Technical report

Experts in team – TPG4852 – Norne Village

Pimyco Petroleum

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Preface

This project is a result of the subject “Experts in Team” at NTNU spring 2010. “Experts in team” is required for all students studying a master program at NTNU. This report counts for 50 % of the grade in the subject. The remaining 50 % of the grade is from the process report.

The project team is a composition of five students from five different studies; Kjersti Selstad Thingbø studying petroleum engineering, Placidius Fru studying geoscience, Syed Amjad Hussain Zaidy studying chemical engineering, Kim Taehun studying marine costal engineering and Francisca Amonua Quayson studying geography.

We would like to thank our teaching supervisors at NTNU, who have helped us a lot with this project. Tom Aage Jelmert, our village leader, has given us a lot of help and extra lectures about well completion. Mohsen Dadashpour, Per Einar Kalnæs and Jan Ivar Jensen have given us a lot of help with Eclipse 100, and Nan Cheng created time to give us valuable assistance on the theory of waterflooding. We will also thank Statoil for releasing data for the Norne field, and the wonderful accommodation they gave us in Harstad.

Abstract

The Norne field has a world record in subsea oil recovery, but the production is now in it's last phase. Statoil is now trying to get the out as much as possible of the oil left before the operation costs become higher than the income. To manage this, many EOR (enhanced oil recovery) methods have to be evaluated, and this is what we have been working with in the Norne village.

Pimyco Petroleum has been working with water injection. We have been simulating five different cases from 2004 to 2010. The five cases was; base case, changing injection rates, sidetracking wells, re-complete wells and drilling new wells. We had many examples for every case, and the best example for each case has been simulated until 2021. We also did an economic evaluation of them. We compared production and net present value with the base case to see if a change in waterflooding strategy can be an alternative for the Norne field.

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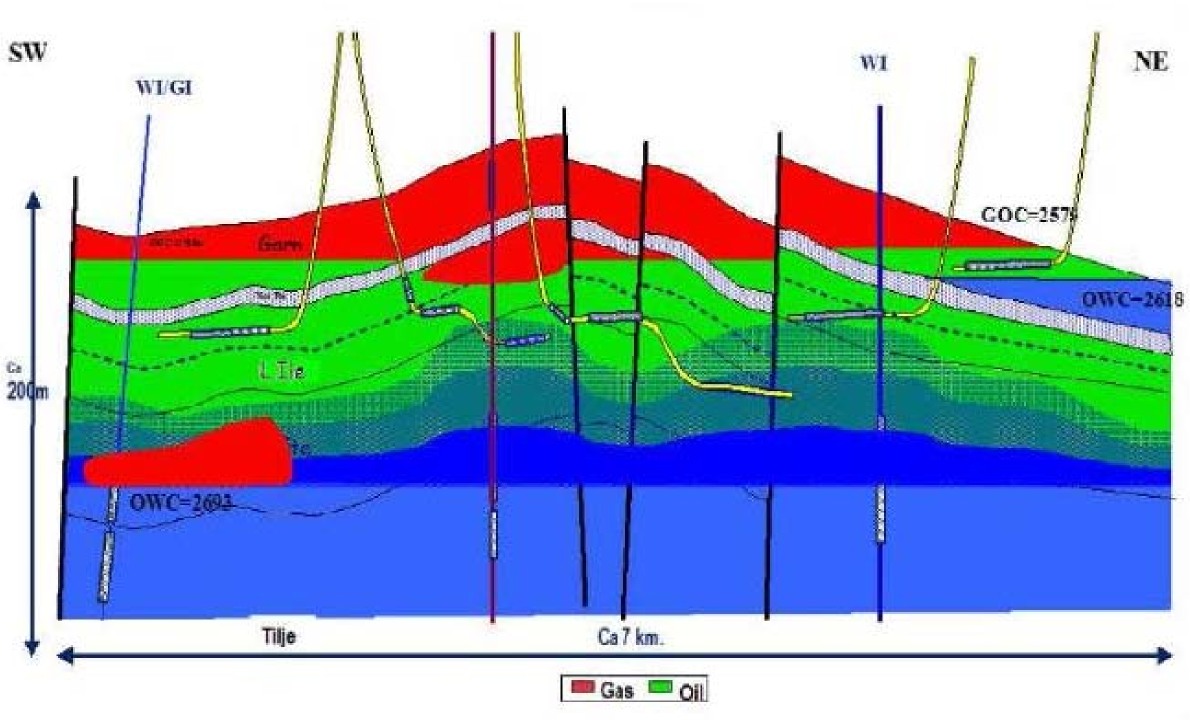
1. Introduction

The area selected for study is the Norne E-segment, located 80 km north of the Heidrun field in the Norwegian Sea. The field is operated by Statoil. Norne was discovered in 1991, and the oil production started November 6th 1997. Norne is a subsea field with six templates connected to a production vessel [1].

The sediments consist of a monotonous succession of sand, sandstones, shale, clay and silts. Three formations can be distinguished, Garn, Ile and Tofte. Each formation is likely to contain varying amounts of each facies and massive sandstone beds are rarely found. Reservoirs in the Norne E-segment are result of fluvial and lacustrine deposition. Sand formations are characterized by good porosity (0.2-0.3) and medium to high permeability (20-2500mD). Geological correlation of reservoir zones is complicated by faults and the area is strongly heterogeneous even in each reservoir zone, where the oil viscosity varies.

The E-segment of the Norne field has five wells; two injection wells and three production wells. One of the production wells, E-3H, is closed.



Figur 1: Norne reservoir [1]

The drainage strategy was originally injection of water in the water zone, and re-injection of gas into the gas cap. But, by injecting the gas the pressure in the upper formations increased dramatically due to a pressure barrier, and the injection had to be stopped [2].

We picked project number 4, and the task was: “New injection well placements and completions for existing water injection wells”, which includes:

- Understand basics of well completion
- Based on existing water injectors
- Sidetracking
- Re-completion
- Injection rate
- Economic evaluation

Most of the project is done in Eclipse 100, a program for reservoir simulation. We had 5 different cases:

Case 1: Base case. We were running the simulation with the given data from 1997 to 2021.

Case 2: Changing the injection rates of some wells in the E-segment.

Case 3: Sidetracking the injection wells.

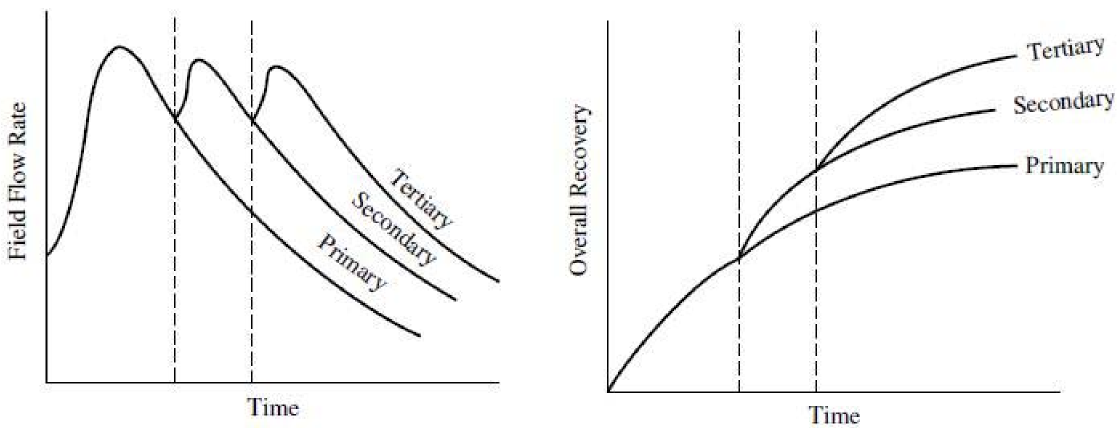
Case 4: Re-complete the injection wells.

Case 5: Drilling new injection wells.

2. Reservoir recovery

Some of the reservoir engineer's tasks are estimation of hydrocarbons in place and find out how to recover as much as possible.

There are three main types of hydrocarbon recovery [8]; primary, secondary and tertiary recovery. Primary recovery is the volume of hydrocarbons that can be produced by utilizing the natural pressure in the reservoir. The pressure is kept up by expansion of fluids in the reservoir. In secondary recovery are the hydrocarbons recovered by adding pressure to the reservoir. The most common type of secondary recovery is injection of water, where the water will keep the reservoir pressure up and displace the hydrocarbons towards the well. Tertiary recovery is obtained after the secondary process, when the recovery methods have been exploited to the economic limits. Examples are adding chemicals or thermal energy to the reservoir. If the oil is very viscous, water flooding may not increase the recovery very much, and chemicals may be the best solution and therefore the secondary recovery process. Tertiary recovery is therefore often called enhanced oil recovery, EOR.



Figur 2: Flow rate and recovery for the different types of recovery [9]

Water injection

Water is injected in the reservoir for two main reasons [8];

1) To keep up the reservoir pressure
2) To displace the oil and push it towards the production wells

Water and oil are immiscible fluids, and are always separated by an interface, they will not mix. This property plays an important role in the flow and displacement in a porous media, because one phase will displace another phase. Because oil is lighter than water, the injected water will push the oil upwards in the reservoir, and the water-oil contact will rise.

To know if a reservoir is a good candidate for waterflooding, the following reservoir properties must be considered [9]:

• Reservoir geometry

• Fluid properties

• Reservoir depth

• Lithology and rock properties

• Fluid saturations

• Reservoir uniformity and pay continuity

• Primary reservoir driving mechanisms.

The effectiveness of the waterflooding is dependent of how much of the reservoir volume that will be contacted by the injected water [8]. This is dependent on the horizontal and vertical sweep efficiency of the process, which is controlled by [8];

1) Selection of injection pattern is one of the first steps in the design of a water injection project. The pattern chosen must follow all the physical characteristics of the reservoir. One has to consider flood life, well spacing, injectivity, response time, productivity and the points below (2 - 8). The

injectivity and productivity are best determined from pilot operations. The response time is depending on the injectivity and spacing.

2) Off-pattern wells. Wells in pattern are only applicable under some conditions, as thin and horizontal reservoir, homogenous reservoir, only crude oil in the reservoir etc.
3) Unconfined patterns where loss of injected energy to wells and aquifer outside of the injection pattern can be a problem.
4) Fractures, that can have both positive and negative effect on the sweep efficiency, dependent on if they are located in a favorable direction or not. The breakthrough sweep efficiency drops with increasing fracture length.
5) Reservoir heterogeneity, changes in permeability and porosity.
6) Continued injection after breakthrough can result in increased oil recovery.
7) Mobility ratio, which is defined as the ratio of the mobility of the driving phase (water) to the mobility of the driven phase (oil). A high mobility ratio (>1), often caused by high oil viscosities, generally results in poor recovery because of unstable fronts.
8) Position of gas-oil – and water-oil contacts.

The most common procedure for determining the optimum time to start waterflooding is to calculate [9]:

• Anticipated oil recovery

• Fluid production rates

• Monetary investment

• Availability and quality of the water supply

• Costs of water treatment and pumping equipment

• Costs of maintenance and operation of the water installation facilities

• Costs of drilling new injection wells or converting existing production wells into injectors.

There are also some problems with waterflooding [10];

- Reaction of formation water with injected water when mixed forming salts that precipitate damaging the reservoir, clogging perforation and decreasing the flow by reducing the flow area.
- Corrosion of the surface and subsurface equipments and installations.

It is impossible to produce all the oil from a reservoir by use of waterflooding. Capillary forces acting during the injection will cause some of the oil to be retained in the reservoir rock. The watercut in the produced fluid will increase during the injection time, and the costs of pumping, separation, disposal of floodwater and cleaning and storage of produced water will one day exceed the income of the oil recovered [8].

3. Well completion

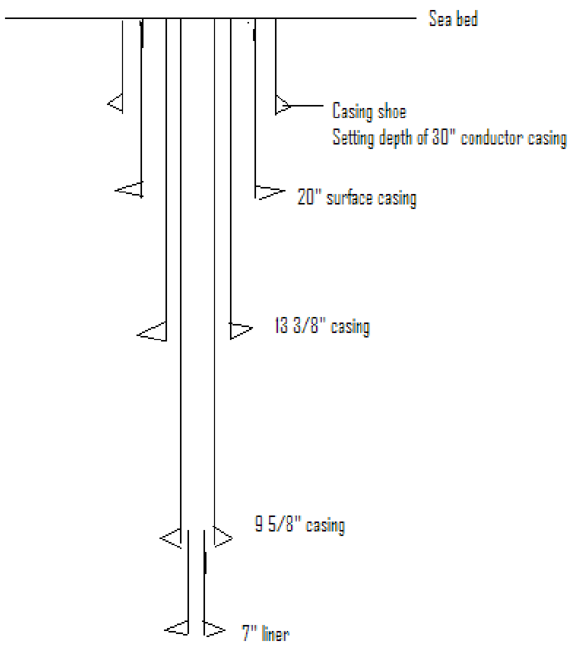
The drilling operation

When drilling a well, drilling fluid (mud) is circulated down the drill string and bit and up the annular space between the drill string and the borehole wall to remove cuttings and control the pressure. The first section to be drilled is the 36” hole. This section is usually so shallow and the drilling fluid is water, so the cuttings can be disposed on the sea bed. After the hole has been drilled, the 30” conductor casing is run and cemented in place. Then the 26” hole with the 20” casing (surface casing or wellhead casing) is drilled in the same way. After the 26” section the blow out preventer (BOP) and the riser are installed because of increasing formation pressure deeper down. The drilling fluid might have a higher density than sea water and the cuttings might be polluted, so the mud with cuttings needs to be transported back to the surface through the riser. The next sections are normally 17 ½“ bit size – 13 3/8“ casing, 12 ¼” bit size – 9 5/8“ casing and 8 ½” hole – 7“ liner through the reservoir. When the drilling operation is finished the well completion - and subsea equipment are installed [11].

Basic well completion

The installation of completion equipment makes the well ready for production/injection (“completing” the well). Some of this equipment is explained below.

Casing is a steel pipe run into a recently drilled section to protect the borehole, the formation around and make a smooth borehole for installation of production equipment. Every casing string is fastened in the wellhead on the sea bed. A liner is the last casing string, fastened in the 9 5/8” casing shoe. The space between the casing and the borehole wall is filled with cement to prevent communication between the well and the surrounding formation. The figure below shows a typically casing scheme for a subsea well [5, 11]



Figur 3 Typically casing scheme

The casing prevents inflow of formation fluids from permeable zones into the borehole and outflow of drilling fluids into permeable or fractured formation (fluid loss). It also prevents cavings to fall into the borehole and it seals off high pressure zones from the surface avoiding potential for a blowout. In normal, overbalanced drilling, the mud weight has to be between the pore pressure and the fracturing pressure of the formation. Because the formation pressure is increasing with depth, you have to increase the mud weight to balance the well. After setting a casing, one can increase the mud weight without fracturing the formation above.

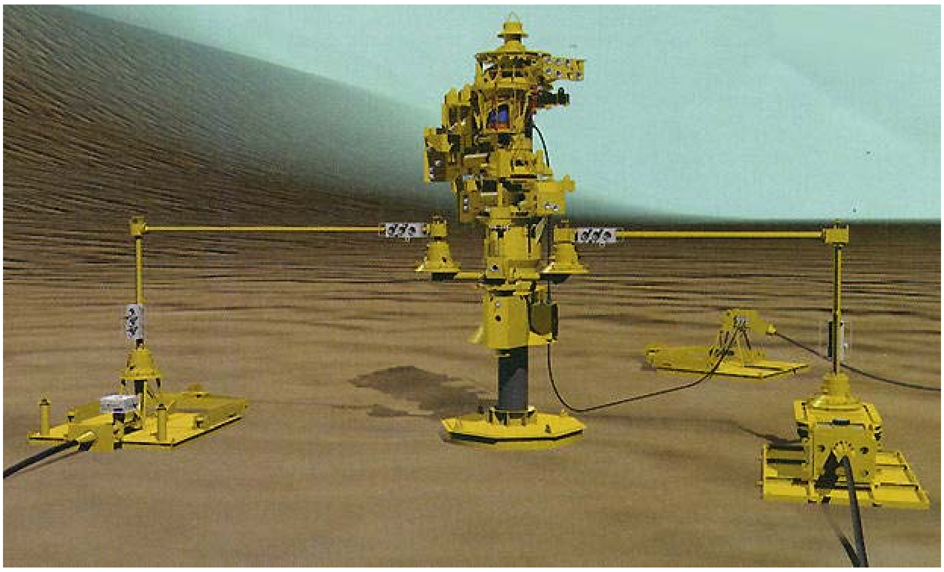
Production tubing makes up the production string with other completion components, and is used to produce reservoir fluids. It is run into the drilled hole after the last casing section is run and cemented in place, and makes a continuous bore from the reservoir to the well head [5].

Mono bore completion implies a large and nearly even diameter of the production string.

Perforations are punched holes in the production casing or liner to connect the well and the reservoir. They are made by lowering a string of charges, perforating guns, down to the preferred depth to perforate the casing. By this technique the well is protected by the casing, and can produce from preferred parts of the reservoir [5].

Solid particles may follow the production flow of reservoir fluids when producing a reservoir, this is called sand production. Sand production may cause erosion of the production equipment, instability of the perforations and the wellbore, and it will be necessary to handle large amounts of polluted sand. Sand control equipment may be installed to predict or reduce the production of sand, but this equipment is very expensive and reduces the production. Therefore it is preferable to avoid using it. Types of sand control equipment are for example screens, chemical consolidation and gravel pack, where a steel screen is placed in the wellbore and the surrounding annulus is packed with gravel so that sand cannot pass [12]

The subsea X-mas tree is placed on the wellhead and is an assembly of valves, spools, pressure gauges and chokes to control the production or injection. The two main types of x-mas trees are conventional (vertical) and horizontal trees. Most of the valves in the tree are gate valves [13]



Figur 4 Subsea x-mas tree [18]

Valves are installed both in the x-mas tree and in the well. The down hole safety valve (DHSV) is a flapper valve, and it is placed in the well to prevent backflow into the reservoir. The valves in the xmas tree closes if the rate becomes uncontrolled and too high (kick). The first valve to close is usually a wing valve, which is located on the horizontal outlet from the x-mas tree. Then one of the master valves closes the other one is usually a back-up valve. Swab valves are installed on the vertical bore in the x-mas tree, one for the production line and one for the annulus line, to prevent backflow into the well. A choke valve is located downstream the production wing valve o control the rates, especially in clustered wells [7, 13].

Smart wells: Advanced wells that are completed with valves or chokes downhole in the reservoir and with equipment which can be operated from the surface. This hardware can be installed in both platform – and subsea completed wells and has several advantages:

- Shut down unwanted production and control individual well sections.
- Control water injection rates.
- Eliminate the need of well intervention.
- Improve reservoir description.
- Increase ultimate recovery factor.

Smart well completion increases the costs, since it requires more equipment and takes longer to implement. These extra costs need to be evaluated against the profit of increased oil/gas recovery [1, 3].

Water injector completions on Norne

The Norne field is a subsea field consisting of five templates, which means that several subsea wellheads are located on a central subsea structure. These templates are grouped together in two clusters, the southern cluster with 3 templates and the northern cluster with two templates. There are nine flowlines that are linked to the Norne production vessel, placed between the two clusters. The injectors in the E-segment are F-1H and F-3H.

All templates, see figure attached, have four well slots and an option to hook up two more wells. One template, F, in the northern cluster is dedicated for water injection, and the C-template in the southern cluster is a combined water and gas injection template. This template has two flowlines, one for water and one for gas. All four well slots on this template can switch between injecting water and gas by use of a ROV. The F-template has only one flowline and is therefore just able to inject water. The water injection flowlines have an inner diameter of 9 inches, while the gas injection flowline has an inner diameter of 8 inches [2].

All the wells have a horizontal x-mas tree, se figure attached. Unlike the vertical x-mas tree, the production and annulus bores go horizontally out of the tree, and the valves are oriented horizontally. The tubing hanger is installed in the tree itself, rather than in the wellhead, and the blow out preventer (BOP) is placed on the top of the tree. This allows the tubing string to be recovered without retrieving the tree. Access to the wellbore is done by removing the tree cap and a wireline plug in the tubing hanger. By use of a horizontal x-mas tree, future well operations are simplified [2, 13]

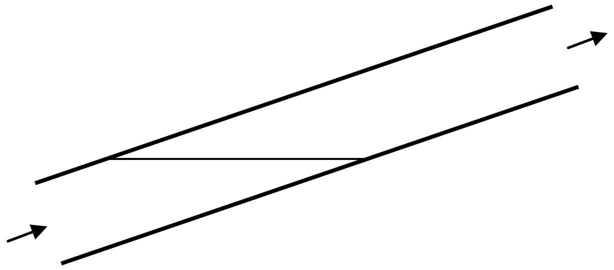
Water injection wells are perforated in Tilje 3 and 4, and Tofte. Tilje 1 is no longer a candidate for perforations due to the possibility of unconsolidated sand and lack of vertical communication [2].

The injectors are drilled to true depth with a 12 ¼ inch bit, and a 9 5/8 inch casing has been run to save drilling costs [2]. See figure attached.

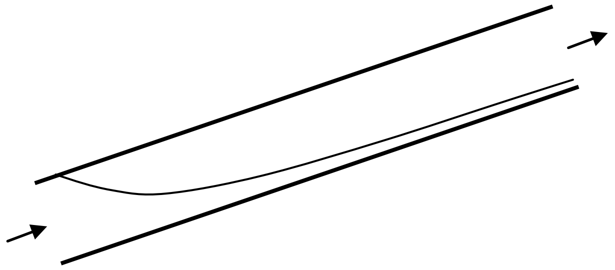
Due to corrosion protection and monitoring the water injectors are completed with carbon steel. Some of the water injectors have Duoline 20 glass fibre coating, but tests have shown that glass fibre is destroyed by the perforation guns and could harm the perforation tunnels, so it is not installed in all of them [2].

4. Injection rates

When you are injecting water you want an injection rate as high as possible, and at the same time displace as much oil as possible. In an inclined layer, where the gravity plays an important role, a very low rate will give a horizontal interface between water and oil (figure to the left). The displacement is stable, but because of the low rate, it takes too much time to increase the pressure as much as preferred. With a very high injection rate (figure to the right), the interface will become parallel to the layer, and the displacement is not gravity stable [14]

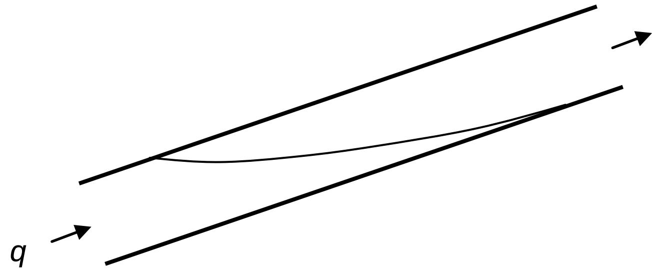


A very low water injection rate [14]



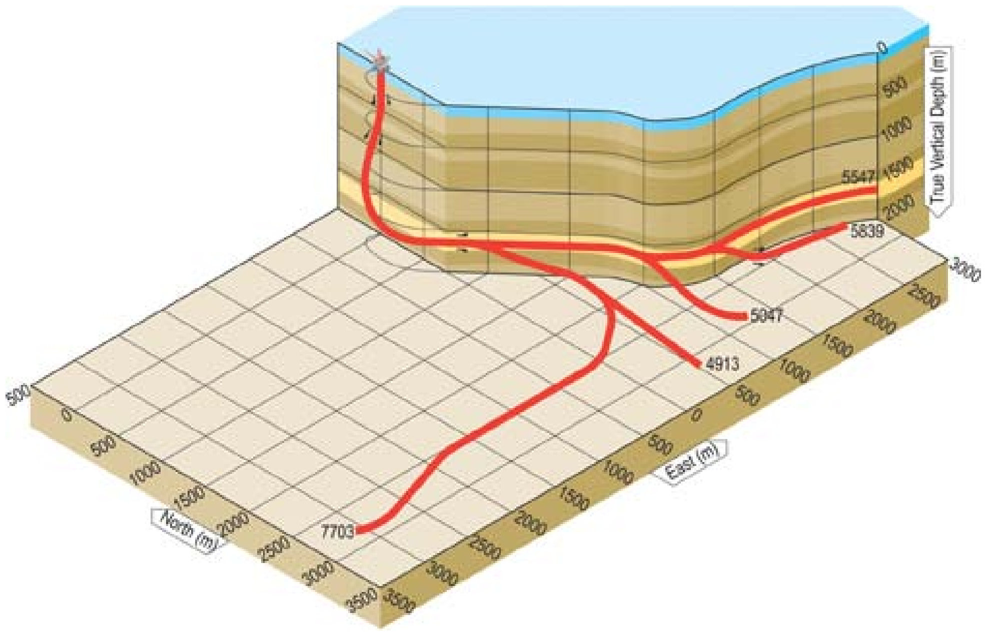
A very high water injection rate [14]

The challenge is therefore to find an injection rate where the water is displacing the oil and at the same time keeping the pressure at a preferred level, like in the figure below.



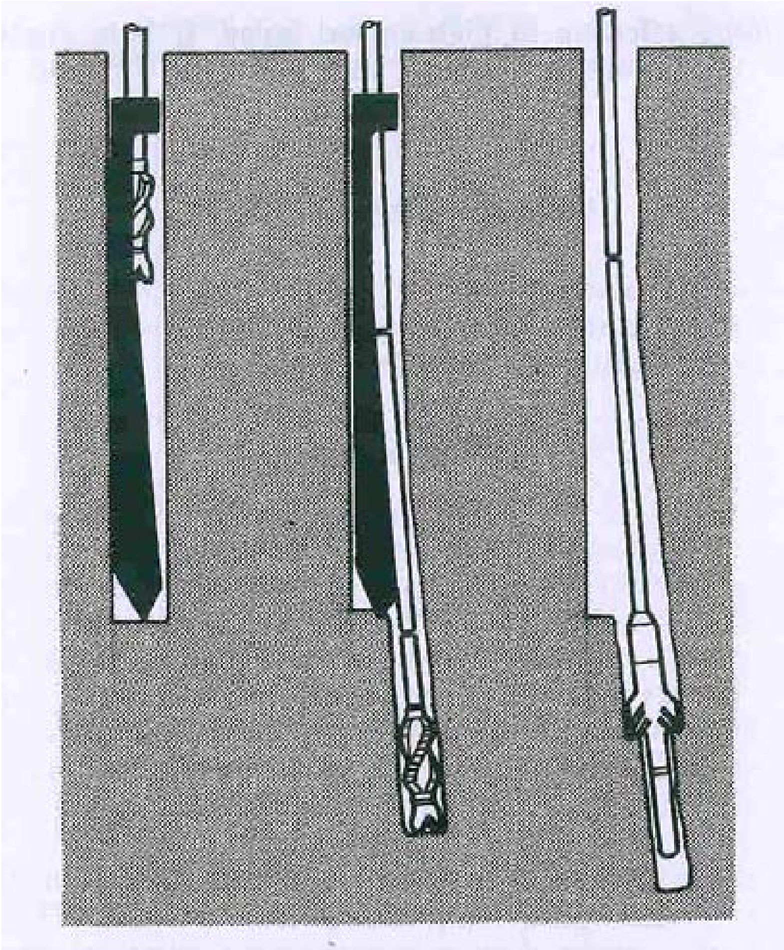
5. Multilateral wells

Multilateral wells can be defined as a construction of two or more wellbores into one or more reservoirs for the purpose of managing and optimizing fluid movement within the reservoir(s). These lateral wellbores are connected back to a common main bore that extends to surface. The main wellbore is drilled to above the target, and from there one or more wellbores, branching off the main wellbore, are drilled into the target zone [3].



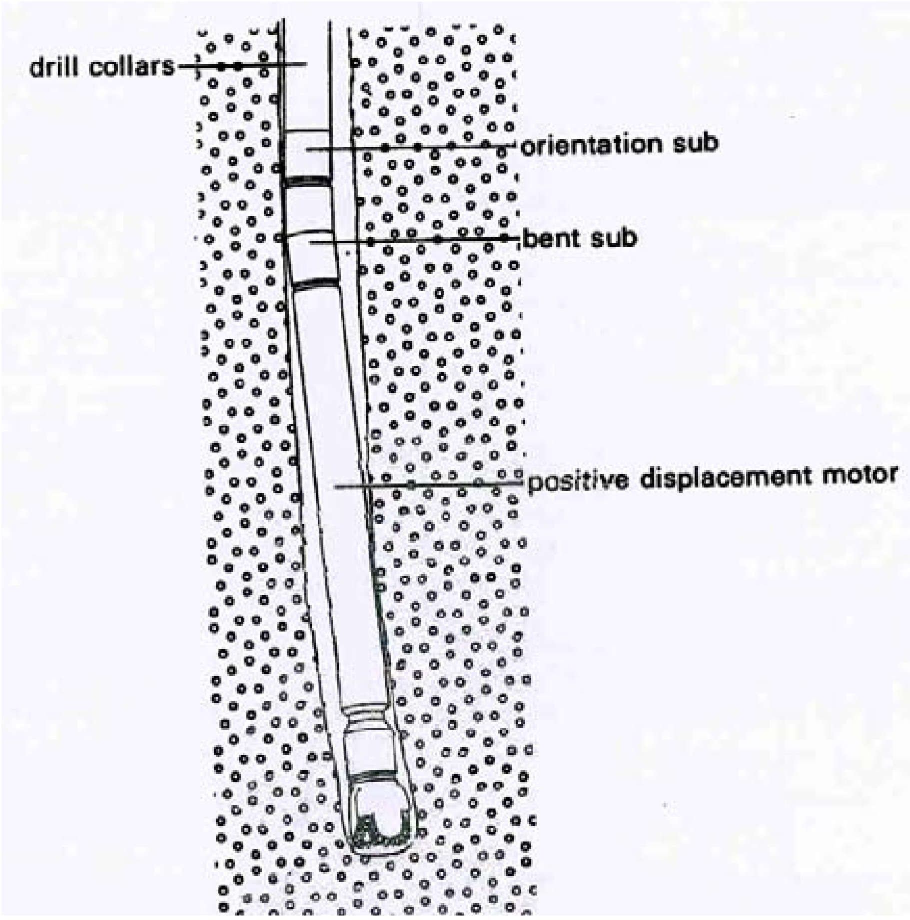
Figur 5 Multilateral well [15]

The sidetrack drilling operation can be explained by use of a whipstock, originally a wedge-shaped piece of wood. The tool is attached to the drill string by a shear pin. The drill string is run into the hole, and rotated until the toolface of the whipstock has the right position. By applying weight from surface, a chisel point is set into the formation or cement plug to prevent movement. Then the pin is sheared off and drilling of a small pilot hole (rathole) can begin. The rathole needs to be surveyed to know that the hole has the right direction. When this is done the whipstock and bit are tripped out, and the pilot hole is reamed out to full size. Further drilling can then be done by use of rotary building assembly. This drilling technique is a very accurate and is able to provide a controlled and gradual build of angle, but there are also some disadvantages [6].



Figur 6 Drilling by use of a whipstock [6]

The disadvantages have caused the whipstock to be replaced by new techniques, but it may still be used for specific applications. The most common deflection technique today is running a downhole motor and a bent sub. The sub, a short length drill collar with a slightly off vertical axis, is placed above the motor to create a side force at the bit. The drill string is not rotated [6].



Figur 7 Drilling by use of a bent sub [6]

It is cheaper to drill a sidetrack from an already existing well than to drill a new well from the surface, therefore multilateral wells can offer a great economic potential if they are drilled appropriately. The drilling and completion of multilateral wells are technically very difficult, and requires use of advanced equipment. This technology has progressed because of increasing system capabilities, greater experience and understanding of their applications. As a result, multilateral wells are more and more used [3].

To describe the complexity a classification system called TAML, Technology Advancement for MuliLateral) has been developed [3].

TAML classification system:

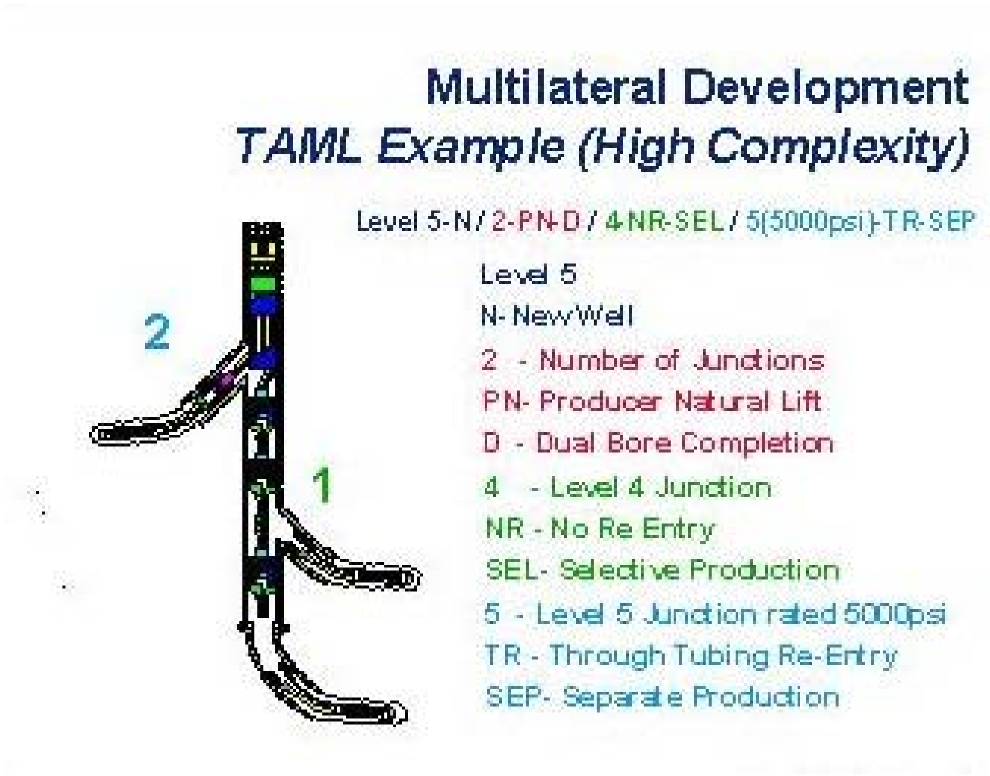
The objectives of this system are to aid in determining the functional requirements of a proposed multilateral well, assist the selection of the most appropriate system for the determined functional requirements, and facilitate the transfer of project information and experience.

The TAML classification system has a complexity ranking and a functionality classification. The complexity ranking system gives an indication of how complex the well is. The ranking is from level 1 to level 6:

- Level 1: Open/unsupported junction.
- Level 2: Main bore cased and cemented, lateral bore open.
- Level 3: Main bore cased and cemented, lateral cased but not cemented.
- Level 4: Both main and lateral bore cased and cemented.
- Level 5: Pressure integrity at the junction achieved with completion equipment (cement is not acceptable).
- Level 6: Pressure integrity at the junction achieved with casing (cement is not acceptable)
- Level 6S: Downhole splitter: large main bore with two smaller lateral bores.

The complexity of the borehole is increasing with increasing numerical value. This shows that multilateral technology is driven by the completion required, and not the drilling operation. Level 1 and level 5 can have similar drilling requirements, but very different completion.

The functionality classification has a well description and a junction description. An example is given below.



Figur 8 TAML example [3]

6. Re-completion

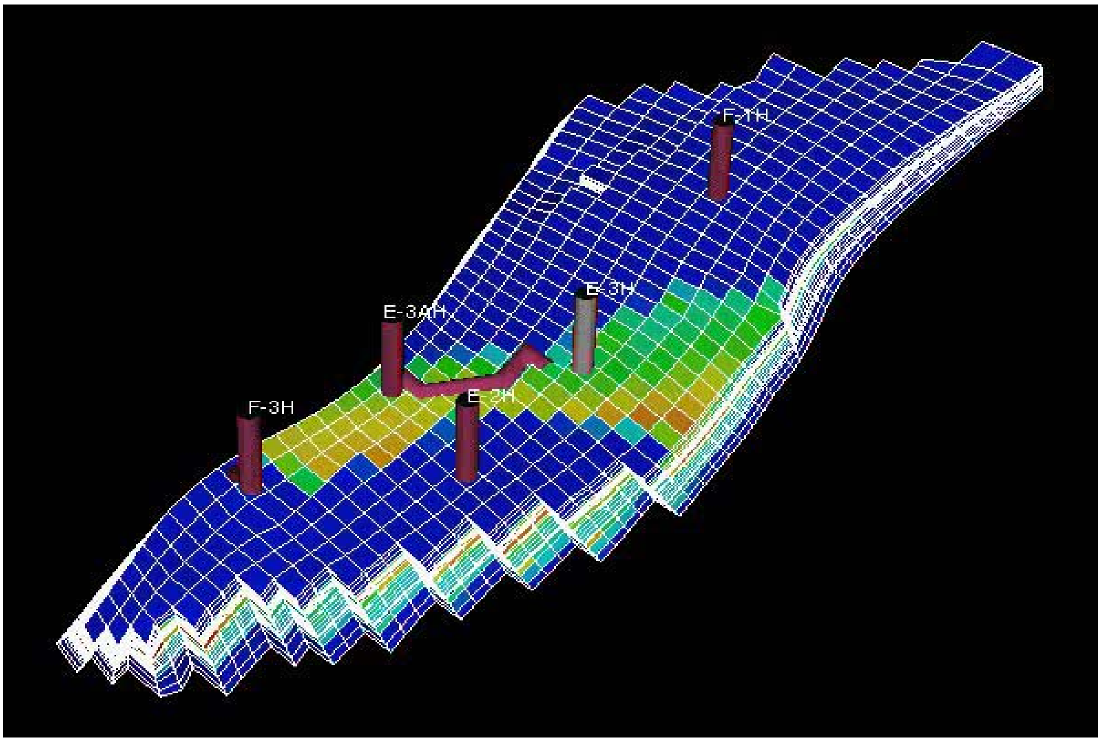
Re-completion can be defined as: “After the initial completion of a well, the action and techniques of reentering the well and redoing or repairing the original completion to restore the well’s productivity.” [16]

One can restore the well’s productivity (or injectivity in our case) by drilling a well to a new target. For production wells this may be done when the producing zone is depleted, when it is no longer economical to produce from this zone. For injection wells it means that increasing the pressure in a zone, no longer affect the production of hydrocarbons. One can affect the production again by increasing the pressure in another zone of the reservoir.

Re-completion can also be done by re-using old wells to new purposes. For example can a closed production well be used as an injection well. This is done to increase the oil recovery in an economic way. Re-completion of an old well may be more economic than drilling a new.

7. Simulation

We have used a 3-dimensional model for the simulation, where the axes are named i, j and k. The model is divided into smaller blocks, called grid blocks, with coordinates (x, y, z) in i, j and k direction. I and j is in the horizontal plane, while k is in the vertical. The origin is the top left back corner. Coordinates on the i-axis are increasing from left to right, and the j-axis from back to front. K is increasing with depth. Combining this with geology, k is the geological layer. Our model of the Norne E-segment has 22 layers. By use of these coordinates one can decide the position and direction of a well.



Figur 9 3D-model of the E-segment

We were just looking at the E-segment of the Norne field. Before we started the simulation, we used 3D-models from Eclipse Office to see how the segment looks like. These programs make it possible to see how for example the oil saturation or the pressure in the reservoir changes over time. Oil and water saturation and pressure are important parameters to look at when the injection is evaluated. We want the oil saturation to increase near the production wells, and the water to stay away from the production wells. High pressure will normally increase the production of oil, if we are not having a water break through, but too high pressure can damage the formation and make it difficult to produce as much oil as possible.

We had five different cases for our simulation:

Case 1 was the base case. We were running the simulation with the given data from 1997 to 2021. This is the case we have to compare the other cases with to see if we can increase the production.

Case 2 was changing the injection rates of some wells in the E-segment.

Case 3 was sidetracking the existing injection wells, F-1H and F-3H.

Case 4 was re-completion of existing wells.

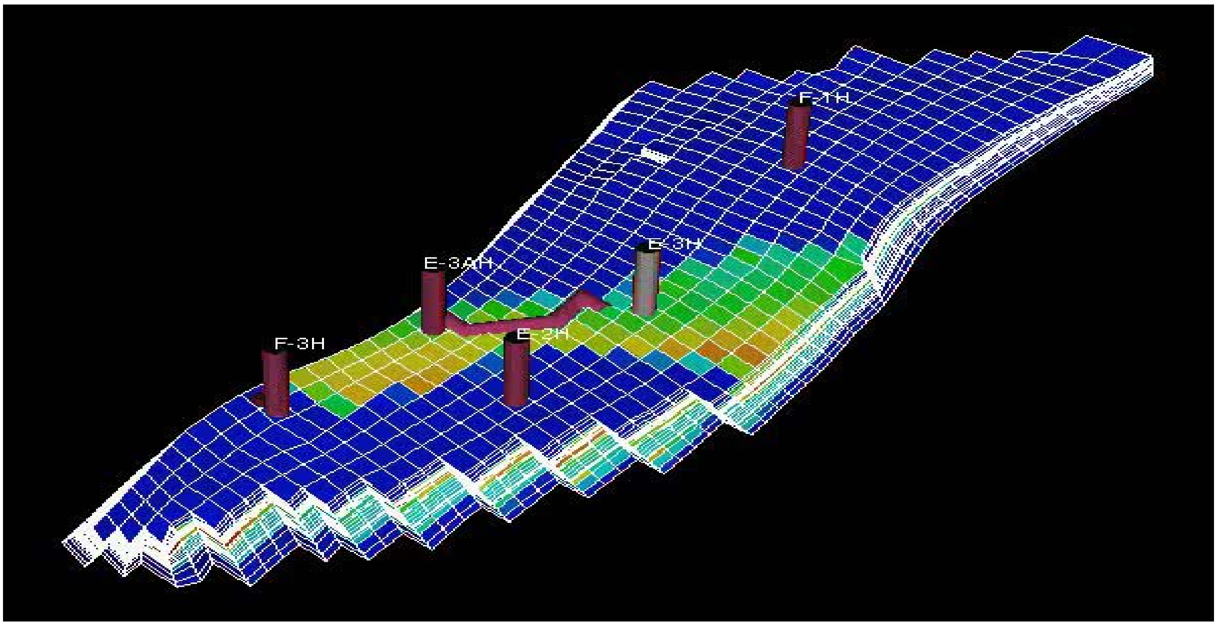
Case 5 was drilling new injection wells. How much will a new injection well increase the oil production from the Norne E-segment?

To define a new well we used the keyword WELSPECS followed by the keyword COMPDAT to define where (coordinates and layers) the well should be perforated. The injection rates are changed under the keyword WCONINJE. An example of a code for defining a new injection well, it’s coordinates and rate is attached.

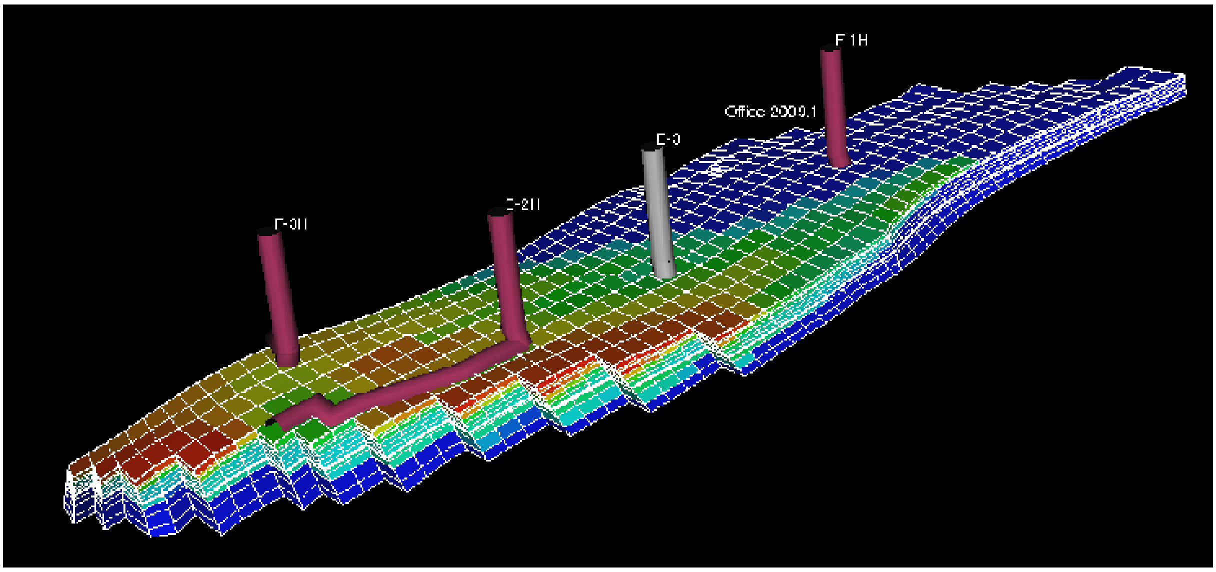
8. Results

Case 1: Base case

The figures below are 3D models of the E-segment from Eclipse Office.



Figur 10 #d modell, layer 1, base case

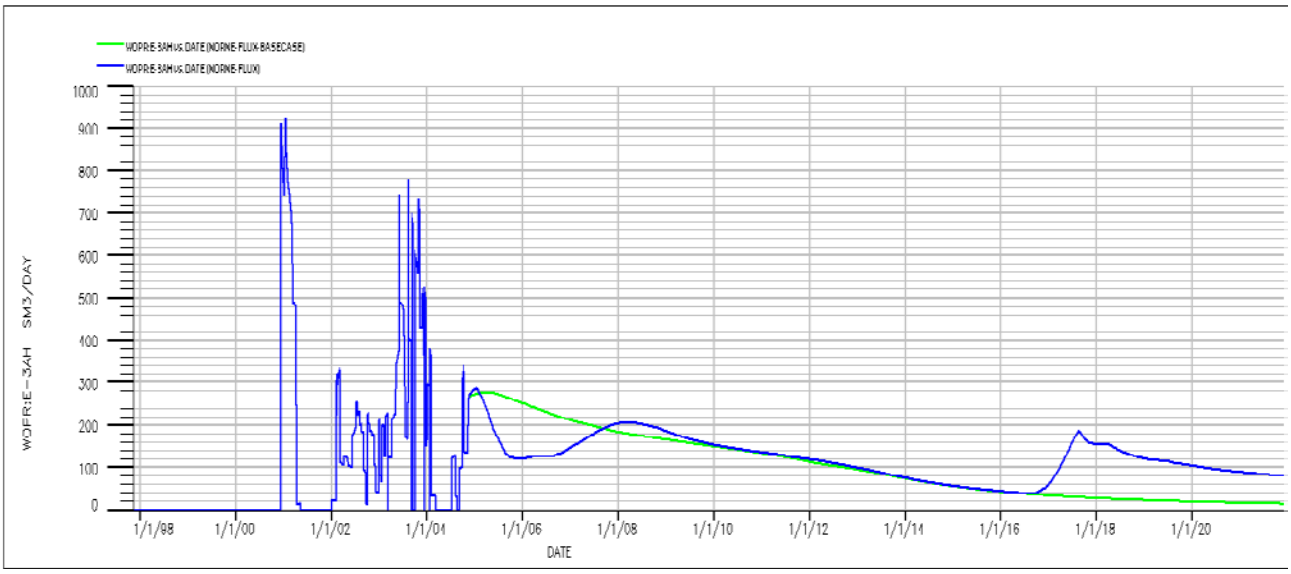


Figur 11 3D model, layer 9, base case

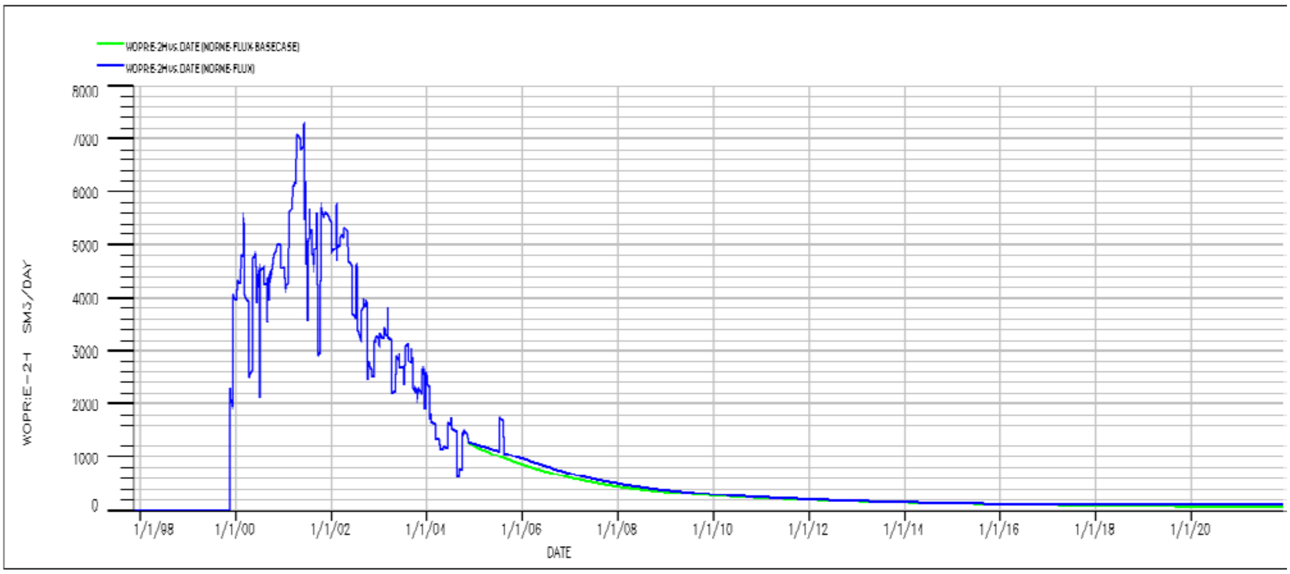
The total production of oil from the base case will in 2021 approximately be 87 million Sm^3. Plots from the base case can be seen under the other cases.

Case 2: Changing the rates

Changing injection rates affect the production from the two wells, E-2H and E-3AH in the E-segment. By decreasing the injection, the production is actually increasing from both production wells. The results can be seen in the plots below. The first plot is showing the production rates from E-2H and the second is showing the production rates from E-3AH.



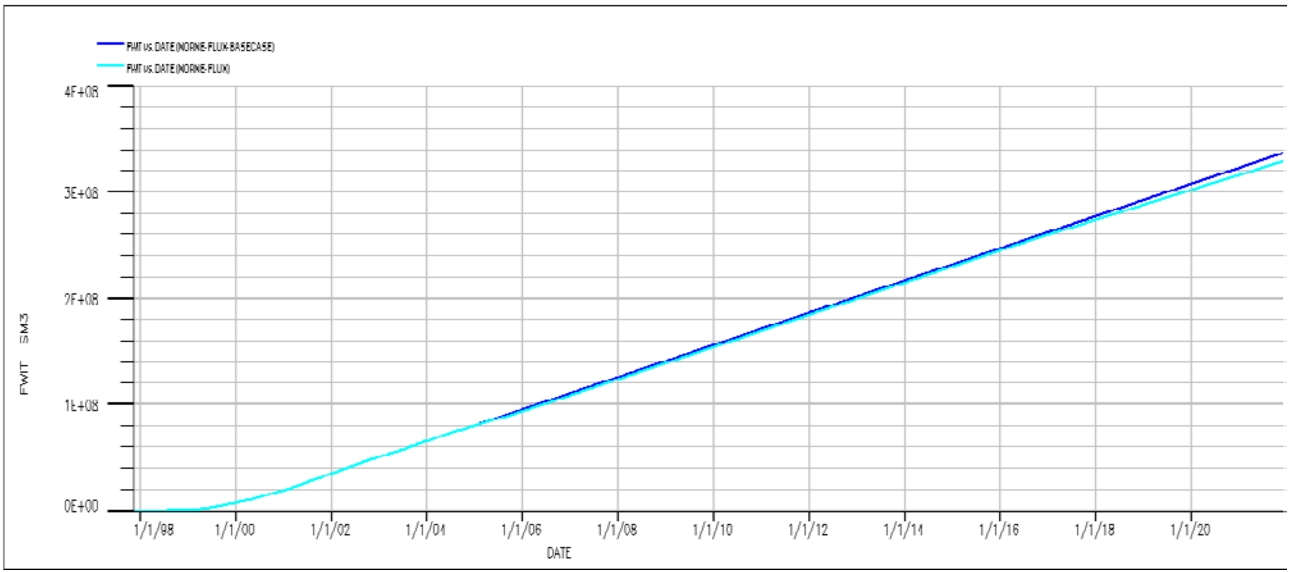
Figur 12 Oil production rates, well E-2H, case 2



Figur 13 Oil production rates, well E-2AH, case 2

The green line represents the base case and the blue line represents the study case.

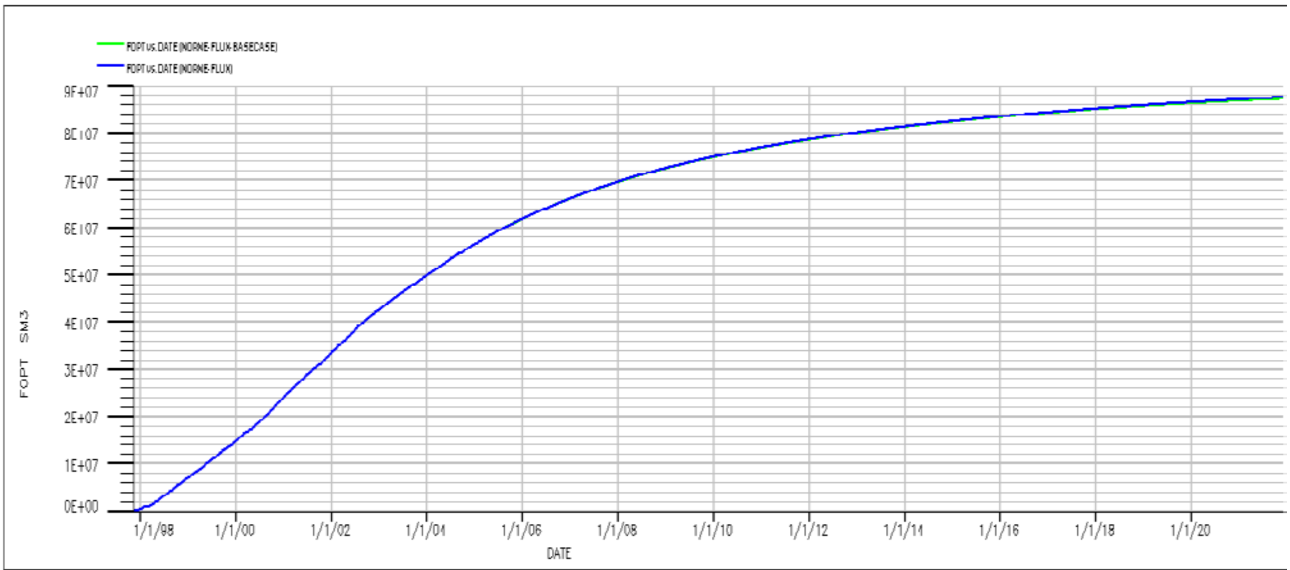
As we can see that both the production wells are showing good results as compared to the base case and the important thing is that the water injection is low as compared to the base case which is illustrated by the graph below.



Figur 14 Water injection, case 2

The blue color represents the base case and the cyan color represents the study case. It can be seen clearly that the water injection is low as compared to base case.

Overall increase in production can be seen in the graph below, which shows total oil production from the Norne field.



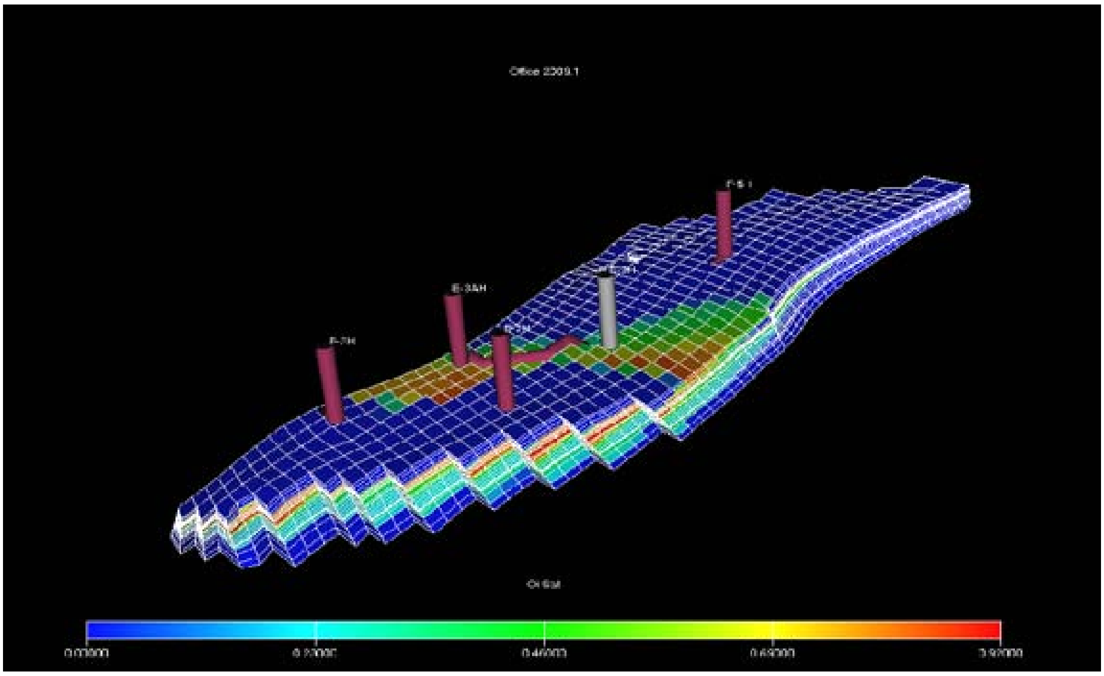
Figur 15 Total field production, case 2

The green line represents the base case and the blue line represents the study case.

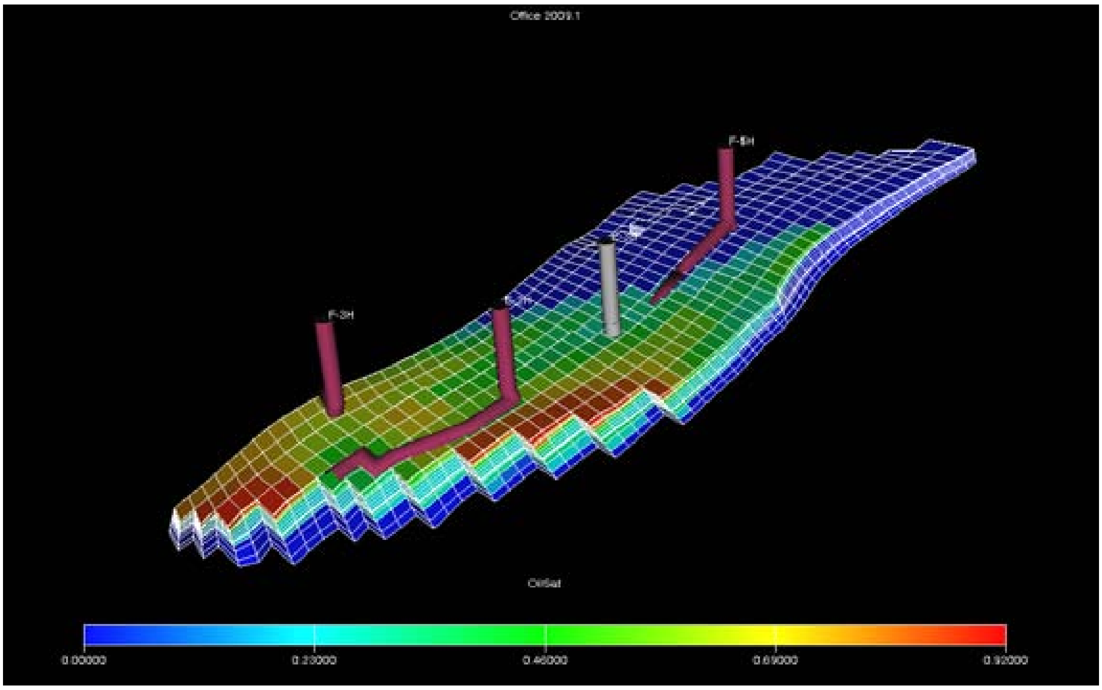
It's hard to see but blue line is a bit above the green line. The total production for this case is 87203400 Sm^3, an increase of 0,23 % in oil recovery.

Case 3: Sidetracking

a) F-1H: Injecting in both bores:



Figur 16 Layer 1, case 3a



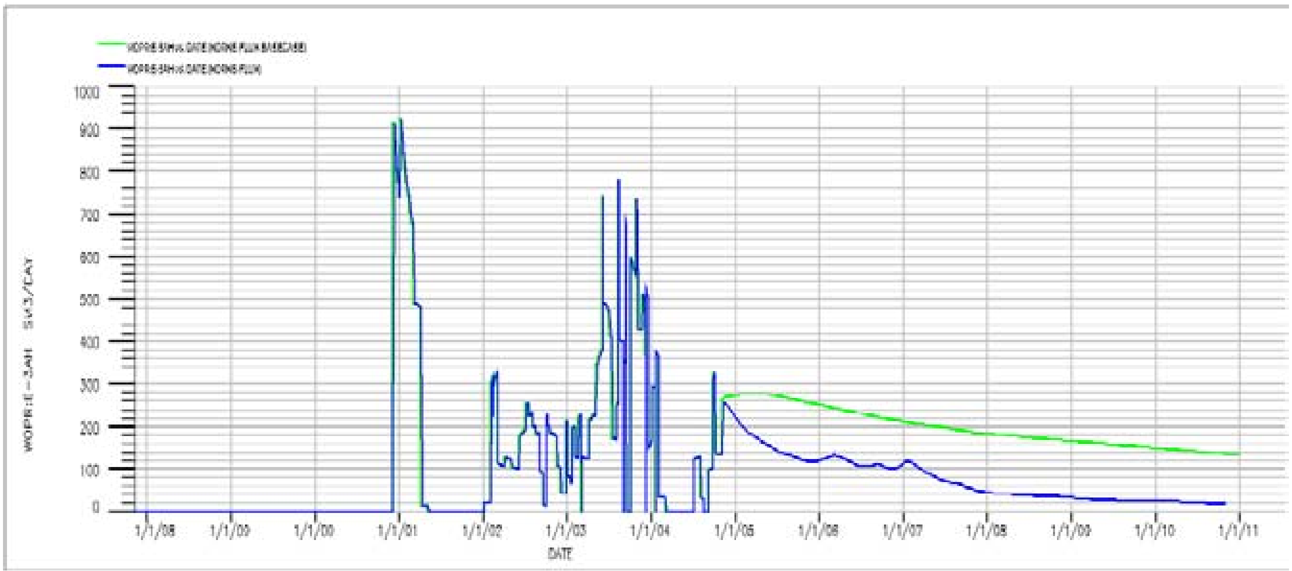
Figur 17 Layer 9, case 3a

The above simulation images from Eclipse Office show the position of sidetracked well and the different cases regarding that is discussed below.

First water was injected in both bores, the original well F-1H and the sidetrack from it. That gave the following results. The first plot is showing the production rate from well E-2H.

Figur 18 Oil production rates from well E-2H, case 3a

The next plot is showing the production rates from E-3AH.



Figur 19 Oil production rates from well E-3AH, case 3a

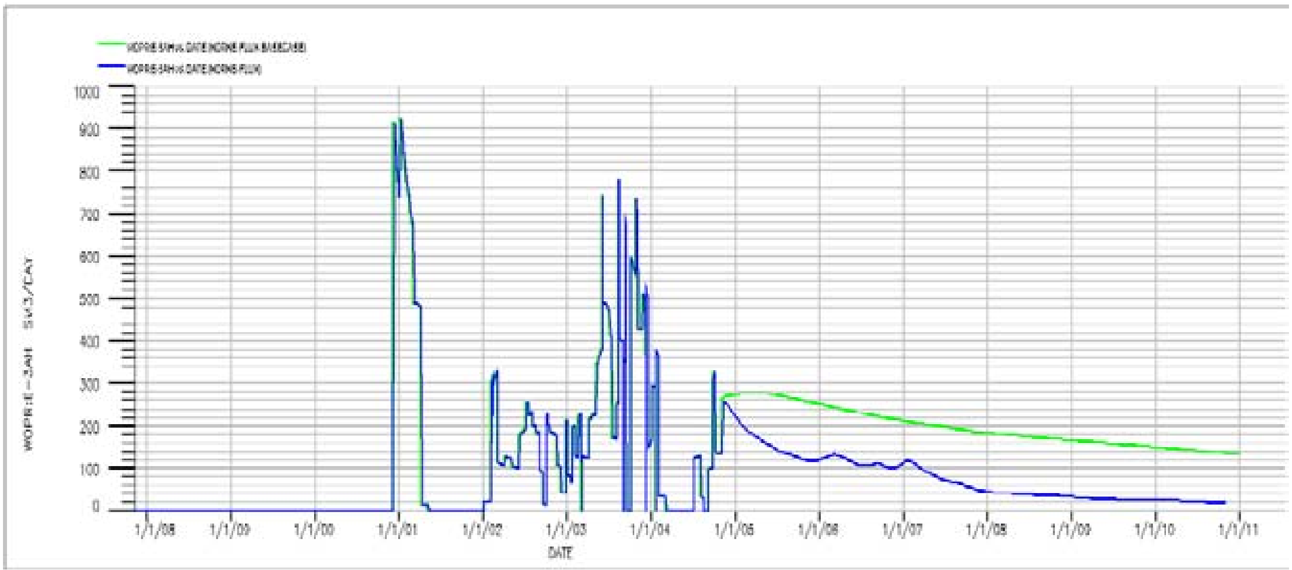
In the figures above the green line represents the base case and the blue line represents the study case. As you can see from the plots, sidetracking of F-1H has not given good results when water is injected in both bores.

b) F-1H: Closing the original bore:

In the first example of this case the original well F-1H has been closed, and only the new sidetrack is injecting. The plots below show some of the results.

Figur 20 Oil production rates from well E-2H, case 3b

The plot above is showing the rate from E-2H, and the one below is showing the well E-3AH.

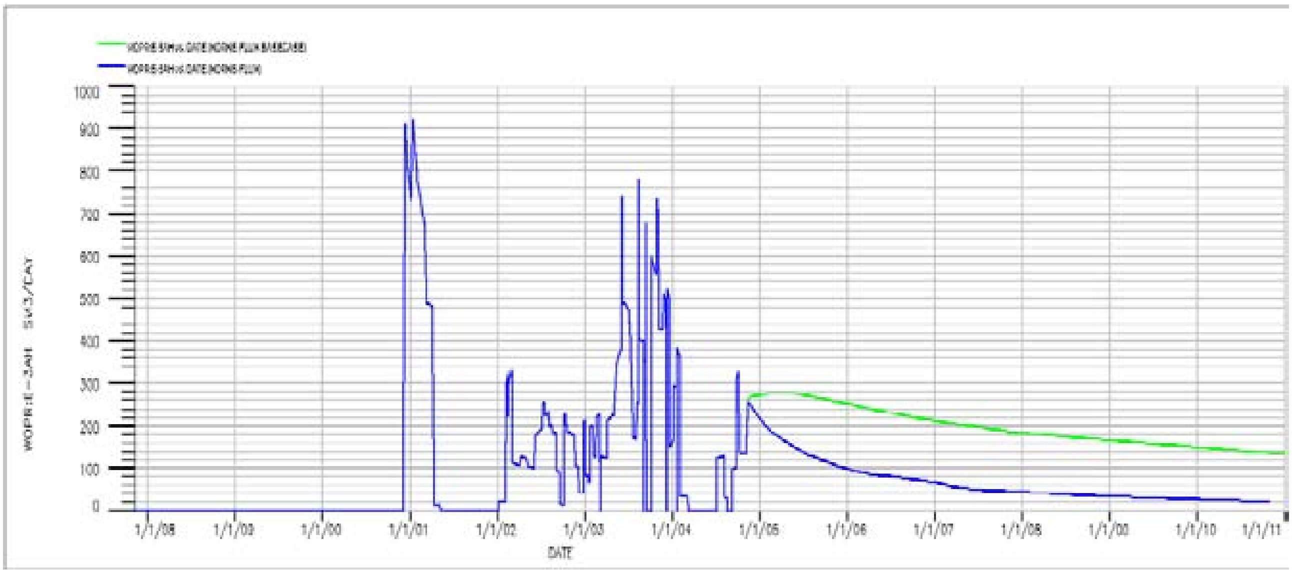


Figur 21 Oil production rates from well 3-AH, case 3b

In this example the injected water rate is constant as in case 1 and the only change is the closing of F-1H. As you can see, the results are not better than the base case.

In the next example the value for the injection rate is higher and as mentioned before the injection is only done in the sidetrack. The first plot is showing production rate from well E-2H, and the second plot is showing the well E-3AH.

Figur 22 Oil production rates from well E-2H, case 3b



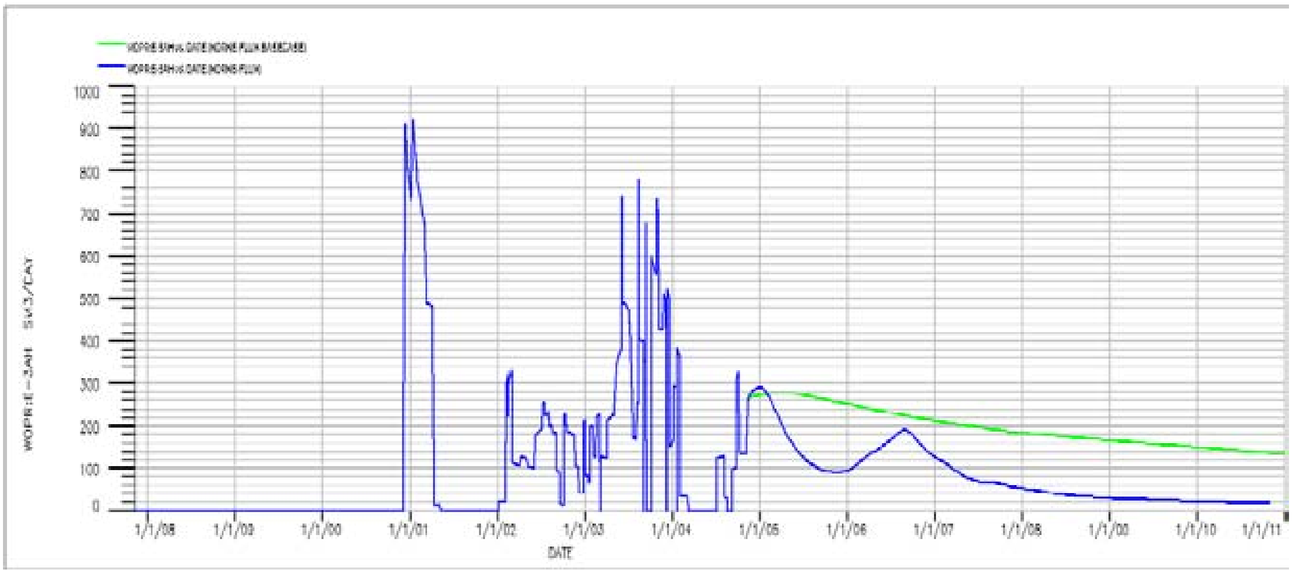
Figur 23 Oil production rates from well E-3AH, case 3b

In the figures above the green line represents the base case and the blue line represents the study case. The plots show that the production is decreasing compared to the base case.

In the next example the value for the injection rate is higher than in the previous cases, and as mentioned before we are only injecting in the sidetrack. The direction of the sidetrack has been changed.

Figur 24 Oil production rates from well E-2H, case 3b

This plot shows the production rate from E-2H.



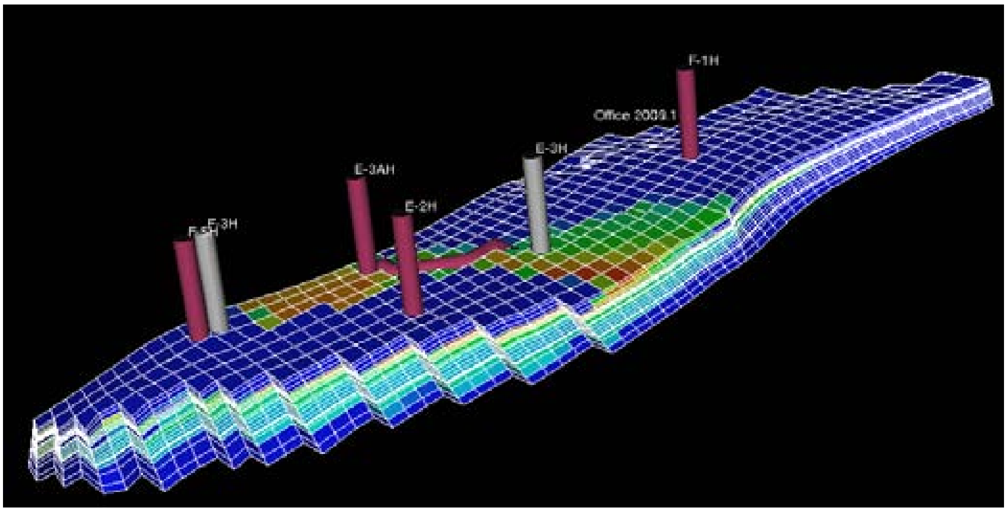
Figur 25Oil production rates from well E-3AH, case 3b

This plot shows the production rate from E-3AH.

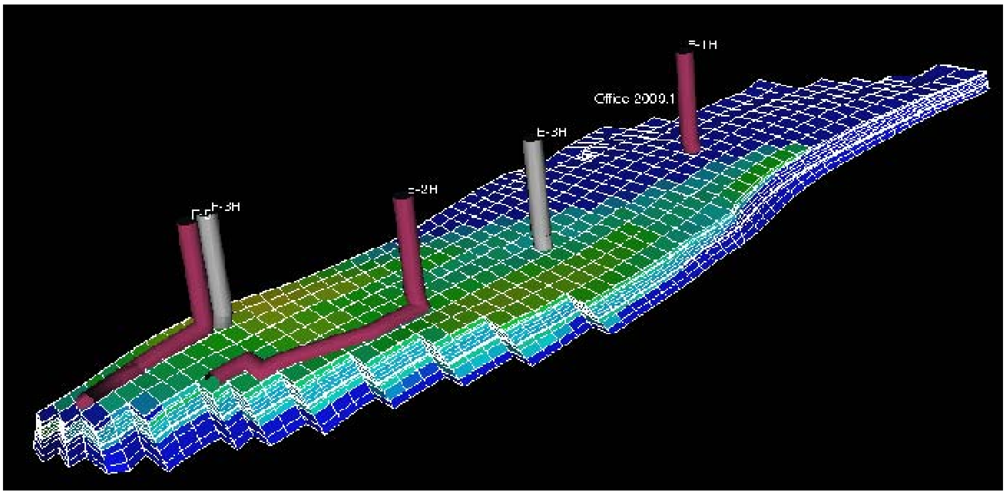
In the figures above the green line represents the base case and the blue line represents the study case. The above figures show values somewhat as usual in other words not any improvement as usual but the oil production from the well E-3AH is somewhat better than the cases before.

The above results clearly show that with the sidetracking of F-1H there is no significant change is the oil production and this may be because the injection well F-1H is far from the other oil producing well and oil saturation is low in the areas F-1H is installed and because of this sidetracking and changing rates with F-1H has no significant effect on the oil production.

c) F-3H: Closing the original bore



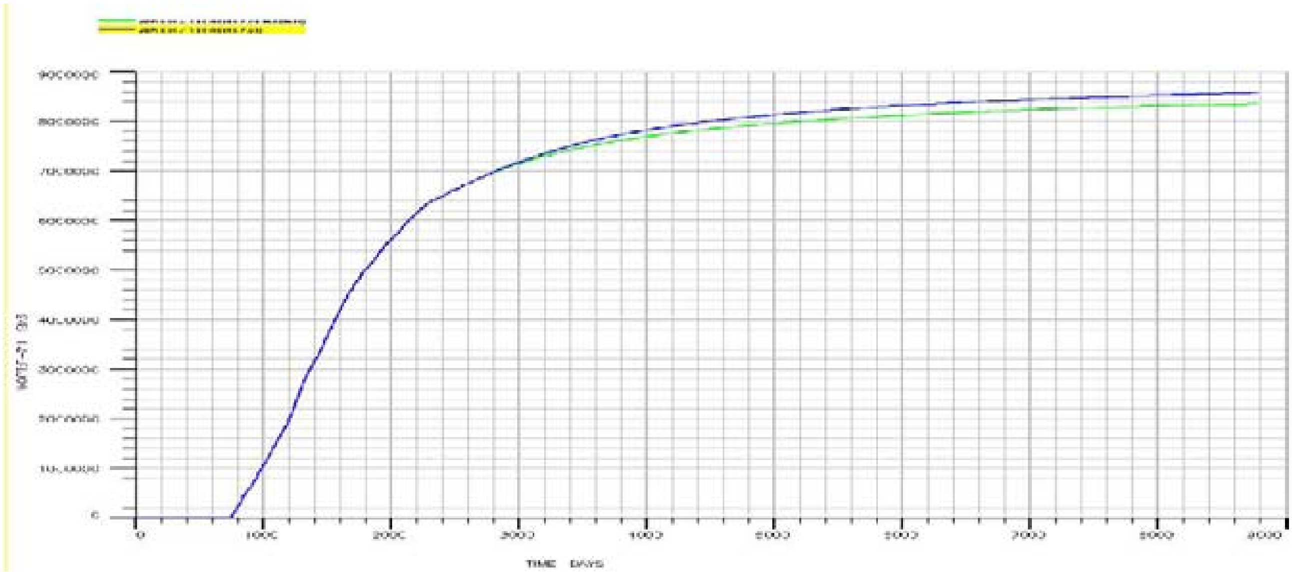
Figur 26 3D model case 3c, layer 1



Figur 27 3D model case 3c, layer 9

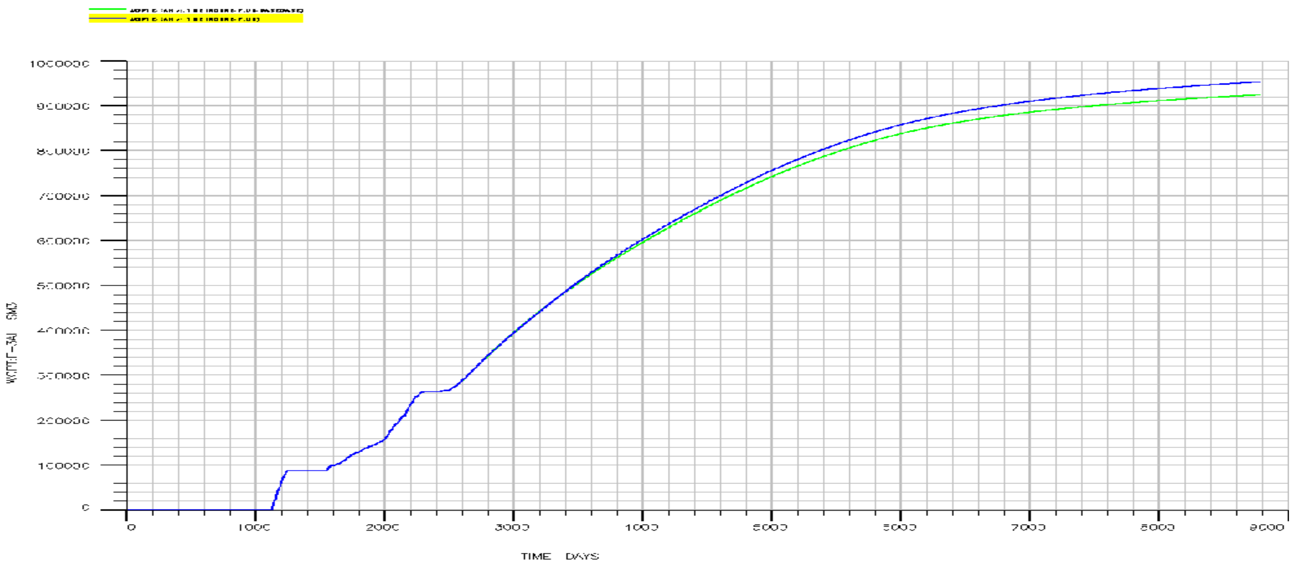
The figures above shows a 3D model of the E-segment with at new sidetrack from the injection well F-3H (to the left in the picture). F-3H was closed in November 2004, when the sidetrack, F-5H, was drilled.

The 3D model of the base case shows that there is much oil left in the left part of the segment, and therefore we decided to drill a sidetrack in that direction, to push the oil against the production well E-2H. Compared to the base case, a lot of the oil is removed from this part of the segment.



Figur 28 Total oil production from well E-2H, case 3c

This plot is showing the total oil production from well E-2H. The blue line is case 3, while the green line is the base case. You can see that the oil production from this well is increasing after the sidetrack is drilled in 2004.



Figur 29 Total oil production from well E-3AH, case 3c

This plot is showing the total oil production from the well E-3AH. Also in this well the production is increasing after the sidetrack is drilled (blue line) compared to the base case (green line).

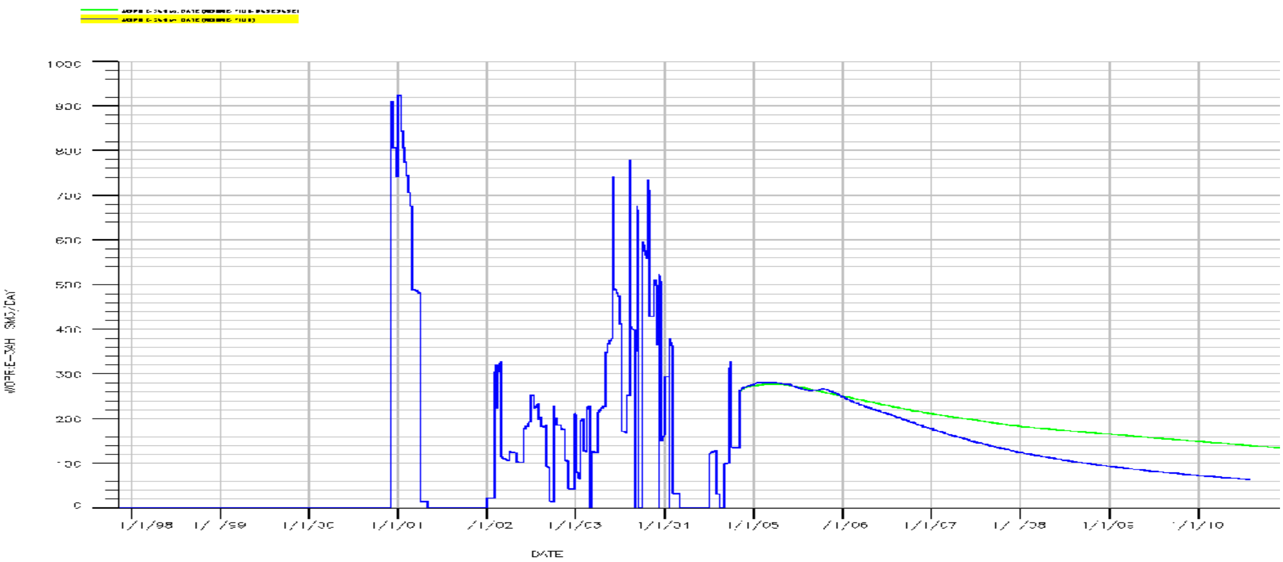
The total production from the field in 2010 is 13000 Sm3 higher for this case compared to the base case. This is an increase in oil recovery of 0,015 %.

d) F-3H: Old bore still injecting

The 3D model shows the same as for the example above. The oil in the left part of the segment is removed. On the other hand, the plots of production rates from the two production wells show something else.

Figur 30 Production rates E-2H, case 3d

The production rate from E-2H is approximately the same as for the base case (green), except from a little peak in 2005.

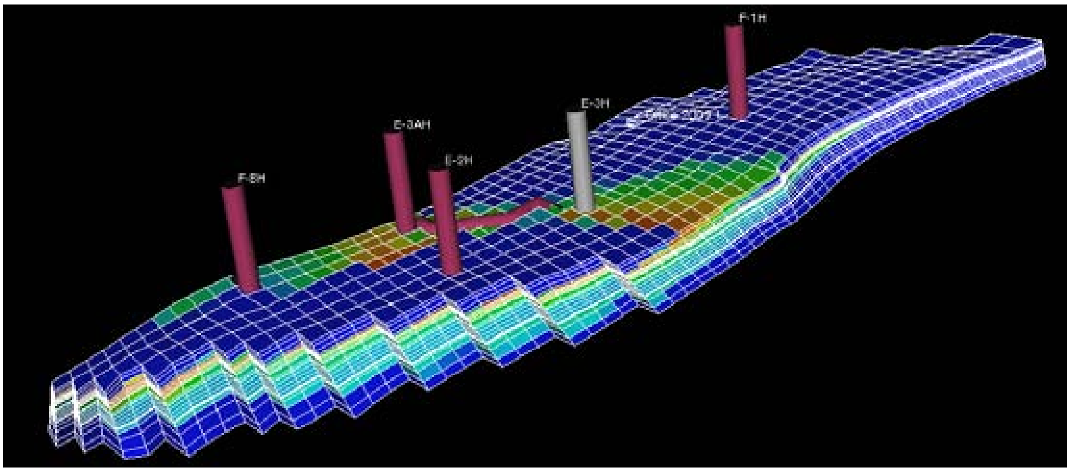


Figur 31 Production rates E-3AH, case 3d

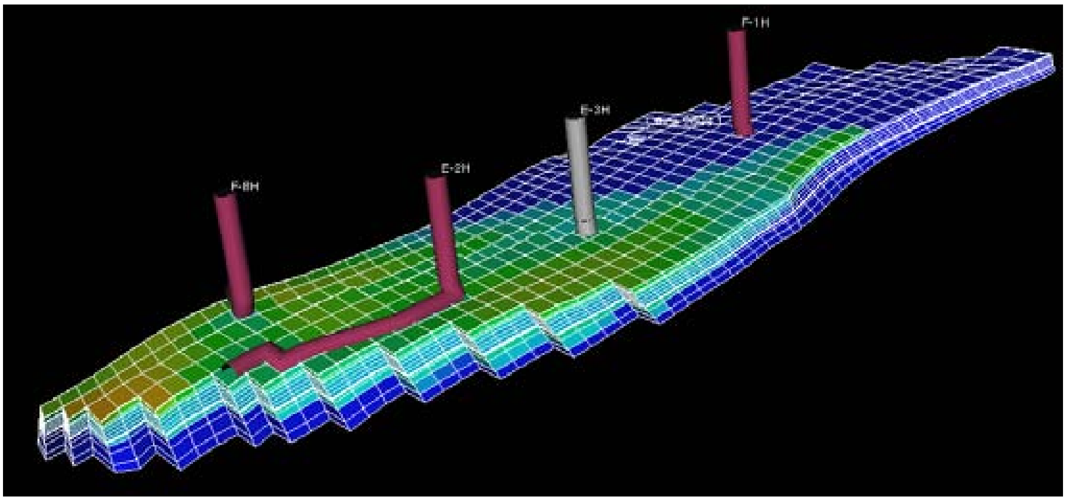
E-3AH has a lower production rate for the new case compared to the base case. The total oil production from this case is therefore lower than the base case, and there is no economical profit in sidetracking the well F-3H and injecting in both bores.

Case 4: Re-completion

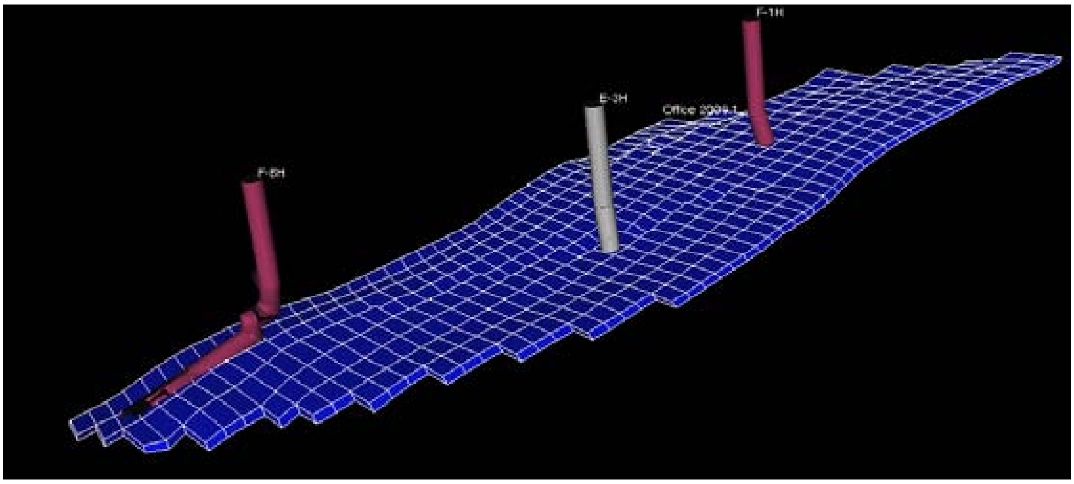
The figures below are showing the 3D model from Eclipse Office, layer 1, 9 and 21.



Figur 32 3d modell, case 4, layer 1



Figur 33 3D model, case 4. layer 9

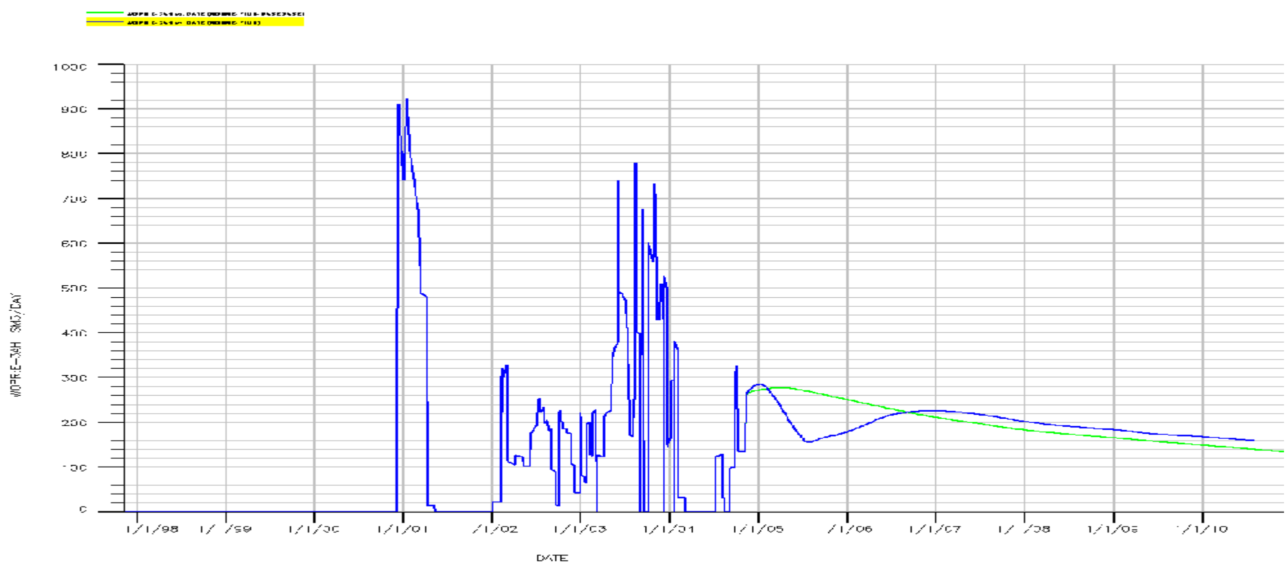


Figur 34 3D model, case 4, layer 21

The well F-3H has now been re-completed with a horizontal part towards the left part of the E-segment, as you can see from the figure of layer 21. The base case left a lot of oil in this part of the segment. Also for this case, a lot of the oil is being removed compared to the base case.

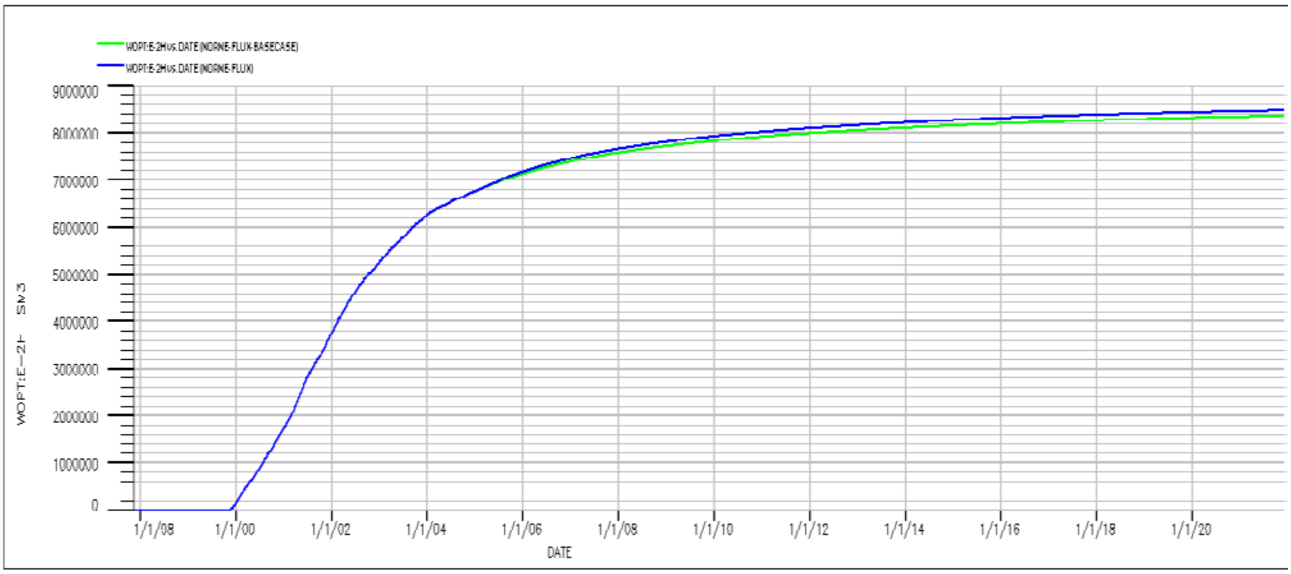
Figur 35 Production rates well E-2H, case 4

The plot above is showing that the oil production from E-2H is increasing after the injection well is re-completed, compared to the base case. The situation for E-3AH is shown in the plot below.



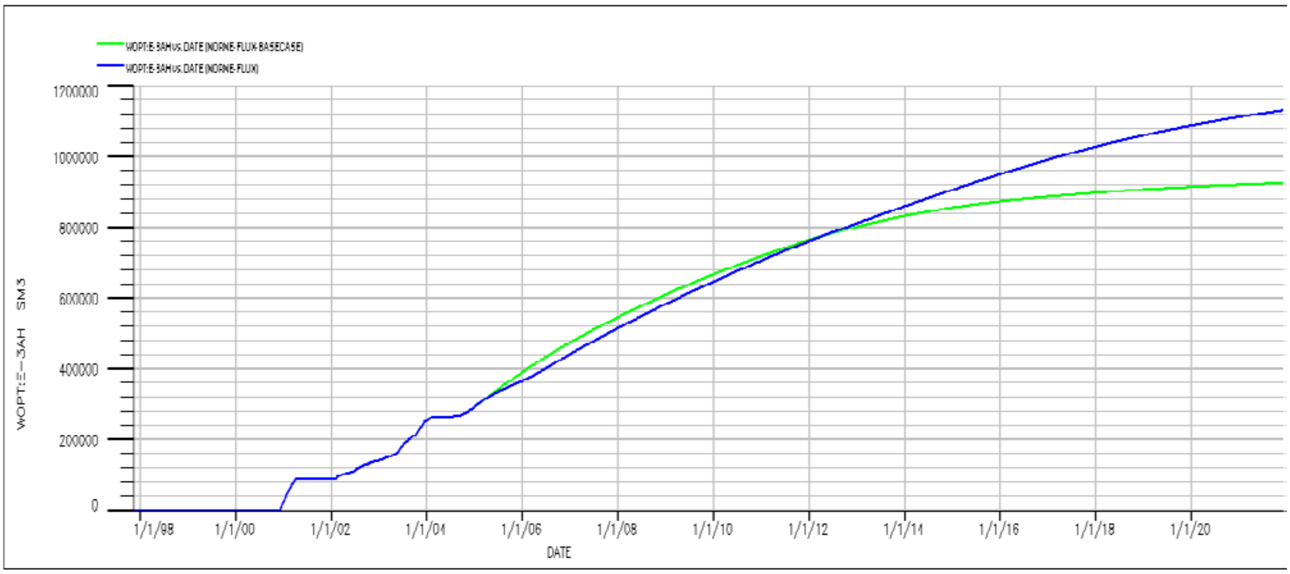
Figur 36 Production rates well E-3AH, case 4

The plot shows that the production rate from this well is decreasing just after the well has been re-completed. In 2006 this turns, and the well is producing with a higher rate compared to the base case, and this is the situation at least until 2010 as this plot shows. We therefore tried to simulate the cases until 2021 to see if there is a possibility that the total production is increasing for the new case.



Figur 37 Total production well E-2H, case 4

This plot is showing the total production from well E-2H, and the production is higher for the new case (blue) than for the base case (green) from 2005 and until 2021.

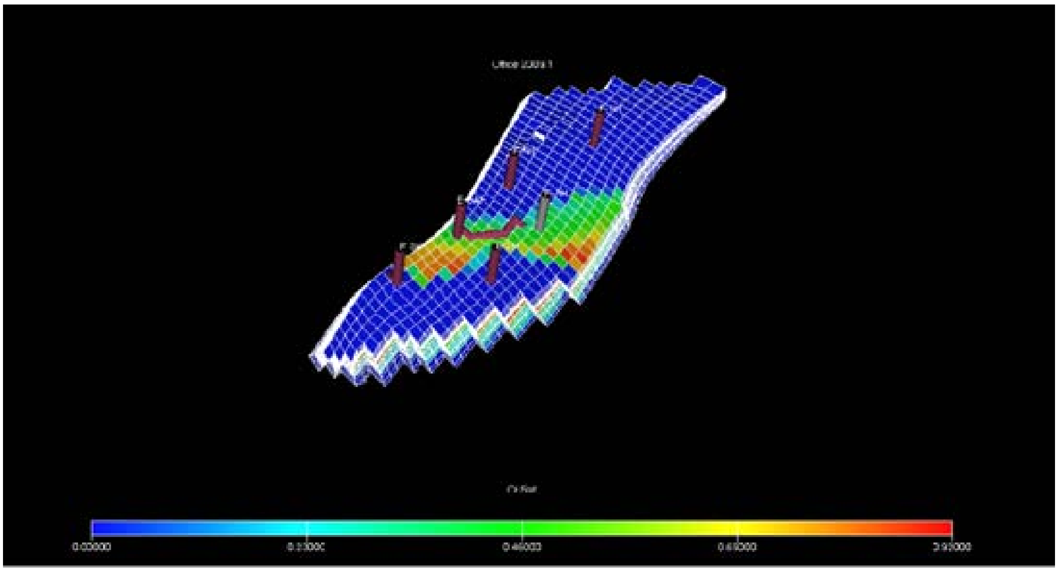


Figur 38 Total oil production well E-3AH, case 4

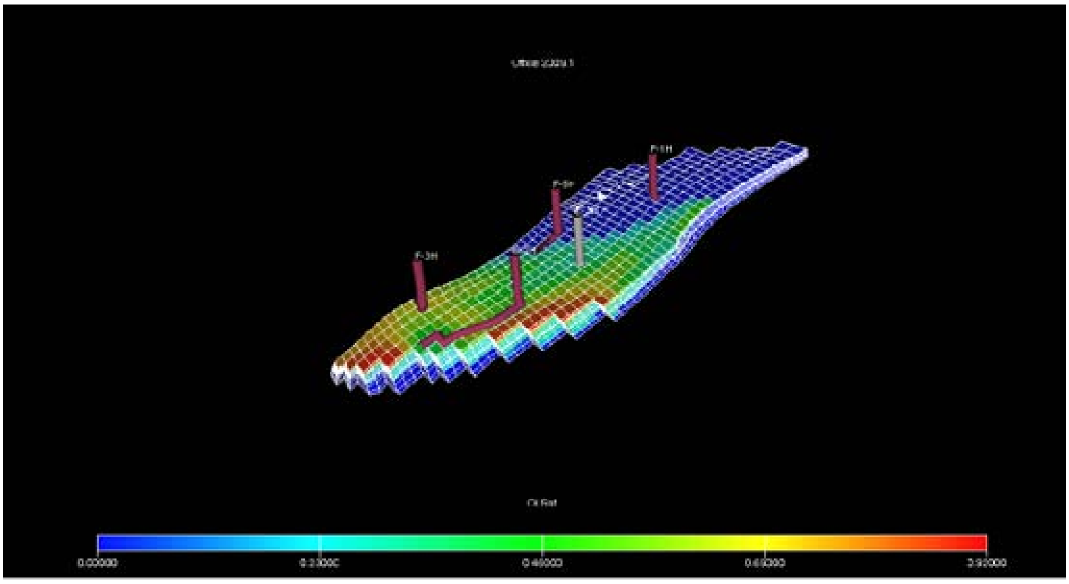
This plot shows the total oil production from well E-3AH until 2021. This is an interesting plot, because you can see that the total production from the new case gets higher than the total production from the base case in 2012. In 2021, both wells together have produced about 20 000 Sm3 more for the new case than for the base case. The total oil production from the field is approximately 88 million Sm3, so this is an increase in the oil recovery by about 0,02 %.

Case 5: New wells

A new horizontal well was installed near E-3AH in order to push the oil up from the lower layer towards the production well E-3AH. The figures below are 3D models showing the new well and the oil saturation in layer 1 and 9.



Figur 39 3D modell case 5, layer 1

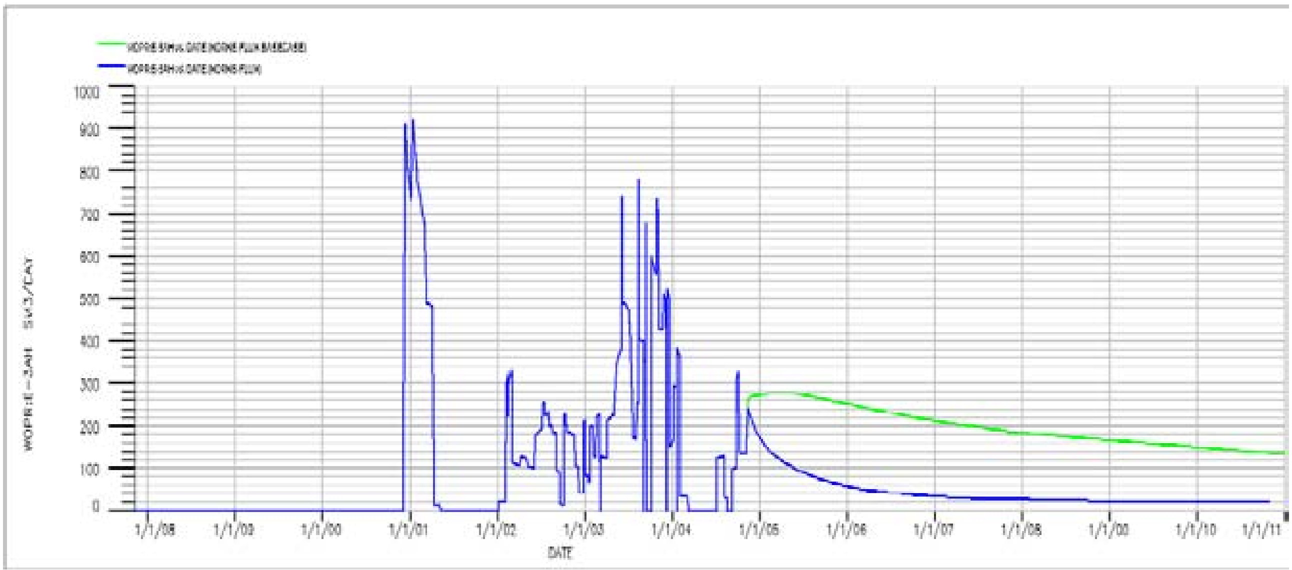


Figur 40 3D model case 5, layer 9

The results obtained showed the following results.

Figur 41 Production rates well E-2H, case 5

This plot shows the production rate from E-2H, where the blue line is the new case, and the green line is the base case.



Figur 42 Production rates well E-3AH, case 5

This plot shows the production rate from E-3AH. Both figures show that installation of this well has no increase in the oil production as compared to base case. In order to get good production, the injection well and the production well must be modified at the same time to get some optimized results.

9. Economic Evaluation

Net present value

To decide whether a project is profitable or not, the net present value has to be calculated. We have used the given excel spreadsheet to do these calculations. The net present value of a project is a measure of how much a future investment is worth today. The calculations are done by use of a discount rate for future in- and outgoing cash. The discount rate can be seen as a price of time, it is a disadvantage to bind the money in a project instead of investing them in something else [17].

An investment will be profitable if the net present value of the profit is higher than the net present value of the investment costs [17].

$$NPV = \sum_{t=0}^{t} \frac{X_t}{(1+r)^t}$$

In this formula, r is the discount rate, t is the time period (year) and X_t is the cash flow in period t. The cash flow is defined as the income minus the costs and investments.

Numbers and prices

The discount rate (7%), increase in price (2,5%), dollar's exchange rate, oil price and taxes are given. The spreadsheet we used is attached (given by Statoil).

The price of a new well is set to 250 – 350 million NOK, and for a sidetrack or re-completion of a well 150 – 200 NOK [7]. In the spreadsheet we used 350 and 200 Million NOK.

Results

The table below shows the total production and net present value for the best example in each case.

	Total oil production [Sm^3]	NPV before taxes [MNOK]	NPV after taxes [MNOK]
Case 1	87000000	75336	19587
Case 2	87203400	82181	21367
Case 3	87013000	75159	19539
Case 4	87020000	75171	19542
Case 5	86949200	81079	21076

Case 2, changing the injection rates gives the highest net present value.

Discussion

The income is based on oil price and the dollar’s exchange rate, two parameters that are constantly changing and difficult to predict. The oil price is dependent on many factors. Increased prosperity in highly populated countries as China and India has made the oil demanded, and the price of it increases. On the other hand, different industries are very dependent on each other, and an economic decline in for example the car industry will affect the oil price. The economic crisis the last years is an example of this. The dollar’s exchange rate varies in the same way, and is in our case dependent on the economic growth or decline in Norway and USA.

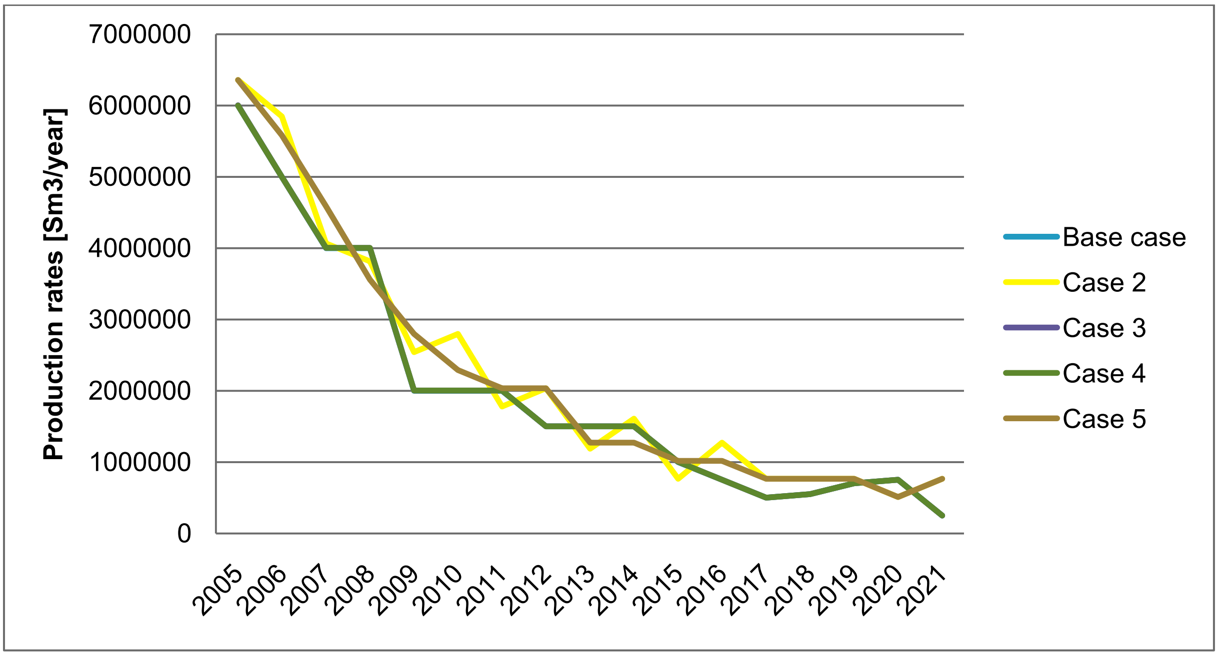
In the table above, you can see that case 5 is producing less oil than the other cases, but still has the second highest NPV. This may be because this case has the highest oil production is the last years compared to the other cases.

10. Conclusion

Our results show that we will increase the oil recovery most by just changing the injection rates, case 2. Reducing the rates can increase the recovery with 0,23 %, or 203400 Sm^3, compared to the base case. This is also the case that gives the best NPV.

We can also increase the recovery by re-completion or sidetracking of the injection well F-3H. The increase in recovery is about 0,02% for these cases, much lower than for case 2. The NPV is also lower because of the drilling costs. Our simulation results show that we will not enhance the oil production by sidetracking or re-complete F-1H. This well is placed quite far from the production wells and the zones in the segment that contains most of the oil. It is placed there to keep the pressure up in that part of the segment, avoiding flow of hydrocarbons in that direction. Injecting more water in this part of the field will therefore increase the pressure further, but it will not result in increased oil recovery.

A new injection well will decrease the total production of oil in 2021, but might increase the field's life time. This case has much higher production rates than the rest of the cases in the last years of our simulation, and therefore the second highest NPV. This shows that case 5 might be an alternative if the field is planned to produce beyond 2021.



Figur 43 Production rates

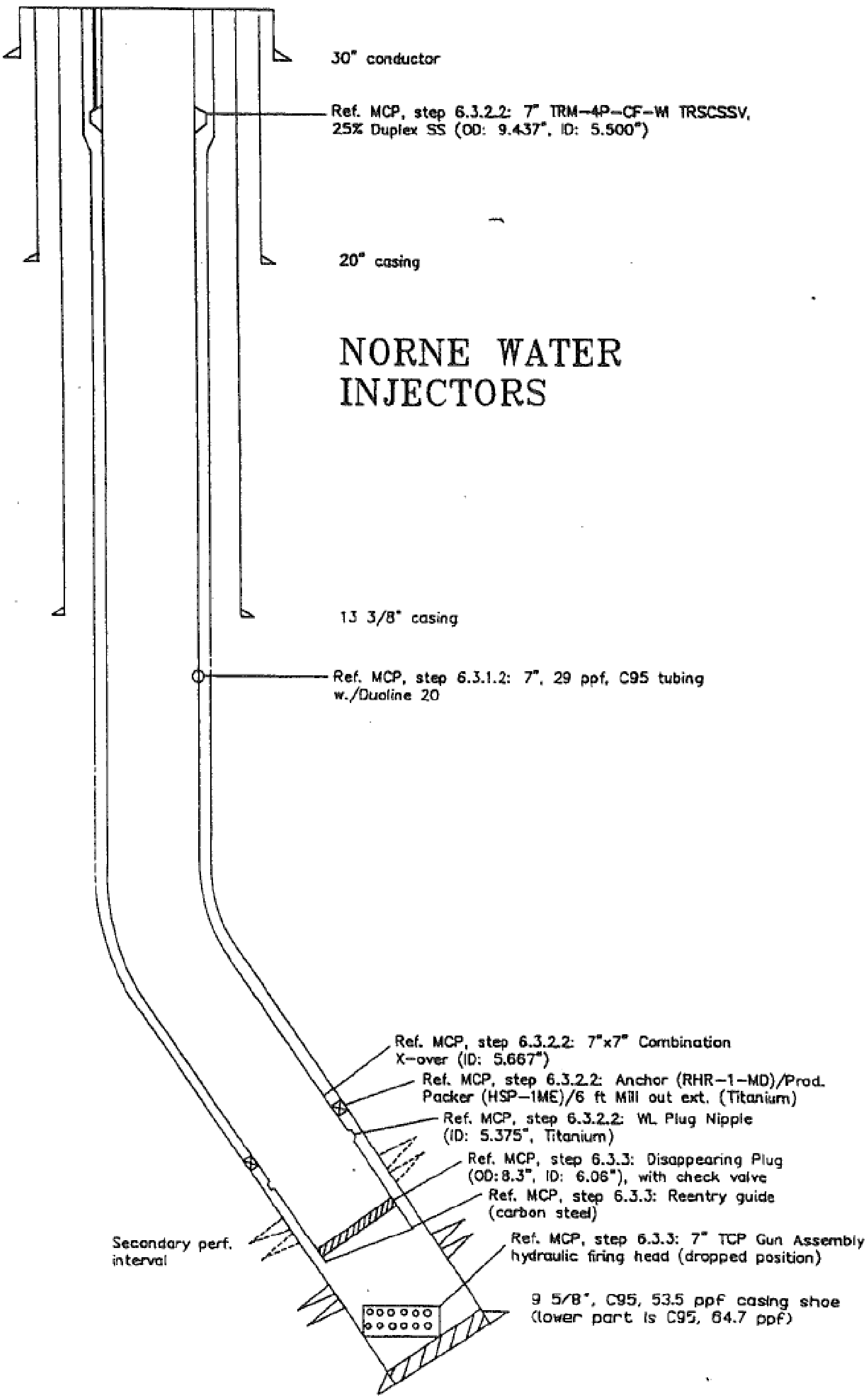
The increase in oil recovery is 0,23 %. This seems like a very small number, but it is actually some barrels of oil, and a lot of money. This recovery factor could be optimized if we had been working with both injection and production wells at the same time.

11. References

1. Statoil: www.statoil.com
2. Norne Management Plan 2001
3. Baker Hughes: http://www.bakerhughesdirect.com
4. Halliburton: www.halliburton.com
5. Schlumberger: www.slb.com
6. Directional Drilling Textbook - T-A. Inglis
7. Lecture notes “Subsea production systems”, spring 2010, by Sigbjørn Sangesland
8. Enhanced oil recovery 1: Fundamentals and analysis, SPE
9. Ahmed,Tarek: Reservoir engineering handbook, third edition
10. http://en.wikiversity.org/wiki/Enhanced_oil_recovery
11. Drilling and completion of subsea wells, Sigbjørn Sangesland, NTNU, 2008.
12. Lecture notes in “formation mechanics” autumn 2009, Sand production by Erling Fjær.
13. Introduction to subsea production technology, Sigbjørn Sangesland and Michael Golan, 1994.
14. Lecture notes in “reservoir recovery techniques”, 2009, by John Kleppe.
15. http://www.epmag.com/resources/images/archives/INTEQ1.jpg
16. http://oilgasglossary.com/recompletion.html
17. http://www.offshore-technology.com/projects/mensa/images/mensa6.jpg

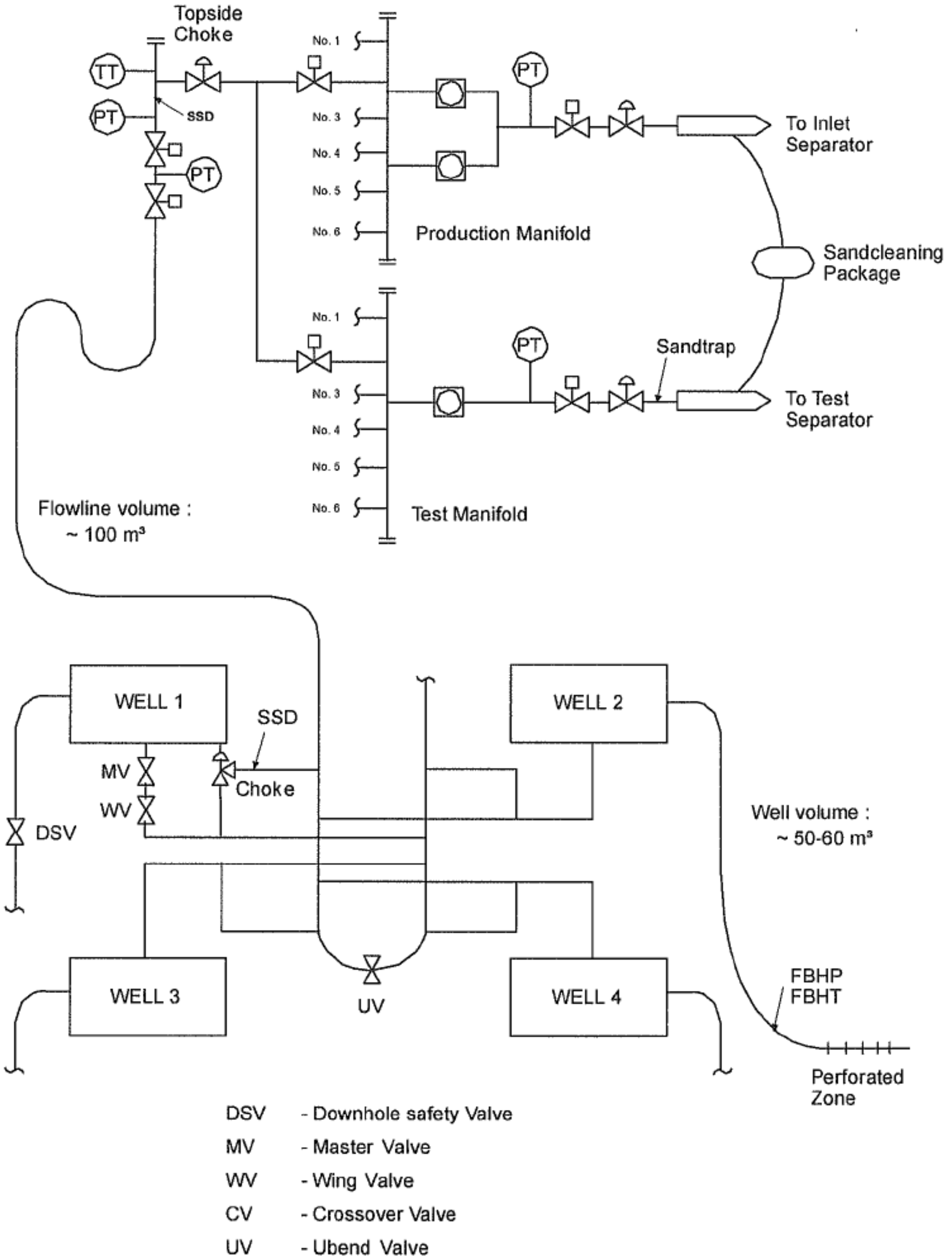
12. Attachments

Norne water injector:



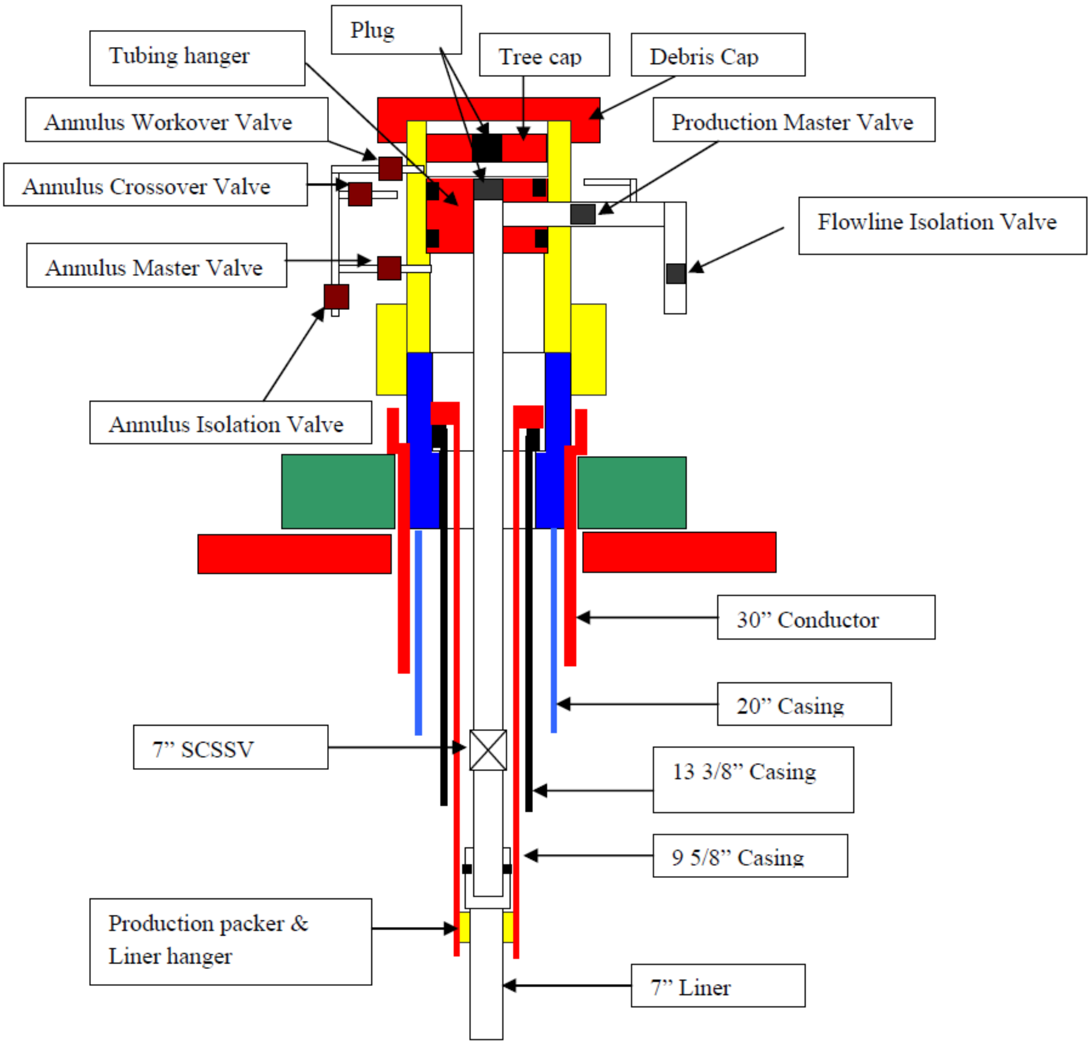
Figur 44 Norne water injector [2]

Norne template:



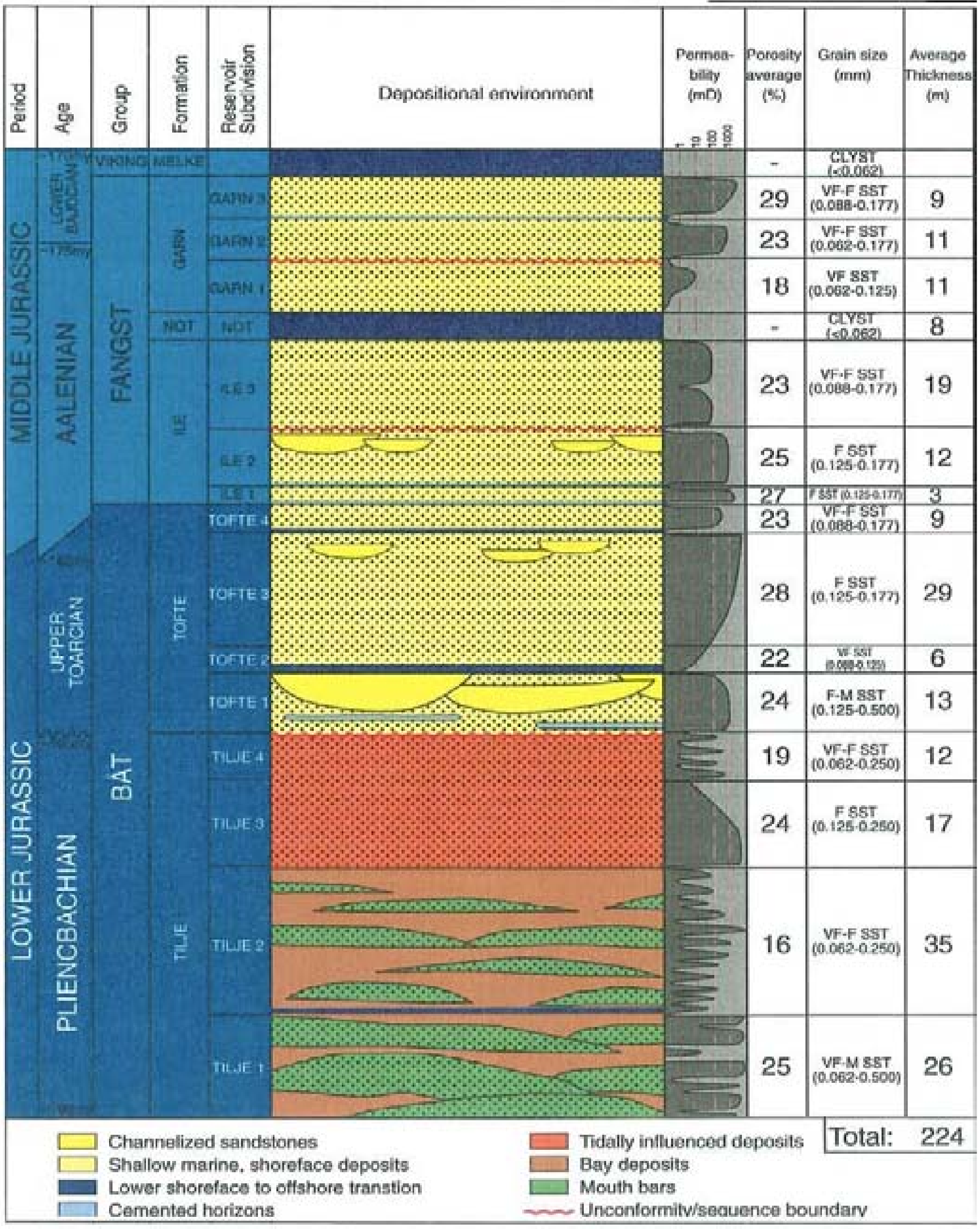
Figur 45 Norne template [2]

Horizontal x-mas tree:



Figur 46 Horizontal x-mas tree [7]

Norne geology:



Figur 47 Geology [1]

Spreadsheet:

Resultat						
NPV MNOK 05	P10		P50		P90	
	Før skatt	Etter skatt	Før skatt	Etter skatt	Før skatt	Etter skatt
Inntekter	0	0	75 371	19 597	0	0
Investeringer	0	0	-350	-95	0	0
Driftskostnader	0	0	0	0	0	0
Sum	**0**	**0**	**75 021**	**19 501**	**0**	**0**

Alternative beregninger P50 (må oppdateres)	Før skatt	Etter skatt
NNV $16/fat	0	0
NNV $40/fat	0	0
NNV 20% inntektsøkning	0	0
NNV 20% inntektsreduksjon	0	0

Oppdater

Lokasjon	
Norne/ Svale	x
Stær	

Produksjon Sm3/ år	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
P10 - produksjon																					
P50 - produksjon	6000500	5000550	4000750	4000950	2001150	2001300	2001450	1501625	1501625	1501500	1001450	751350	501300	551200	701200	751100	251000				
P90 - produksjon																					

Riggbruk - NB! tusen $	2005
Riggrate pr. dag i $K	
Andre dagrate kostnader i $K	
Antall dager	

Investeringer - mill. kr.	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Investering 1																					
Investering 2	350																				
Investering 3																					

Driftskostnader - mill. kr.	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Driftskostnad 1																					
Driftskostnad 2																					
Driftskostnad 3																					

Figur 48 Statoil spreadsheet used in economic evaluation

Example of code to define new injection wells:

```
DATES
1 'JUL' 2005 /
/

WELSPECS
   'F-5H'  'MANI-F'  6  57 1*     'WATER' 7* /
/

COMPDAT
-- WELL    I   J   K1  K2       Sat.     CF      DIAM      KH SKIN ND      DIR   Ro
   'F-5H'  7  56   5   5   'OPEN' 1*   3.427    0.216   328.264 2*     'Z'   18.296 /
   'F-5H'  7  55   6   6   'OPEN' 1*   3.391    0.216   325.229 2*     'Z'   18.420 /
   'F-5H'  7  54   7   7   'OPEN' 1*   4.284    0.216   410.644 2*     'Z'   18.352 /
   'F-5H'  7  53   7   7   'OPEN' 1*   4.241    0.216   407.082 2*     'Z'   18.498 /
   'F-5H'  7  52   8   8   'OPEN' 1*   9.387    0.216   902.750 2*     'Z'   18.667 /
   'F-5H'  7  51   8   8   'OPEN' 1*  101.082   0.216  9741.795 2*     'Z'   18.876 /
   'F-5H'  7  50   9   9   'OPEN' 1*   4.716    0.216   454.519 2*     'Z'   18.880 /
   'F-5H'  7  49   9   9   'OPEN' 1*   1.659    0.216   160.153 2*     'Z'   19.011 /
   'F-5H'  7  49  10  10   'OPEN' 1*  123.532   0.216 11909.055 2*     'Z'   18.905 /
   'F-5H'  7  49  11  11   'OPEN' 1*   23.785   0.216  2299.001 2*     'Z'   19.163 /
   'F-5H'  7  49  12  12   'OPEN' 1*   9.266    0.216   897.482 2*     'Z'   19.375 /
   'F-5H'  7  49  13  13   'OPEN' 1*   2.873    0.216   278.581 2*     'Z'   19.470 /
   'F-5H'  7  49  14  14   'OPEN' 1*  213.422   0.216 20730.869 2*     'Z'   19.660 /
   'F-5H'  7  49  15  15   'OPEN' 1*   22.442   0.216  2174.958 2*     'Z'   19.427 /
   'F-5H'  7  49  16  16   'OPEN' 1*   22.435   0.216  2194.387 2*     'Z'   20.384 /
   'F-5H'  7  49  17  17   'OPEN' 1*   16.226   0.216  1590.031 2*     'Z'   20.581 /
```

Example of code to change rates:

```
/

WCONINJE
   'C-1H'     'GAS'  1*    'RATE' 1416529.875  5* /
   'C-2H'    'WATER'  1*    'RATE'  10560.200  5* /
   'C-3H'     'GAS'  1*    'RATE' 3854904.000  5* /
   'C-4H'    'WATER'  1*    'RATE'   4699.800  5* /
   'F-1H'    'WATER'  1*    'RATE'  6000.200  5* /
   'F-2H'    'WATER'  1*    'RATE'   3979.600  5* /
   'F-3H'    'WATER'  1*    'RATE'   5000.001  5* /
   'F-5H'    'WATER'  1*    'RATE'   5000.001  5* /
/

 RFTPLT
 'F-5H'     'YES'     'YES'  1* /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /


DATES
 1 'AUG' 2005 /
/
```