference between the wells and the reservoir, allowing fluids to flow in the direction with less pressure. In order to mitigate this effect, we often use injection wells to inject gas or water to keep the pressure drop at a low level.

$\triangle P = P_2 - P_1$
P_2 = Reservoir pressure, after depletion
P_1 = Reservoir pressure, before depletion

Compressibility is given by:

$$C_{tot} = C_r + \sum_{i=g,o,w} S_i Ci$$

$$C_r = \frac{1}{\emptyset} \frac{d\emptyset}{dP}$$

$$C_i = \frac{1}{V_{i,1}} \frac{dV}{dP}$$

In this equation, φ symbolizes the porosity, or the pore space compared to total bulk volume. This is important as the porosity works as the storage space for fluids in the rock. A porosity value between 10-35% is normal in a sandstone. The porosity could decrease slightly under production due to reservoir compaction. This is associated with subsidence at surface, which could lead to big problems and platforms "sinking." However, this also leads to compaction drive, which can increase recovery factor significantly and is as a whole considered as a good thing.

The saturation S describes what kind of fluids that are present in the pores. This saturation will change during production and we will see a decrease in oil saturation and increase in water and/or gas saturation.

The chart as seen in Figure 2 shows the pressure development in different areas in the Gullveig Brent Formation. The graphs represent the pressure development through time in four different regions of the Gullveig Brent area. The decline in pressure before Gullveig was placed on production in 1998 indicates leakage/pressure communication to the Gullfaks main field.

We can also infer from the chart that the wells do not have a very good pressure communication with each other.

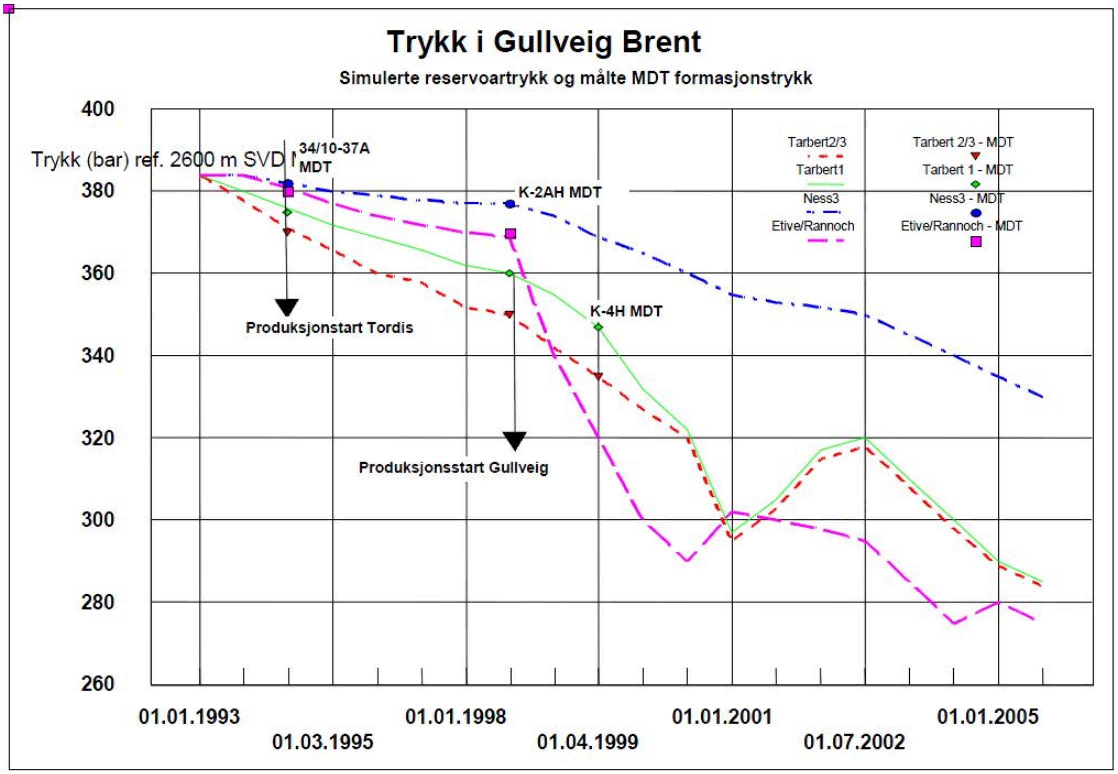

Figure 2: Pressure in the different formations in Gullveig Brent Field

4 Uncertainties and Assumptions

Many reservoir calculations in structurally complex areas are typically characterized by poor seismic imaging, and a number of uncertainties are therefore associated with the interpretation and assumptions. In order to reduce this uncertainty, it is necessary to utilize information from all available seismic data and relevant wells, as well as empirical data from other similar areas of the field. Suitable field analogues are used to guide interpretations of the structural style in the most complex and poorly imaged parts of the field.

In the first part of the assignment, we calculate pressure depletion at Beta Ridge-based on the provided data. The main uncertainty in the calculation is the initial water saturation, and due to the fact that all the reservoir fluids are converted to the water equivalents, we make an assumption that initial water saturation is 1 ($S_w = 1$). The initial reservoir pressure over the whole Beta Ridge area is assumed to be 380 bar according to the data provided by Statoil.

Along with these uncertainties, it is important to remember that in real life, the properties of the reservoir among each segment would be different. Despite the uncertainties, this data is necessary for the PVT calculation. Since we don't know the exactly property values, we assume that we use zero dimension analysis in the material balance (MB) calculation in this project. This means that the properties or parameters in every point in reservoir are the same. Thus, we can apply one value for rock and water compressibility in the whole reservoir for MB analysis as the followings:

- Rock compressibility = 4.5e-5 bar^{-1}
- Water compressibility = 5.2e-5 bar^{-1}

In the second part of the calculation we are using sensitivity analysis. Sensitivity analysis is needed to get a better understanding how each parameter affects results in the material balance equation. We use the Recovery Factor (RF) as a performance parameter to observe the effects of each parameter. Based on a number of available data and well tests in Beta Ridge we can conclude that communication between the fields Gullveig, Tordis, Skinfaks and Gulltopis present. For instance, depleted pressure in the N3 segment is an indication of communication in the water basin along the entire Beta Ridge up to the Tordis Field to the north.

Although a gas and oil correlation study in the south-western parts of the Gullfaks Field supports the assumption for the migration of light oil and gas from Rimfaks/Gullveig into the E2/E3 segments of the Gullfaks Field, in the sensitivity analysis we are looking at the possibility that there is no leakage to the main filed. Applying the same assumptions as in the first part ($S_w = 1$, C_r=4.5e-5 bar^{-1}, C_w= 5.2e-5 bar^{-1}) we calculate the initial volume need to obtain a match with given pressure data.

5 Calculations and Sensitivities

5.1 Initial fluid volume: estimation and sensitivity

Initial fluid volume is an essential parameter needed for planning, developing and understanding a reservoir. Hence, a good estimate must be made. The reservoir depletion can be estimated by use of the simple material balance equation:

$$\triangle V = VC_t\triangle P$$

This equation was described in more detail in section 3.

To get an idea of the initial net pay fluid volume of the Beta Ridge fields, and to get a foundation for the sensitivity analysis, an assumption for the value of the compressibility has been made. The effect of variation in compressibility will be discussed at a later stage.

The goal of the volume sensitivity analysis is to achieve a reasonable match with the simulated reservoir pressure depletion by using the above equation. As mentioned, compressibility is kept constant, and the changes in volume are calculated from the measured data (Appendix A) Initial volume is then varied until a satisfying match is obtained. The simulated result was presented earlier, however, the same plot can be seen in Figure 3.

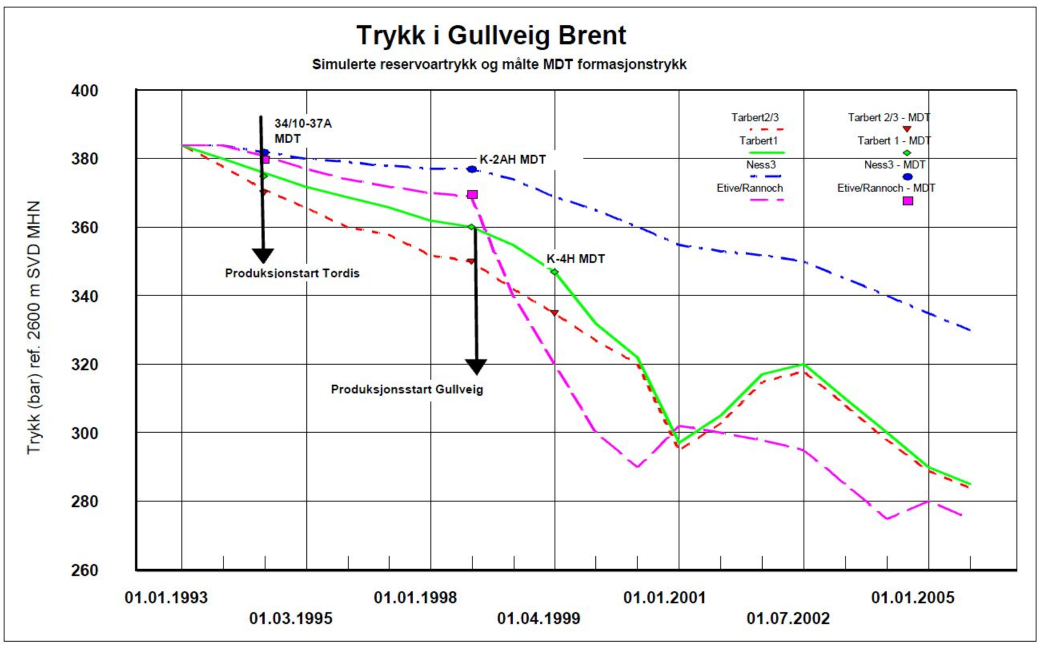

Figure 3: Simulated pressure development for he different formations of the Beta Ridge.

The plot in Figure 4 shows the pressure depletion estimated from the material balance for different initial volumes. It is evident that the pressure development is quite sensitive to variations in initial volume, and it is therefore crucial to make a good estimate of the initial volume. The results from the calculations can be found in Appendix B.

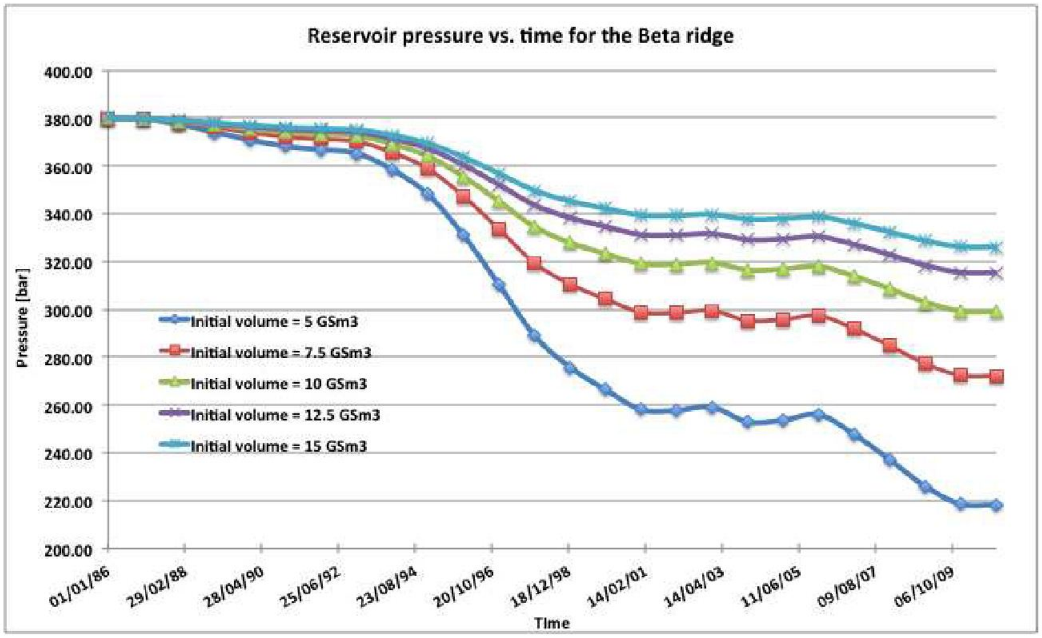

Figure 4: Calculated reservoir pressure for different initial fluid volumes and constant compressibility.

With the compressibility equal to our assumption, a reasonable match is achieved with an initial volume equal to approximately 10 GSm^3. Notice the absence of the downward spikes on the estimated curves that can be observed on the simulated ones. This is a consequence of the fact that our estimates represent the average for the whole field, and not each individual formation. This topic is discussed more in detail under the conclusion section.

However, there is a possibility that there might be even more fluid in place. This can be explained by the fact that our estimates only take the net pay volume into account, and the gross volume might be different. Net pay volume is the part of the total volume that can be produced.

The estimated initial oil in place (IOIP) for the Brent Formation is approximately 200 MSm3; comparing this volume to the estimated fluid in place, we can see that the initial oil saturation (S_o) is quite low. The high water cut observed for this field supports this high initial volume estimate.

5.2 Compressibility sensitivity

From the volume sensitivity above, we have established a ground estimate of the initial volume of fluids in place. However, great uncertainties exist in this estimate due to the many assumptions made. Compressibility is, among others, one of them. Despite the fact that the error in the compressibility may be small, i.e. 10^{-5} bar^{-1}, the effect may be significant. From the material balance equation, we see that the depletion is the change in volume divided by the product of initial volume and compressibility. The effect of changing compressibility is illustrated in the plot in figure 5.

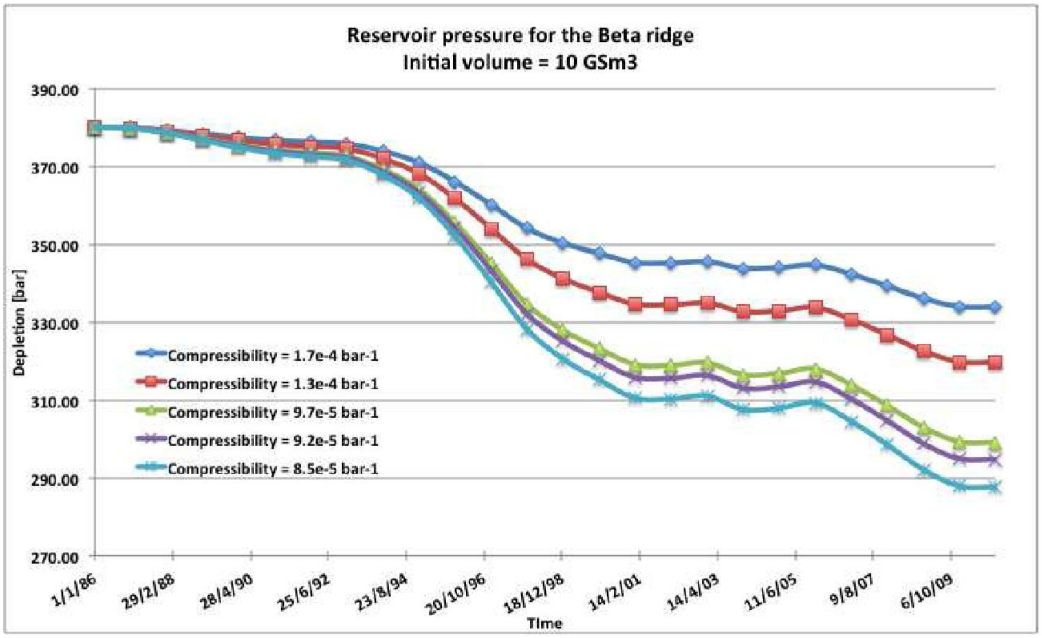

Figure 5: Reservoir pressure development with initial volume equal to 10 GSm compressibilities.

The graphs show the effects of changing compressibility on the reservoir pressure using the estimated initial volume of 10 GSm^3. It can be observed from the plot that compressibility plays a significant role. Changing compressibility will alter the calculated pressure trend, and a match is no longer achieved. To maintain a reasonable match, the initial volume needs to be changed. As an example, the pressure development for a case with initial volume of 7.5 GSm^3 has been performed. From the graph in figure 6, we see that we now have a match with the simulated pressures at a different compressibility. To further support this finding, two scenarios with a match to the simulated data are plotted together in figure 7.

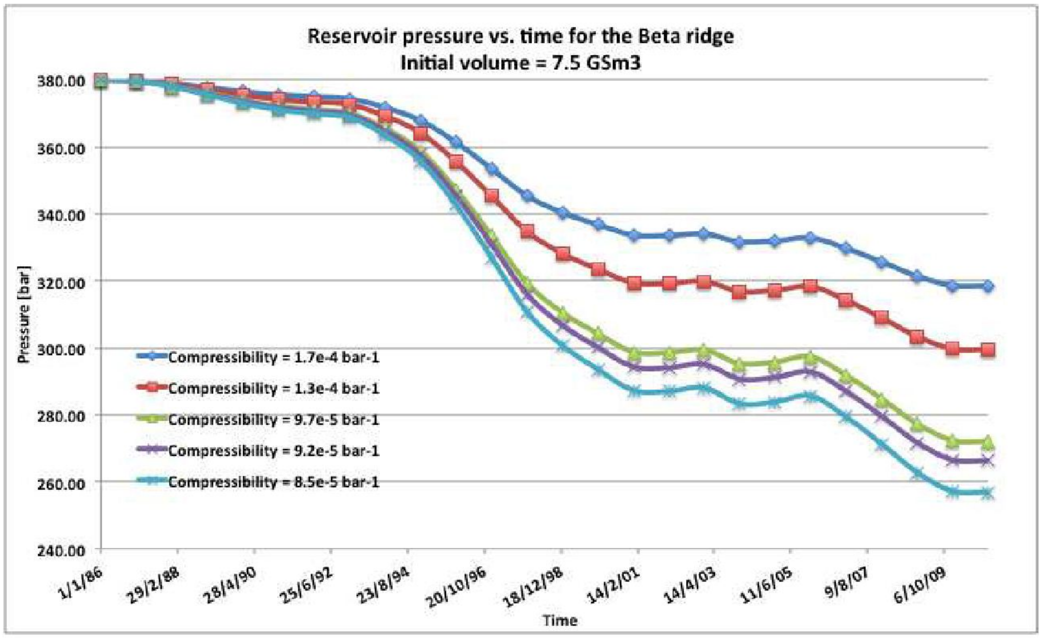

Figure 6: Reservoir pressure development with initial volume equal to 7.5 GSm3 with different compressibilities.

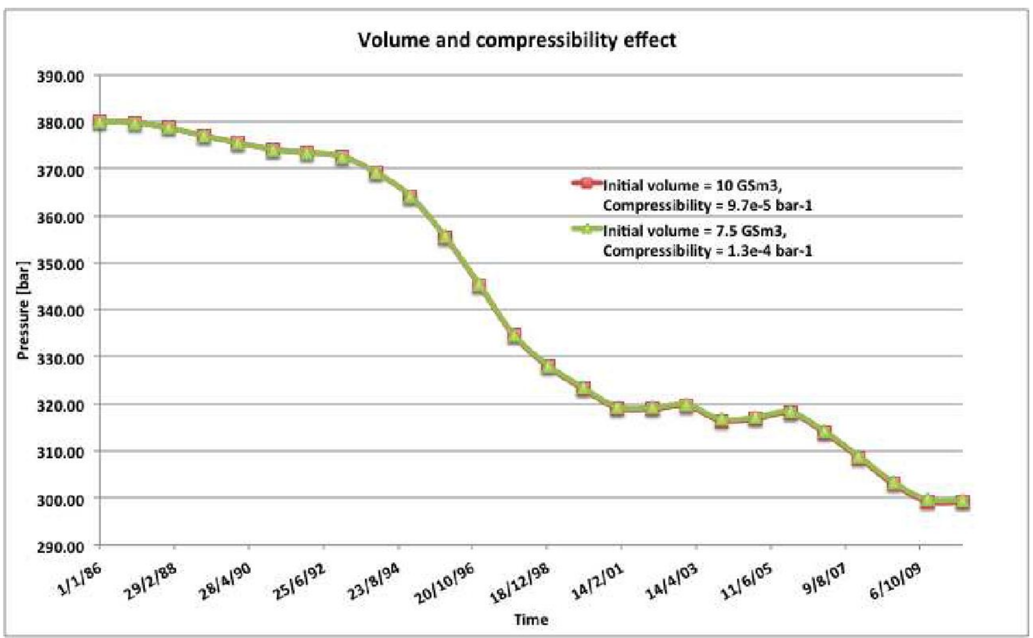

Figure 7: Two different scenarios with the same pressure development result.

Both of these two scenarios give a match, however, having a difference of 2.5 GSm^3 in the initial volume is very significant. As mentioned earlier, the initial volume affects the planning, development and total evaluation of the field, as well as a great number of other parameters used during simulation (e.g. testing, interpretations, etc.) Without any other data and knowledge about the field, is it hard to determine the correct scenario, and thus a definite conclusion is difficult to make. However, we have reason to believe that the compressibility value first assumed is more likely to be correct rather than the value used in the latter scenario. Observations made in these formations have shown that the compressibility normally lies around this value, and that there are minimal deviations from it. Usually, more data is available and several analyses are interpreted together, resulting in a more accurate estimation.

It is important to remember that both the volume analysis and the compressibility analysis are made with the assumption of full communication within the Beta Ridge fields, and the material balance used is a zero dimensional analysis. The results obtained from calculations will therefore, as mentioned earlier, be more representative as an average for the Beta Ridge. An exact match to one of the curves in figure 7 is therefore not what we are looking to achieve. In reality, communication boundaries are very likely to exist and the reservoir is far from homogeneous.

5.3 No leakage

The simulation done for this field has assumed that there is some sort of leakage in and out of the Beta Ridge, which has also been the assumption for the analyses carried outso far. To see the effects of not having this leakage, the change in volume is set to be the difference between production and injection. The plot in figure 8 shows the difference between the case of leakage and no leakage for the change in volume.

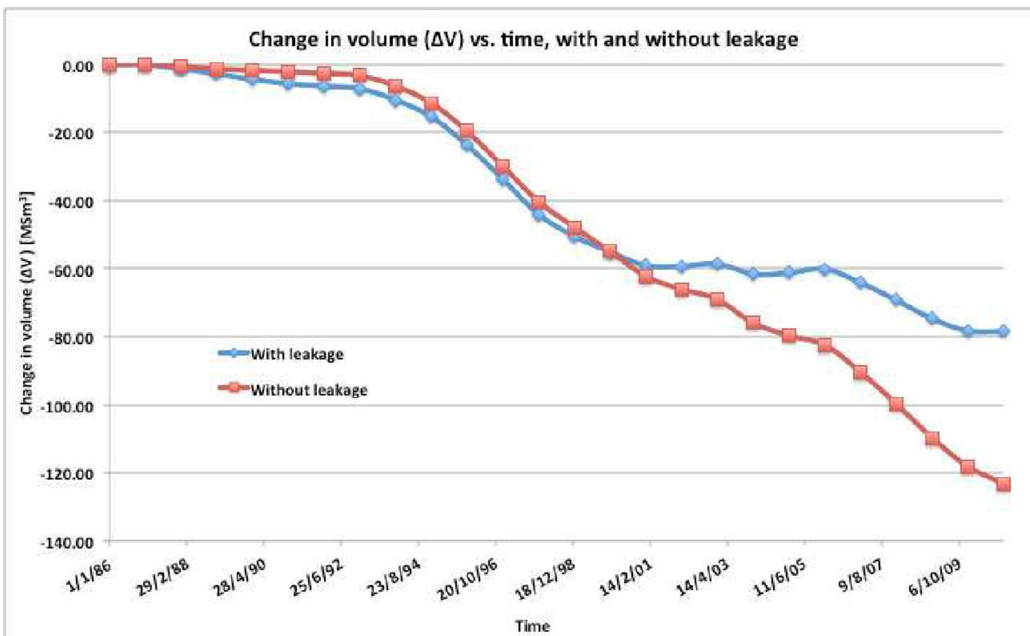

Figure 8: Change in volume with and without the assumption of leakage.

We can see that there is a net leakage into the Beta Ridge area.The pressures are then calculated for the same initial volumes as in the case with leakage. The result is plotted in figure 9, and the calculation results can be found in Appendix B. Note that the compressibility used is the same as assumed in the initial volume analysis.

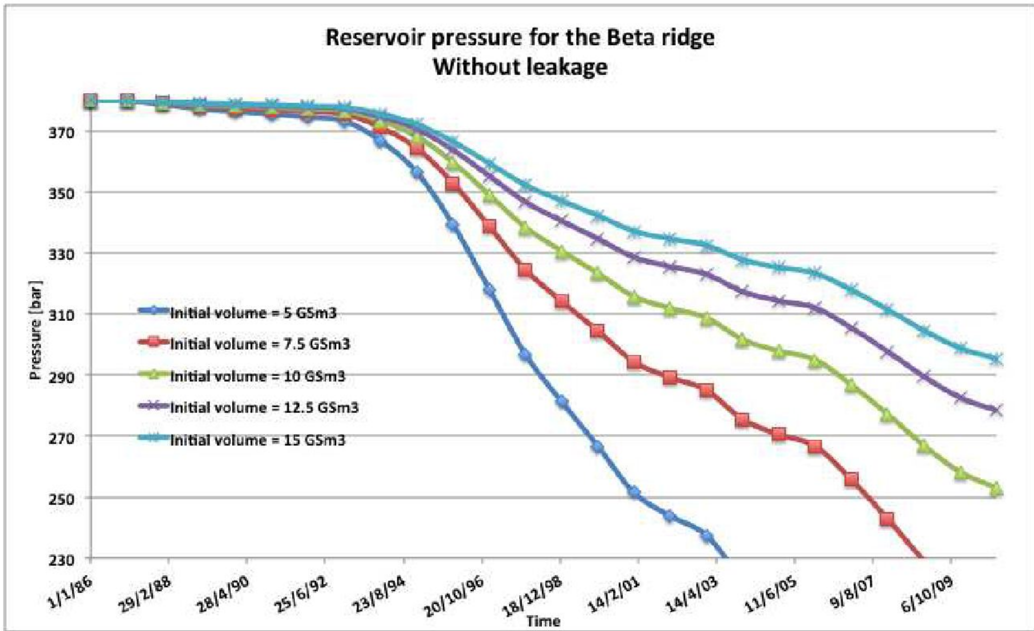

Figure 9: Pressure development without leakage out and in to the Beta ridge area.

The calculation made suggests that in order to maintain a pressure in the reservoir matching the simulated data, a much higher initial volume is needed. This can also be observed on the plot in figure 9.

With leakage, the estimated initial volume to give a match was approximately 10 GSm^3. To see whether or not this is a reasonable assumption for the case without leakage, the pressure development for each case is plotted in the same plot as seen in figure 10.

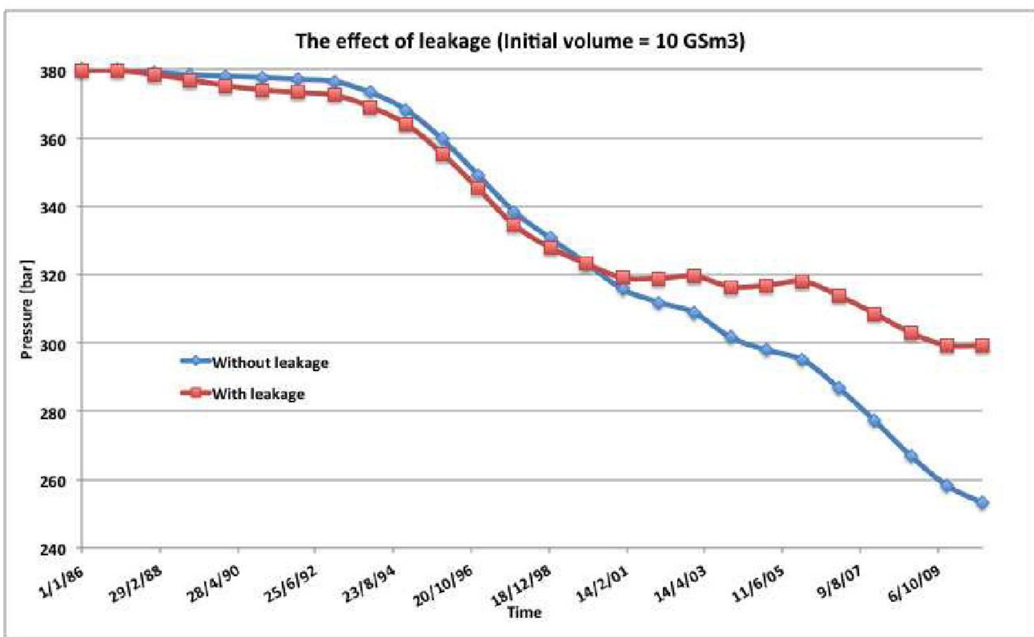

Figure 10: Pressure development with the initial estimated volume for both with and without leakage.

The result is clear. The pressure decreases significantly more without the leakage. This was expected due to the net leakage into Beta Ridge. The net leakage can be looked at as an injection into the Beta Ridge area, creating a pressure support. To make the estimated pressure depletion match the simulated data,either the assumption of leakage is reasonable or, the initial fluid volume needs to be higher as discussed above. However, if the possibility of error in the assumed compressibility is considered, pressure development may still give a reasonable match. This pressure depletion can be seen in figure 11.

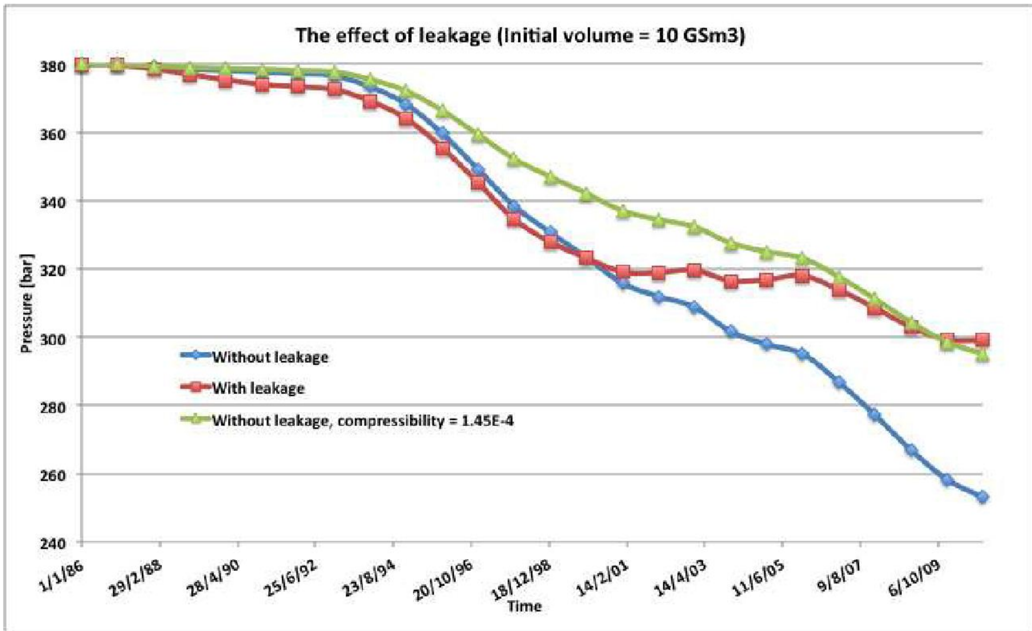

Figure 11: Pressure development with the initial estimated volume for both with and without leakage and including the case with a different compressibility.

Higher compressibility results in better pressure maintenance. However, the difference in compressibility is unreasonably high, thus the scenario is unlikely. This gives an indication that despite the assumption of minimal to no leakage, a reasonable match may be achieved with the same estimated initial volume.

In the case of no leakage, pressure will decline faster for the same initial volume than in the case of leakage. To better maintain the reservoir pressure, either initial volume or compressibility needs to be higher. A combination of these two is more likely if the case of no leakage is assumed to be valid for Beta Ridge.

The reservoir pressure trend is strongly dependent on the initial fluid volume. In the case of leakage in and out of Beta Ridge and compressibility equal to average values, an initial fluid volume of 10 GSm3 gives a reasonable match with simulated data. However, the pressure decline is also significantly affected by changes in the compressibility. Assuming that leakage is occurring, variations in compressibility require a change in the initial volume to maintain a match. The change can be substantial and has a great affect on all parameters that are dependent on the initial fluid volume.

In the case that our assumption of leakage is incorrect, reservoir pressure will decline much faster. As we now have learned from the results in the case of leakage, both initial volume and compressibility affect the pressure decline. To maintain the match with the simulated data, it is probably more correct to make adjustments in initial volume as well as compressibility.

Although unlikely, errors in the input data for the simulation might also be present. The simulation is based on the same principles as for the simple material balance, however, the calculations are much more advanced and several other factors are taken into account. The effects of changing initial volume and/or compressibility in the simulation model will have similar trends as seen in the analyses above, though with a much smaller amplitude.

The most reasonable conclusion is that there is leakage between Beta Ridge and the Gullfaks Main Field, and with net leakage into the Beta Ridge. The leakage discussed above is a result of communication between Beta Ridge and the Gullfaks Main Field, and does not say anything about the intercommunication within Beta Ridge. There is a geological explanation for the possible communication between the fields in Beta Ridge, which is discussed in the conclusion.

6 Recovery Factor

The recovery factor is hard to estimate from the given data, but in the reservoir management plan, it is estimated that the expected recovery is 69% for the Brent Formation. We know that the initial oil saturation is quite low, compared to the initial fluids, so it is easy to make a quick assumption that the final recovery factor will be low. However, due to the high water drive encountered in the Gullfaks area, the recovery factor is higher than we might expect than a similar field without a water drive.

The structural configuration of the reservoir may have a positive influence on the recovery factor. The top of the Tarbert Formation has experienced the most faulting and structural deformation during the rifting event that produced the present configuration of the Gullfaks Field. The extensive network of faults will have cut through geological heterogeneities, and possibly accessed parts of the reservoir that would have otherwise been unable to produce under normal circumstances. In addition to connected heterogeneities within each field, it is likely that the faults have also connected many of the fields, which is evident through the sensitivity analysis performed on the pressure depletion.

It is important to note that economics will play a factor in determining whether or not to continue to produce the field at high water cuts. Should the oil price be too low, it may not be economically feasible to continue to produce the oil due to the high water cut, and the cost associated with disposing of the water.

7 Conclusion

From the analyses carried out in the previous section, we have made an assumption that the initial fluid in place is approximately 10 GSm^3. The achieved pressure depletion with this assumption as well as the assumption of a compressibility of C_t = 9.7e-5 bar^{-1} is plotted in figure 12.

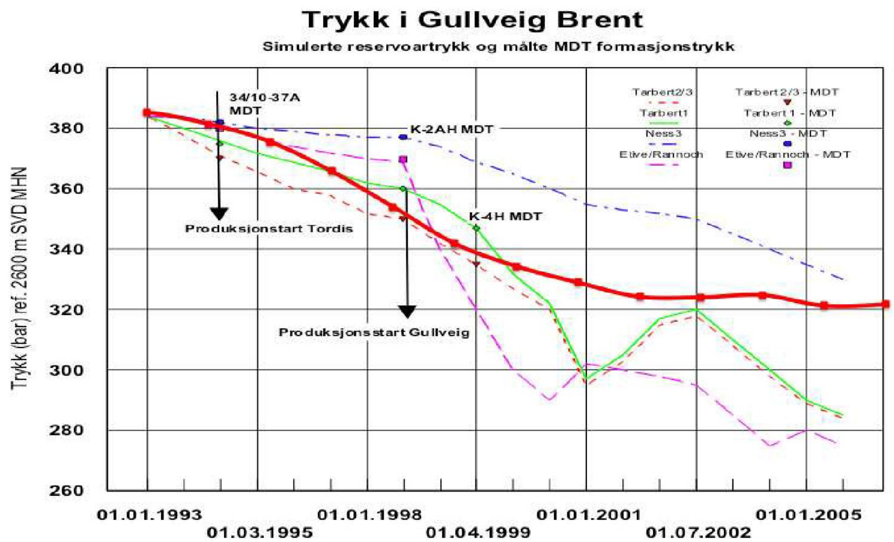

Figure 12: The red line is our estimated depletion with an initial volume of 10 GSm^3 and compressibility equal to 9.7e-5 bar^{-1}.

The red line is the average depletion, whereas the plots given in advance are based on simulations for different formations for the Gullveig field. As we saw in the analyses, there are several parameters that may affect the pressure depletion. While we were able to approximately match the pressure depletion with the plot given, the sensitivity analysis performed showed how compressibility, initial volume, and leakage into and out of Beta Ridge can affect the pressure trends. We had higher confidence in the value of the compressibility used in the pressure depletion trend, and so we determine that large deviations from this value were unreasonably. It is likely that the variations in pressure depletion are due to changes in the initial volumes in place, as well as leakage in and out of the field.

Communication in the field can be highly influenced by the geological heterogeneities that are associated with delta depositional facies. In addition to internal heterogeneities such as shale stringers and cemented zones, the extensive faulting in the area can either increase communication between formations, or hinder it. We are unable to comment on possible communication between different formations in each field (e.g. between Rannoch and Etive Formations), however, the extensive north-south faults that are present suggest that communication between the reservoirs along Beta Ridge is likely.

Part II
Project Part B

8 Geology

The geology of the Gullfaks area is quite complex, and will be simplified in this report. The target formation is the middle Jurassic Brent Formation, with the following formations listed from oldest to youngest: Broom, Rannoch, Etive, Ness, and Tarbert. Overlying shales of the Heather Formation provide a seal for the reservoir. Much of the geological information discussed on the Brent Formation is focused on the Gullfaks Field, but can be used to generalize the geology of the formation in the satellite fields. Where necessary, and where the information is available, differences between geology in the main field and the satellite fields will be noted. In addition to the producing Brent Formation, other underlying producing formations include: Cook Formation, Statfjord Formation, Lunde Formation, and Krans Formation, but will not be further discussed in this report.
The Broom, Rannoch, and Etive Formations (lower Brent Group) represent the progradational phase of the delta complex, while the Ness and Tarbert Members represent the retrogradational phase. The overall depositional setting of the Brent Formation is shown in Figure 13. According to Mjøs [1], the depositional wedge was approximately 250 km long, and 200 km wide.

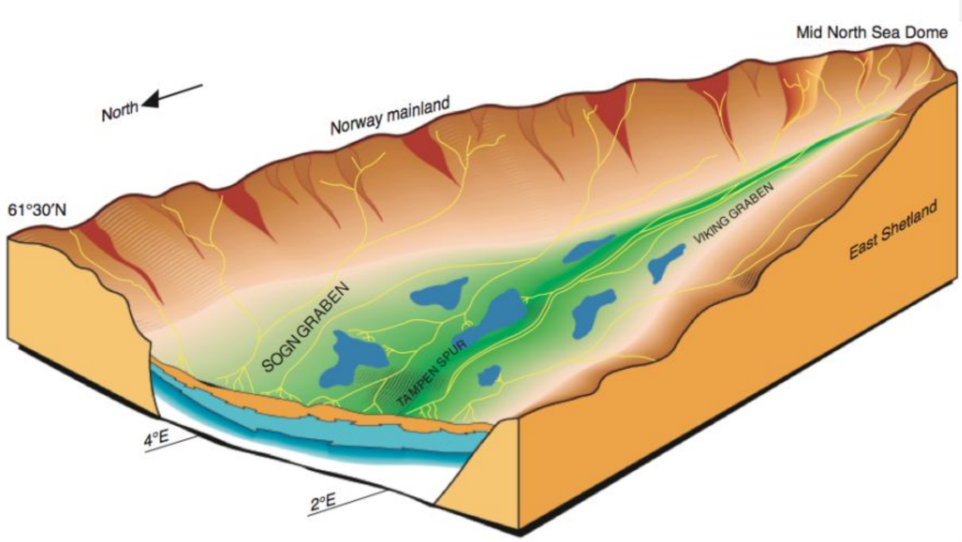

Figure 13: Paleoenvironmental reconstruction of the Brent Formation. Approximate location of the Gullfaks Satellite Fields is highlighted.(Mjos 2009[1])

The lower Brent Group represents the deposits of delta progradation. The lowermost Broom Formation consists of prodelta mudstones, and is not of any interest in reservoir development. Overlying the Broom Formation is the Rannoch Formation, which consists of heterolithic cross-stratified sandstones. The upper part of the Rannoch is generally homogeneous with good reservoir properties, while the lower contains more heterogeneities, including calcite cementation and high clay content. These are barriers to flow within the reservoir, but are not correlable from well to well. The Etive Formation contains the best reservoir of the lower Brent Group, consisting of massive cross-stratified sands, with few heterogeneities that could hinder fluid movement. Figure 14 shows the thickness relationships in the lower Brent group.

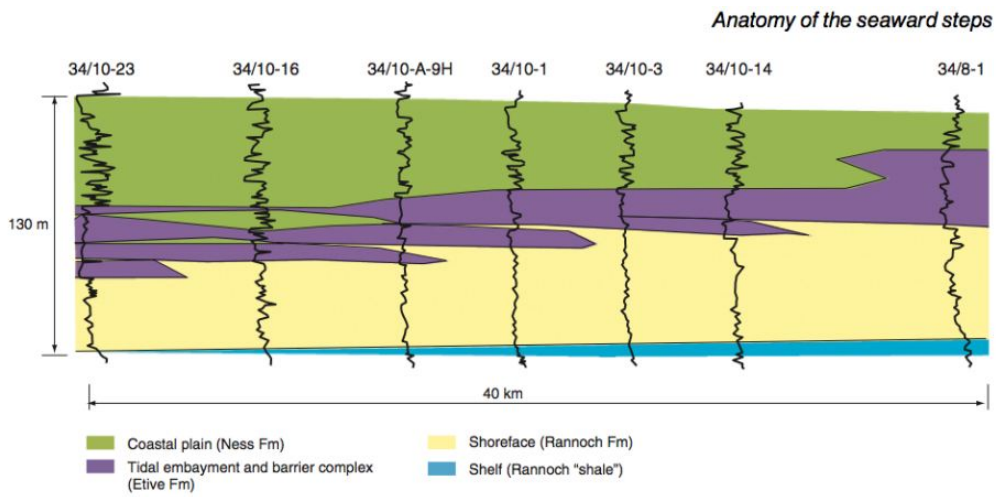

Figure 14: South-North transect from south of Gullfaks to North of Gullfaks. Facies encountered in wells 34/10-16 and 34/10-A-9H are located along a similar depositional strike as the Beta Ridge Fields. Wells 34/10-1, 34/10-3 and 34/10-14 are located within the Gullfaks main field. (Mjos 2009[1])

The Ness Formation is highly heterogeneous formation that was interpreted to have been deposited at the top of the Brent delta. Two main facies dominate this section, namely: floodplain sediments, and crevasse splay complexes with minor mouth bar deposits.

The Tarbert Formation contains various packages of sediments that represent facies encountered in a retreating delta front. These include:

- Bay in-fill sediments, which are capped by pervasive coal deposits that facilitate correlation of units
- Tidal surfaces and coastal plains
- Fluvial channels – some of which contain excellent reservoir properties (e.g. Silky Sand)
- Shoreface deposits, which are encountered in the uppermost part of the formation, and are thought to represent the final pulse of the delta prior to drowning.

The upper reservoir units in the Tarbert are dominantly homogeneous, with permeability values between 3 and 10 Darcy encountered. In the Gullfaks satellite fields, the permeabilities are much lower, with maximums just over 1 Darcy. The lower portion of the reservoir, however, contains several heterogeneities that include: mudstones, coal layers, and calcite cementation.

In addition to the complex geology seen through the Brent Formation, the region has been influenced extensively by regional tectonics. The Gullfaks region lies in a structurally high area to the west of the Viking Graben, with current structural configuration due to rifting during late Jurassic/early Cretaceous time. The most important part of the Gullfaks field lies within the westerly domino system of westward dipping rotated fault blocks. The main faults are oriented in a north-south direction, with fault throws of 50 and 250 meters. Three main structural regimes exist across the Gullfaks area, namely: the domino system, the accommodation zone, and the horst complex. The important parts of the Gullfaks field lie within the domino system, where the Brent group hasn't been eroded away (as is seen in the horst complex). As the Brent Formation is located near the top of the stratigraphic section, it has experienced intense tectonic deformation, with numerous faults that can aid or hinder fluid movement throughout the reservoir.

The Gullfaks satellite fields have undergone similar tectonic deformation, but are located on a structural high to the west of the main Gullfaks field.

8.1 Heterogeneities and connectivity of the Brent Formation in the GF SAT fields

In the main Gullfaks field, the depositional history of the Brent Group can be identified, however, in the Satellite fields, this information is more difficult to discern.

In attempting to understand how water injection affects pressure distribution in the Eclipse models, we must first understand the heterogeneities in the Brent Formation. Namely, the ease with which fluid can flow vertically and horizontally through the formations, and also how fluids flow between adjacent fault blocks. The heterogeneities may be geological, structural, or both.

The Tarbert Formation is highly heterogeneous, with alternating sequences of massive, homogeneous and highly permeable sands, and thin shales, coals, and carbonates. The lower Tarbert has lower reservoir quality than the upper, and presents a barrier to flow between the upper Tarbert, and the underlying Ness Formation. However, the highly variable nature of geology presents problems when trying to determine overall properties for a formation. For example, in the Gullveig field, parts of the Tarbert contain a well-developed sand, which has led to higher reservoir pressures than in the same formation in other fields. We must be aware of situations like this when trying to determine the effects of water injection on certain parts of the field. When comparing the Tarbert Formation from the main Gullfaks field to the Satellite fields, we see that the Tarbert in generally thinner in the latter.

The Ness Formation is characterized by highly variable reservoir properties, with frequent interbeds of reservoir sands, and impermeable shale and coal layers. The impermeable layers, along with numerous faults that criss-cross the fields, create complex pressure and flooding communication patterns. Although this zone is thinner than the lesser quality Tarbert Formation, the pressure barrier in the Ness is present across all of the Satellite fields.

The Etive Formation, Rannoch 2 & 3, and Ness 1 Formations are shown to be in pressure communication with one another in the satellite fields. Eclipse modeling has shown that injection in either the Etive or Rannoch Formation does not have an effect on the results, reiterating the pressure communication. Is it important to note that the geology can change rapidly from one locale to another, which can affect the results of the pressure maintenance, and how easily the injected water can flow. In the Gullveig Field, the Etive Formation is separated into two by a coal layer. It is unknown how extensive the layer is, but could hinder fluid flow in the general vicinity. When planning the injection wells, whether horizontal or vertical, we must be aware of these possibilities, and attempt to mitigate risks with proper research. Figure 15 shows a generalized stratigraphic column of the Brent Formation.

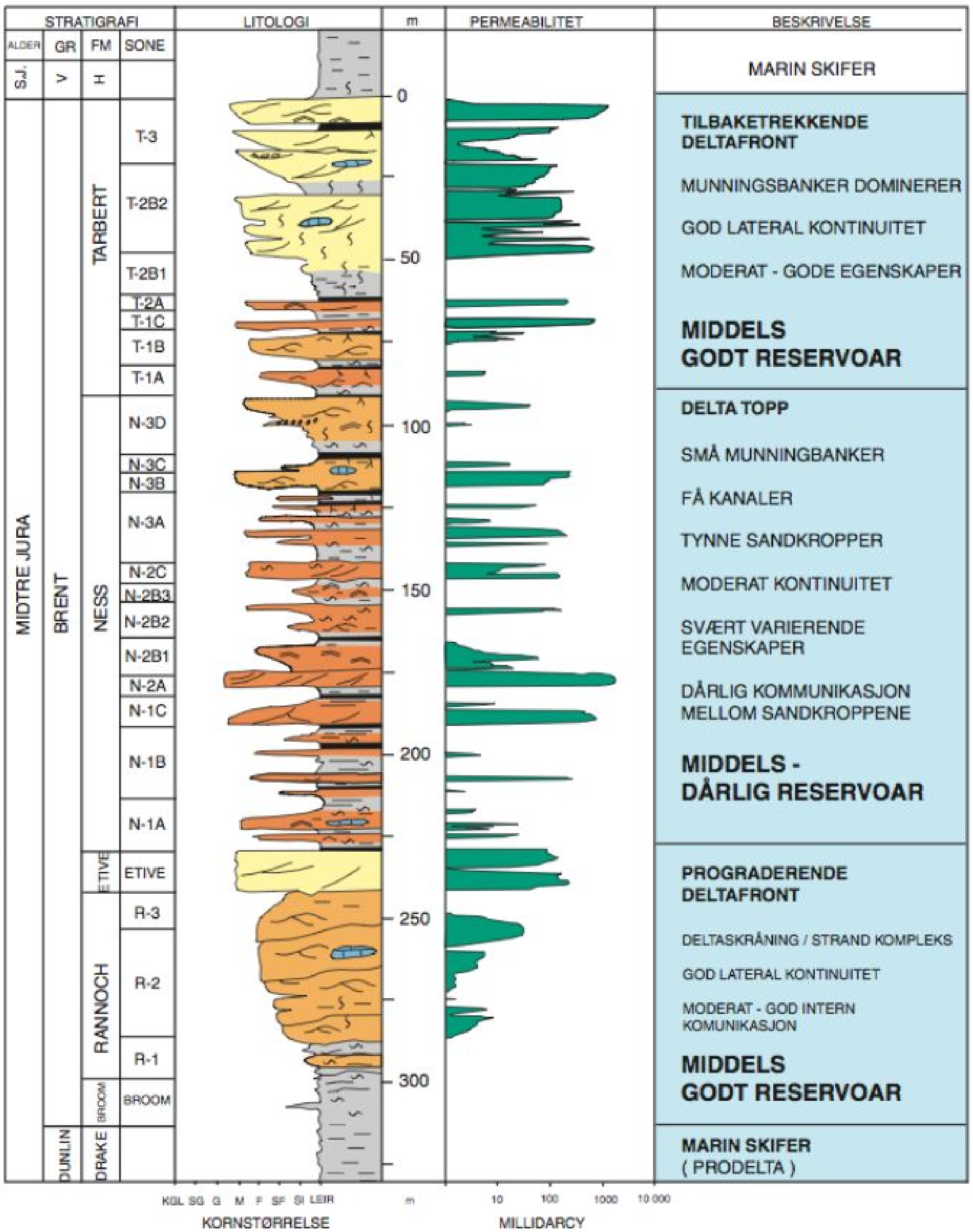

Figure 15: Stratigraphic column of the Brent Formation, Gullfaks South (StatoilHydro 2008) [2]

8.2 Structural Uncertainties

The structural geology of the Gullfaks main field is more complex than that of Beta Ridge. The Ridge itself is part of a separate structure, where most of the small fields lie on their own separate fault blocks. In the case of Rimfaks and Skinfaks, the relative lack of faulting has resulted in better communication between the sand bodies in the

Brent Formation. Between the small fault blocks that exist in these two fields, there is relatively good communication, however, if the fault throw is large, the communication appears to decrease. In the case of Gullveig, one of the fields closest to our injection well (the other field being Gulltopp), the field is located on one westwardly dipping fault block. From Figure 16 below, you can see that communication within the formations should be relatively good, but could decrease going across the fault.

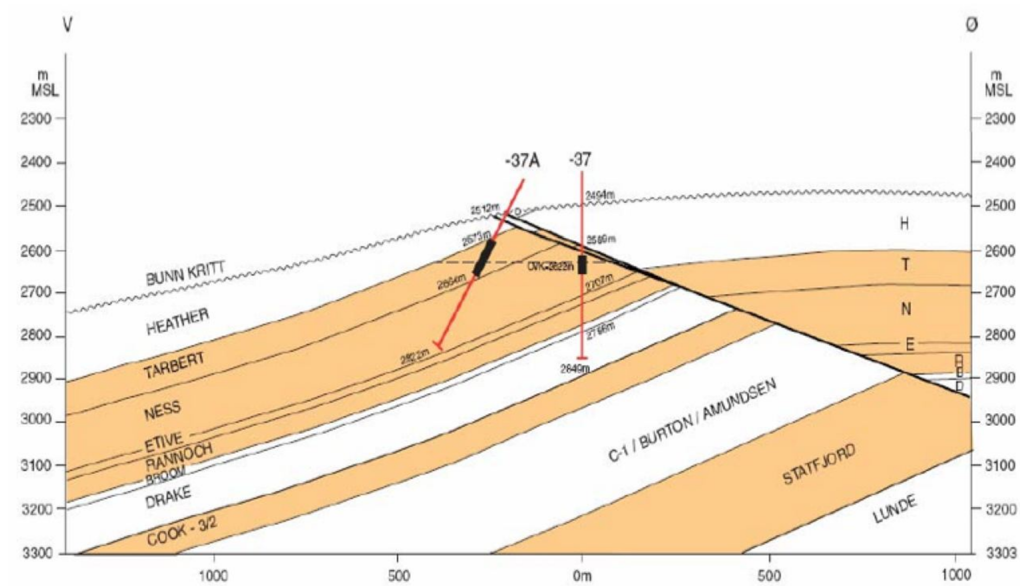

Figure 16: Structural cross-section of the Gullveig field. The injection well will be located located on the eastern side of the fault. (StatoilHydro 2008) [2]

9 Reservoir Model Description

The studies that we are going to do in this project are based on the use of an Eclipse model of the Vestlig Provins, which has been provided by Statoil. The model is briefly described below, and includes the discussion of some parameters, and weaknesses in the model.

9.1 Geometry

All simulations are based on a model of the reservoir it is simulating. This model should in theory be a complete replica of the actual reservoir to get correct and realistic results. Unfortunately, this is impossible to achieve. The model is built based on the geological knowledge, presented in the previous section, and property data aquired from field and laboratory measurements, and experiments. This is then applied to a grid-based layout. The grid is divided into tiny blocks, where each block is assigned properties such that it represents the actual reservoir in the best possible way. The model we are working with is made out of a [45, 80, 8] dimension grid system., which is the "big box" that the reservoir has to fit into. As we can see on Figure 17 , most of the cells are removed, to better show the real reservoir.

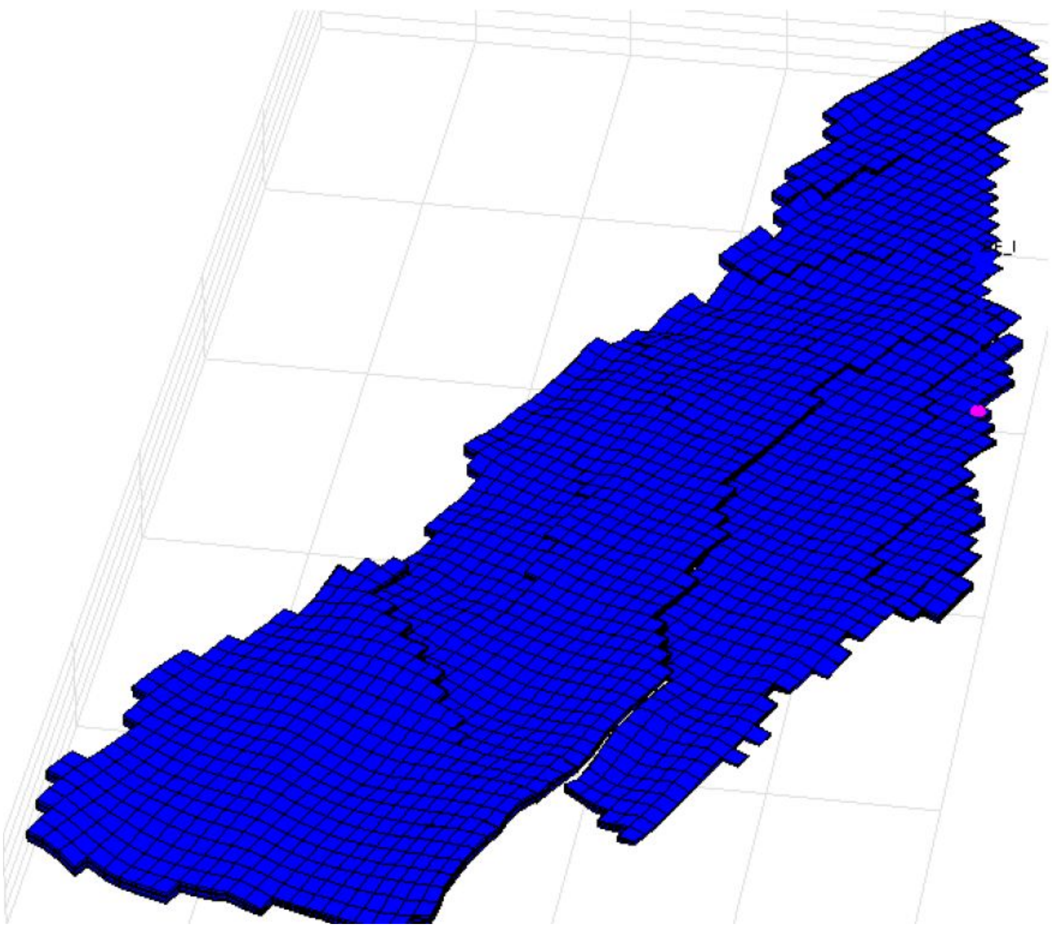

Figure 17: Reservoir model

The layers represent Tarbert, Ness III, Ness II, Ness I and Etive/Rannoch Formations starting from the top.

9.2 Parameters

In reservoir characterization many parameters are important to help fully understand the reservoir behavior, but two of the most important ones would undoubtedly be permeability and porosity. Porosity and permeability are often related to each other in clastic reservoirs, where higher porosity generally indicates high permeability and vice versa. In a reservoir, porosity acts as a storage room, indicating how much oil it is possible to store in a given reservoir. Permeability on the other hand, describes the ability of the rock to transmit fluids. Big interconnected pores are preferable to give high permeability.

9.2.1 Permeability

The permeability distribution around the reservoir shows that the reservoir is assumed to have the same permeability in x-, y-, and z- direction. It also shows high permeability in the area we are about to place the water injector well. High permeability is important in reservoir production, as permeability is a way to describe the ease of fluid flow through the reservoir, and may be the most important property when the reservoir is put on production. High permeability will help evenly distribute the water around the reservoir, and evenly provide pressure support. The permeability differs for different layers, with layer 4 (the Ness Formation), showing a pronounced decrease in permeability than the other layers. This may work as a barrier, thus separating the upper layer from the bottom three. It is very important to understand these kinds of barriers and flow patterns when drilling wells. Simulating how perforations in different layers will affect the pressure increase is therefore necessary. Maybe low permeability and slow pressure equalization have to be solved with an additional injection wells? However, this is a solution that strongly needs economical evaluation.

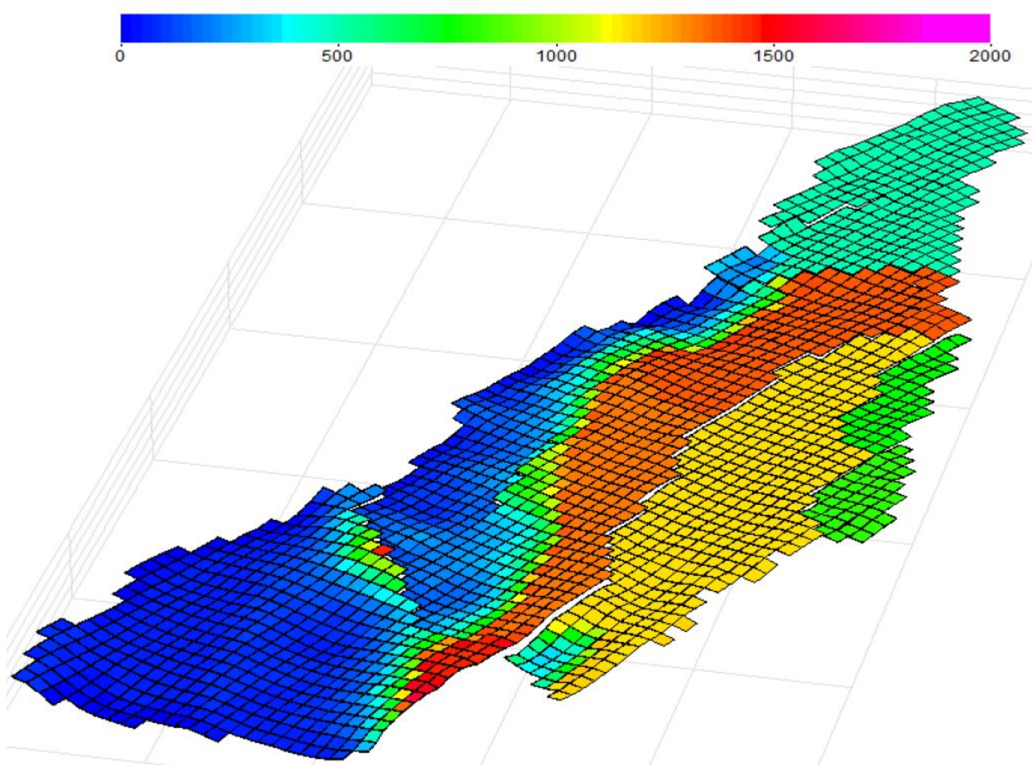

Figure 18: Permeability distribution in layer 5

9.2.2 Porosity

Below, in Figure 19 the porosity distribution is shown. We can see that the porosity is higher in the northeastern part of the reservoir. This seems to be valid for all layers even though the permeability changes significantly throughout the different layers.

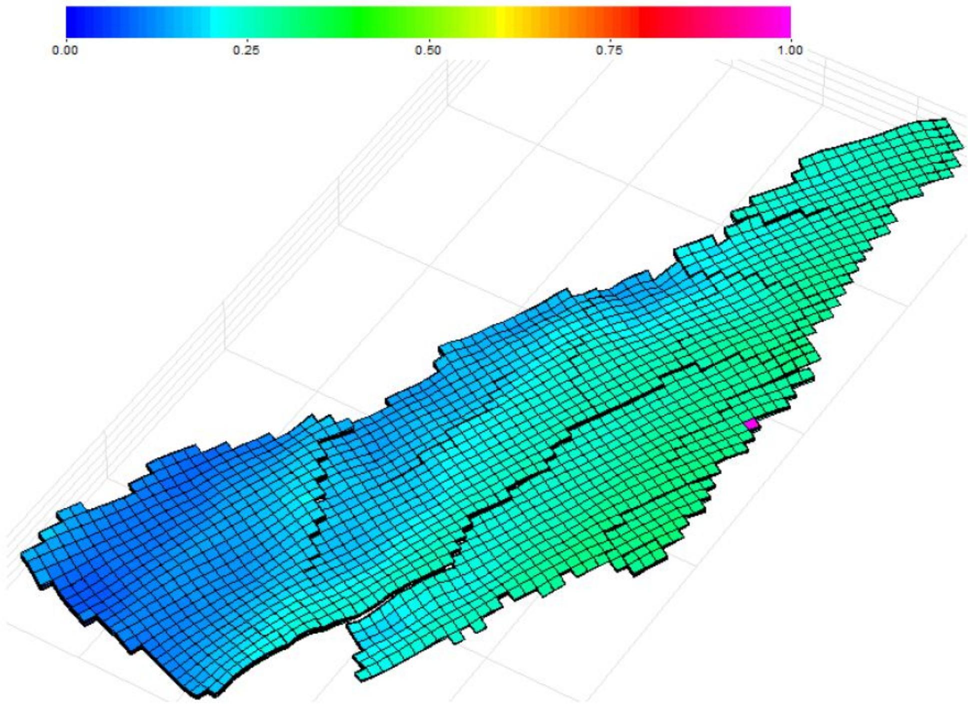

Figure 19: Porosity distribution in the reservoir model

9.2.3 Net-to-Gross (NTG)

NTG describes how much of the reservoir that is able to produce compared to the whole reservoir. In the northeastern part of the reservoir, the NTG is one. This means that the this whole part of the reservoir is expected to contribute to production. The parts of the reservoir with a low NTG correspond to areas which also have low porosity and low permeability. The NTG will change in each block in each layer, but in general, the NTG will have low values when the permeability is low, owing to shaley layers and microporosity.

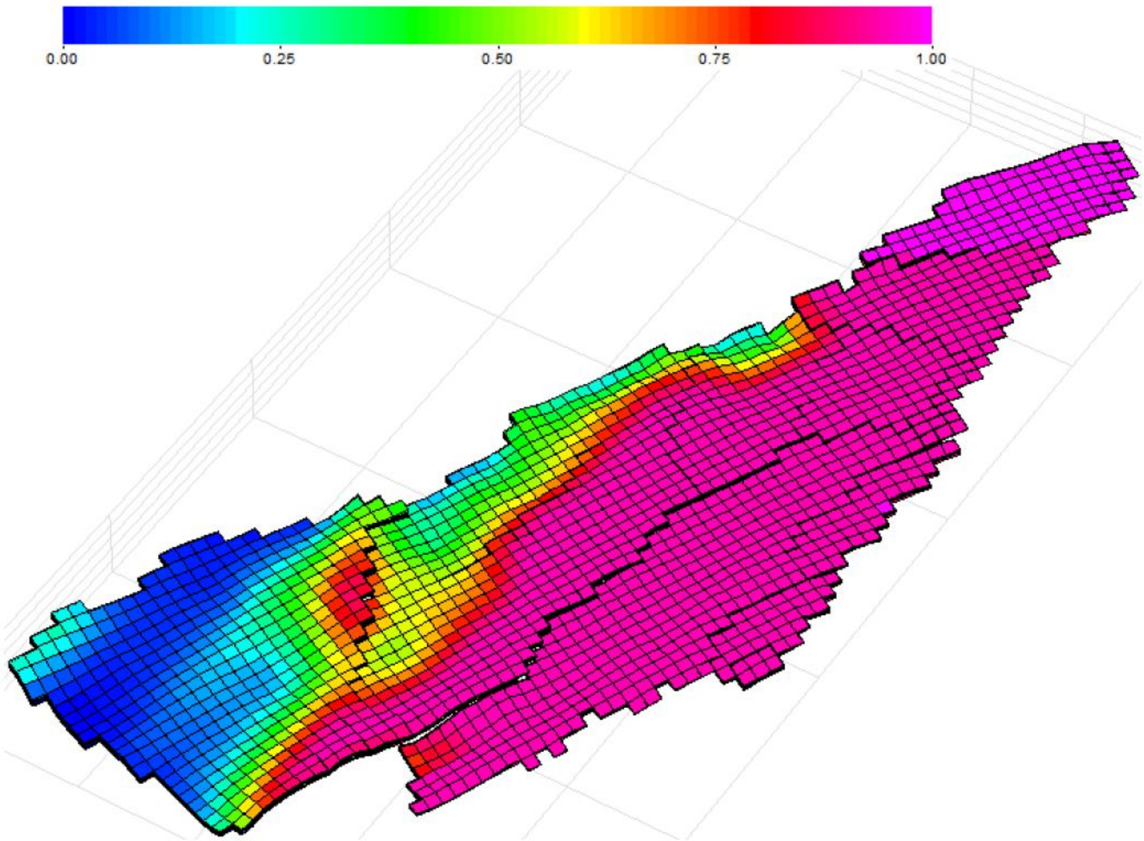

Figure 20: NTG distribution in the reservoir model.

9.3 Weaknesses

This model is mainly used for pressure studies in the Vestlig Provins area. The pressure is most affected by the fluid, and how the fluid moves throughout the reservoir. Each fluid, oil, water and gas, all have different properties and thus, their effects on pressure are different. However, it is possible to convert one fluid to another by converting the properties that are most important for the behavior, and those who affect pressure. For example, converting gas and oil to water equivalents will simplify the studies significantly. This is reflected in the model, and makes the model faster and easier to work with. On the downside, the model becomes a pure water model, where parameters such as oil production, GOR and WCT are unavailable for evaluation. Thus, the use is rather limited. The reservoir characteristics mentioned above need to be intact in order to obtain the correct fluid behavior in the reservoir. Despite the limited use of the model, the ability to model pressure behavior is of great importance in field development and operation.

Our main task for this project is to perform pressure studies in the reservoir, which makes the model the perfect working tool. Due to the nature of the model, there is an issue related to estimating recovery, but this issue is addressed in the recovery chapter later in section 15 .

10 Well Performance

There are a number of important points that need to be taken into account during the planning of an injection well. Several parameters, including geological and offshore equipment capacities could limit injection rates and pressure values. Thus, the main parameters are the following:

- Maximum allowable injection pressure (MAIP)
- Maximum cumulative injection Rate (MCIR)
- Formation or Fracture Parting Pressure (FPP)
- Durability of the Upper and Down Completion System

The initial MAIP is determined from field-wide average fracture gradients. Only after tests have been performed to determine the actual formation fracture pressure can the MAIP be increased. This pressure can only be exceeded during stimulation treatments [5]. Rapid water breakthrough in production wells can be a direct result of exceeding a certain critical injection pressure in nearby injection wells. This critical injection pressure is called the formation or fracture parting pressure (FPP). Several studies recently demonstrated that a fracture would propagate if injection is above the FPP and the injection/withdrawal ratio is greater than one. In addition to this uncontrolled fracture extension, injection above the FPP may also cause fracturing out of pay. These factors may lead to premature breakthrough of injected fluid, poor sweep efficiency, reduced recovery, and loss of costly injection fluids. It is therefore very important that MAIP will not cause any fracture in a wellbore.

To become familiar with formation characteristics, Leak-off Tests are required. This is a test to determine the strength or fracture pressure of the open formation, usually conducted immediately after drilling below a new casing shoe. During the test, the well is shut in and fluid is pumped into the wellbore to gradually increase the pressure that the formation experiences. At some pressure, fluid will enter the formation, or leak off, either moving through permeable paths in the rock or by creating a space by fracturing the rock. The results of the leak-off test dictate the maximum pressure or mud weight that may be applied to the well during drilling operations. To maintain a small safety factor to permit safe well control operations, the maximum operating pressure is usually slightly below the leak off test result. Figure 21 shows Pore and Overburden Pressures vs. depth in Gullfaks formations. The main objective is to not allow BHP (bottom hole pressure) to overtake the Fracture Parting Pressure (FPP) (Rocha et al. 2004)[6].

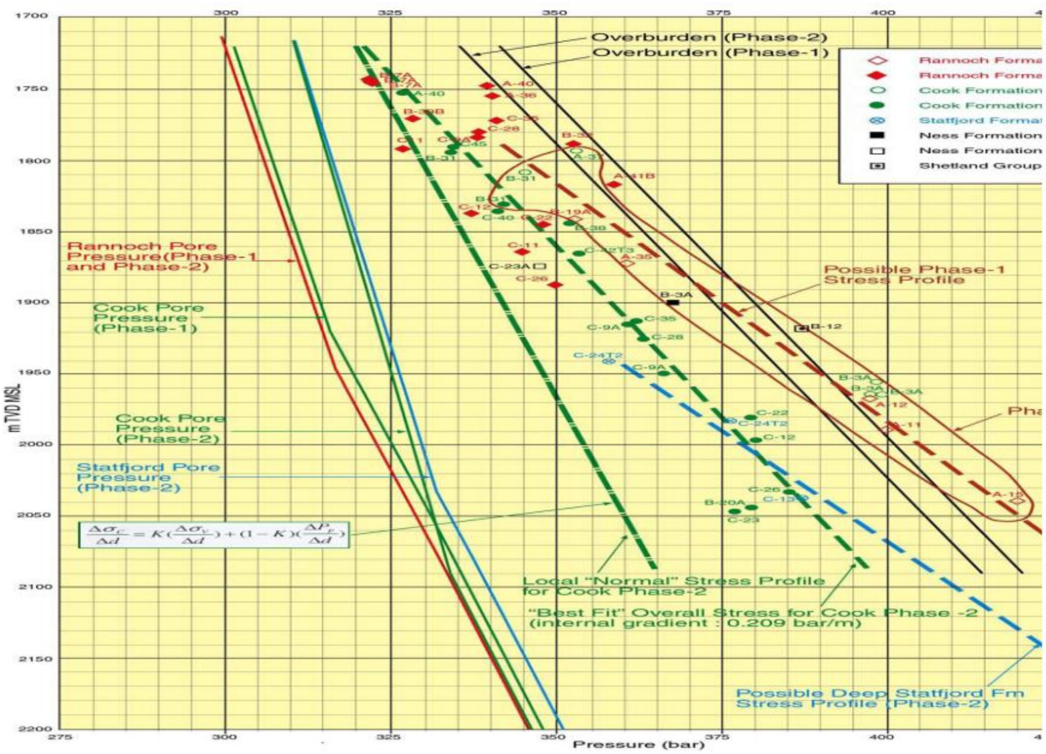

Figure 21: Estimated original minimum horizontal stress, σ_x, versus depth [3]

Information regarding formation fracture pressure is not limited to determining MAIP and MCIR. Information included in calculations includes, but is not limited to, the following (Bale et al. 2008) [6]:

- Formation strength, formation collapse and kill calculations in conjunction with well planning,
- Sand prediction work,
- Design of surface water injection equipment,
- Choice of perforation strategy in wells with multiple injection zones,
- Matrix scale squeeze and stimulation operations,
- Characterization of reservoir structure or fault placements.

10.1 Durability and Maintenance

Appropriate injection pressures and injection rates are determined by a number of factors that change from well to well [7]. In extreme cases, injection can occur under vacuum, or under pressure where high formation pressures exist. In these situations, care must be taken to ensure excessive pressure is avoided. Injection rates are kept low enough to ensure that no decrease in fluid temperature at production wells is recorded, and no pressure build-up in the formation occurs [7]. By monitoring these rates, one is able to ensure that no unexpected consequences arise.

Maintenance factors on injection wells are also site-specific, and a proper well design can help minimize maintenance required. Maintenance of wells may depend on the design of the well, the corrosive nature of the injected fluids, and the well environment. Continual monitoring of injection pressure, flow rates, and volume changes can indicate that a leak may exist in the injection casing [7].

In our case, as will be seen later, when we have high injection rate/pressure and high enough BHP, completion system should be selected with a particular precaution. Open hole in such conditions could sustain for a long time due to the higher erosion factor. Along with this, the salt content of the injected fluid is an important property, and it is therefore very important to use treated fluid. Completion systems such as Open-hole gravel packing and ESS (Expandable Sand Screen) are quite reliable over the long period of time. These systems could be used for deep water reservoirs, which are typically high permeability, unconsolidated formations.

11 Drilling Challenges at the Gullfaks Field

To select the proper well parameters for the injection well is important for enhanced oil recovery. StatoilHydro's Reservoir Management Plan (2007)[8] lists the following parameters that are of particular importance when drilling:

- Compliance with the reservoir strategy
- Time-criticality
- Net present value
- Focus on available slots/sidetracking possibilities
- Qualification of new technology
- Rig access

In order to facilitate the process of obtaining the remaining oil in Gullfaks, Statoil has put together a process that forms the basis by which drilling recommendations are made. A lead group, known as the 'Maturation group', is a group that consists of the lead engineers from respective disciplines that will challenge the drilling targets made by the reservoir groups (StatoilHydro Reservoir Management Plan 2008)[2]. Economics and logistics play a roll in the development of the operations, with priority taken based on highest net present value (NPV), but also include other operational considerations. These operational considerations may include the availability of equipment, and how these activities can be coordinate with others on other Gullfaks platforms. The interdisciplinary basis of identifying drilling targets gives way to a thorough and detailed drilling schedule. Many issues and outside considerations are taken into account during this process, and may include:

- Available platform
- Template and slot utilization
- Water depth
- Geology (faults, unconsolidated formation, abnormal formation pressure)
- Multiple Targets
- Well Depth and Complex Well Trajectory
- Completion System

According to the survey data, geological structural of Beta Ridge is quite complex. In addition to the complex geology seen through the Brent Formation, the region has been influenced extensively by regional tectonics. The challenges that can cause problems during drilling are faults and high heterogeneities in the formation. It is very important to precisely understand and control drilling parameters such as drilling mud, pump rate, WOB (Weight on Bit), ROP (Rate of Penetration) and RPM (Revolutions per Minute) in layers with diverse geological or structural properties. Along with this, a diverse pressure depletion data is a direct indicator of the different reservoir properties such as permeability and porosity. During the drilling operations, this should be taken into account when choosing drilling mud. Properties of the mud like; particle sizes, polymer content, shear rate, gel strength, etc., must be adjusted to improve efficiency of drilling and decreasing filter loss.

Logging in well K2-H has shown that pressure depletion within the Brent, varies with the formation. This means that the drilling crew should be ready to detect high-pressure zone and react accordingly. In case of a narrow drilling window (the difference between pore and fractured pressure), the best option would be to use a MPD (Managed Pressure Drilling) system. The main objectives for these kinds of systems are to ascertain the downhole pressure environment limits, and to manage the annular hydraulic pressure profile accordingly. The drilling team must work in close collaboration with the geologist and geophysicist to obtain Real Time Well Data.

Based on StatoilHydro's 2008 Reservoir Management Plan Internal Report, the reservoirs are over-pressured, with an initial pressure of 310 bars at datum depth of 1850 m below mean sea level, and a temperature of 70 degrees C. There have been relatively few pressure measurements in the water zone, thus an assumption of 327.5 bars is accepted for this zone. This is quite normal for drilling with conventional drilling methods. Water depth's between 130 and 180 meters is also quite normal.

11.1 Vertical wells compared to horizontal wells

In the sensitivity analysis we are discussing at a later stage in the report, one of the studies considers whether or not the orientation of the injection well should be vertical or horizontal. Drilling challenges, economical aspects, as well as the performance must be taken into account. The latter will be discussed under the sensitivity analysis. The challenges are addressed more above, while some aspects regarding the economical drawbacks and advantages are listed below.

11.1.1 Disadvantages:

1. High cost compared to a vertical well. According the cost evaluation, a new horizontal well drilled from the surface costs 1.5 to 2.5 times more than a vertical well. A re-entry horizontal well costs about 0.4 to 1.3 times a vertical well cost.

2. Generally, only one zone at a time can be used for injection in a horizontal well. If the reservoir has multiple pay-zones, especially with large differences in vertical depth, or large differences in permeabilities, it is not easy to pressurize all layers using a single horizontal well.

3. The overall current commercial success rate of horizontal wells in the world appears to be 65%. (This success ratio improves as more horizontal wells are drilled in the given formation in a particular area.) This means, initially it is probable that only 2 out of 3 drilled wells will be commercially successful. This creates extra initial risk for the project.

11.1.2 Benefits of horizontal wells:

1. While the cost factor for a horizontal well may be as much as two or three times that of a vertical well, the injection factor can be enhanced as much as 15 or 20 times, making it very attractive.

2. To inject the same amount of water, one needs fewer horizontal wells as compared to vertical wells. This results in reduced need for surface pipelines, locations, etc.

3. Horizontal wells offer greater contact area with the productive or injected layer than vertical wells (Fig 22)

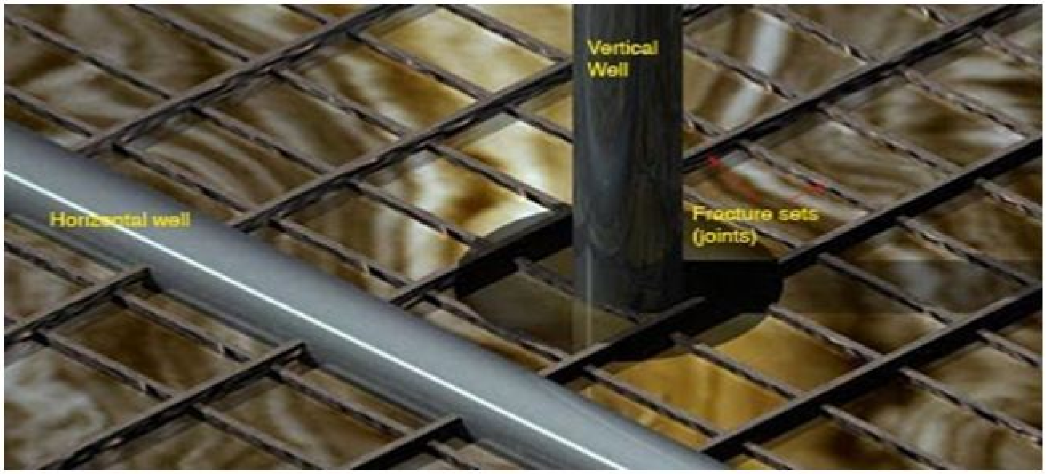

Figure 22: Simplified picture showing two joint sets (the grid) as they could be intersected by a vertical and a horizontal well.[4]

During the drilling of a horizontal well, evaluation and qualification of drilling targets/well interventions are a continuous process. It could be challenging to drill a horizontal well with multiple targets through thin layered formation. Significant advances have been made in drilling technology to drill straight horizontal holes. As a solution, progressively, SRA (steerable rotary assembly) could be suggested, especially in deep water reservoirs to achieve fairly straight drilled holes.

12 Estimating Water Injection Volume

As a part of this project, Statoil wants us to find out how much water needs to be injected to achieve pressure maintenance along Beta Ridge. There are several measures that can be done to add pressure support in a reservoir, but we are focusing on water injection, and the effects of drilling one or two injector wells. There are several aspects that must be considered to determine whether one or two wells are the best option. Some of them are placement, orientation, and which layers to perforate and inject into. The economical aspect related to these factors must also be considered to make any recommendation on the best solution.

As mentioned earlier, we have been provided with a simulation model from Statoil called Vestlig Provins. This is the model we are using to analyze the problems we have been presented with. The model, as stated earlier, simulates Beta Ridge up until Oct 31^{st} 2025. However, Statoil's model predicts an increasingly average field pressure from 2011, see Figure 23.

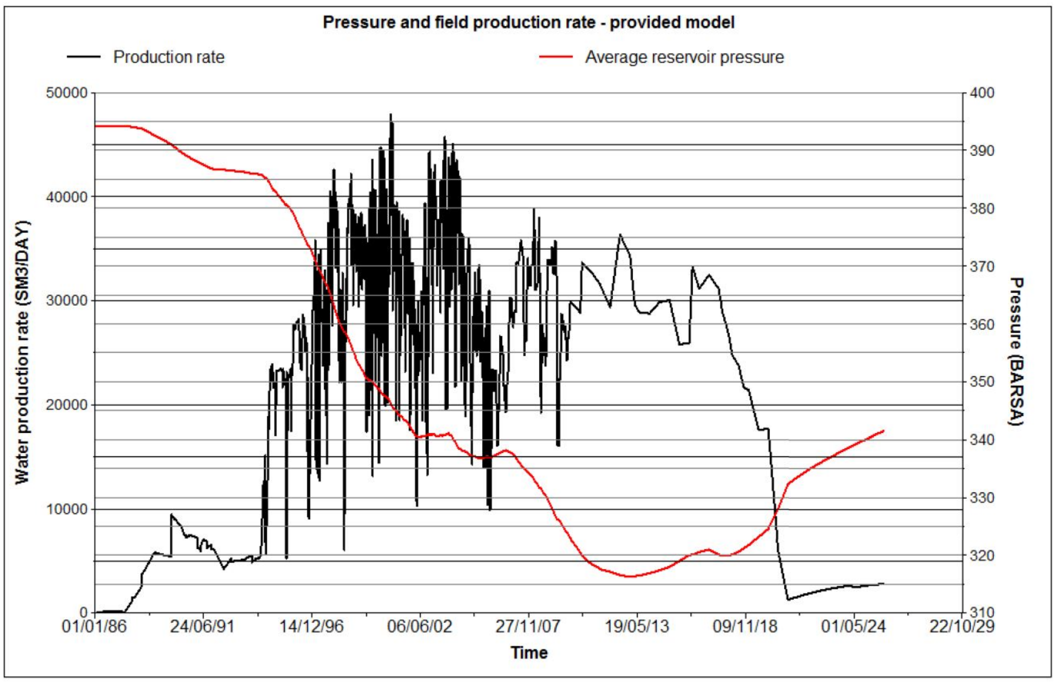

Figure 23: Average reservoir pressure and the field production rate

Comparing the field pressure with the rate, Figure 23, suggests that a declining production rate is causing the buildup. An increasing pressure trend does not require maintenance, thus no injection is needed. What we want to work with is a model that predicts depletion of the reservoir. By modifying the input data for the model, we obtain a prediction seen in Figure 24. We also compare our model's production rate and pressure with the ones provided.

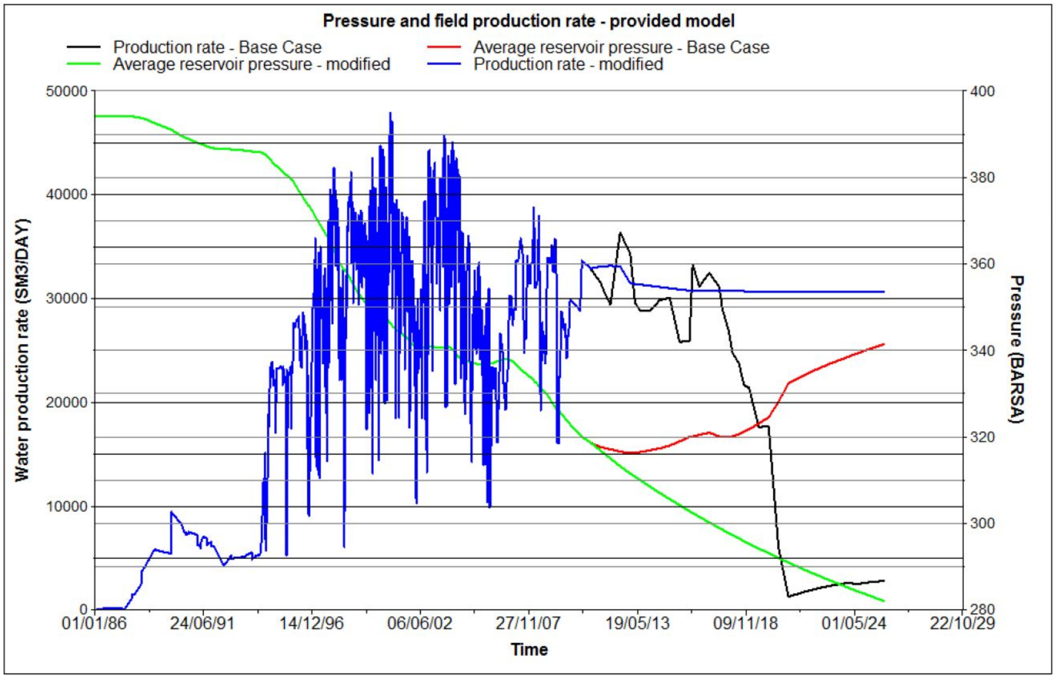

Figure 24: Comparison of reservoir pressure and production rate for the unmodified and the modified models

The basis for the modification is the assumption of constant production rate beyond 2011. Removing history matching input data, from 2011 and to the end of the simulation, makes the model maintain the production rate at the same level as of January 1st 2011. An excerpt from the original "SCHEDUAL" part and the modified "SCHEDUAL" part of the input file to the simulator is shown in Figure 25.

ORIGINAL

```
DATES
 1 'JAN' 2011 /
/

GPMAINT
 'GFP'  'PROD' 50  1*  327.  100   20 /
 'GFI'  'WINJ' 50  1*  327.  100   20 /
/


WCONHIST
 'TORN_E_P'    'OPEN'    'WRAT'    0.000   1862.000     0.000  3*     0.000  1* /
 'TORN_T_P'    'OPEN'    'WRAT'    0.000   1654.000     0.000  3*     0.000  1* /
    'J-2AH'    'OPEN'    'WRAT'    0.000   3752.000     0.000  3*     0.000  1* /
     'I-1H'    'OPEN'    'WRAT'    0.000   2052.000     0.000  3*     0.000  1* /
    'I-2AH'    'OPEN'    'WRAT'    0.000    938.000     0.000  3*     0.000  1* /
 'VIG_ER_P'    'OPEN'    'WRAT'    0.000   3602.000     0.000  3*     0.000  1* /
 'VIG_TA_P'    'OPEN'    'WRAT'    0.000   1058.000     0.000  3*     0.000  1* /
     'D-4H'    'OPEN'    'WRAT'    0.000   1957.000     0.000  3*     0.000  1* /
     'C-2H'    'OPEN'    'WRAT'    0.000   1488.000     0.000  3*     0.000  1* /
 'GFV_DT_P'    'OPEN'    'WRAT'    0.000   1609.028     0.000  3*     0.000  1* /
 'GFV_ET_P'    'OPEN'    'WRAT'    0.000    607.878     0.000  3*     0.000  1* /
  'A-48B_C'    'OPEN'    'WRAT'    0.000   1183.127     0.000  3*     0.000  1* /
  'GV_UB_P'    'OPEN'    'WRAT'    0.000   2000.724     0.000  3*     0.000  1* /
   'GT_T_P'    'OPEN'    'WRAT'    0.000   3235.177     0.000  3*     0.000  1* /
 'SN3_UB_P'    'OPEN'    'WRAT'    0.000   2083.514     0.000  3*     0.000  1* /
 'SN2_UB_P'    'OPEN'    'WRAT'    0.000   1983.608     0.000  3*     0.000  1* /
/

WCONINJH
     'K-3H'   'WATER'    'OPEN'       849.000  1*     0.000  3* /
     'E-2H'   'WATER'    'OPEN'      4158.000  1*     0.000  3* /
     'E-3H'   'WATER'    'OPEN'      4158.000  1*     0.000  3* /
 'GFV_ET_I'   'WATER'    'OPEN'      6592.431  1*     0.000  3* /
/

-- 9677.000000 days from start of simulation ( 1 'JAN' 1985 )
DATES
 1 'JUL' 2011 /
/
```

MODIFIED

```
DATES
 1 'JAN' 2011 /
/

-- 9677.000000 days from start of simulation ( 1 'JAN' 1985 )
DATES
 1 'JUL' 2011 /
/

-- 9708.000000 days from start of simulation ( 1 'JAN' 1985 )
DATES
 1 'AUG' 2011 /
/

-- 9861.000000 days from start of simulation ( 1 'JAN' 1985 )
DATES
 1 'JAN' 2012 /
/
```

Figure 25: Excerpt original and modified schedual file

12.1 Adding a Well

Statoil has already decided roughly on possible locations for the wells, one on each side of the main Beta Ridge fault. The three main cases we are studying are: adding one well on the east side; adding one on the west side; or adding one on each side. Figure 26 shows a map marked with the regions where the wells are planned. We have chosen to name the east and the west side wells "INJ_E" and "INJ_W", respectively, and will refer to these names throughout the remainder of the report. The map also shows the exact location we have chosen as an initial case for our analysis, with the sensitivity of the positioning studied at a later stage.

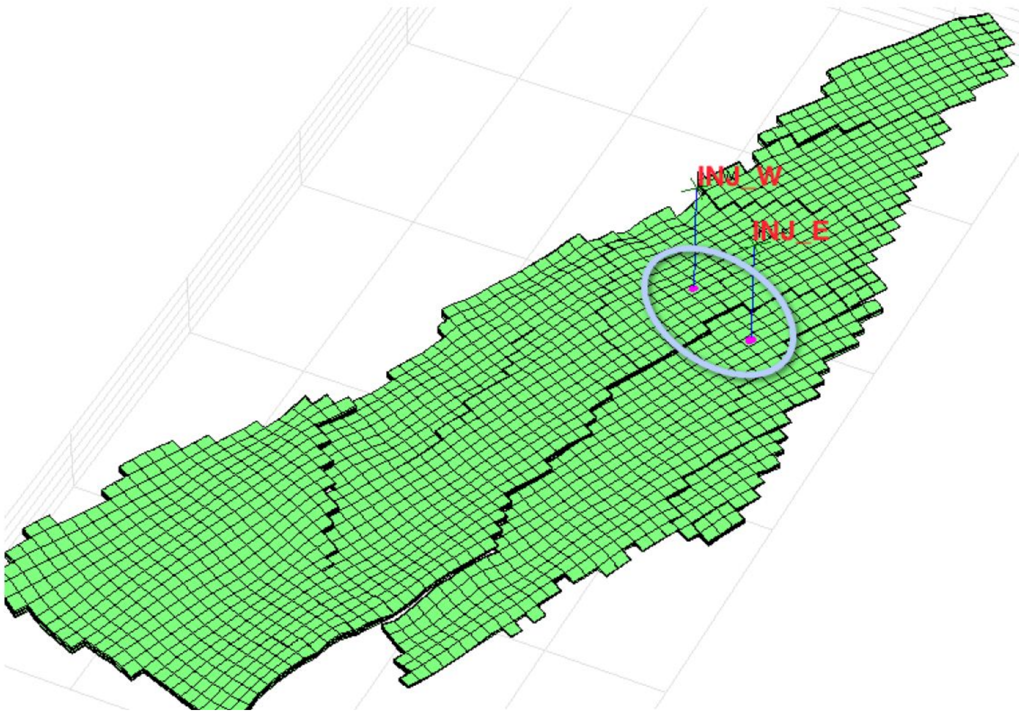

Figure 26: Map

The wells used in Eclipse simulations are all defined in the "SCHEDUAL" section of the input file. In our case, this section is located in its own include file. Several keywords must be used to specify a single well. The first mandatory keyword is "WELSPECS". The parameters that are defined here are: the name of the well, which group the well belongs to, and the I and J position. In the case of a horizontal well, I and J refer to the heel position. Further on, parameters such as reference depth for the bottom hole pressure and preferred fluid phase, among others, are defined. Figure 27 shows an excerpt of our wells in the "WELSPECS" keyword.

```
-----------------------------------------------------------------------------
-------------------OUR ADDED WELLS-------------------------------------------
-----------------------------------------------------------------------------
  'INJ_E'    'PROJECT'   21   51   2222.000    'WATER'  3*       'NO'  3* /
--'INJ_W'    'PROJECT'   14   51   2222.000    'WATER'  3*       'NO'  3* /
-----------------------------------------------------------------------------
-----------------------------------------------------------------------------
```

Figure 27: Welspecs

The next keyword is "COMPDAT". This is where all the completion data for the wells are specified. Some of the new parameters are: the blocks and layers the well should perforate, if the well is open or not, and the diameter. An excerpt from this keyword can be seen in Figure 28.

```
-----------------------------------------------------------------------------------------
-------------------OUR ADDED WELLS-------------------------------------------------------
-----------------------------------------------------------------------------------------
'INJ_E'      21  51   3   3     'OPEN'  1*    1*      0.200  1*   2*         'Z'    1* /
'INJ_E'      21  51   4   4     'OPEN'  1*    1*      0.200  1*   2*         'Z'    1* /
'INJ_E'      21  51   5   5     'OPEN'  1*    1*      0.200  1*   2*         'Z'    1* /
'INJ_E'      21  51   6   6     'OPEN'  1*    1*      0.200  1*   2*         'Z'    1* /
'INJ_E'      21  51   7   7     'OPEN'  1*    1*      0.200  1*   2*         'Z'    1* /
--'INJ_W'    14  51   3   3     'OPEN'  1*    1*      0.200  1*   2*         'Z'    1* /
--'INJ_W'    14  51   4   4     'OPEN'  1*    1*      0.200  1*   2*         'Z'    1* /
--'INJ_W'    14  51   5   5     'OPEN'  1*    1*      0.200  1*   2*         'Z'    1* /
--'INJ_W'    14  51   6   6     'OPEN'  1*    1*      0.200  1*   2*         'Z'    1* /
--'INJ_W'    14  51   7   7     'OPEN'  1*    1*      0.200  1*   2*         'Z'    1* /
-----------------------------------------------------------------------------------------
-----------------------------------------------------------------------------------------
```

Figure 28: COMPDAT

For our well(s), the last mandatory keyword is "WCONINJE". This keyword specifies the control mechanism for the wells. By placing our well under this keyword, and not for example "WCONPROD", we define the well as an injector. Other parameters that are being specified are: what phase to inject, if it's open or shut, the control mode, and the target value for the control mode. We have also included an excerpt from this part in Figure 29. We are interested in starting the injection in 2011, thus the wells are flagged as shut in the "WCONINJE" keyword. However, we add a keyword called "WELOPEN" on January 1st 2011 that gives the opportunity to flag the wells as open on this date.

```
-------------------------------------------------------------------------------
-------------------OUR ADDED WELLS---------------------------------------------
-------------------------------------------------------------------------------
------------INITIALY, OUR WELLS ARE SHUT. THEY ARE OPENED AT FIRST OF JANUARY 2011--
------------THERE IS A KEYWORD THERE: WELOPEN. HERE THE WELLS ARE OPENED/CLOSED-----
-------------------------------------------------------------------------------
'INJ_E'     'WATER'   'SHUT'  'RATE'    6000 /
--'INJ_W'   'WATER'   'SHUT'  'RATE'    6000 /
-------------------------------------------------------------------------------
-------------------------------------------------------------------------------
```

Figure 29: WCONINJE

There are several records for each of the above keywords that are not listed above, however, we are mostly interested in those already mentioned.

N.B.: A well may be disabled in a number of ways. One can add a comment mark (–) in front of each input, or specify that the well should be shut. The difference is that when the comment mark is added, all specifications for the well are ignored and the well is treated as non-existing. When the well is flagged as shut, it will still be treated as a well in the simulation but with no injection. We have chosen to use a combination of the two possibilities. In the case of only looking at one well, we add the comment mark for the other, but the well used is flagged as shut in until January 1st 2011.

12.2 Perforation Studies

The first main challenge is to determine which layers to perforate, as all layers in a reservoir have different properties. The effect of injecting fluids to add pressure support in a reservoir can be strongly dependent of the layer it is injected in. Injecting in an isolated layer will not distribute the pressure throughout the reservoir, and it is therefore necessary to find the most preferable layer(s) to inject into in order to optimize the effects of the injection.

12.2.1 Optimizing Injection Effects: Perforation Planning

From the model description, we know that layer 3 represents the Tarbert Formation, layers 4, 5, and 6 represent the Ness Formation, while layer 7 represents the Etive/Rannoch Formations. In this chapter, we look at the effects of injecting water at a constant rate for the following perforation cases:

- all layers
- 3 upper layers (Tarbert, Nees III and II)
- 2 bottom layers (Nees I and Etive/Rannoch
- only bottom layer (Etive/Rannoch)
- layer 6 (Ness I)
- bottom layer + layers 4 and 5
- bottom layer + layer 5

We have made a simulation run for each of these cases for both "INJ_E" and "INJ_W". The main parameters that must be compared for determining which layers to perforate, is the effect different perforated layers have on the average reservoir pressure and the bottom hole pressure in the well. Perforations cost money, and thus, the fewer the better. However, the pressure in the well might become too high, hence both of these parameters need to be considered in context with each other. Another parameter that needs to be included when considering where to perforate, is the total production. One perforation combination may give an extra increase in the total production, thus making that particular choice much more profitable.

Table 1 presented below lists all the well specifics we have chosen for the perforation analysis, which include the I and J locations on the grid. These specifications will also be used for all future simulations unless other is specified, and will be referred to as the initial case.

Specification	"INJ_E"	"INJ_W"
I-position (block nr)	21	21
J-position (block nr)	51	14
BHP reference depth	2222 m	2222 m
Fluid phase	Water	Water
Well diameter	0.2 m	0.2 m

Table 1: Inital specifications

12.2.2 "INJ_E"

The simulation run done for each case has been carried out with an injection rate of 6000 Sm^3 /D. The average reservoir pressure for each case is plotted together in Figure 30. As we can see, there are only two different outcomes, but we are mostly interested in the cases resulting in the least depletion at the end. When we perforate the upper three layers, we end up with the worst pressure maintenance. We see that as long as one of the bottom layers is perforated, the highest possible effect on the average reservoir pressure is achieved. Perforating one of the 3 upper layers while having a perforation in 6 or 7 does not result in any additional effect compared to only perforating 6 or 7. It is evident from the results that perforating layers 6 or 7 seem to be the most preferable choice.

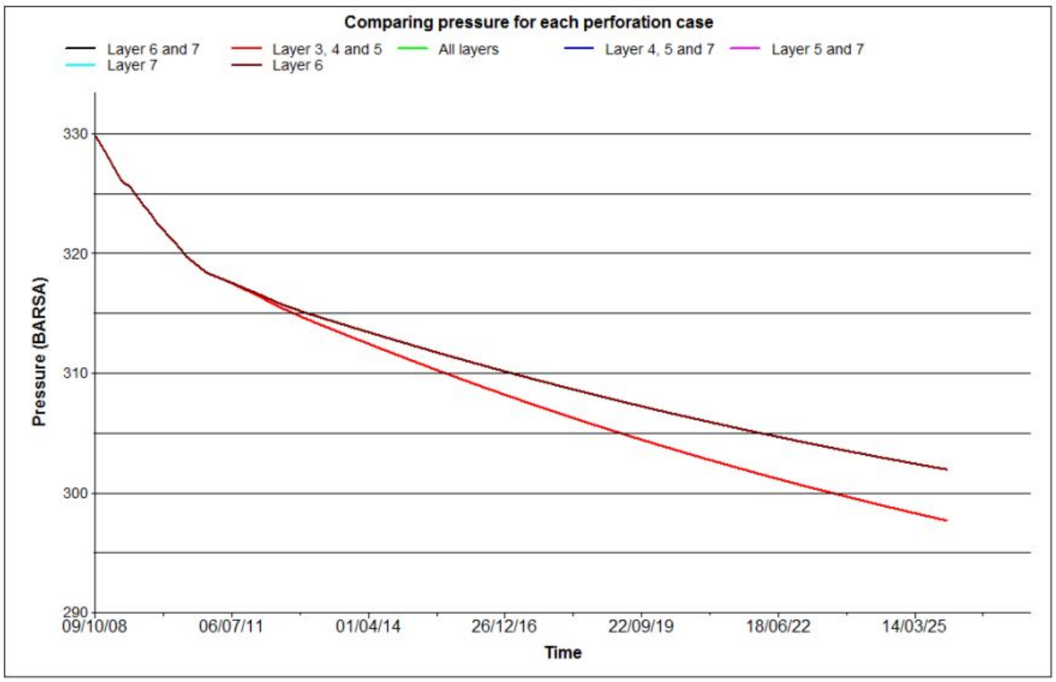

Figure 30: Comparing average reservoir pressure trend for each of the perforation cases.

Figure 31 presents the bottom hole pressure for the layer 6 case and the layer 7 case.

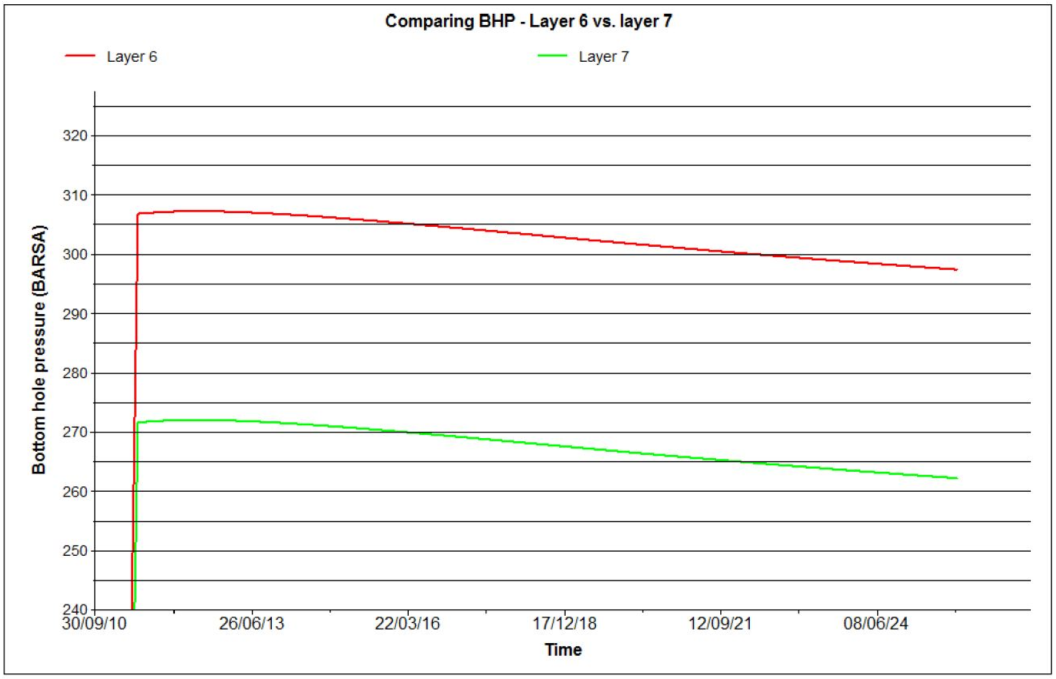

Figure 31: Comparing BHP for the case of perforating layer 6 and the case of layer 7.

The pressure difference between the well and the reservoir is the primary drive mechanism for the flow, and higher bottom hole pressures result in higher flow rates. However, fracturing of the formation can result from too high BHP and formation pressure. This can lead to uncontrolled leakage into the formation, which is not always a bad outcome. It is frequently used in controlled fracturing of the formation to decrease the skin factor, improving the well performance. Fractures increase the permeability, thus allowing the fluid to flow more easily. In the case of injection, fractures make it easier to inject the fluid, and distribute the fluid to the reservoir. Due to a better distribution, a more extended part of the reservoir might take advantage of the effect obtained by the injections. Looking at the logs (Figure 15) we see that the Etive/Rannoch formation is more homogeneous than the Ness I formation. The permeability is also better. This explains why the BHP is lower for layer 7 since the injected fluid meets less resistance. One of the more crucial consequences of too high BHP and formation pressure is the possibility of fracturing the overlaying formations due to high formation pressure. This aspect is addressed in more detail under the actual estimation of the required amount of water and the under Chapter 14. After studying the pressures in the formation in each case, we see that neither of the layers has a formation pressure that constitutes any risks related to fracturing. However, the situation can be different when we increase the injection rate. As we see from the pressure plot, a rate of 6000 Sm^3/D is far from enough, hence the possibility of fracturing still needs to be kept in mind.

The last parameter to consider in making a good decision is the total production. The case resulting in the highest production might be the most beneficial one to choose. The plot in Figure 61 below presents the total production achieved from the case of perforating layer 7, and the case of perforating layer 6. As expected, the difference is absent. The production parameter does not qualify to be a determining factor.

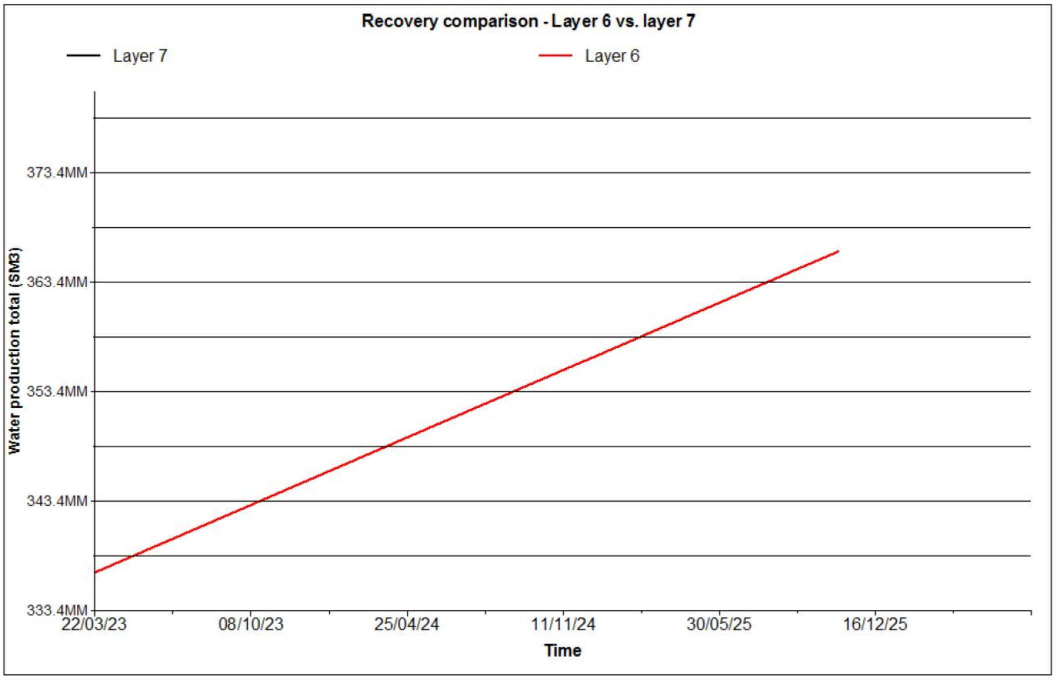

Figure 32: Comparing recovery for the case of perforating layer 6 and the case of layer 7.

12.2.3 "INJ_W"

The injection rate used during the simulations for "INJ_W" is also 6000 Sm^3/D. The results are exactly the same as achieved for "INJ_E". We want to achieve the highest possible reduction of the pressure depletion together with having as few perforations as possible. If the case were that two perforations had given a better pressure maintenance than one perforation, cost vs. profit would need to be considered. However, this was not the case, and the best pressure maintenance is achieved with the same perforation case as for "INJ_E".

12.2.4 Location Selection and Discussion

Based on the interpretation of the results obtained from the simulations discussed above, we have decided that "INJ_E" and "INJ_W" both should perforate only layer 7. This will be the case for all simulations run unless otherwise indicated.

The results from the modeling show some interesting results, which can be explained by understanding the geology, as well as general fluid flow behavior. Several scenarios are discussed below, in a geological context.

The worst results from the modeling were seen when we injected only in layers 3, 4, and 5, which correspond to the Tarbert Formation, and parts of the Ness Formation. These formations are highly heterogeneous, and although contain some higher permeability sands, is considered to be poor reservoir. An extensive permeability barrier also exists in the formation, which hinders the flow of fluids, and thus the pressure maintenance support from water injection.

When only layer 7 (Etive/Rannoch Formation) was perforated, we saw a large increase in the pressure support, which in the end turned out to be the best scenario for water injection. As mentioned earlier in the geological discussion, the Etive/Rannoch Formations have the fewest heterogeneities, highest permeabilities, and highest reservoir quality within the Brent Group in Beta Ridge. With the formation easily able to accept the injected water and transport it throughout the formation, it is easy to understand why we have such good results with pressure support.

In another scenario, layers 4, 5, and 6 were perforated, but the results were nearly the same as only perforating in layer 7. If we remember the principles of fluid flow behaviour, we know that fluids flow in the path of least resistance. In our case, this means that water will flow into layers with high permeabilities, and perforating layers 4 and 5 will have a negligible effect.

Another aspect which makes layer 7 the ideal injection layer is that when water is injected at the bottom of a oil column, the water forces the oil to migrate upwards. This gathers the oil and makes it more concentrated, which again leads to easier production and better recovery.

12.3 Initial estimation of water injection rate – 3 cases

The main task, as mentioned earlier, is to estimate the amount of water needed to maintain the reservoir pressure in the Beta Ridge area. The decrease in pressure due to depletion is to be compensated by injecting water. Three different possibilities are to be studied. As described in the beginning of previous section, the three cases are: one well on the east side, one well on the west and two wells, one on each side. Refer to Figure 26 and Table 1 for a more detailed description of the specifics and the placement of the wells. These three cases will be referred to as the initial cases throughout the rest of the report. From the section on determining which layer(s) to perforate, we saw that a rate of 6000 Sm^3/D wasn't enough to level out the pressure decline. Therefore, we are starting with a rate of 7000 Sm^3/D and then increasing it until the pressure decline is negligible.

12.3.1 Case 1 – One well on the east side

For this first case, we place one well on the east side.

The process of finding the approximate amount of water needed to maintain pressure is a trial and error procedure. One has to make some guesses, and work their way from there. As stated above, our initial rate was 7000 Sm^3/D, and from the plot below in Figure 33, we can easily see that the decline is still quite severe.

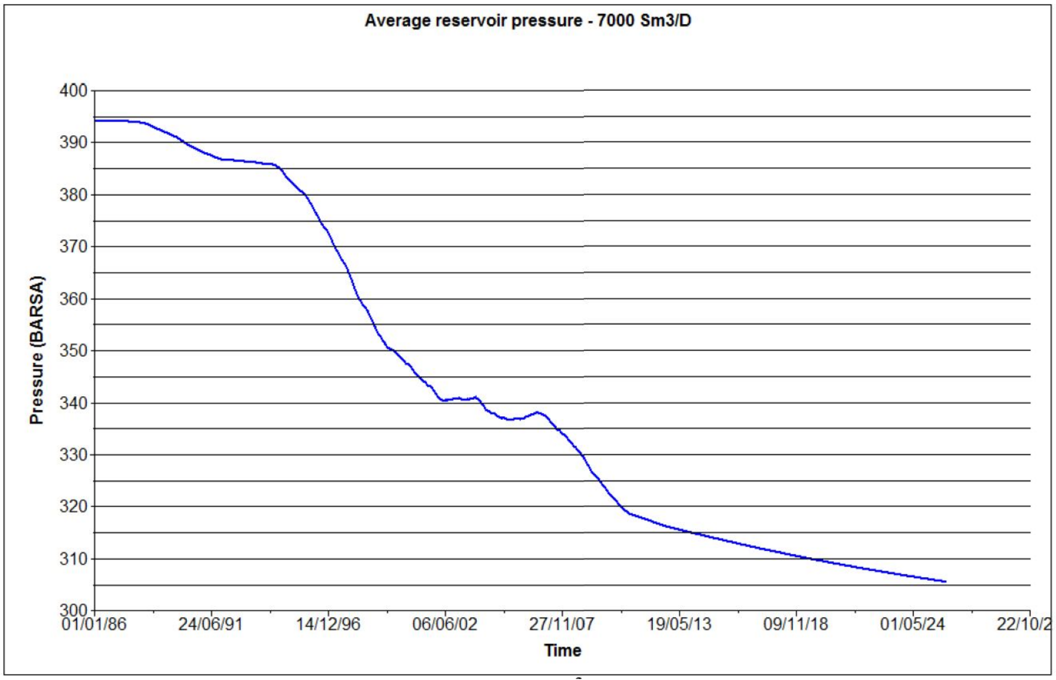

Figure 33: Average reservoir pressure with injection rate of 7000 Sm^3/D

We saw similar results when injecting 8000 Sm^3/D, however, injection rates of 12000 Sm^3/D caused the pressure to increase, and thus the rate was too high. We made runs with rates of 10000 Sm^3/D and 11500 Sm^3/D, which both did not satisfy the result we were looking for. However, rates of 11000 Sm^3/D seemed to level out the pressure drop. The average field pressure for the case of 11000 Sm^3/D is plotted below in Figure 34, while Figure 35 shows a combined plot of all attempted rates.

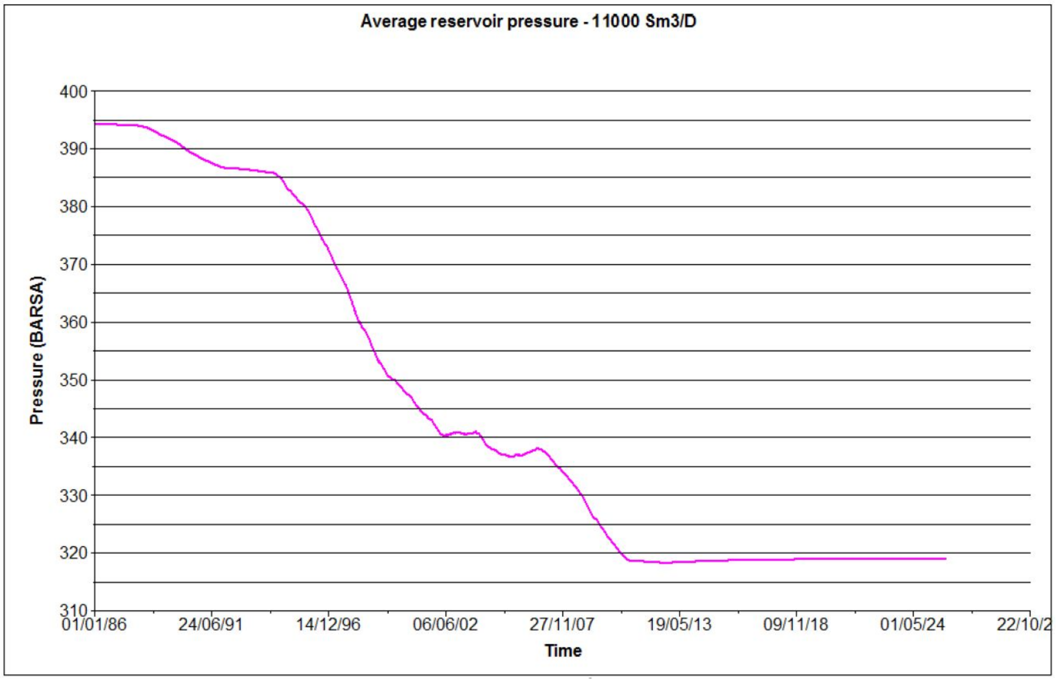

Figure 34: Average reservoir pressure with injection rate of 11000 Sm^3/D

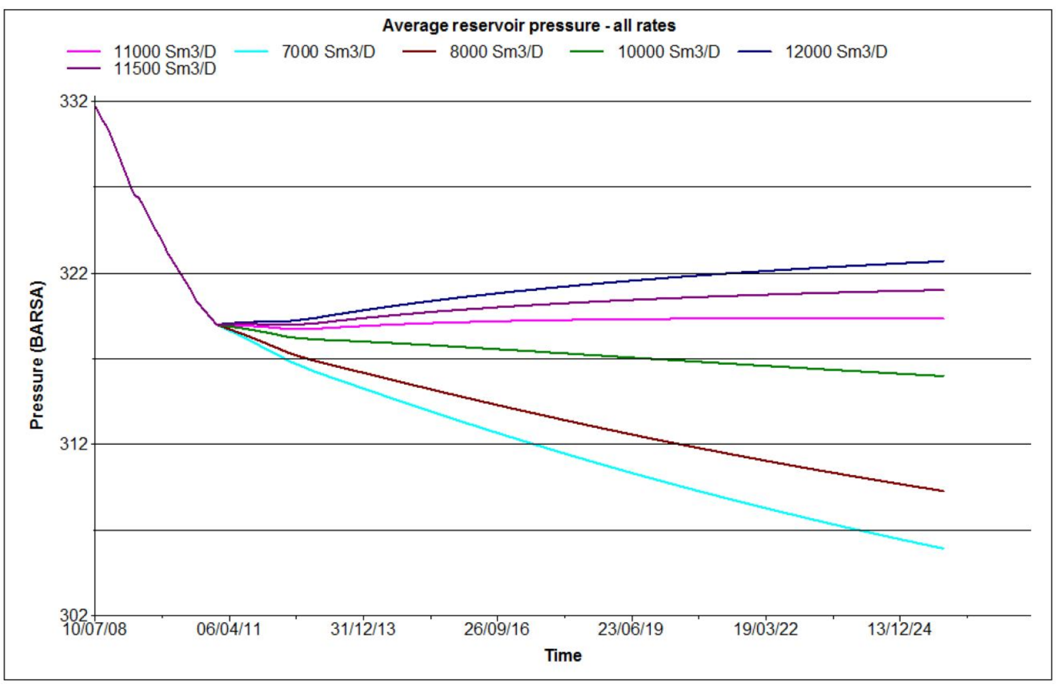

Figure 35: Average reservoir pressure – all rates combined for "INJ_E"

By studying the results, a certain degree of mathematical connection between an increase in rate and the resulting pressure increase can be drawn. It seems that the relationship between the change in rate and the pressure change due to this is approximately proportional. An increase of 1000 Sm^3/D (ΔQ) results in an increase of roughly 3.2 bars in the pressure (ΔP). However, this is very theoretical, and based on rough approximations by looking at the plotted results.

12.3.2 Case 2 – One well on the west side

For this second case, one well is placed on the west side of the Beta Ridge. Due to the well similarities learned in the perforation analysis, the same approach for case 1 was also used here. The rates we tried were exactly the same: 7000, 8000, 10000, 12000, 11500 and finally, 11000 Sm^3/D. The results are shown in Figure 36.

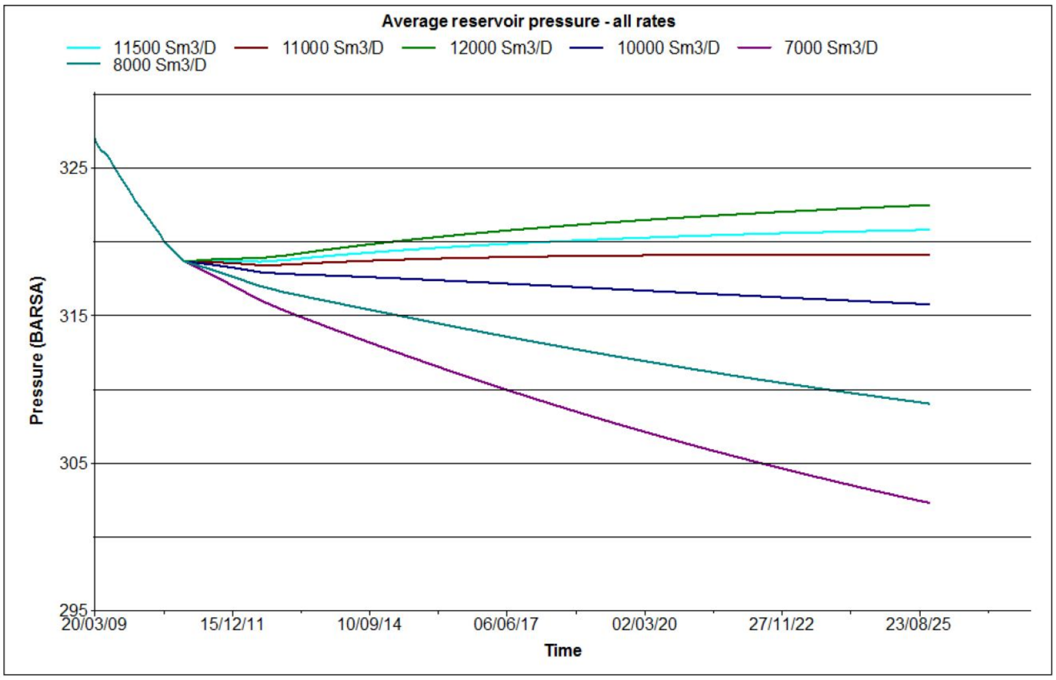

Figure 36: Average reservoir pressure – all rates combined for “INJ_W”

The sensitivity to rate change is about the same as for “INJ_E”. A change of 1000 Sm^3/D resulted in a pressure increase of about 3.2 bars. The pressure support obtained at a rate of 11000 Sm^3/D is acceptable, however, it differs slightly from the result for the east case, see Figure 37.

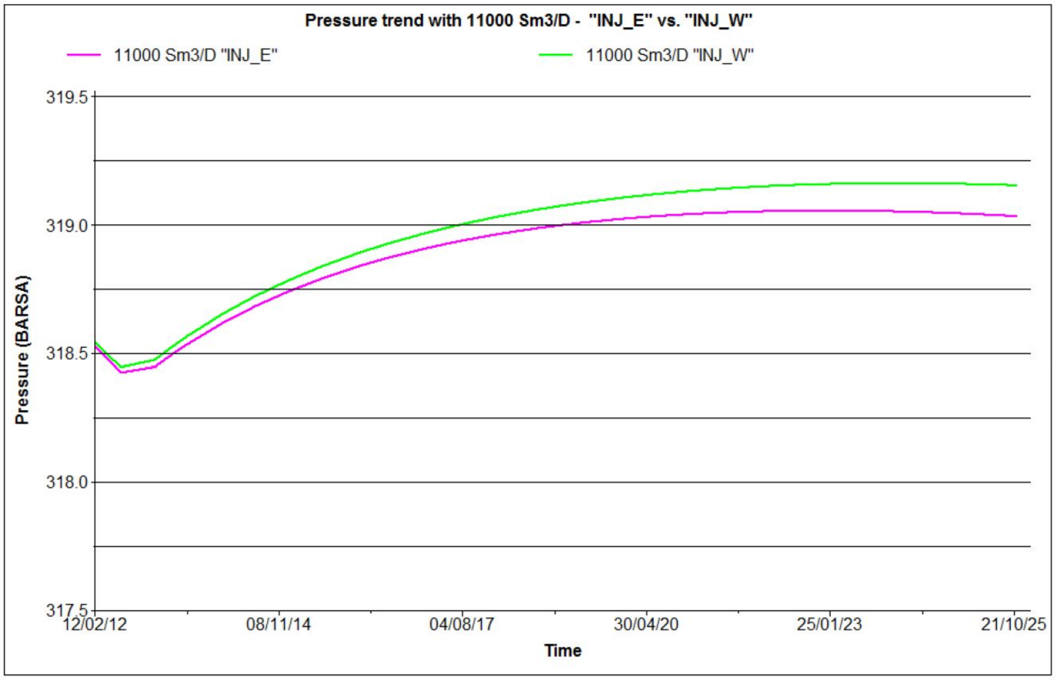

Figure 37: Comparison of pressure trend for "INJ_E" and "INJ_W" with an injection rate of 11000 Sm^3/D for both wells

To be able to compare the two cases in the best way, equal pressure support is of interest. We chose the result from "INJ_E" as the base case and want to match the reservoir pressure for "INJ_W" with that one. We know from the tested rates above that 11000 Sm^3/D is quite close, and after a bit of trial and error, the estimated rate of 10965 Sm^3/D resulted in a nearly perfect match, see Figure 38.

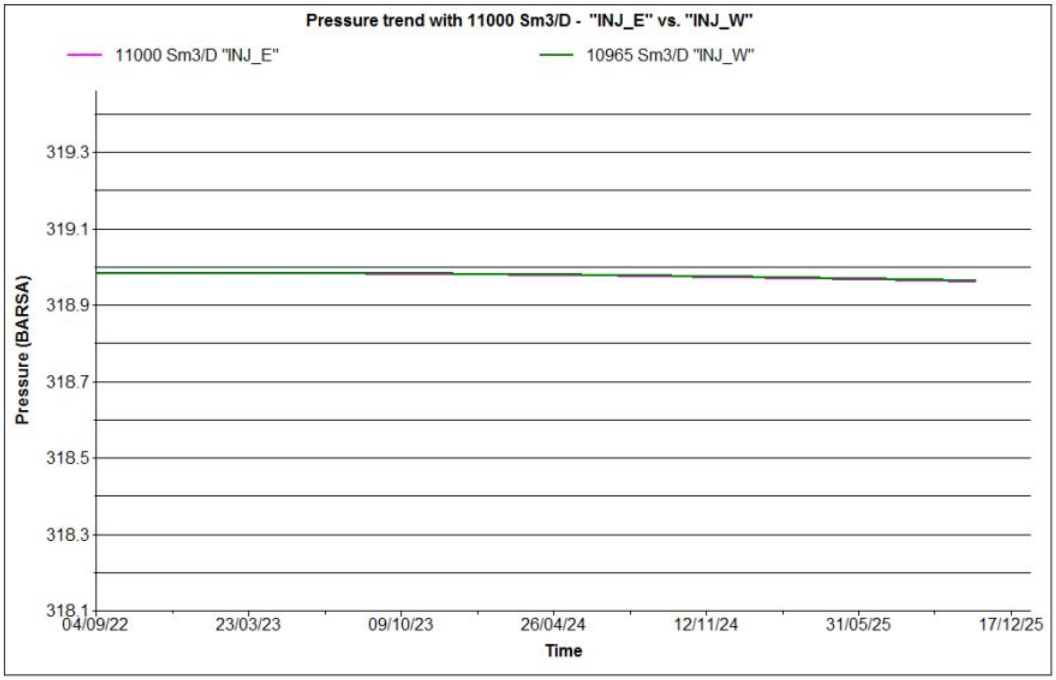

Figure 38: Comparison of average reservoir pressure for the case of "INJ_E" and "INJ_W" with estimated injection rates.

12.3.3 Case 3 – Two wells, one on each side

The last case that we are going to study is the case with two wells, with one well on each side of the main fault. Although the additional pressure support and production benefits from adding 2 injectors compared to one can be significant, the additional profit might be negligible, with costs potentially quickly overriding gains. This is what makes the two-well scenario less relevant than the others, with the economical aspect discussed in more detail at a later stage. There is one factor though that may determine whether we have to use two wells despite the economical consequences. Seeing these high injection rates for a single well scenario increases the possibility of potential risks related to formation fracturing. This issue is addressed in chapter 14.

Based on the results we have seen above, we expect to see the same pressure support by setting the total injection rate to be equal to the one estimated in the two previous cases (i.e., 10965 Sm^3/D). Due to the observations made for the single cases, we have chosen to simplify the model and carry out the analysis with equal rate for the two wells at all times. To establish an overview, we chose to make the first run with a rate of 5000 Sm^3/D in both wells, and as expected, the rate was too low. Injection rates of 6000 Sm^3/D resulted in an increase in pressure support, which was not our goal. A rate of 5500 Sm^3/D however, results in the establishment of adequate pressure support. As mentioned in Case 2, we need to have a nearly perfect pressure match in order to compare the different cases. After some trial and error, the estimated water rate needed is 5490 Sm^3/D. This is the rate per well, and thus, the total rate becomes 10980 Sm^3/D. The reservoir pressure for the rates that we have used can be seen in Figure 39. This estimated rate is approximately the mean value of the two previous estimated rates, thus the hypothesis regarding equal total rate fits.

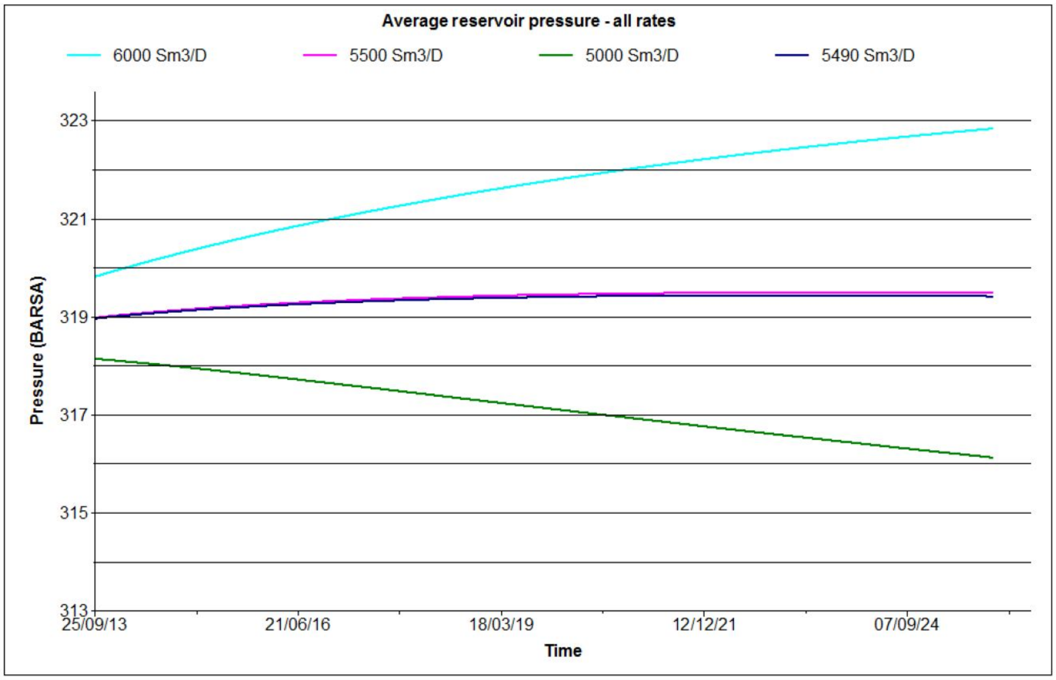

Figure 39: Average reservoir pressure – all rates combined

12.3.4 Comparisons, Comments, and Result

For the cases studied above, it is safe to say that all three are essentially equal regarding the estimated injection rate required. The maximum difference between the single cases is around 35 Sm^3/D. This difference is insignificant, and neglecting it is a reasonable assumption. The third case places itself in between the two single cases. Thus, by looking only at the rates, a recommendation on which case to choose is hard to make, and could be only be a matter of taste. To make a better comparison of the three cases, other parameters like BHP, total production, and costs must be considered. The potential of formation fracturing must also be considered due to the high rates. In that case, the two-well scenario is the best and safest option. This is discussed in more detail later.

The similar results obtained from all the cases were not unexpected. The pressure in the reservoir is strongly dependent on the total amount of fluid in place. Moving the well to a complete new location, or adding more injectors does not affect the amount needed. Whether this hypothesis is correct or not, will be justified in the sensitivity analysis we will do later.

The fault that separates the wells, the Beta Ridge, is quite long. At first, it's easy to make the conclusion that this fault should result in some difference between the cases above. However, the Vestlig Provins continues farther north, and thus the entire area is not completely divided by the fault. Despite the long distance from the wells, the possibility of good communication between the two sides can be present. The fault may also not be of the sealing type. To be able to understand the results, we have to look into the geological aspects and the properties of the Vestlig Provins. We need to know how the different reservoirs are connected, and the communication within the Vestlig Provins.

The geology will always vary from well to well, but in general, the reservoir properties are similar to one another on either side of the fault. Depending on the depositional environment, local variations may exist that can have an effect on the injectability of the formation. Significant permeability differences are seen between the formations, and also within the formations. Of the formations, the Etive Formation has the most consistent vertical and lateral permeability, which is a large part of the reason that it works best for the injecting formation. The faulting that has occurred in Beta Ridge has, for the most part, increased the permeability and connectivity between the different fault blocks. There are some instances where faults may create permeability barriers, but this is not the case with the fault separating the two injection wells. It is because of the connectivity of the main fault that we see similar results in our first two injection scenarios.

As mentioned in the case 3 section above, the result for this case was not that unexpected when looking at the result from the two first cases. If the difference between case one and two had been more substantial, the outcome of case 3 would most likely have been more discussible. Choosing two wells based on the total rate of water needed is not beneficial whatsoever. The cost of drilling an extra well is too high when the same results are achieved with only one well. The main reason and benefit of choosing two wells rather than one, is most likely the ability to divide the estimated rate between two wells, reducing the wear on each of the wells, and the reduction in risks related to formation fracturing due to the high pressure that occurs around the borehole.

We have now estimated the rate required to achieve pressure maintenance for different scenarios. To illustrate the results better, the three pictures below display the pressure distribution in the reservoir on January 1^{st} 2011, and twice on October 30^{th} 2025. The first two show the pressure of injection, while the latter shows the case where we have no injection. As we can see in the injection case, the pressure is almost the same. This means that pressure maintenance is achieved, which completes our task. The slight differences observed are due to slightly varying pressure trends. This can also be observed on the plots above. If we compare the last two images, we can clearly see that the pressure is considerably higher in case of injection.

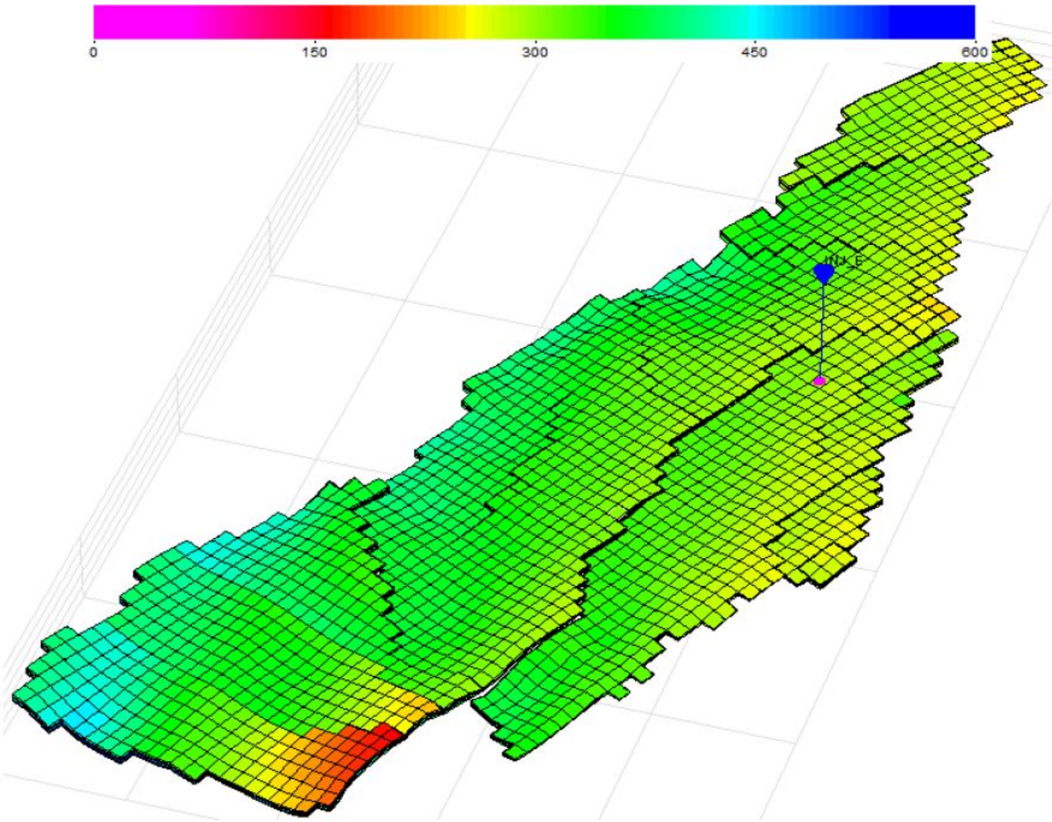

Figure 40: Pressure distribution Jan 1^{st} 2011, with injection

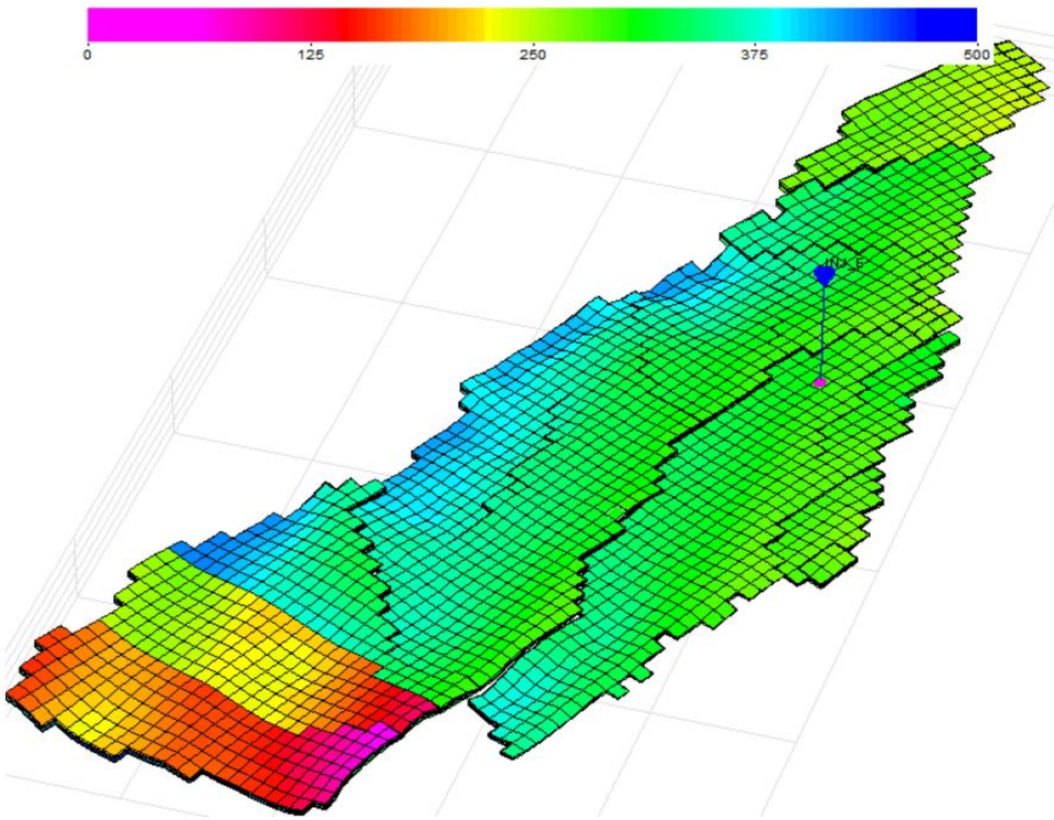

Figure 41: Pressure distribution Oct 30^{th} 2025, with injection

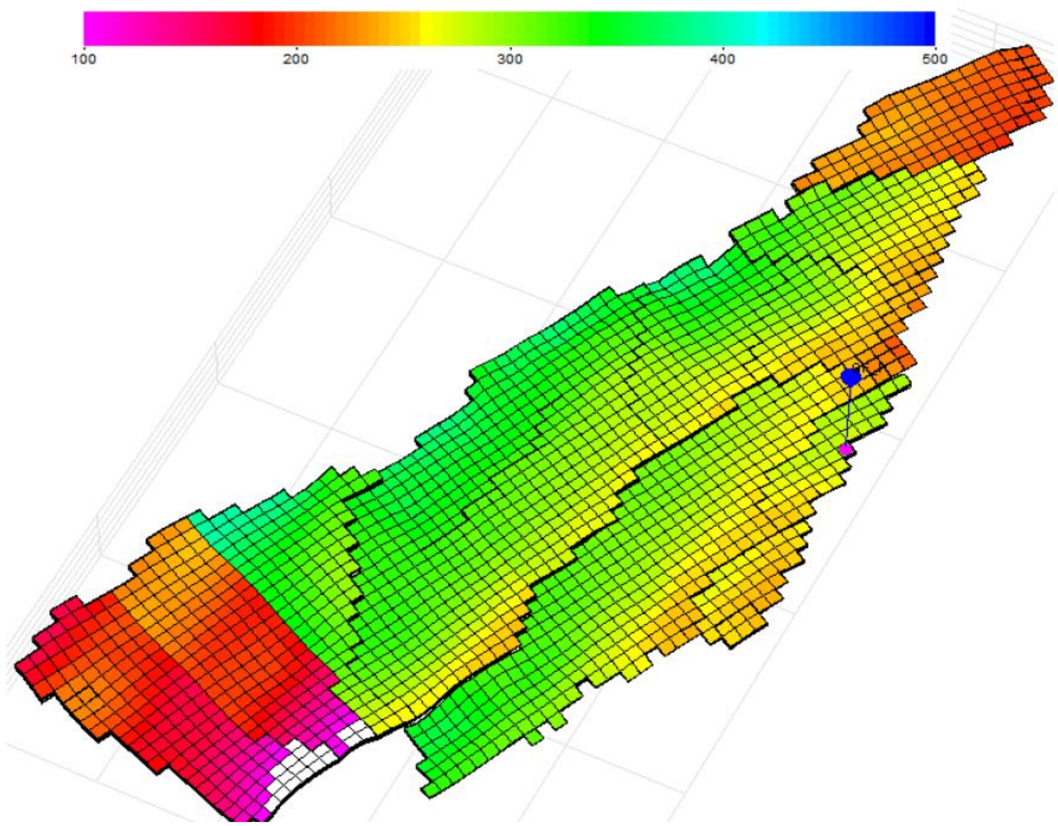

Figure 42: Pressure distribution Oct 30^{th} 2025, with no injection

13 Sensitivity Analysis

The pressure maintenance is not only sensitive to which layer the injection well(s) perforate, but also on a number of other factors, including the well placement and orientation. To get a better understanding of their effects, we conducted sensitivity analysis of the required injection rate with respect to these parameters.

13.1 Sensitivity – Placement

The general placement of the well(s) is the most crucial factor. Moving the well(s) to a completely different area would most likely give us different results. The general task was given with predetermined areas for where to approximately place the well(s). Moving the well(s) within these given areas might have a certain affect. The analysis to see whether or not this is the case, was done by running 7 different simulation scenarios for “INJ_E” and “INJ_W”, all with new well locations each time. The different cases are listed in Table 2 below, with Case 0 referring to the initial case.

Case	“INJ_E”		“INJ_W”	
	I-position	J-position	I-position	J-position
0	21	51	14	51
1	20	54	13	54
2	23	54	16	54
3	24	51	17	51
4	24	48	17	48
5	21	48	14	48
6	20	48	13	48
7	19	51	12	51
Rate	11000 Sm^3/D		10965 Sm^3/D	

Table 2: Position overview for each case

The rate used for the respective wells is the one estimated in the initial case.

13.1.1 Results

The results are mostly as expected, with movement of the well in a limited area showing no significant effects. This applies for both wells. Figure 43 shows the different cases for “INJ_E”, while Figure 44 shows the result for “INJ_W”

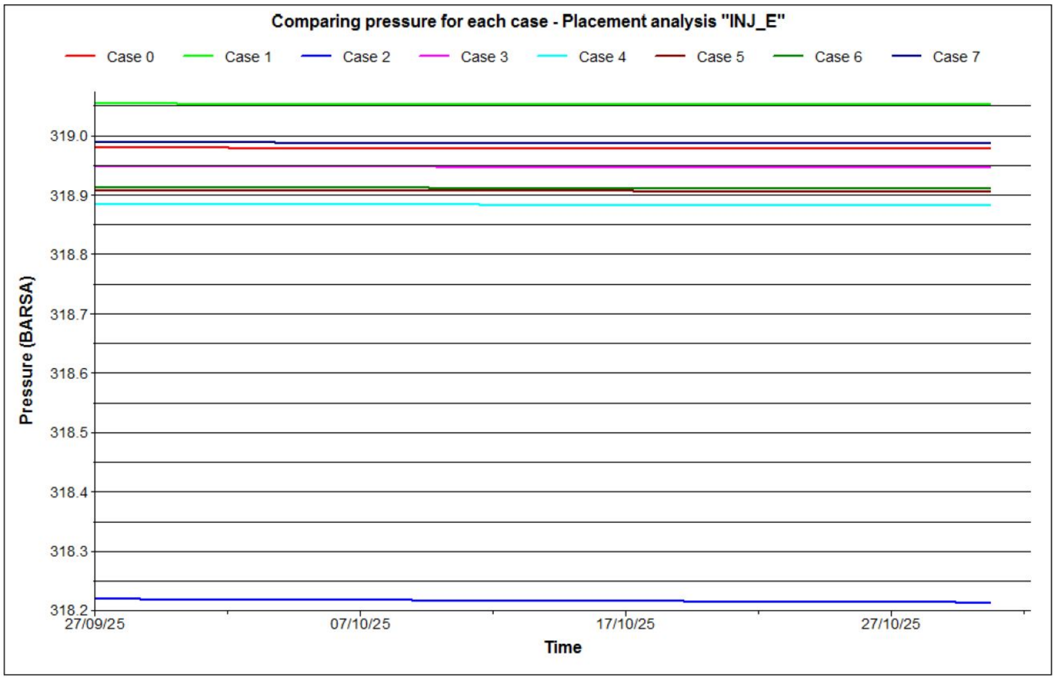

Figure 43: Comparison of the pressure for each case for "INJ_E"

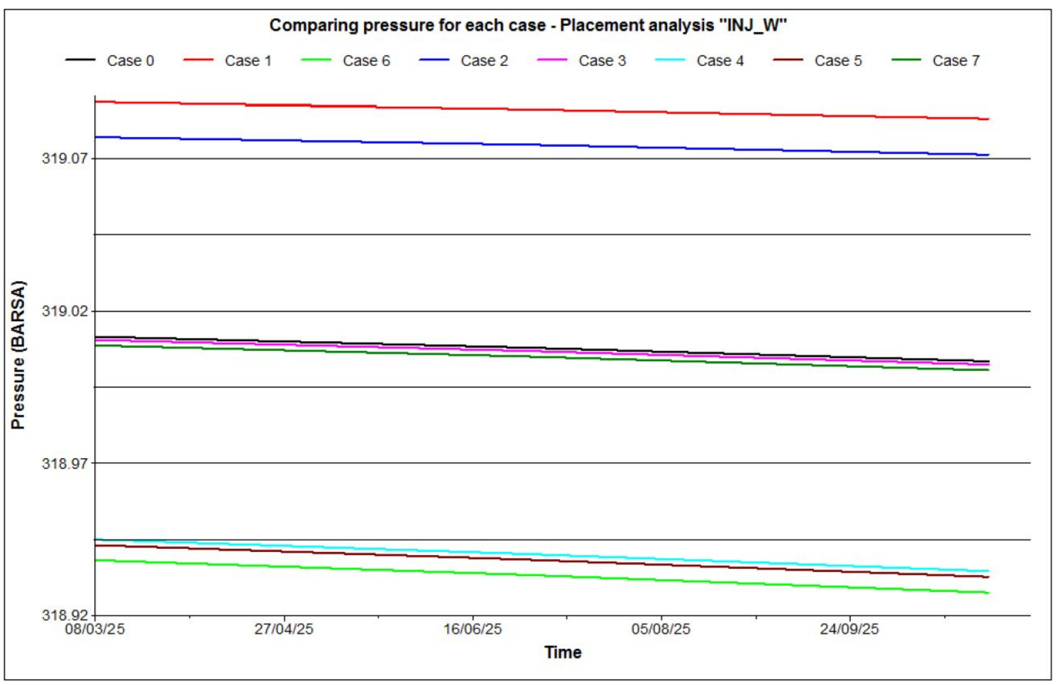

Figure 44: Comparison of the pressure for each case for "INJ_W"

For "INJ_E", the two cases that stand out are the first case and the second case. The first case results in a better pressure support, while case 2 results in a lower support. However, the difference is quite small. Comparing with the initial case, case 1 gives an extra support of 0.08 bars, while the difference is 0.8 bars for c ase 2. As for "INJ_W", the upper case is number 1 with an increase of 0.08 bars, and the lower case is number

6 with a decline of 0.075 bars. This is even less significant than for “INJ_E”, and is negligible in real life.

Although the geology will vary from well to well, the overall depositional environments in each formation are similar, which result in reservoir properties that are generally similar to one another. As mentioned earlier, there may be some local large-scale changes (such as seen in the large coal layer in the Etive Formation in the Gullveig Field), but this is not the case in the areas where we are injecting water. In addition, any permeability contrasts between the two injection areas are mitigated by the increased connectivity of these areas due to faulting. The resulting connectivity helps to explain why the pressure variations are so little during our injection modeling.

Despite these small differences in pressure, we chose to look at the water rate needed to get these “extreme” cases to result in the same pressure support as for the initial case for “INJ_E” and “INJ_W”.

The reason why it’s only the extreme cases that are being analyzed further, is that the other cases will only place themselves in between the initial case and the upper and lower case. The lower, the upper or the initial case represents the best-case scenario. The same goes for the worst-case scenario. One of these three cases will be the most favorable one.

13.1.2 New water estimates

For “INJ_E”, trial and error resulted in the same pressure trend for Cases 1 and 2 with rates 10978 Sm^3/D and 11233 Sm^3/D, representing a decline of 0.2% and an increase of 2.1%, respectively. Due to the small difference we had in the pressure, the result is not unexpected. An increase of 2.1% is relatively significant, and will probably result in noticeable effects regarding the recovery and bottom hole pressure.

The extremes for “INJ_W” require rates of 10942 Sm^3/D for the upper case, and 10988 Sm^3/D for the lower case, corresponding to a decrease and increase of 0.21%, respectively. These differences will not greatly influence the rates, but may have some noteworthy effects on the recovery and bottom hole pressure.

Well	Case	Rate *[Sm^3/D]*	Difference from initial
INJ_E	0	11000	0.00 %
	1	10978	0.20 %
	2	11233	2.10 %
INJ_W	0	10965	0.00 %
	1	10942	0.21 %
	6	10988	0.21 %

Table 3: estimated rates - Placement sensitivity

As we observed when analyzing which the most preferable layer for injection, an increase of 1000 Sm^3/D resulted in a pressure increase of approximately 3.2 bars. This is also valid for the new locations, and the sensitivity to rate change is similar. Thus, we can conclude that the relationship, as discussed in the preferred layer section, is a trivial description of the pressure-rate relationship in these areas. Essentially, it seems that the relationship is relatively independent of the positioning of the wells.

Without considering the possibility of an improvement of the recovery, the lowest possible rate is most desirable. Based on the rate benefits, the effort of trying to hit the exact spots during drilling is not worth it. The recovery and bottom hole/formation pressure aspects, for both "INJ_E" and "INJ_W", are discussed in more detail at a later stage.

13.2 Sensitivity – orientation

The orientation of a well is also of great importance. A horizontal exposes a much larger area of a formation compared to a vertical well. From the analysis regarding layer perforation, we saw that perforating either one or both of the two bottom layers did not make any difference in the average field pressure. This may be interpreted as a situation where good communication exists between the layers, thus a horizontal well in layer 7 will not be isolated from the rest of the reservoir. The pressure support will still be distributed to the other layers.

Although the main task involved studying vertical wells, we have carried out some simulations with a horizontal well. The reason for doing so is to see if there is a positive effect of using a horizontal compared to a vertical well, despite the additional cost by drilling horizontally.

We have run four different simulations for this sensitivity analysis, carried out on both "INJ_E" and "INJ_W". This analysis is not completely realistic due to the assumption of a ninety-degree angle on the well heel. To get an overview of the sensitivity to perforating a more extended part of a layer, this simplification is good enough.

The well location and completion data for this analysis are as follows: for all 4 cases, the heel of the well is located at the initial I and J position. The layer, which is being perforated, is layer 7, which was the preferred layer for a vertical well. The well perforates three grid blocks in each case. The difference from case to case is the direction of the horizontal projection: North, East, South and West. Table 4 lists the grid blocks being perforated in each case.

Direction	I	J	K
North (INJ_E)	21	51, 52, 53, 54	7
East (INJ_E)	21, 22, 23, 24	51	7
South (INJ_E)	21	51, 50, 49, 48	7
West (INJ_E)	21, 20, 19, 18	51	7
North (INJ_W)	14	51, 52, 53, 54	7
East (INJ_W)	14, 15, 16, 17	51	7
South (INJ_W)	14	51, 50, 49, 48	7
West (INJ_W)	14, 13, 12, 11	51	7

Table 4: Perforated grid blocks for each case

The rates used for "INJ_E" and "INJ_W" are the ones estimated initially, 11000 Sm^3/D and 10965 Sm^3/D.

13.2.1 Results

The two plots below show the results from both "INJ_E" and "INJ_W", respectively. For both wells, the results are the same. The north-oriented well resulted in a better pressure support, while less pressure support was obtained from the south-oriented injector. The differences are, as for the other sensitivity analysis, quite small.

For “INJ_E”, the difference in pressure between the vertical case and north-oriented well is 0.054 bars, and 0.022 bars for the south-oriented well.

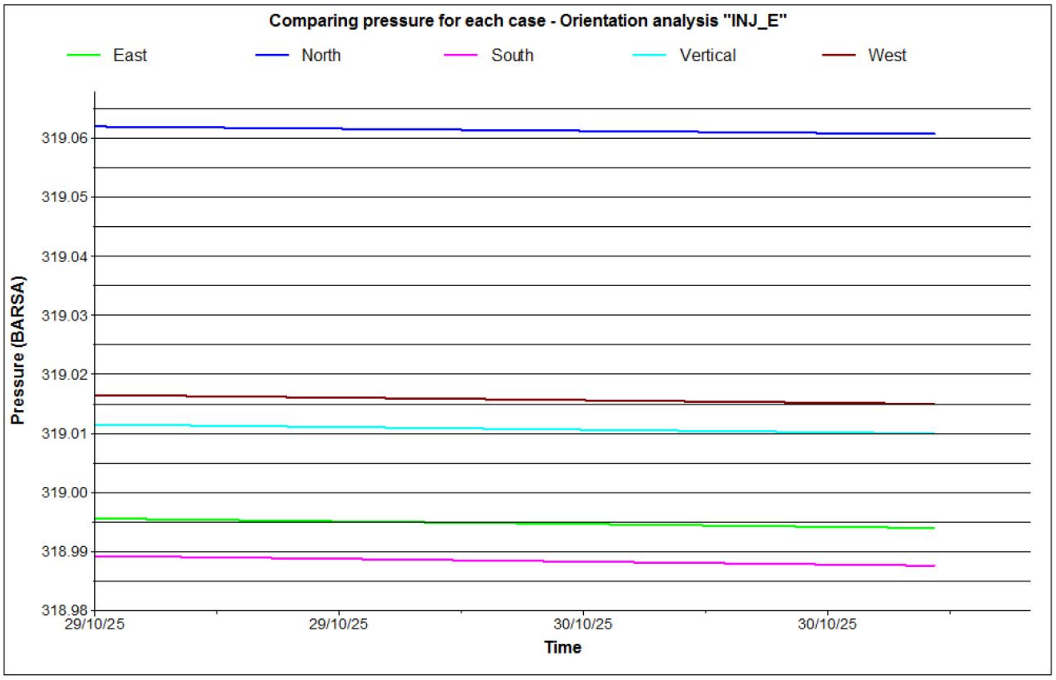

Figure 45: Comparison of pressure for each case for “INJ_E”

For “INJ_W”, the result is 0.052 bars for the north case and 0.025 bars for the south case. These are the extreme cases for both “INJ_E” and “INJ_W”, and are the cases we are interested in analyzing further.

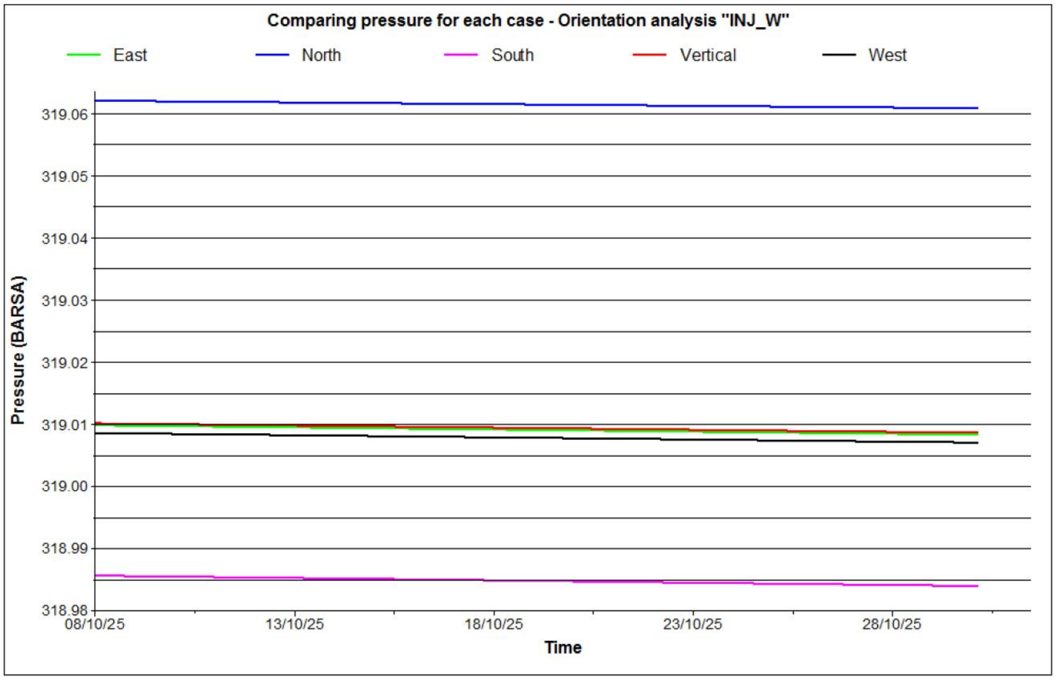

Figure 46: Comparison of pressure for each case for "INJ_W"

The slight difference in pressure support seen between the north-oriented and south-oriented horizontal injection wells is not entirely unexpected. The deposition and progradation of the Brent Delta was towards the north, and understanding the sedimentology of deltas, one can see that there heterogeneities are generally greater along depositional strike than depositional dip. Although the faulting has enhanced the connectivity from one fault block to another, the small differences in pressure support in the modeling are likely due to initial depositional heterogeneities.

13.2.2 New water estimates

It is still the water rate estimation that is our primary interest. Thus, new simulations have been run to find the rates required to obtain the same pressure trend as the initial estimates. The relationship we found between pressure and rate earlier seems to also be valid for the horizontal scenario. Estimating the new rates for the extremes by this relationship and running the simulation results in an almost perfect match. Table 5 below shows the new rates.

Well	**Direction**	**Rate** *[Sm^3/D]*	**Difference from vertical**
INJ_E	Vertical	11000	0.00 %
	North	10984	0.15 %
	South	11007	0.06 %
INJ_W	Vertical	10965	0.00 %
	North	10949	0.15 %
	South	10973	0.07 %

Table 5: New estimated rates - Orientation sensitivity

It seems that, for the orientation sensitivity as well, the recovery and BHP comparison will be crucial for determining which case is the most preferable. The recovery is especially important due to the additional costs of drilling a deviated well. The additional recovery needs to be significant to compensate for the small effects these horizontal wells have on the pressure and the estimated water rate.

It is important to note that the projection into layer 7 is quite small in all the cases. The most likely result by extending the wells farther is that the differences increase. The main factor determining if a well is profitable, i.e., the drilling costs, increases in line with the length of the horizontal projection into layer 7. The relationship between additional profit and cost due to extension is probably not proportional, and an increase in expenses will most likely exist.

14 Formation and Bottom Hole Pressure

The formation pressure around the borehole and the bottom hole pressure (BHP) are directly related to each other. This applies for both production and injection wells. In our case, injection is the main focus. The injected fluid will cause the pressure around the borehole to be a lot higher than farther away from the well. This high increase in the formation pressure is something that needs to be considered when planning an injection well due to the risks related to formation fracturing. The bottom hole pressure is strongly dependent of the injection rate, whereas the increase in the formation pressure around the borehole is strongly affected by the bottom hole pressure and thus the injection rate. It is therefore crucial to not inject with too high rates, causing the formation pressure to increase above the fracturing limit for the formation. The fracture can propagate not only horizontally in the reservoir, but also upwards and into the overburden. This can again lead to severe problems.

In the following section, we are evaluating the bottom hole pressure and the formation pressure around the borehole to see whether the formation is capable of receiving the required amount of water we have estimated, through one well. This evaluation will be determining whether we need one or two wells when injecting the estimated amount of approximately 11000 Sm^3/D. As we saw from the initial estimation analysis, the use of two wells enabled us to divide the required rate between two wells, thus reducing the force from the injection on the formation between two locations.

We have also done a brief analysis on the effect the sensitivity analysis we did have on the formation pressure at the borehole wall as well. Due to the relationship between the formation pressure and BHP, this analysis will also indirectly be on the BHP. Thus a more detailed BHP pressure study will not be carried out for the sensitivity analysis. Another important result that we can obtain from the sensitivity study is to see if there are any measures that can be made to maintain the formation pressure at the borehole wall as low as possible. This is something that is very favorable for both a single and two-well injection..

14.1 Initial case

The main issue related to the initial estimations we did is whether the formation is capable of receiving the required amount of water through one well or not. If the injection causes the pressure near the borehole to exceed the fracturing limit, severe problems can occur. It is the formation closest to the well that is most likely to fracture first. There is a negative pressure gradient from the borehole wall and into the reservoir. The formation's ability to distribute the injected fluid throughout the reservoir is what determines the size of the gradient.

For the single well case, we have not chosen which of "INJ_E" and "INJ_W" to use yet. The studies and observations we already have done suggest that these wells behave similarly when the conditions for the wells are altered in the same way. This is most likely the case for the formation pressure around the borehole and the BHP as well. We do however want to justify this, thus both positions will be studied for both scenarios.

From the plot below, we can observe that the BHP pressure is higher on the east side than on the west side. The comparison is done during the two-well case because this scenario implies equal injection rates for the two sides. Comparing the single well cases will have cause an additional uncertainty due to different injection rates.

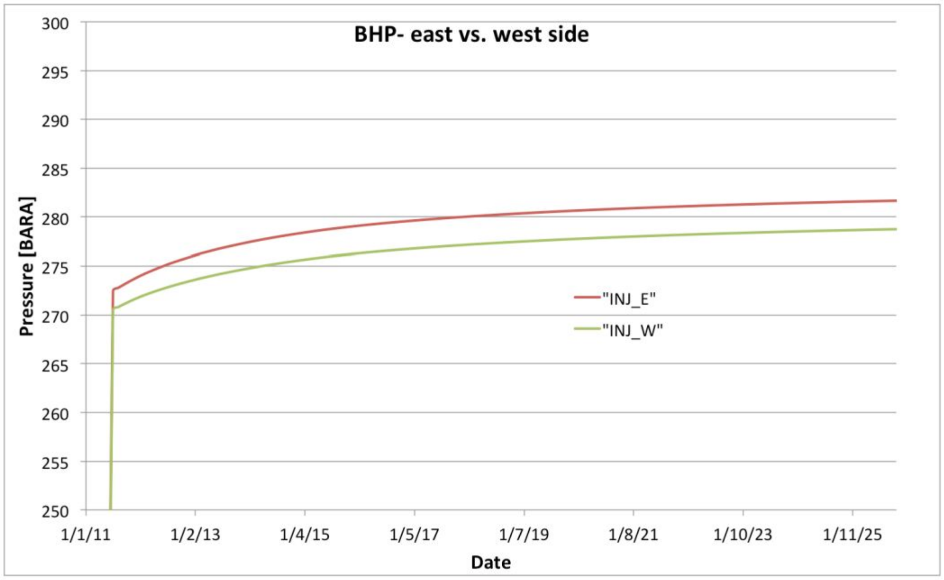

Figure 47: Bottom hole pressure – east side vs. west side – two-well scenario

As we can see, the difference is not even 3 bars. This is in our context negligible and does not justify any choice of which well is better than the other. The reference depth for the BHP calculation is the same for both wells, eliminating this factor. From the geological section and understanding of the reservoir, we know that the properties are quite similar from one side to the other. However, it is possible that the faulting and formation pressure differences have created small changes and thus given rise to the results we observe for the BHP.

From the initial estimation, we saw that in the case of having only “INJ_E” the rate required to maintain pressure was approximately 11000 Sm^3/D and that “INJ_W” required a rate of 10965 Sm^3/D. Injecting all this through one well can created quite a lot of stress on the formation around the borehole. As for the case of having two wells, we saw that we were able to divide the rate, thus only having to inject 5490 Sm^3/D through one well. This will reduce the stress and the bottom hole pressure in the well, which again reduces the pressure in the injection block. The reduction in pressures is what we must investigate in order to determine if the risk related to fracturing is less in the case of a two-well injection.

14.2 BHP - single well versus two-well injection

We need to consider if the formation pressure in the single well scenario is too high, and if that is the case, does using two injection wells reduce it enough. The two plots below show the BHP in “INJ_E” and “INJ_W”, respectively, for the single case compared to the two-well case.

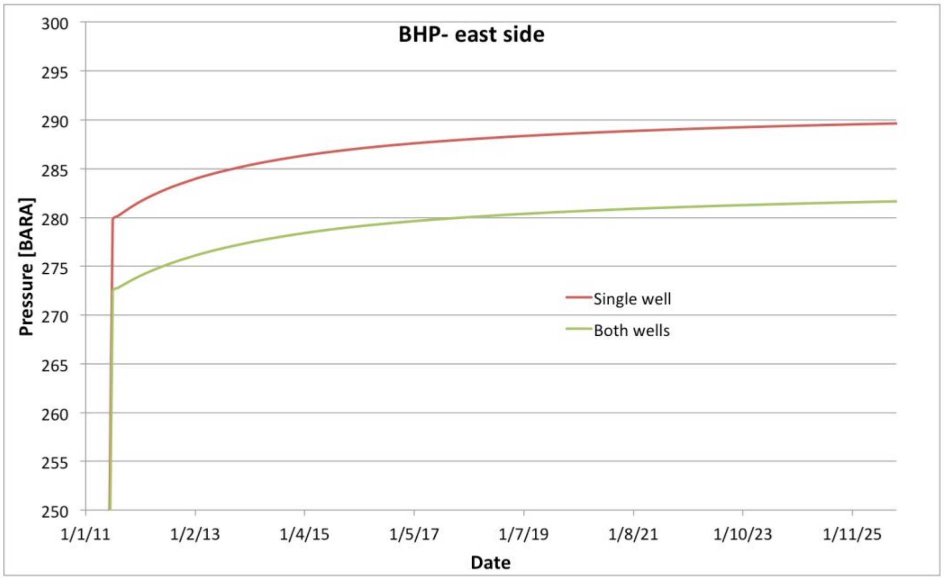

Figure 48: Bottom hole pressure east side – single and two-well cases

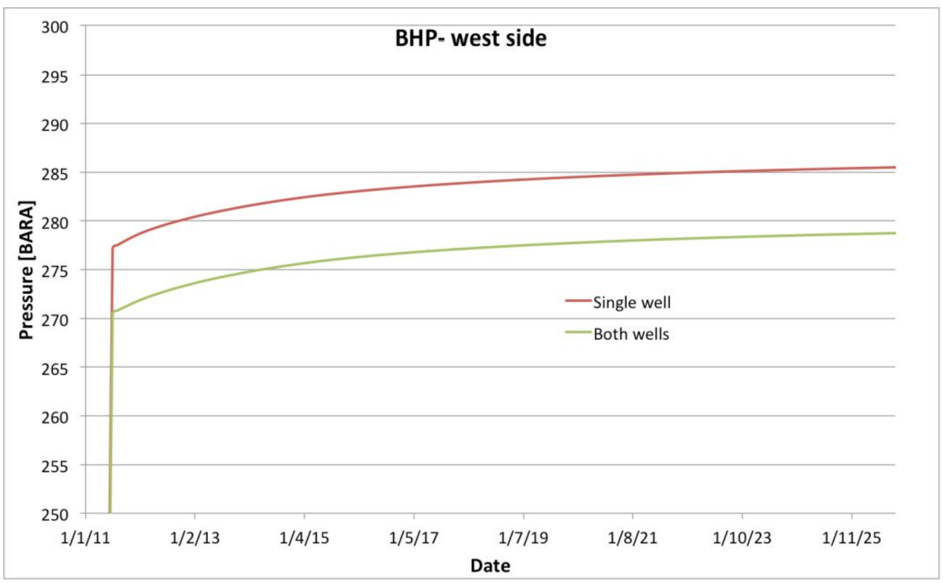

Figure 49: Bottom hole pressure west side – single and two-well cases

The plots clearly show that there is a reduction in the BHP in the well when we reduce the injection rate by half. This applies for both sides. The reduction is approximately 8 bars on the east side, while on the west side 6 bars. This is less significant than we expected. Based on these results, there is already reason to believe that the changes in formation pressures also will be of less significance. The reference depth for the BHP is shallower than where we have perforated the well. This means that the actual pressure at our depth of interest is higher. However, for the BHP, it is the difference seen going from single to two-well injection that we are most interested in. This difference will stay more or less constant as we get deeper in the well. The crucial factor regarding risks is the formation pressure at the depth of injection, and this must be evaluated against the fracturing limits in the formation around the borehole.

14.3 Formation pressure - single well versus two-well injection

To verify if the small changes that we see in BHP when going from one to two wells also applies for the formation, we need to investigate the pressure in the formation and not in the well. The formation will experience highest pressure at the borehole wall, thus the pressure in the injection block is the most critical. We have also investigated the pressure in formations above the perforated layer. All pressures evaluated are from the block directly above the perforated one, meaning closest to the borehole wall. In the plots below, we have included the pressure in the injection block as well as the block above (layer 6), for both single and two-wells injection scenarios. Table 6 and 7 contains the pressure in for each respective layer in the simulation model. The table values are from the last simulation year.

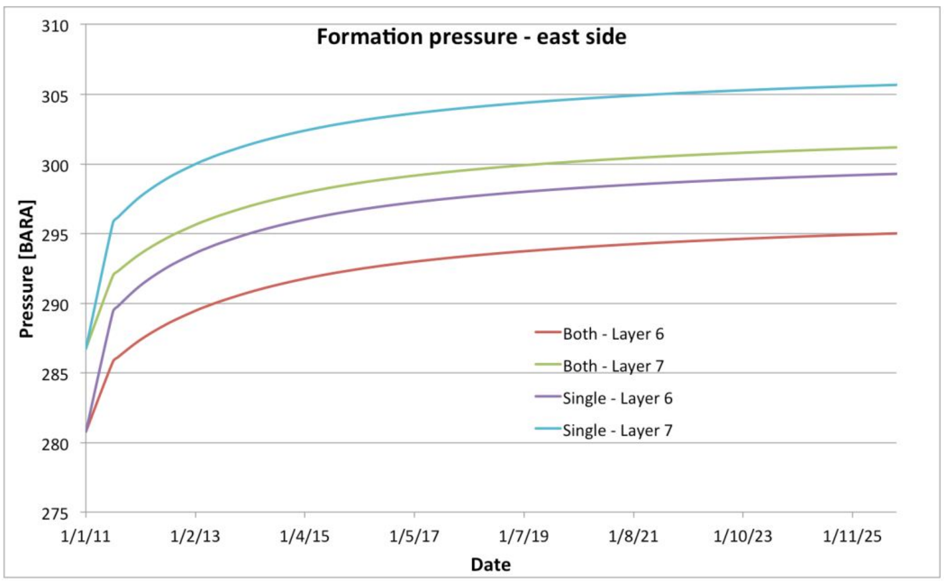

Figure 50: Formation pressure layer 6 and 7 on the east side – single and two-well cases

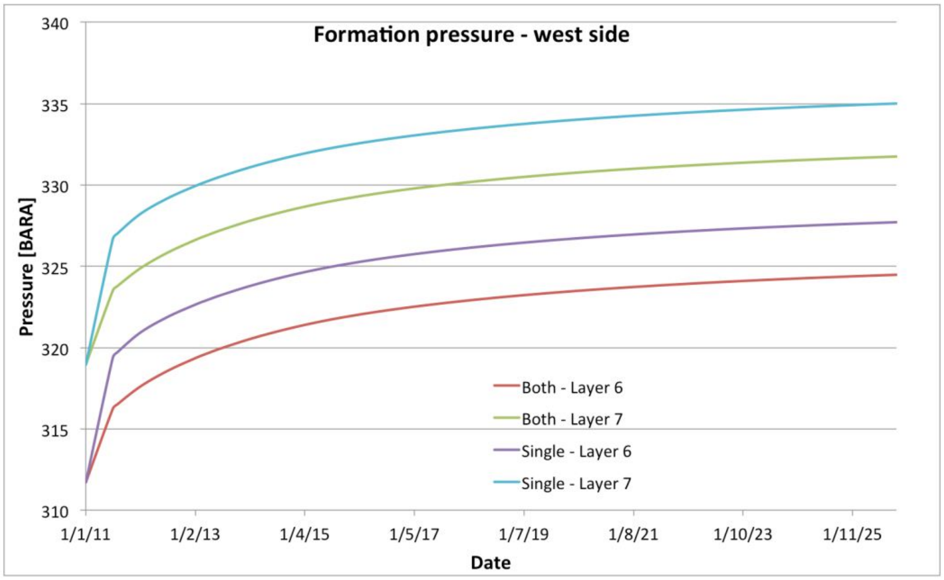

Figure 51: Formation pressure layer 6 and 7 on the west side – single and two-well cases

Layer	BPR [bars] – East Side		
	One well	Two wells	Difference
3	300.0456	300.1048	-0.1
4	303.9740	304.0316	-0.1
5	305.7396	305.7970	-0.1
6	299.3008	295.0219	4.3
7	305.6967	301.2048	4.5

Table 6: Formation pressure at borehole wall - all layers, east side

Layer	BPR [bars] – West Side		
	One well	Two wells	Difference
3	320.138	319.513	0.6
4	324.819	324.186	0.6
5	324.579	323.670	0.9
6	327.723	324.488	3.2
7	335.030	331.767	3.3

Table 7: Formation pressure at borehole wall - all layers, west side

The first observation that can be made is that pressures are well below the original minimum horizontal stress seen in figure 21. This applies for both sides of the Beta Ridge and the use of either one or two wells. This indicates that it might be safe to inject with the rates specified for the wells in both cases. A more thorough analysis of the formation fracturing limits needs to be done before a conclusion regarding fracturing of the formation. When a reservoir is depleted, the effective stresses in the reservoir are changed, which implies changes in the fracturing limits. Another major uncertainty is that the block pressure calculated by the simulator depends on the block size. Smaller blocks will give a more representative pressure for that particular position. Our model consists of rather big blocks. This means that the block pressure is less than what it actually is exactly at the borehole wall. The difference can be significant due to fast decline away from the wall.

As expected from the BHP observations, the pressure difference in the formation between the two cases is also of less significance. In fact, the difference is even less in the upper layers, where dividing the injection between two wells has no affect at all. Seen in context with the reduction in the risk of fracturing the formation, choosing one or two wells is more or less negligible. We have to be very close to the fracturing limit for the difference to be of any significant importance. This result is very interesting because of the consequences this have for the economical aspect of the project. However, this is addressed in chapter 17.

As mentioned, the pressure gradient away from the well is dependent on the properties of the injection layer as well as the layers above and below. The permeability is of special importance. From the log in Section 8.1, we can see that the permeability is quite good in the Etive/Rannoch Formations, which makes the formation's ability to distribute the injected fluid throughout the layer very good. The property of being able to distribute the fluid may be the explanation of why there is such little significant difference between injecting 11000 Sm^3/D and 5490 Sm^3/D in the well. The fluid is transported away from the well quickly, which again prevents the permit for a large pressure build-up around the well. Due to the small difference at the borehole wall, the difference diminishes quickly moving away from the well.

Another observation that can be made is that the 3 upper layers have all higher pressure than layer 6, and layer 5 has also higher formation pressure than where we inject. This is most likely due to that layer 6 and 7 was more depleted when the injection started. As we know, the fracture gradient increases as we get deeper. If the pressure gradient downward is more or less constant, one needs to be aware of the possibility to cross the fracture limit, despite being on the safe side at injection point. In addition, injection causes not only pressure in the injected layer to increase, but layers above will also get an increase. This leads to the need to ensure that the pressure in each layer does not exceed the fracturing limit as we continue injecting. In our case, the purpose of the injection is not to increase the pressure, but maintain it at the same level as from the start of process. The increases in stress at the borehole wall can still be very large and quite critical.

If the final choice falls on a single-well injection, the results obtained from the formation pressure and BHP study done above, does not justify a choice on which side to make the injection from. This needs to be done by evaluating different parameters such as recovery and economy.

14.4 Placement sensitivity

The first sensitivity analysis we did on the required amount of water was the placement of the wells. The result we came up with was that a rate change of maximum 2.1% was needed. In this section, we are going to study how the sensitivity of the pressure in the formation at the borehole wall is to movement. Due to the observations and results we have seen from all the studies done above, we choose to only study the effect that movement has on the east side of the Beta Ridge. The similarities we have seen, and the relationship we have learned that the different cases have, as well the small difference we get by dividing the required amount of water between two wells compared to only using one, justifies the choice. Sensitivity and changes due to movement for single-well east side scenario will apply in more or less the same extent to the other cases. In addition, the maximum change in rate was achieved for the east side single-well scenario, suggesting that the sensitivity for the formation pressure also is biggest for this case.

It is the extremes that are also important in this analysis. For "INJ_E", we saw that Case 1 and 2 were the ones that resulted in the biggest changes in the rate. Below is a plot of the formation pressure in the grid block we inject the water for the two extremes compared with the initial position case. The injection rates are the estimated ones for each respective case. Table 8 contains the formation pressure in all layers for each case.

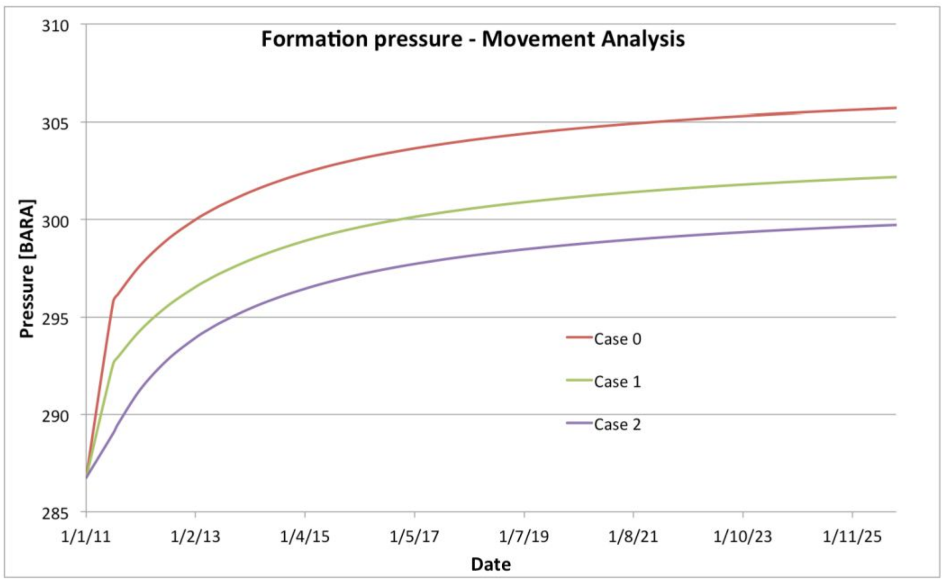

Figure 52: Formation pressure at borehole wall layer 7 – movement analysis

Layer	BPR [bars] – Movement		
	Case 0	Case 1	Case 2
3	300.046	300.038	300.632
4	303.974	303.966	304.559
5	305.740	305.731	306.325
6	299.301	296.213	293.764
7	305.697	302.187	299.729

Table 8: Formation pressure at borehole wall – movement analysis, all layers

We see that the differences are small. Case 2 results in the lowest formation stress in the layer we inject into. It is also noteworthy that the pressure in the 3 upper layers increases compared to the initial case (Case 0). This shows the importance of also monitoring the pressure in the layers above the injection layer.

Knowing that the result above is a combination of repositioning, as well as increasing/decreasing the rate, the main question is what factor that influence changes the most. One can get an idea by comparing the pressure for the three cases with equal rates and the required rates, as seen in the figure below. The notation "Extreme" in the legend donates that the case is ran with the new estimated rate. The thought behind this comparison is that if the formation pressure differs from case to case when the rate is equal, the positioning is responsible for the change.

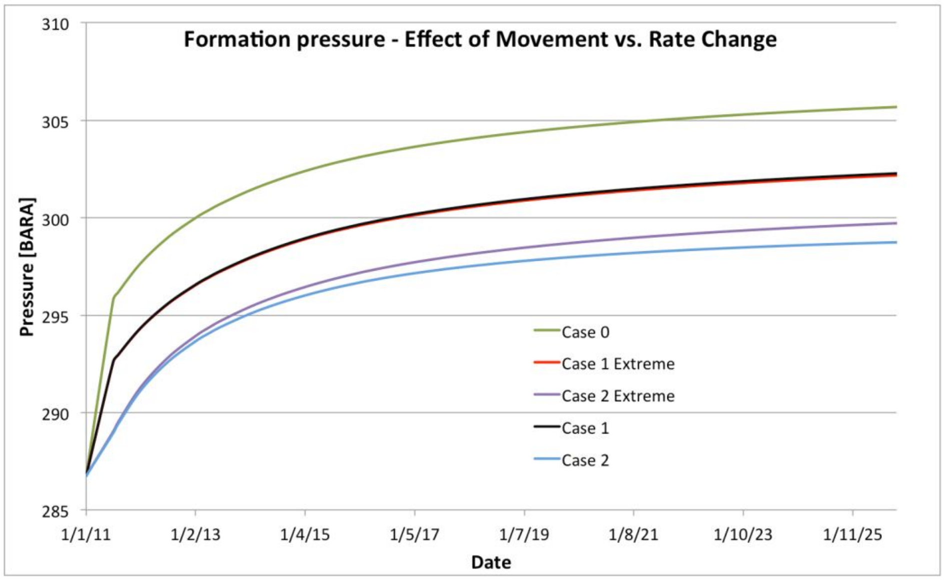

Figure 53: Comparing the movement cases with initial rates and new rates

In both cases, changing the rate has more or less an insignificant effect on the formation pressure. Therefore, repositioning is the most probable cause to the differences between the cases.

Moving the well does have an effect on the formation pressure and the risks related to formation fracturing. Both extreme cases in our case will in fact reduce the risk of fracturing. It is Case 2 that results in the lowest formation stress, thus making it more favorable than the initial case, and Case 1. However, drilling is a difficult operation. To hit the exact spot when the length of the well is in the 2500 m range is quite difficult. The gain in risk reduction is small compared to the effort that needs to be put into the project.

14.5 Completion sensitivity

As we discovered in the study on which layer to perforate and inject into, as long as we inject into layer 7 we achieve the best pressure support. Injecting into additional layers neither increases nor decreases the required amount of water. It does not affect the pressure support either. Another measure for maintaining the stresses at the borehole wall as low as possible might be to perforate more layers to spread the injection over a widespread area. This should in theory reduce both the stress applied to the formation and the bottom hole pressure in the well. There is a physical reasoning to this hypothesis. The physics behind pressure distribution is that pressure equals force per area. In our case, the fluid exerts the force while the area is the perforated part of the well. Increasing this area should reduce the pressure against the borehole wall. In reality, there are many factors that can cause deviation from this theory. We are in this section going to make a study regarding this theory.

14.5.1 Perforating several layers

To see if our well actually follows the above theory, we choose to compare the initial case with a case where we perforate the well in layers 5, 6 and 7. The injection rate is still 11000 Sm3/D. Based on the same arguments stated in the previous section, we continue to only study the east side single well scenario. The two plots below shows the formation pressure in layers 6 and 7, and the bottom hole pressure for both completion cases.

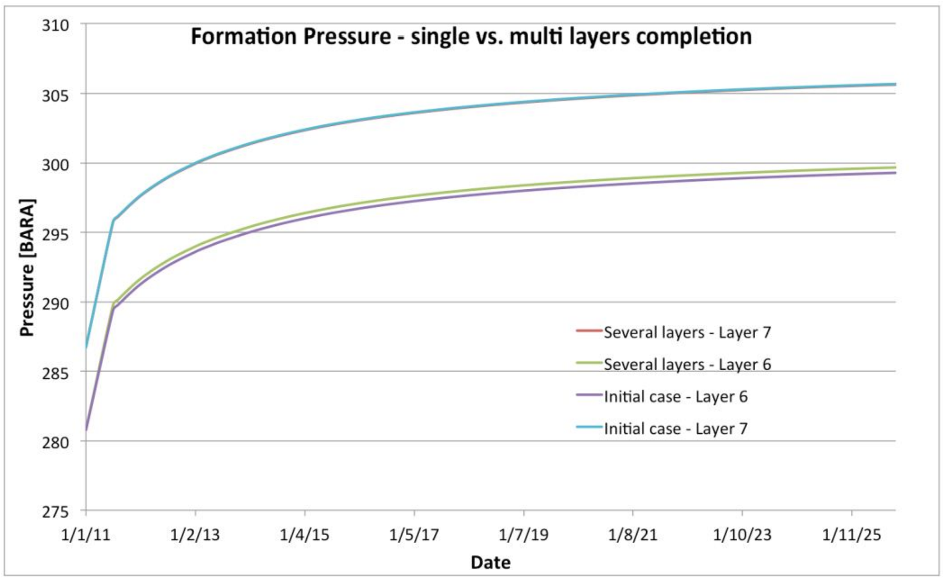

Figure 54: Comparing formation pressure at borehole wall in layers 6 and 7 for the case of single layer completion and multi layer completion.

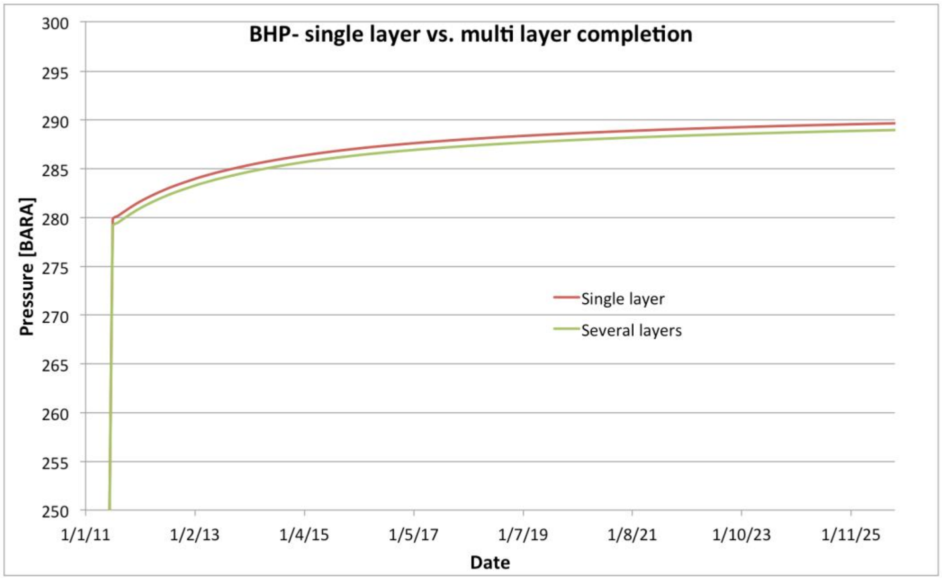

Figure 55: Comparing bottom hole pressure in the case of single layer completion and multi layer completion

What we can see from the plots above is that perforating more layers has more or less no effect at all. This result is a bit unexpected, however, the explanation might be in understanding the geology and the properties to the formations we perforate in addition to layer 7. From the log in Section 8.1 we see that layer 5 and 6 are quite heterogeneous. This might be a hindrance when we try to inject into these layers making layer 7 still the major injection section. This will result in a more or less unaltered pressure both in the well and the formation.

Based on these results, perforating more layers has little or no effect on the reduction of risks related to formation fracturing. A more selected perforation plan might be a solution though. Mapping zones and layers with very good permeability and ability to distribute the injected fluid throughout the reservoir, and then perforating only these, can result in a more significant reduction of pressure and stresses.

14.6 Orientation sensitivity

The final sensitivity analysis we are going to do is the benefit of a vertical versus a horizontal well. For "INJ_E", we saw that it was the case having a northern and a southern oriented well that resulted in the most significant rate changes. A horizontal well has a more widespread perforation area than the vertical well that is only perforated in layer 7. The perforation conditions can be compared to the case where we perforated layers 5, 6 and 7, except that in the horizontal case, only layer 7 is perforated. This will eliminate the potential effect that the heterogeneity of layer 5 and 6 had on the injection area. Layer 7 is quite homogeneous and the ability of the layer to distribute fluid is great.

Below is the formation pressure along the well in both directions. Table 9 contains the formation pressure data in both directions as well as the formation pressure in the same block in the vertical case. Block 1,2 and 3 refers to the additional blocks that are perforated in layer 7, while block 4 is the next block after the well toe.

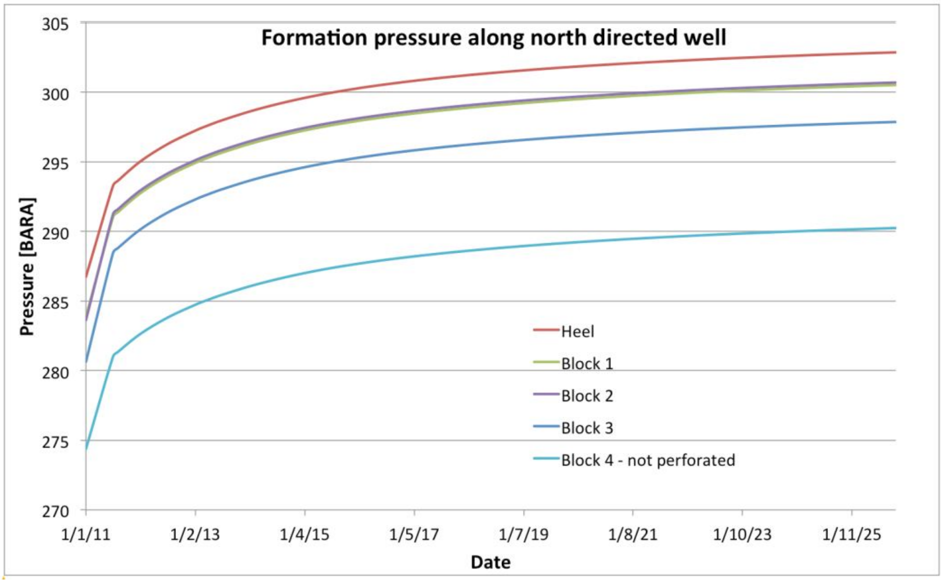

Figure 56: Formation pressure at borehole wall along the north directed horizontal well

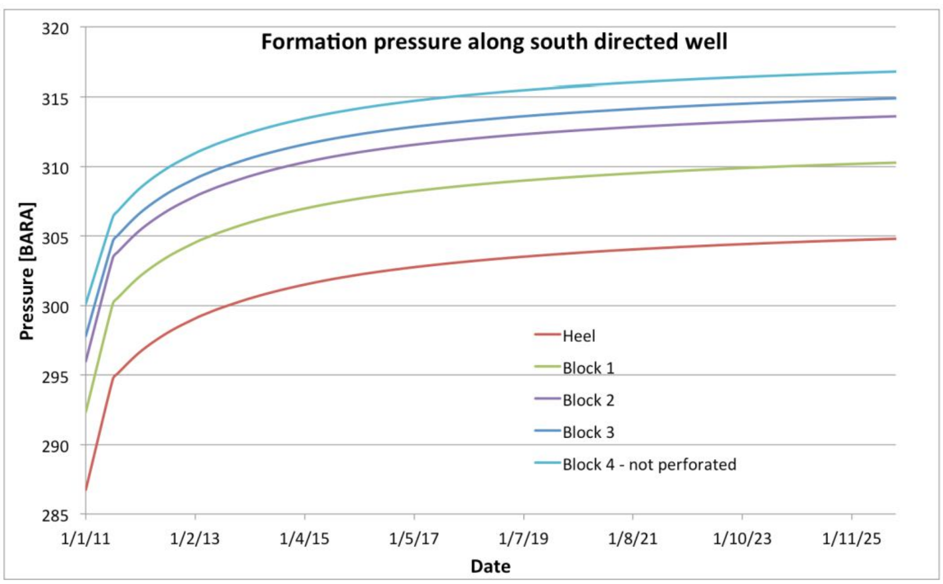

Figure 57: Formation pressure at borehole wall along the south directed horizontal well

Block	BPR [bars] – Orientation			
	Vertical - North	North	Vertical - South	South
Heel	300.046	300.042	300.046	300.053
1	301.025	300.522	309.783	310.285
2	299.784	300.702	312.856	313.619
3	295.964	297.871	314.254	314.914
4	288.871	290.247	316.242	316.780

Table 9: Pressure data for the vertical and the oriented horizontal wells

We see that for the north-oriented well, pressure is highest at the heel, while moving along the well results in lower pressure. For the south-oriented well, the pressure increases. However, looking at the data in Table 9, we see that in the vertical case, pressure increases moving southwards as well. The important observation is that there is no significant increase in the stress at the borehole wall in each respective block due to injection. We also see that the pressure at the heel in the horizontal wells is approximately the same as the pressure in the vertical well. This suggests that orienting the well horizontally does not give any benefits regarding risk reduction. The explanation to this result is most likely that the ability for layer 7 to distribute fluid is so strong that perforating one block is more than enough to not give rise for any significant pressure build-up. We must keep in mind that the size of the blocks are significant and this will cause a less representative pressure for the actual pressure at the borehole wall.

For the bottom hole pressure we see a decrease of approximately 10 bars using a horizontal well. This applies for both directions. Should a reduction of BHP be of desire, the use of a horizontal well is a good measure. The additional costs and effort of drilling a horizontal well must be considered. The study is not quite realistic, because, as mentioned earlier, a ninety-degree well is impossible.

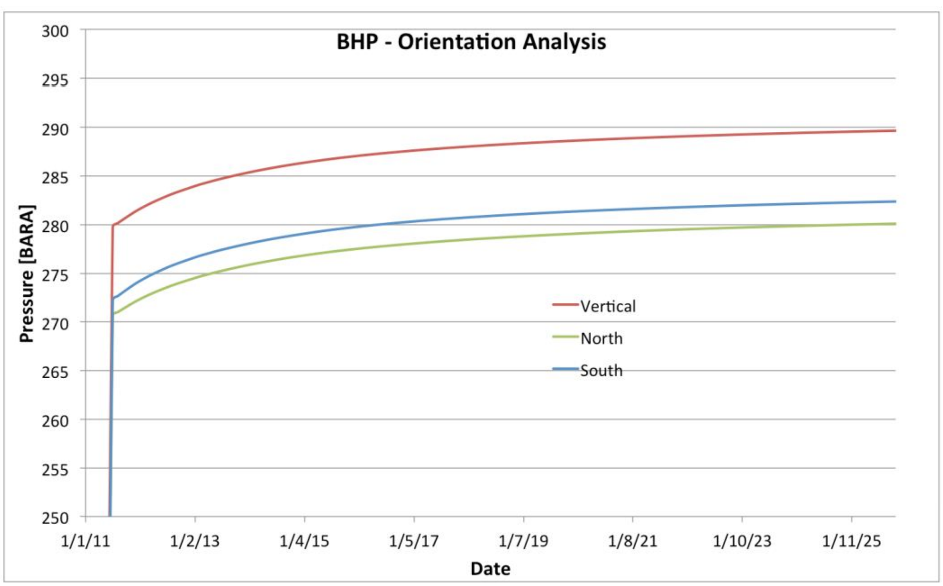

Figure 58: Comparing bottom hole pressure for the orientation analysis.

The observations we have done show that it is less beneficial to use a horizontal well in our case. Should the case have been that the injection were to be done in a more heterogeneous layer, e.g. layer 6, the use of a horizontal well would have most likely shown a much more significant effect.

To summarize, making a choice of the best-case scenario based on the above results, is rather difficult. Observations do however justify that there is no reason for using a two-well injection for avoiding and reducing the risk of fracturing the formation compared to the use of a single well. The reduction of stresses at the borehole wall due to this choice is negligible. The sensitivity analysis also shows that there are only small gains in moving and completing the well differently. This allows us to make the final recommendation based on recovery and an economical evaluation. The recovery is addressed in the next section.

15 Recovery

The main reason why an oil company wants to maintain the pressure in the reservoir is to maintain production and increase the total recovery for the oil field. The oil production from the reservoir is strongly driven by the pressure difference between the reservoir and the well, and thus a high reservoir pressure is favorable. Injecting water into the reservoir is one of many measures that can be applied to reduce the pressure depletion. An oil company's profit is based on recovery, thus the highest recovery possible is the most desirable. The recovery is therefore something we need to take into consideration when analyzing which case to recommend as the most favorable. The recommendations done in this chapter are based solely on the recovery. The final recommendation will be based on the results we have from the studies done earlier as well as the results we obtain from the following recovery study.

A major uncertainty in our case is that the model we are using is based on only water. The fluid initially in place is water, and the oil we consider being produced is water. Thus, we are not able to distinguish between what the actual recovery of oil is, because we will probably have water breakthrough at some point. This water is, in our model, added to the production data that we consider as oil recovery. Despite this uncertainty, the comparison of the scenarios is still valid to some degree. The reason for this is that the effect applies to each case, thus making it less important during a comparison.

15.1 The Initial Analysis

This analysis consisted of the three scenarios faced under the initial case. The recovery difference between the cases with the single wells is not that significant. The plot below compares the recovery in the cases of only having "INJ_E" or "INJ_W" as an injector.

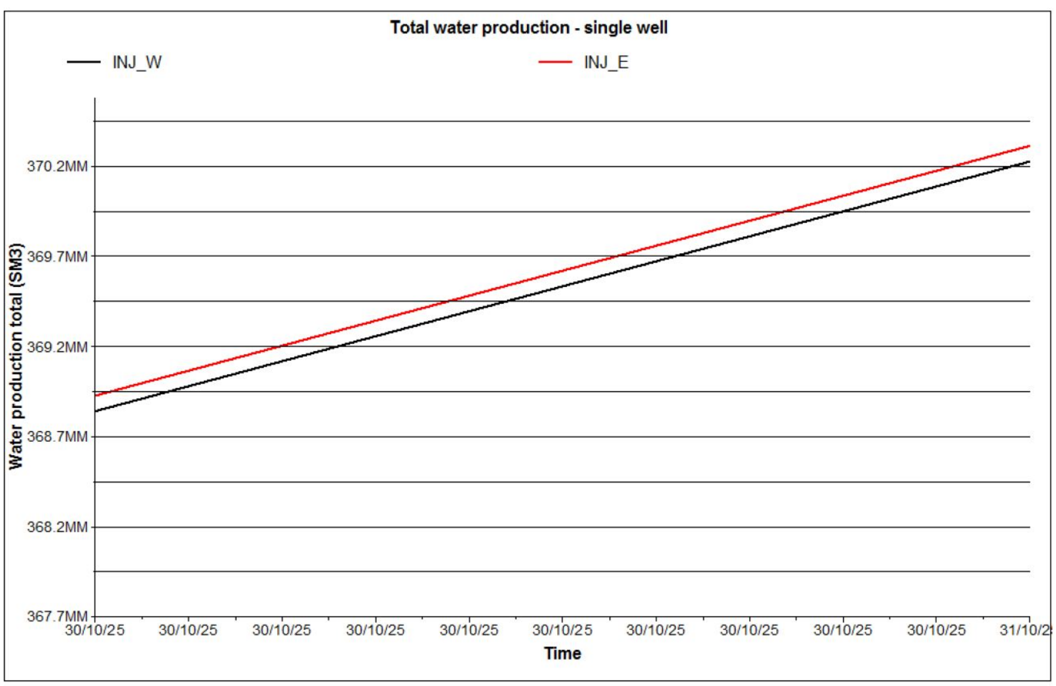

Figure 59: Comparing recovery from the east side single well and the west side single well scenario

The simulations result in approximately 86600 Sm^3 more recovery for the east well compared to the west well. This is equivalent to a difference of 0.023 % between the cases. Table 10 contains the estimated recovery for each specific case. As a percentage, this might not seem very significant, however, with an oil price of $100/bbl (USD), the additional income is $54 million (~313 million NOK). This increase in income is extremely theoretical and it is simply meant to give a sense of the dimensions we are talking about. Dozens of factors may contribute to give a completely different outcome.

Case	**Recovery** *[Sm^3]*
INJ_E	3.702929E+08
INJ_W	3.702063E+08
Both	3.702475E+08

Table 10: Recovery estimates - Initial analysis

Based on this calculation and the fact that the east well is closer to the drilling rig, which will make the drilling process a bit easier and cheaper; the choice falls on the east well as the best option. However, this is only the case if only one well is the best option, and that we choose the initial positioning of the wells. We will compare this initial case with the outcome of the sensitivity cases shortly. The completion sensitivity we did in the pressure study is not considered because the outcome was more or less exactly the same as for initial case of INJ_E.

Referring to the study we did whether a two-well injection would result in a significant reduction in stresses applied on the borehole wall when injecting the required amount of water, we saw that there were no benefits of using two wells.

Having two wells is only beneficial if the recovery is much higher than the case for having only one well. There must also be an economical gain, thus the additional costs related to drilling the extra well must be considered. Comparing the recovery, from the initial east side single well case with the initial case of having two wells, has an interesting outcome. The plot shows clearly that the recovery is the highest for the case of only having "INJ_E". Two wells seem to result in a higher recovery than for the "INJ_W".

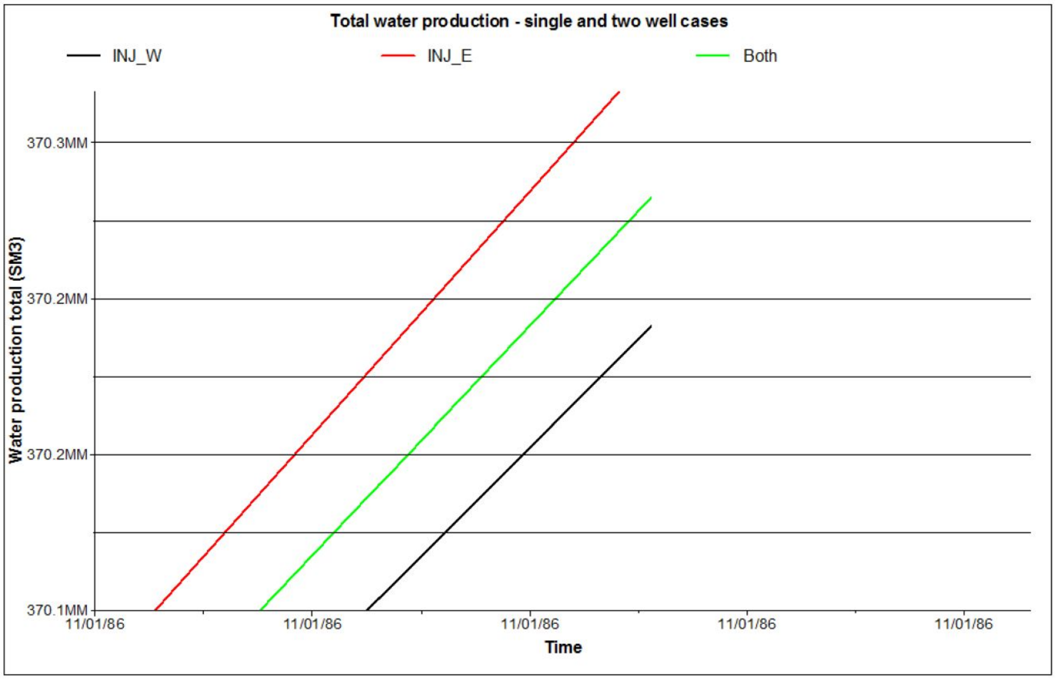

Figure 60: Comparing recovery from all three initial cases

This is a very profitable outcome, and together with the fact that it is redundant to use two wells as a measure to lower the risk and avoid fracturing, having "INJ_E" alone as the injector is the most favorable choice.

15.2 Placement

As mentioned in the BHP analysis regarding the placement sensitivity, the determining factor for which case that is the most preferable and beneficial one is the recovery. First off, we start with comparing the recovery for the four extreme cases. The recovery from the two extremes from "INJ_E" is plotted together with the two from "INJ_W". This can be seen in Figure 61.

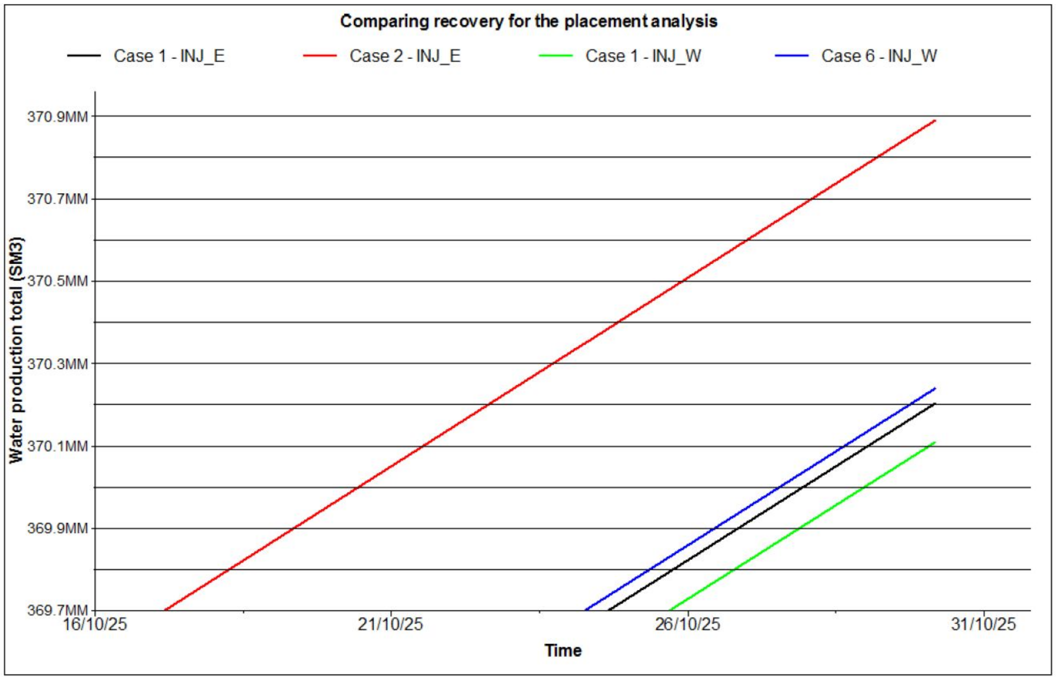

Figure 61: Comparisons plot the two extreme cases for all 4 cases.

The highest recovery for "INJ_E" is obtained with positioning the well according to Case 2, while for "INJ_W", the highest recovery is obtained for the position of Case 6. This means that the best recovery is obtained with the cases requiring the highest rate to maintain the reservoir pressure. Table 11 contains the estimated recovery for each of the cases above.

Well	Case	Recovery $[Sm^3]$
INJ_E	1	3.702344E+08
	2	3.709209E+08
INJ_W	1	3.701401E+08
	6	3.702707E+08

Table 11: Recovery estimates - Placement analysis

This result is not unexpected as the pressure in the reservoir is not the only drive mechanism. Displacement of the fluid in place by another fluid is also a major factor regarding the production. Thus, more fluids injected result in a better and more effective displacement process. This is not always the case though, and many factors affecting the process, including: wettability, capillary effect, and relative permeability. In our case, this increase in rate is probably making the drainage process more effective. As the rate increases, it is likely this effect will dissipate.

There is without doubt the case of having "INJ_E" at the position of Case 2 that is the most preferable. The recovery is much higher, and thus has increased economical benefits. However, this is the best choice of the extremes from the placement analysis.

We still have to compare the extremes from the orientation analysis, and with the initial analysis.

15.3 Orientation

The recovery that we might expect from the extremes in the orientation analysis is plotted in Figure 62, with the estimated numbers seen in Table 12.

Well	**Direction**	**Recovery** *[Sm^3]*
INJ_E	North	3,702523E+08
	South	3,703108E+08
INJ_W	North	3,701619E+08
	South	3,702276E+08

Table 12: Recovery estimates - Orientation analysis

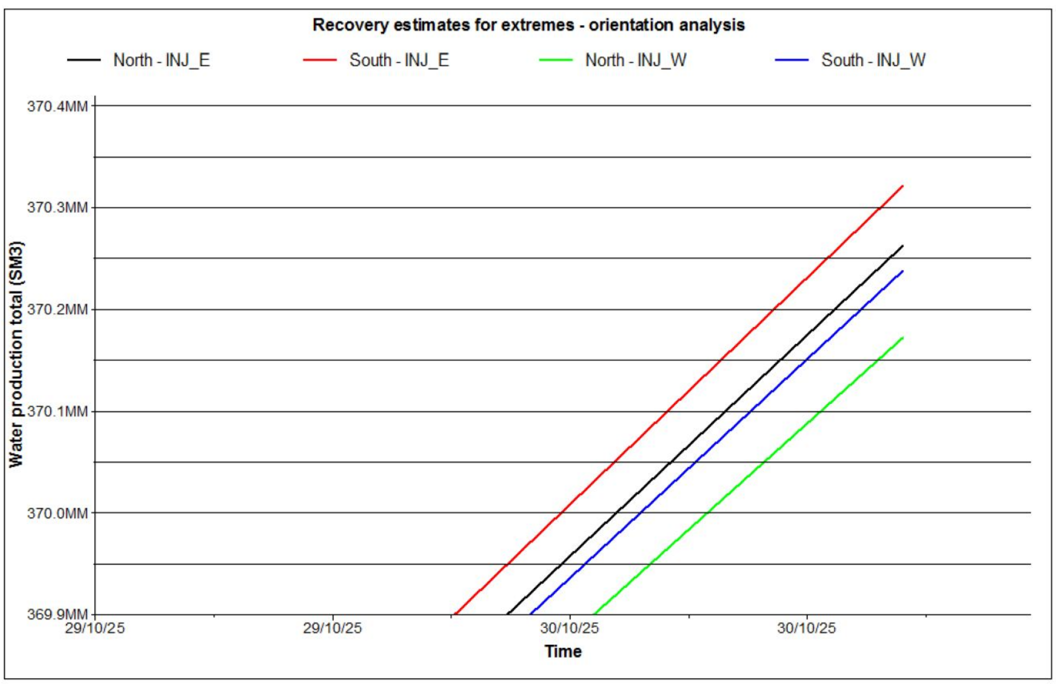

Figure 62: Comparing recovery from orientation analysis cases

Making a conclusion based on the estimated recoveries we obtain for the orientation analysis, the South-oriented well seems to be the most preferable one for both the case of "INJ_E" and "INJ_W". Both the orientations of "INJ_E" result in a higher recovery than "INJ_W". However, we must keep in mind that the injection rate is generally higher for "INJ_E". If the additional recovery covers the additional requirements regarding a higher injection rate, than the South case of "INJ_E" is the recommended choice. However, this is a recommendation based on only comparing the cases from the orientation analysis.

15.4 Recommendation

Thus far, we have compared the recovery for each of the sensitivity analyses separately. The best-case scenarios from each analysis are identified and a final comparison between these cases is left. To recap the results thus far: for all the three sensitivity analysis carried out, having "INJ_E" alone as an injector, is the most preferable scenario. For the placement, having "INJ_E" at the position of Case 2, turned out to be the best choice. A South-oriented "INJ_E" was the best scenario for the orientation analysis. These three are compared in the plot below, while the estimated numbers can be seen in Table 13.

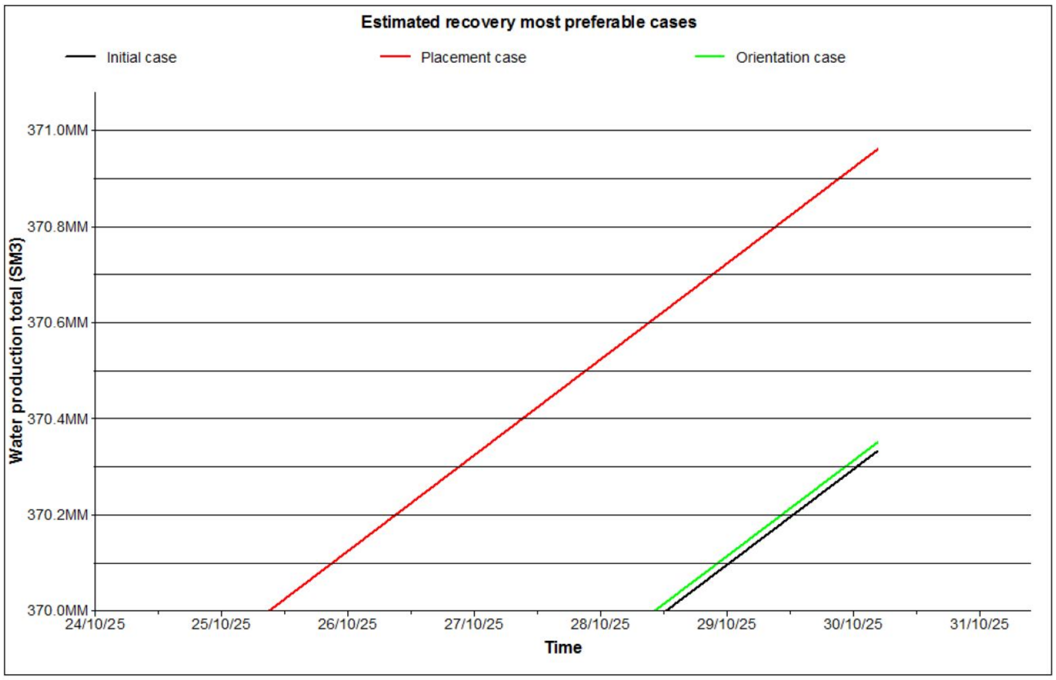

Figure 63: Comparing recovery from the best cases in each analysis

Case	Recovery $[Sm^3]$
Base case	3,644291E+08
Initial	3,702929E+08
Placement	3,709209E+08
Orientation	3,703108E+08

Table 13: Recovery estimates - Best case scenarios

The result is quite clear. The case from the placement analysis is the one resulting in the highest recovery. This means that having "INJ_E" placed at the position defined by Case 2 in the placement analysis is the most preferable scenario based on the analysis we have conducted.

As mentioned earlier, the injection rates are different for each of the cases above.

Whether or not the additional recovery is only the extra water injected, is hard to determine due to the nature of the model we are using.

15.5 Improved recovery estimate

The case of having no injector at all and the most preferable case are compared in the plot below.

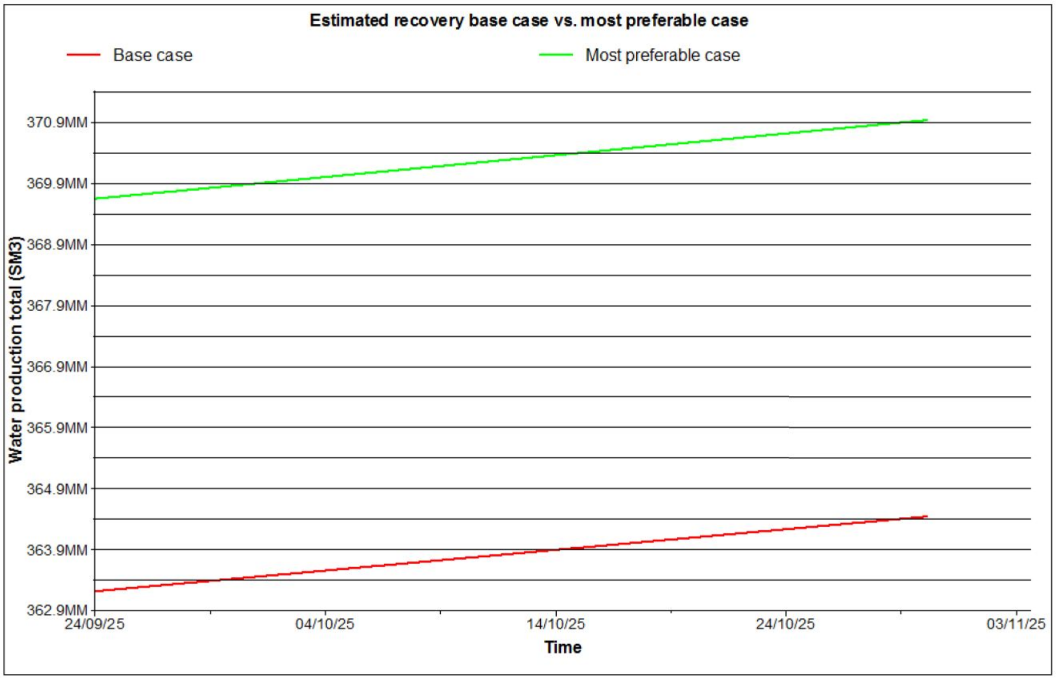

Figure 64: Best case scenario vs. base case with the modified future

The recovery we now have ended up with includes water, oil and gas. The oil and gas recovery is what we are interested in, but in reality, the cycled water constitutes a large fraction of the fluids being produced. As mentioned, the weakness of the model is its limiting use regarding the production parameters. Thus, we have to assume a water cut. This assumption is required to make a more qualifying estimate of what we actually recover, and to form a basis for the economical aspect to the project.

The annual additional recovery obtained by placing a water injector at the location specified by Case 2 in the placement analysis is plotted below. This applies to an injection well that injects with a rate of 11233 Sm^3/D and has other specifics according to the initial ones. By the end of 2025, the additional cumulative recovery will have reached 6,490,000 Sm^3. Assuming average water cut of 40%, and that gas is in oil equivalents, we achieve an additional oil recovery of 3,894,000 Sm^3 or 24,350,000 STB; equivalent to an IOR of 1.1 %. This result is quite significant in a real life scenario. To get a picture of the values we are talking about, an oil price of $100//bbl gives $2,44 billion (~13.9 billion NOK) in additional income. This number should however be compared with the costs related to having the well drilled in the first place, which is addressed in the economical section.

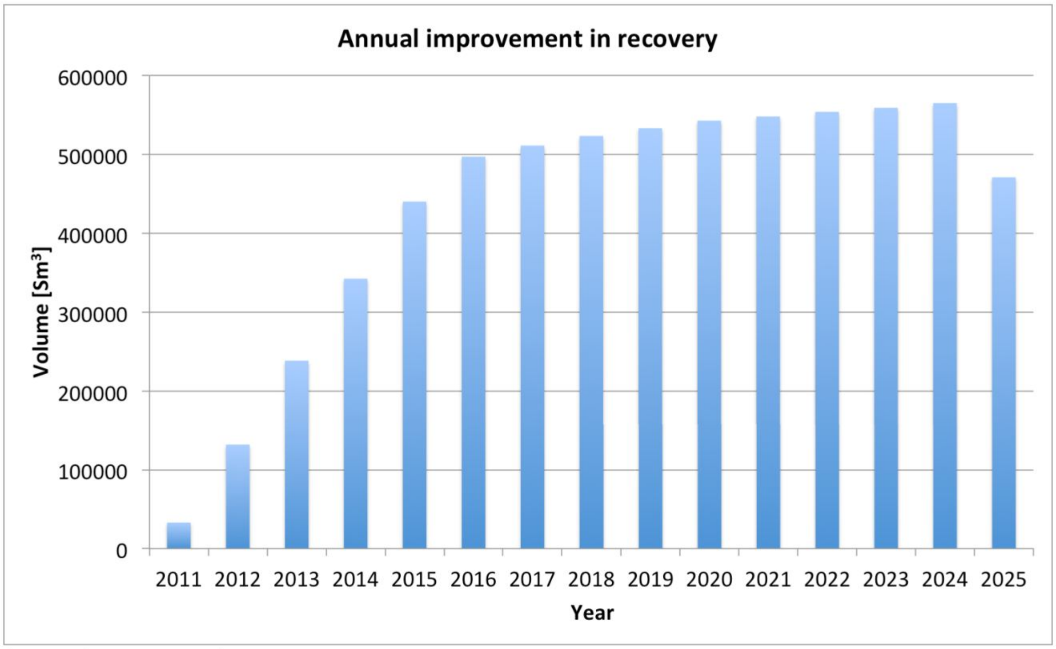

Figure 65: Annual improvement in total recovery

16 Alternative Methods and Measures for Enhanced Recovery

Water injection is not the only measure for enhanced recovery. There are several other methods that may lead to improvement. There are also aspects regarding the rate of the injection that might have an effect. A brief discussion on some additional methods and aspects is shown below, with the primary focus on injection methods.

16.1 The effect of high injection rate

The improvement in recovery we have achieved thus far is mainly based on the thought of maintaining the pressure in the reservoir. The injection rate of water needed is estimated without considering additional factors that may contribute to optimizing the recovery. The main production zone in the reservoir is somewhat fractured, and fractures have a significantly higher permeability than the matrix blocks. By the time we start injecting, most of the oil that initially occupied the fractures has been produced, and is referred to as the "early stage". The "intermediate stage" is the stage we most likely are in, when the matrix provides the fractures with oil. The fluid in the fractures imbibes the matrix and displacing the oil. When injecting water, fractures are the main flow path and water is therefore the imbibing fluid.

Theory and studies done on water imbibition in fractured reservoirs not only shows that injection of water at high rates increases the likelihood of earlier breakthrough, but they also suggest that high rates create a counter-current flow mode between the fracture and the matrix block. This implies that oil is flowing in the two-phase region. Lower injection rates have the ability to make the flow mode co-current. The studies have shown that this mode is more efficient regarding recovery of oil. A possible explanation for this is that lower injection rates increase the contact time between the water and the matrix surface, thus extending the time for the imbibition process. This is an issue we might face with our estimated rates. To discuss and investigate this in more detail is far too extensive for this report.

16.2 Gas injection

Gas injection is also a quite common method of injection. The main difference from our method is obviously that the fluid being injected is gas instead of water. These two fluids have quite different properties, and behave differently in the reservoir. Gas is less dense and migrates upwards, while water is denser than oil, resulting in migration downwards. The oil is therefore displaced in different directions, which might result in two quite different outcomes for the recovery of the oil. The drainage area for the producers is the most crucial factor for determining the most preferable direction of the displacement.

16.3 WAG – Water Alternating Gas Injection

This is a method that involves alternating the nature of the injected fluid. The two fluids being used are water and gas. In high permeability reservoirs, segregation of fluids happens quite quickly. In the case of WAG, the injected water sinks, while injected gas migrates towards the top. Instead of only having one displacement force, we now have two. The effect might then be the combined effect from gas injection alone and water injection. Different methods lead to different results. One method might be the most beneficial for some reservoirs, while other reservoirs might have better advantage of a different one.

17 Economics

To look into the economics, and to compare money gained with money spent is the most important element of any operation in the petroleum industry, and all other industries alike. The whole reason for making an injection wells is to enhance the recovery.The reward for making an injection well is therefore strongly related to the recovery factor (RF). The reward for making an injection well is therefore strongly related to the recovery factor (RF). The enhanced RF was discussed in detail in the Recovery section, together with its weaknesses. Despite the result that a two-well injection did turn out to be redundant regarding fracturing risks, we have done the economical analysis of both drilling only "INJ_E" and both "INJ_E" and "INJ_W". Having two wells can be a safety measure. If the east well should fail in some way, "INJ_W" can be put into operation, avoiding a complete stop in the injection process.

Since we used a water model in the simulations, we have to make an educated guess of how much of the additional produced volume that is oil. As discussed in the recovery section we assumed that 60% of the volume is oil. Since the extra produced volume is 6,490,000 Sm^3, if ignoring bulk volume factor, this means that we will get an additional 3,894,000 Sm^3 of oil, or approximately 24,350,000 barrels.

17.1 Evaluation

In this part we will go through the economic evaluation through a method called the NPV. This is in order to find out if it is economically responsible to drill the well(s), and if so, how much could we expect to earn from it. As mentioned previously, the evaluation is done with the case of drilling one well, and the case of drilling two wells. The assumptions we have done apply for both cases

When calculating cost associated with the wells and production there are two different expenses we have to calculate for: Operational Expenses (OPEX) and Capital Expenses (CAPEX).

17.2 Assumptions

We have used Statoil's estimates and suggested data as follows:

- Oil price 2011: 90 USD/bbl. increasing 1 % p.a.
- Inflation: 0%
- Discount factor 15%

Sensitivity

- -Oil and gas prices increasing 5% p.a./decreasing 3 % p.a.
- Production +/- 30 %
- Investments: +/- 40 %

Operational costs

- Platform production 100 NOK/bbl. o.e.
- Transportation 10 NOK/bbl. o.e.

Drilling production wells

- From a semi-submersible 120 days - 460 mill NOK/well

- From an integrated drilling rig 80 days - 160 mill NOK/well
  - INJ_E 160 mill NOK
  - INJ_W 200 mill NOK

Plugging and abandonment

- Sub-sea 200 million NOK

Currency estimation

- 1 USD = 5,8 NOK

In additional to Statoil's estimates, we have assumed a value for the USD, which is based on an average value over the last six months. We have also assumed that drilling a production well from an integrated drilling rig will cost the same as an injection well, i.e., 160 million NOK for an 80 day drilling operation, "INJ_E". The drilling time for "INJ_W" is assumed to be longer, therefore more expensive. On recommendation from Statoil we have assumed this cost to be 200 million NOK.

Things seldom go as expected, and the oil business is no exception. In order to do a proper estimate of an investment we therefore would have to consider different scenarios.

The scenarios we have chosen to follow is:

- Base Case: No surprises. Cost and prices will be as estimated
- Worst case: Oil & gas price: - 3% OPEX: +30% CAPEX: +40%
- Best case: Oil & gas price: + 5% OPEX: -30% CAPEX: -40%

Keeping the OPEX at a minimum is a favorable condition when adding the injection wells. We already have the rig in place and the additional running cost associated with extra people working on the rig is negligible. This means that the only operational expenses we have are from the extra produced oil, and that this is proportional with the production and 110 NOK/bbl. This means that the net income for one barrel is 412 NOK.

17.3 Net Present Value and Internal Rate of Return

The single well injection turned out to be the most preferable case. Below is an economical analysis of both a single well project and a two-well project. The analysis is carried out with both 0% discount rate and with 15%. The latter is the most realistic case and is the rate that Statoil operates with. Tables 14 and 15 contain the NPV and IRR for 0% and 15% discount rate for the single and the two-well project, respectively.

Case	NPV		IRR	
	0%	15%	0%	15%
Worst Case	4587 million NOK	1673 million NOK	114%	86%
Base Case	10612 million NOK	3657 million NOK	252%	206%
Best Case	16402 million NOK	5299 million NOK	653%	555%

Table 14: NPV and IRR for a single well project from a Fixed Platform at end of simulation in 2025

Case	NPV		IRR	
	0%	15%	0%	15%
Worst Case	4027 million NOK	1358 million NOK	55%	35%
Base Case	10212 million NOK	3433 million NOK	113%	85%
Best Case	16162 million NOK	5165 million NOK	208%	168%

Table 15: NPV and IRR for two-well project from a Fixed Platform at end of simulation in 2025

Due to that the case of using 15% discount rate is the most realistic scenario, we have only included a plot of NPV and annual additional income, Figure 67, calculated with this rate.

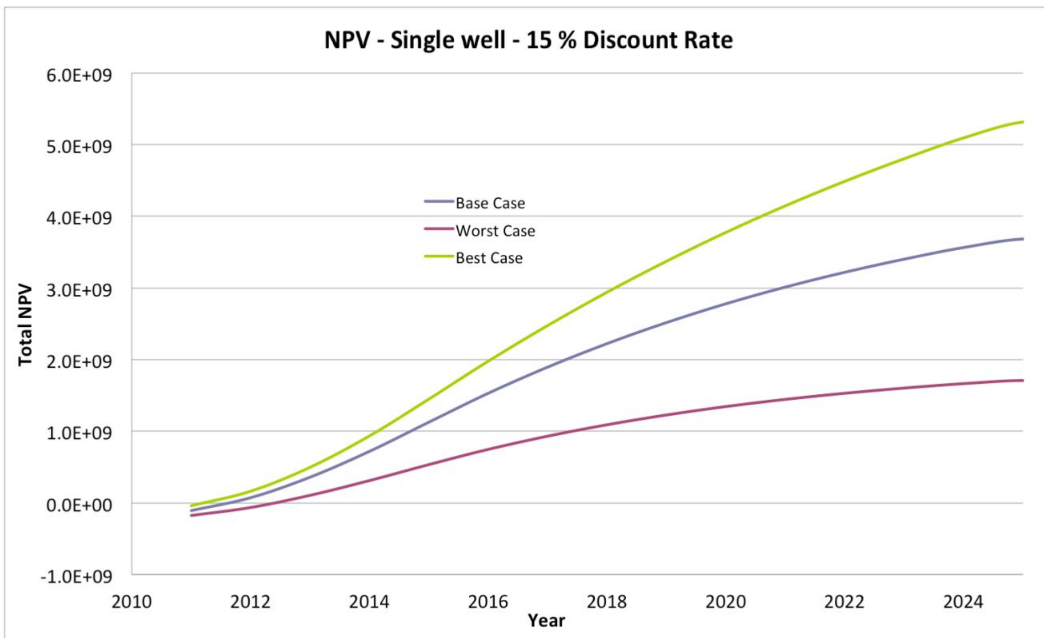

Figure 66: NPV single well project

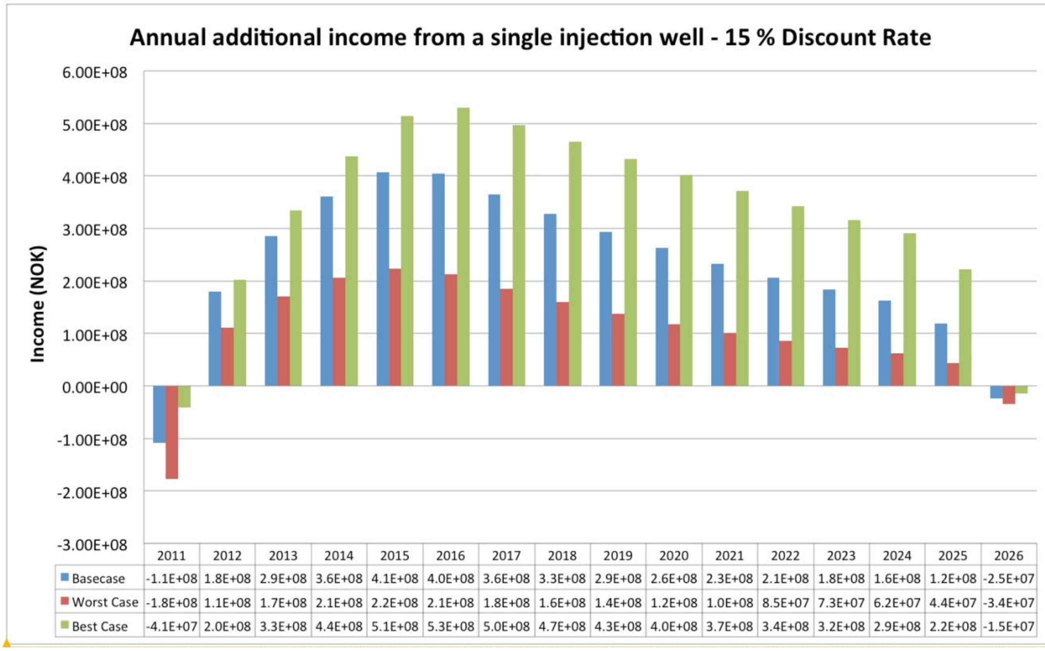

Figure 67: Annual additional income from a single well project

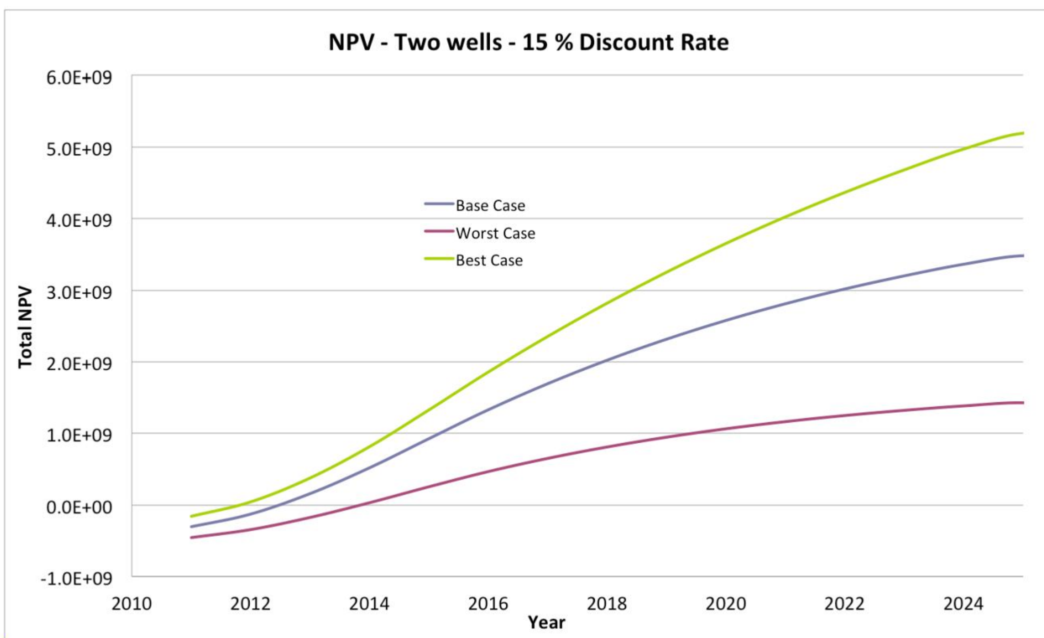

Figure 68: NPV two-well project

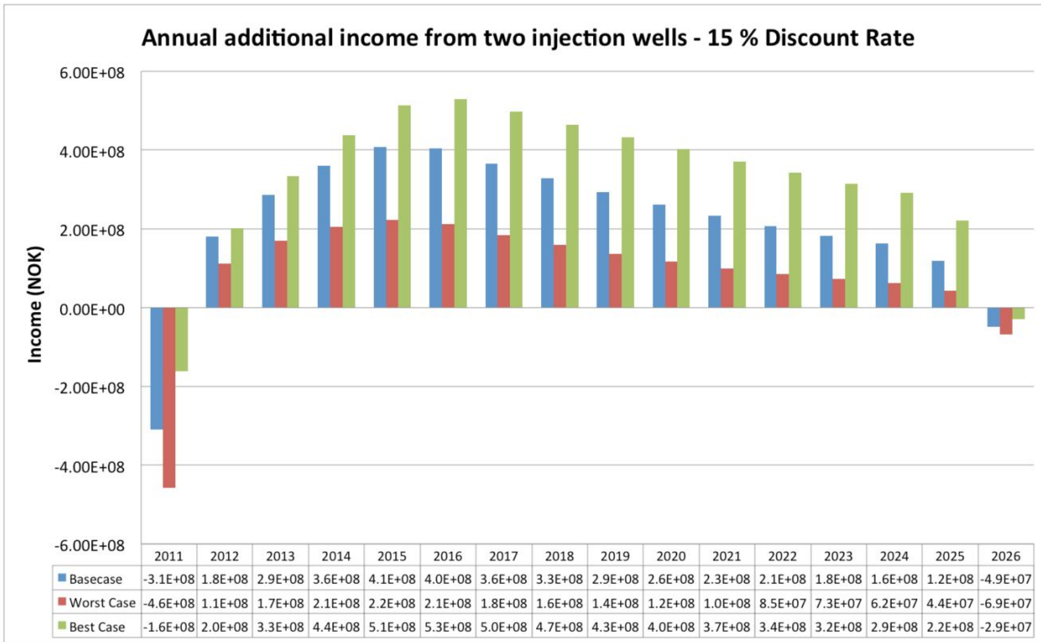

Figure 69: Annual additional income from a two-well project

As we can see, we have high positive values for all cases and a high Internal Rate of Return. This indicates that the investment is highly recommended from an economical point of view, and even the scenario that we have considered as the worst still gives a high reward. This applies for both the single well project and the two-well project. The decline in profitability is significant, but the having two wells are a safety measure as well. Failure of the well in the single well project might cause severe problems and eventually make the project less profitable than drilling two wells, and use one of them as a backup well.

Another important aspect for oil companies is the breakeven point, or when the investment has paid back all the original expenses. For the base case of the two-well project this happens after 1.2 years after the investment is done, indicating that this investment is beneficial after just a short amount of time. This time is even less for the single well project. Of course, our estimate is closely related to the assumption of 40% water cut, an alteration of this number would strongly influence the money made. The decline in NPV the last year is due to the reinvestment that needs to be done when plugging and abandoning the wells.

The difference between using 0% and 15% discount rate is that with 15% the project becomes less profitable. However, despite the assumption of a 15% rate and all uncertainties considered, this investment seems very profitable, no matter if the choice falls on a single or a two-well project. We have great belief in this project, and recommend Statoil to carry out the project.

18 Conclusion

Our final recommendation regarding water injection along Beta Ridge was based on a number of factors that were part of our main task throughout the project. These factors included:

- The volume of injected water necessary to maintain reservoir pressure along Beta Ridge.
- The cost of drilling the required water injection wells.
- The estimated additional recovery the increased injection will give.
- The economics of the project.

Our first task was to determine which layers in the model should be perforated for injection. Through simulations using an injected volume of 6000 Sm^3/D, in combination with geological knowledge, we determined that we should inject into layer 7 (i.e., the Etive/Rannoch Formations). To model how much water would be required to maintain the reservoir pressure, we ran a number of simulations using various water injection volumes, and determined that the volume required to maintain the reservoir pressure is 11233 Sm^3/D.

Several simulations were run with one well on the east side of the main fault, one of the west side, and one well on either side of the fault. We determined that in the first two scenarios, the water injection volumes required were nearly the same, and in the latter scenario, the total water needed was roughly the same, but volumes were split between either well. As the results were nearly identical regarding the volume of water needed, other parameters were investigated.

Sensitivities were run on the wells to determine the effects of general placement in the vicinity of the initial location, the orientation of the wellbore (i.e., vertical or horizontal), formation pressure around the borehole and BHP, and the increased recovery factor from the wells. We discovered that the placement and orientation of the wells had little impact on the volume of injected water needed to maintain reservoir pressure. Investigations of the formation pressure around the borehole, and the BHP in a one well, and a two well scenario were made. This was to ensure the injected water would not exceed the fracture limit of the formation. it was surprising to see that the maximum decline in pressure recorded was only 8 bar, which in this case is a negligible decrease since we are not near the fracturing limit of the formation.

The increased recovery factor played an important role in the selection, and it was determined that the INJ_E well gave the highest amount of additional recovery, at 1.1%. Although this well gave us the highest increased recovery, we ran economics on both the INJ_E well, as well as the two-well scenario. We considered the latter scenario as a safety measure for injection in the field. In this way, we have a back up well in case the INJ_E fails, and should high formation pressures and BHP exist, this would have reduced the risks involved with water injection. This is clearly not the most profitable scenario, but one we thought deserved to be highlighted.

The economics of drilling the INJ_E well are listed below, with the assumptions provided by Statoil (i.e., platform & drill costs, price deck, etc.). We ran the economics based on several scenarios that included sensitivities for OPEX and CAPEX, and adjustments in the oil price. We came up with the following results NPV, and IRR, which included both a 0% and 15% discount rate:

Case	NPV		IRR	
	0%	15%	0%	15%
Worst Case	4587 million NOK	1673 million NOK	114%	86%
Base Case	10612 million NOK	3657 million NOK	252%	206%
Best Case	16402 million NOK	5299 million NOK	653%	555%

Table 16: NPV and IRR for a single well project from a Fixed Platform at end of simulation in 2025

It is clear from the simulations that were run throughout the project, and the positive economics, that drilling the INJ_E water injector well will be highly beneficial, and we recommend that Statoil proceed with the project.

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19 Appendix

Appendix A

Day rates for the production from the West Province (Sm3/d). Rates include oil, gas and water GFHF represents assumed flow between the West Province and the Gullfaks Main Field (production => flow from West to the Main Field)

DATE	GFHF	Tordis	Vigdis	GF Vest	Gullveig	Gulltopp	Skinfaks
1/1/1986	130	0	0	0	0	0	0
1/1/1987	454	0	0	0	0	0	0
1/1/1988	1285	0	0	1812	0	0	0
1/1/1989	2388	0	0	1956	0	0	0
1/1/1990	3757	0	0	1179	0	0	0
1/1/1991	3485	0	0	989	0	0	0
1/1/1992	2457	0	0	1449	0	0	0
1/1/1993	2450	0	0	1639	0	0	0
1/1/1994	2450	5492	0	3203	0	0	0
1/1/1995	2192	14977	0	3735	0	0	0
1/1/1996	2236	17065	0	5618	0	0	0
1/1/1997	1873	17455	4087	6656	0	0	0
1/1/1998	2179	15332	11618	4370	602	0	0
1/1/1999	701	12926	13557	3183	3077	0	0
1/1/2000	1	9933	15565	3149	6341	0	0
1/1/2001	0	8985	16811	3614	4108	0	0
1/1/2002	0	12159	11706	3784	2059	0	0
1/1/2003	0	11593	17089	5078	3995	0	0
1/1/2004	4	10804	10596	7073	6191	0	0
1/1/2005	48	7797	8337	4679	4782	0	0
1/1/2006	174	6983	8502	4580	3119	0	0
1/1/2007	187	14107	9343	3821	2886	0	896
1/1/2008	4	13972	5897	1611	1625	3649	3766
1/1/2009	4	12413	5371	2149	1549	5546	770
1/1/2010	0	10329	10102	2416	1682	4126	2132
1/1/2011	86	10258	8105	3579	1056	3129	3997
1/1/2012	37	19415	7047	2560	0	2813	2859
1/1/2013	194	15063	6658	2153	0	2656	1806
1/1/2014	589	15680	7721	2074	0	2288	1568
1/1/2015	1042	13789	6706	2292	0	2319	0
1/1/2016	1484	14175	8585	1871	0	2215	4366
1/1/2017	1734	13538	9072	1370	0	1426	3409
1/1/2018	1915	12009	8958	142	0	207	1060
1/1/2019	2236	12420	4611	0	0	0	0
1/1/2020	3027	0	2520	0	0	0	0
1/1/2021	3993	0	0	0	0	0	0
1/1/2022	4553	0	0	0	0	0	0
1/1/2023	4859	0	0	0	0	0	0
1/1/2024	4805	0	0	0	0	0	0
1/1/2025	4156	0	0	0	0	0	0

Day rates for the injection in the West Province (Sm3/d). Rates include oil, gas and water. GFHF represents assumed flow between the West Provice and the Gullfaks Main Field (injection => flow from Main Field to West)

DATE	GFHF	Tordis	Vigdis	GF Vest
1/1/1986	1	0	0	0
1/1/1987	8	0	0	0
1/1/1988	6	0	0	0
1/1/1989	67	0	0	0
1/1/1990	681	0	0	0
1/1/1991	953	0	0	0
1/1/1992	1981	0	0	0
1/1/1993	1988	0	0	0
1/1/1994	1987	0	0	89
1/1/1995	2245	14	0	5049
1/1/1996	2200	0	0	0
1/1/1997	2562	0	0	0
1/1/1998	2254	0	3579	0
1/1/1999	3809	1754	10333	0
1/1/2000	6886	3726	11675	221
1/1/2001	9259	2609	10666	0
1/1/2002	9692	6534	10801	2191
1/1/2003	10154	5221	17521	6645
1/1/2004	10710	2984	12753	0
1/1/2005	11032	5204	10356	0
1/1/2006	10908	5519	10046	0
1/1/2007	10918	1481	7826	0
1/1/2008	11561	1484	3457	0
1/1/2009	12358	523	27	0
1/1/2010	13286	1061	3452	3206
1/1/2011	13399	849	8316	7125
1/1/2012	13563	849	14905	7524
1/1/2013	13519	0	13980	7523
1/1/2014	13126	0	16622	7125
1/1/2015	12674	0	14990	7523
1/1/2016	12233	0	18425	7524
1/1/2017	11984	0	16505	0
1/1/2018	11803	0	18617	0
1/1/2019	11483	0	16605	0
1/1/2020	10696	0	18617	0
1/1/2021	9732	0	0	0
1/1/2022	9173	0	0	0
1/1/2023	8868	0	0	0
1/1/2024	8922	0	0	0
1/1/2025	7241	0	0	0

Production and injection in Sm^3/d and water equivalents

Date	Total production rate [MSm^3/year]	Cumulative production [MSm^3]	Total injection rate [MSm^3/year]	Cummulative injection [MSm^3]	Total encroachment rate [MSm^3/year]	Total encroachment [MSm^3]	Change in volume with leakage [MSm^3]	Change in volume without leakage [MSm^3]
1/1/1986	0.00	0.00	0.00	0.00	-0.05	-0.05	-0.05	0
1/1/1987	0.00	0.00	0.00	0.00	-0.16	-0.21	-0.21	0
1/1/1988	0.66	0.66	0.00	0.00	-0.47	-0.68	-1.34	-1
1/1/1989	0.71	1.38	0.00	0.00	-0.85	-1.52	-2.90	-1
1/1/1990	0.43	1.81	0.00	0.00	-1.12	-2.65	-4.45	-2
1/1/1991	0.36	2.17	0.00	0.00	-0.92	-3.57	-5.74	-2
1/1/1992	0.53	2.70	0.00	0.00	-0.17	-3.75	-6.44	-3
1/1/1993	0.60	3.29	0.00	0.00	-0.17	-3.91	-7.21	-3
1/1/1994	3.17	6.47	0.03	0.03	-0.17	-4.08	-10.52	-6
1/1/1995	6.83	13.30	1.85	1.88	0.02	-4.06	-15.48	-11
1/1/1996	8.28	21.58	0.00	1.88	-0.01	-4.08	-23.77	-20
1/1/1997	10.29	31.87	0.00	1.88	0.25	-3.82	-33.81	-30
1/1/1998	11.65	43.52	1.31	3.19	0.03	-3.80	-44.13	-40
1/1/1999	11.95	55.47	4.41	7.60	1.13	-2.66	-50.54	-48
1/1/2000	12.77	68.24	5.70	13.30	2.51	-0.15	-55.09	-55
1/1/2001	12.23	80.48	4.85	18.15	3.38	3.23	-59.10	-62
1/1/2002	10.84	91.32	7.13	25.27	3.54	6.77	-59.28	-66
1/1/2003	13.78	105.10	10.73	36.00	3.71	10.47	-58.63	-69
1/1/2004	12.65	117.75	5.74	41.74	3.91	14.38	-61.63	-76
1/1/2005	9.34	127.10	5.68	47.42	4.01	18.39	-61.28	-80
1/1/2006	8.46	135.56	5.68	53.10	3.92	22.31	-60.15	-82
1/1/2007	11.33	146.89	3.40	56.50	3.92	26.22	-64.17	-90
1/1/2008	11.14	158.03	1.80	58.30	4.22	30.44	-69.29	-100
1/1/2009	10.15	168.18	0.20	58.51	4.51	34.95	-74.72	-110
1/1/2010	11.24	179.42	2.82	61.32	4.85	39.80	-78.29	-118
1/1/2011	11.00	190.41	5.95	67.27	4.86	44.66	-78.48	-123

Appendix B

Pressure calculations

Volume sensitivity
Variation in initial volume

Initial pressure: 380 bar
Compressibility: 9.70E-05 bar^{-1}
Leakage: yes

Initial volume [MSm^3]:	5000		7500		10000		12500		15000	
Date	ΔP [bar]	Pressure [bar]	ΔP [bar]	Pressure [bar]	ΔP [bar]	Pressure [bar]	ΔP [bar]	Pressure [bar]	ΔP [bar]	Pressure [bar]
1/1/1986	-0.10	379.90	-0.06	379.94	-0.05	379.95	-0.04	379.96	-0.03	379.97
1/1/1987	-0.43	379.57	-0.29	379.71	-0.22	379.78	-0.17	379.83	-0.14	379.86
1/1/1988	-2.76	377.24	-1.84	378.16	-1.38	378.62	-1.10	378.90	-0.92	379.08
1/1/1989	-5.98	374.02	-3.99	376.01	-2.99	377.01	-2.39	377.61	-1.99	378.01
1/1/1990	-9.18	370.82	-6.12	373.88	-4.59	375.41	-3.67	376.33	-3.06	376.94
1/1/1991	-11.83	368.17	-7.89	372.11	-5.92	374.08	-4.73	375.27	-3.94	376.06
1/1/1992	-13.28	366.72	-8.85	371.15	-6.64	373.36	-5.31	374.69	-4.43	375.57
1/1/1993	-14.86	365.14	-9.91	370.09	-7.43	372.57	-5.94	374.06	-4.95	375.05
1/1/1994	-21.69	358.31	-14.46	365.54	-10.84	369.16	-8.67	371.33	-7.23	372.77
1/1/1995	-31.92	348.08	-21.28	358.72	-15.96	364.04	-12.77	367.23	-10.64	369.36
1/1/1996	-49.02	330.98	-32.68	347.32	-24.51	355.49	-19.61	360.39	-16.34	363.66
1/1/1997	-69.72	310.28	-46.48	333.52	-34.86	345.14	-27.89	352.11	-23.24	356.76
1/1/1998	-90.99	289.01	-60.66	319.34	-45.50	334.50	-36.40	343.60	-30.33	349.67
1/1/1999	-104.20	275.80	-69.47	310.53	-52.10	327.90	-41.68	338.32	-34.73	345.27
1/1/2000	-113.59	266.41	-75.73	304.27	-56.80	323.20	-45.44	334.56	-37.86	342.14
1/1/2001	-121.86	258.14	-81.24	298.76	-60.93	319.07	-48.74	331.26	-40.62	339.38
1/1/2002	-122.23	257.77	-81.48	298.52	-61.11	318.89	-48.89	331.11	-40.74	339.26
1/1/2003	-120.88	259.12	-80.59	299.41	-60.44	319.56	-48.35	331.65	-40.29	339.71
1/1/2004	-127.07	252.93	-84.71	295.29	-63.54	316.46	-50.83	329.17	-42.36	337.64
1/1/2005	-126.36	253.64	-84.24	295.76	-63.18	316.82	-50.54	329.46	-42.12	337.88
1/1/2006	-124.01	255.99	-82.67	297.33	-62.01	317.99	-49.60	330.40	-41.34	338.66
1/1/2007	-132.30	247.70	-88.20	291.80	-66.15	313.85	-52.92	327.08	-44.10	335.90
1/1/2008	-142.86	237.14	-95.24	284.76	-71.43	308.57	-57.14	322.86	-47.62	332.38
1/1/2009	-154.07	225.93	-102.71	277.29	-77.03	302.97	-61.63	318.37	-51.36	328.64
1/1/2010	-161.43	218.57	-107.62	272.38	-80.71	299.29	-64.57	315.43	-53.81	326.19
1/1/2011	-161.82	218.18	-107.88	272.12	-80.91	299.09	-64.73	315.27	-53.94	326.06

Compressibility sensitivity
Variation in compressibility
Initial volume is assumed based on the best match from volume sensitivity analysis

Initial pressure: 380 bar
Initial volume 10000 MSm^3
Leakage: yes

Compressibility [bar^{-1}]:		1.70E-04		1.30E-04		9.70E-05		9.20E-05		8.50E-05
Date	ΔP [bar]	Pressure [bar]	ΔP [bar]	Pressure [bar]	ΔP [bar]	Pressure [bar]	ΔP [bar]	Pressure [bar]	ΔP [bar]	Pressure [bar]
1/1/1986	-0.03	379.97	-0.04	379.96	-0.05	379.95	-0.05	379.95	-0.06	379.94
1/1/1987	-0.12	379.88	-0.16	379.84	-0.22	379.78	-0.23	379.77	-0.25	379.75
1/1/1988	-0.79	379.21	-1.03	378.97	-1.38	378.62	-1.45	378.55	-1.57	378.43
1/1/1989	-1.71	378.29	-2.23	377.77	-2.99	377.01	-3.15	376.85	-3.41	376.59
1/1/1990	-2.62	377.38	-3.43	376.57	-4.59	375.41	-4.84	375.16	-5.24	374.76
1/1/1991	-3.38	376.62	-4.41	375.59	-5.92	374.08	-6.24	373.76	-6.75	373.25
1/1/1992	-3.79	376.21	-4.95	375.05	-6.64	373.36	-7.00	373.00	-7.58	372.42
1/1/1993	-4.24	375.76	-5.54	374.46	-7.43	372.57	-7.83	372.17	-8.48	371.52
1/1/1994	-6.19	373.81	-8.09	371.91	-10.84	369.16	-11.43	368.57	-12.37	367.63
1/1/1995	-9.11	370.89	-11.91	368.09	-15.96	364.04	-16.83	363.17	-18.21	361.79
1/1/1996	-13.98	366.02	-18.29	361.71	-24.51	355.49	-25.84	354.16	-27.97	352.03
1/1/1997	-19.89	360.11	-26.01	353.99	-34.86	345.14	-36.75	343.25	-39.78	340.22
1/1/1998	-25.96	354.04	-33.95	346.05	-45.50	334.50	-47.97	332.03	-51.92	328.08
1/1/1999	-29.73	350.27	-38.87	341.13	-52.10	327.90	-54.93	325.07	-59.45	320.55
1/1/2000	-32.41	347.59	-42.38	337.62	-56.80	323.20	-59.88	320.12	-64.81	315.19
1/1/2001	-34.77	345.23	-45.46	334.54	-60.93	319.07	-64.24	315.76	-69.53	310.47
1/1/2002	-34.87	345.13	-45.60	334.40	-61.11	318.89	-64.43	315.57	-69.74	310.26
1/1/2003	-34.49	345.51	-45.10	334.90	-60.44	319.56	-63.73	316.27	-68.97	311.03
1/1/2004	-36.25	343.75	-47.41	332.59	-63.54	316.46	-66.99	313.01	-72.50	307.50
1/1/2005	-36.05	343.95	-47.14	332.86	-63.18	316.82	-66.61	313.39	-72.10	307.90
1/1/2006	-35.38	344.62	-46.27	333.73	-62.01	317.99	-65.38	314.62	-70.76	309.24
1/1/2007	-37.75	342.25	-49.36	330.64	-66.15	313.85	-69.75	310.25	-75.49	304.51
1/1/2008	-40.76	339.24	-53.30	326.70	-71.43	308.57	-75.31	304.69	-81.51	298.49
1/1/2009	-43.95	336.05	-57.48	322.52	-77.03	302.97	-81.22	298.78	-87.91	292.09
1/1/2010	-46.05	333.95	-60.22	319.78	-80.71	299.29	-85.10	294.90	-92.11	287.89
1/1/2011	-46.17	333.83	-60.37	319.63	-80.91	299.09	-85.31	294.69	-92.33	287.67

Initial volume is set lower

Initial pressure:	380 bar
Initial volume	7500 MSm^3
Leakage:	yes

Compressibility [bar^{-1}]:		1.70E-04		1.30E-04		9.70E-05		9.20E-05		8.50E-05
Date	**ΔP** *[bar]*	**Pressure** *[bar]*	**ΔP** *[bar]*	**Pressure** *[bar]*	**ΔP** *[bar]*	**Pressure** *[bar]*	**ΔP** *[bar]*	**Pressure** *[bar]*	**ΔP** *[bar]*	**Pressure** *[bar]*
1/1/1986	-0.04	379.96	-0.05	379.95	-0.06	379.94	-0.07	379.93	-0.07	379.93
1/1/1987	-0.16	379.84	-0.22	379.78	-0.29	379.71	-0.30	379.70	-0.33	379.67
1/1/1988	-1.05	378.95	-1.37	378.63	-1.84	378.16	-1.94	378.06	-2.10	377.90
1/1/1989	-2.27	377.73	-2.97	377.03	-3.99	376.01	-4.20	375.80	-4.55	375.45
1/1/1990	-3.49	376.51	-4.57	375.43	-6.12	373.88	-6.45	373.55	-6.98	373.02
1/1/1991	-4.50	375.50	-5.88	374.12	-7.89	372.11	-8.32	371.68	-9.00	371.00
1/1/1992	-5.05	374.95	-6.61	373.39	-8.85	371.15	-9.33	370.67	-10.10	369.90
1/1/1993	-5.65	374.35	-7.39	372.61	-9.91	370.09	-10.45	369.55	-11.31	368.69
1/1/1994	-8.25	371.75	-10.79	369.21	-14.46	365.54	-15.24	364.76	-16.50	363.50
1/1/1995	-12.14	367.86	-15.88	364.12	-21.28	358.72	-22.43	357.57	-24.28	355.72
1/1/1996	-18.64	361.36	-24.38	355.62	-32.68	347.32	-34.45	345.55	-37.29	342.71
1/1/1997	-26.52	353.48	-34.68	345.32	-46.48	333.52	-49.00	331.00	-53.04	326.96
1/1/1998	-34.61	345.39	-45.26	334.74	-60.66	319.34	-63.96	316.04	-69.23	310.77
1/1/1999	-39.64	340.36	-51.83	328.17	-69.47	310.53	-73.24	306.76	-79.27	300.73
1/1/2000	-43.21	336.79	-56.50	323.50	-75.73	304.27	-79.84	300.16	-86.42	293.58
1/1/2001	-46.35	333.65	-60.62	319.38	-81.24	298.76	-85.65	294.35	-92.71	287.29
1/1/2002	-46.49	333.51	-60.80	319.20	-81.48	298.52	-85.91	294.09	-92.99	287.01
1/1/2003	-45.98	334.02	-60.13	319.87	-80.59	299.41	-84.97	295.03	-91.97	288.03
1/1/2004	-48.34	331.66	-63.21	316.79	-84.71	295.29	-89.32	290.68	-96.67	283.33
1/1/2005	-48.07	331.93	-62.85	317.15	-84.24	295.76	-88.82	291.18	-96.13	283.87
1/1/2006	-47.17	332.83	-61.69	318.31	-82.67	297.33	-87.17	292.83	-94.35	285.65
1/1/2007	-50.33	329.67	-65.81	314.19	-88.20	291.80	-93.00	287.00	-100.65	279.35
1/1/2008	-54.34	325.66	-71.06	308.94	-95.24	284.76	-100.41	279.59	-108.68	271.32
1/1/2009	-58.61	321.39	-76.64	303.36	-102.71	277.29	-108.29	271.71	-117.21	262.79
1/1/2010	-61.41	318.59	-80.30	299.70	-107.62	272.38	-113.47	266.53	-122.81	257.19
1/1/2011	-61.55	318.45	-80.49	299.51	-107.88	272.12	-113.74	266.26	-123.11	256.89

The effect of no leakage

Estimating initial volume if compressibility is assumed as initially and that there is no leakage

Initial pressure: 380 bar
Compressibility: 9.70E-05 bar^{-1}
Leakage: no

Initial volume [MSm^3]:	5000		7500		10000		12500		15000	
Date	ΔP [bar]	Pressure [bar]	ΔP [bar]	Pressure [bar]	ΔP [bar]	Pressure [bar]	ΔP [bar]	Pressure [bar]	ΔP [bar]	Pressure [bar]
1/1/1986	0.00	380.00	0.00	380.00	0.00	380.00	0.00	380.00	0.00	380.00
1/1/1987	0.00	380.00	0.00	380.00	0.00	380.00	0.00	380.00	0.00	380.00
1/1/1988	-1.36	378.64	-0.91	379.09	-0.68	379.32	-0.55	379.45	-0.45	379.55
1/1/1989	-2.84	377.16	-1.89	378.11	-1.42	378.58	-1.13	378.87	-0.95	379.05
1/1/1990	-3.72	376.28	-2.48	377.52	-1.86	378.14	-1.49	378.51	-1.24	378.76
1/1/1991	-4.47	375.53	-2.98	377.02	-2.23	377.77	-1.79	378.21	-1.49	378.51
1/1/1992	-5.56	374.44	-3.70	376.30	-2.78	377.22	-2.22	377.78	-1.85	378.15
1/1/1993	-6.79	373.21	-4.53	375.47	-3.40	376.60	-2.72	377.28	-2.26	377.74
1/1/1994	-13.27	366.73	-8.85	371.15	-6.63	373.37	-5.31	374.69	-4.42	375.58
1/1/1995	-23.54	356.46	-15.69	364.31	-11.77	368.23	-9.42	370.58	-7.85	372.15
1/1/1996	-40.61	339.39	-27.07	352.93	-20.31	359.69	-16.24	363.76	-13.54	366.46
1/1/1997	-61.83	318.17	-41.22	338.78	-30.92	349.08	-24.73	355.27	-20.61	359.39
1/1/1998	-83.16	296.84	-55.44	324.56	-41.58	338.42	-33.27	346.73	-27.72	352.28
1/1/1999	-98.71	281.29	-65.81	314.19	-49.35	330.65	-39.48	340.52	-32.90	347.10
1/1/2000	-113.28	266.72	-75.52	304.48	-56.64	323.36	-45.31	334.69	-37.76	342.24
1/1/2001	-128.52	251.48	-85.68	294.32	-64.26	315.74	-51.41	328.59	-42.84	337.16
1/1/2002	-136.18	243.82	-90.79	289.21	-68.09	311.91	-54.47	325.53	-45.39	334.61
1/1/2003	-142.48	237.52	-94.99	285.01	-71.24	308.76	-56.99	323.01	-47.49	332.51
1/1/2004	-156.72	223.28	-104.48	275.52	-78.36	301.64	-62.69	317.31	-52.24	327.76
1/1/2005	-164.27	215.73	-109.52	270.48	-82.14	297.86	-65.71	314.29	-54.76	325.24
1/1/2006	-170.01	209.99	-113.34	266.66	-85.00	295.00	-68.00	312.00	-56.67	323.33
1/1/2007	-186.37	193.63	-124.25	255.75	-93.19	286.81	-74.55	305.45	-62.12	317.88
1/1/2008	-205.62	174.38	-137.08	242.92	-102.81	277.19	-82.25	297.75	-68.54	311.46
1/1/2009	-226.13	153.87	-150.75	229.25	-113.07	266.93	-90.45	289.55	-75.38	304.62
1/1/2010	-243.49	136.51	-162.33	217.67	-121.75	258.25	-97.40	282.60	-81.16	298.84
1/1/2011	-253.90	126.10	-169.27	210.73	-126.95	253.05	-101.56	278.44	-84.63	295.37

Pressure development without leakage but with varying compressibility

Initial pressure: 380 bar
Initial volume 10000 MSm^3
Leakage: no

Compressibility [bar^{-1}]:		1.45E-04		1.30E-04		9.70E-05		9.20E-05		8.50E-05
Date	**ΔP** *[bar]*	**Pressure** *[bar]*	**ΔP** *[bar]*	**Pressure** *[bar]*	**ΔP** *[bar]*	**Pressure** *[bar]*	**ΔP** *[bar]*	**Pressure** *[bar]*	**ΔP** *[bar]*	**Pressure** *[bar]*
1/1/1986	0.00	380.00	0.00	380.00	0.00	380.00	0.00	380.00	0.00	380.00
1/1/1987	0.00	380.00	0.00	380.00	0.00	380.00	0.00	380.00	0.00	380.00
1/1/1988	-0.46	379.54	-0.51	379.49	-0.68	379.32	-0.72	379.28	-0.78	379.22
1/1/1989	-0.95	379.05	-1.06	378.94	-1.42	378.58	-1.49	378.51	-1.62	378.38
1/1/1990	-1.25	378.75	-1.39	378.61	-1.86	378.14	-1.96	378.04	-2.12	377.88
1/1/1991	-1.49	378.51	-1.67	378.33	-2.23	377.77	-2.35	377.65	-2.55	377.45
1/1/1992	-1.86	378.14	-2.07	377.93	-2.78	377.22	-2.93	377.07	-3.17	376.83
1/1/1993	-2.27	377.73	-2.53	377.47	-3.40	376.60	-3.58	376.42	-3.87	376.13
1/1/1994	-4.44	375.56	-4.95	375.05	-6.63	373.37	-6.99	373.01	-7.57	372.43
1/1/1995	-7.87	372.13	-8.78	371.22	-11.77	368.23	-12.41	367.59	-13.43	366.57
1/1/1996	-13.58	366.42	-15.15	364.85	-20.31	359.69	-21.41	358.59	-23.17	356.83
1/1/1997	-20.68	359.32	-23.07	356.93	-30.92	349.08	-32.60	347.40	-35.28	344.72
1/1/1998	-27.82	352.18	-31.03	348.97	-41.58	338.42	-43.84	336.16	-47.45	332.55
1/1/1999	-33.02	346.98	-36.83	343.17	-49.35	330.65	-52.04	327.96	-56.32	323.68
1/1/2000	-37.89	342.11	-42.26	337.74	-56.64	323.36	-59.72	320.28	-64.64	315.36
1/1/2001	-42.99	337.01	-47.95	332.05	-64.26	315.74	-67.75	312.25	-73.33	306.67
1/1/2002	-45.55	334.45	-50.81	329.19	-68.09	311.91	-71.79	308.21	-77.70	302.30
1/1/2003	-47.66	332.34	-53.16	326.84	-71.24	308.76	-75.11	304.89	-81.30	298.70
1/1/2004	-52.42	327.58	-58.47	321.53	-78.36	301.64	-82.62	297.38	-89.42	290.58
1/1/2005	-54.95	325.05	-61.29	318.71	-82.14	297.86	-86.60	293.40	-93.73	286.27
1/1/2006	-56.86	323.14	-63.43	316.57	-85.00	295.00	-89.62	290.38	-97.00	283.00
1/1/2007	-62.34	317.66	-69.53	310.47	-93.19	286.81	-98.25	281.75	-106.34	273.66
1/1/2008	-68.78	311.22	-76.71	303.29	-102.81	277.19	-108.40	271.60	-117.33	262.67
1/1/2009	-75.64	304.36	-84.36	295.64	-113.07	266.93	-119.21	260.79	-129.03	250.97
1/1/2010	-81.44	298.56	-90.84	289.16	-121.75	258.25	-128.36	251.64	-138.93	241.07
1/1/2011	-84.93	295.07	-94.72	285.28	-126.95	253.05	-133.85	246.15	-144.87	235.13