2011

Technical Report
Challenge 6

NTNU – Trondheim
Norwegian University of
Science and Technology

Ahmed Awol Tebarek, Brigite Caleca Cabenguela, Farid Abadli, Håkon Eidem Christiansen and Øystein Texmo Prytz
NTNU
13.04.2011

Table of content

1 Abstract

Oil production is the single greatest income source in Norway. Most of the large oil fields in the Norwegian sector have already been developed. The most important source of oil in the future is from smaller fields. Often pockets of oil close to the larger, developed fields. These pockets can only be drained with new technology which can reduce the cost of developing these small reservoirs.

To days' focus is to increase the recovery of oil from all the fields in production and the new fields coming on line. In this challenge we have plotted the inflow from well A-32CT6. We have used a segmented well in eclipse which is able to record the flow at the segments locations. The result is used to find out how much oil is produced from different locations, which zone is most productive and where the water breaks through first. We have also made a Sensitivity case for comparison.

The second part of the report is focusing on how to make flow measurements downhole in situ. Tools from different vendors are presented along with the technology they are based on, their use and an estimate of costs.

Based on our results and the information about tools we have made some recommendations on how to resolve the uncertainty of where to flow is coming from in the well, and on cost and possible gains of data gathering in the Gulltopp well.

2 Introduction

Petroleum in an unrefined state has been utilized by humans for over 5000 years. Oil in general has been used since early human history to keep fires ablaze, and also for warfare. Petroleum is a naturally occurring liquid found in rock formations. It consists of a complex mixture of hydrocarbons of various molecular weights, plus other organic compounds. It is generally accepted that oil, formed mostly from the carbon rich remains of ancient plankton after exposure to heat and pressure in the Earth's crust over hundreds of millions of years. Over time, the decayed residue was covered by layers of mud and silt, sinking further down into the Earth's crust and preserved there between hot and pressured layers, gradually transforming into oil reservoirs.

An early petroleum industry was established in the 8th century in Baghdad, Iraq and evolved in to the modern history when Imperial Russia produced 3,500 tons of oil in 1825, the starting of oil drilling in the United States in 1859, the establishments of oil fields in the 1920's in many countries including Canada, Poland, Sweden, the Ukraine, the United States, and Venezuela and until the recent histories of oil exploration in North sea which lead to the first well drilling in Norway in the summer of 1966 which took of the industry to an important part of the world's history.

From the first unsuccessful drilling in 1966, Norwegian oil exploration went on adventure in 1969 when Ekofisk was discovered. Production from the field started on 15 June 1971, and in the following years a number of major discoveries were made. Foreign companies dominated exploration off Norway in the initial phase, and were responsible for developing the country's first oil and gas fields until Statoil established in 1972.

Since the petroleum industry started its activities on the Norwegian continental shelf (NCS), enormous sums have been invested in exploration, field development, transport infrastructure and land facilities. In spite of more than 40 years of production, only around 40 percent of the total expected resources on the NCS have been produced. Norwegian oil production has remained at plateau level of about 3 million barrels per day since 1995. Production (including NGL) reached a peak in 2001 of 3.4 million barrels per day. In 2009, the oil production had decreased to 2.4 barrels per day, and is expected to shrink further in the years to come.

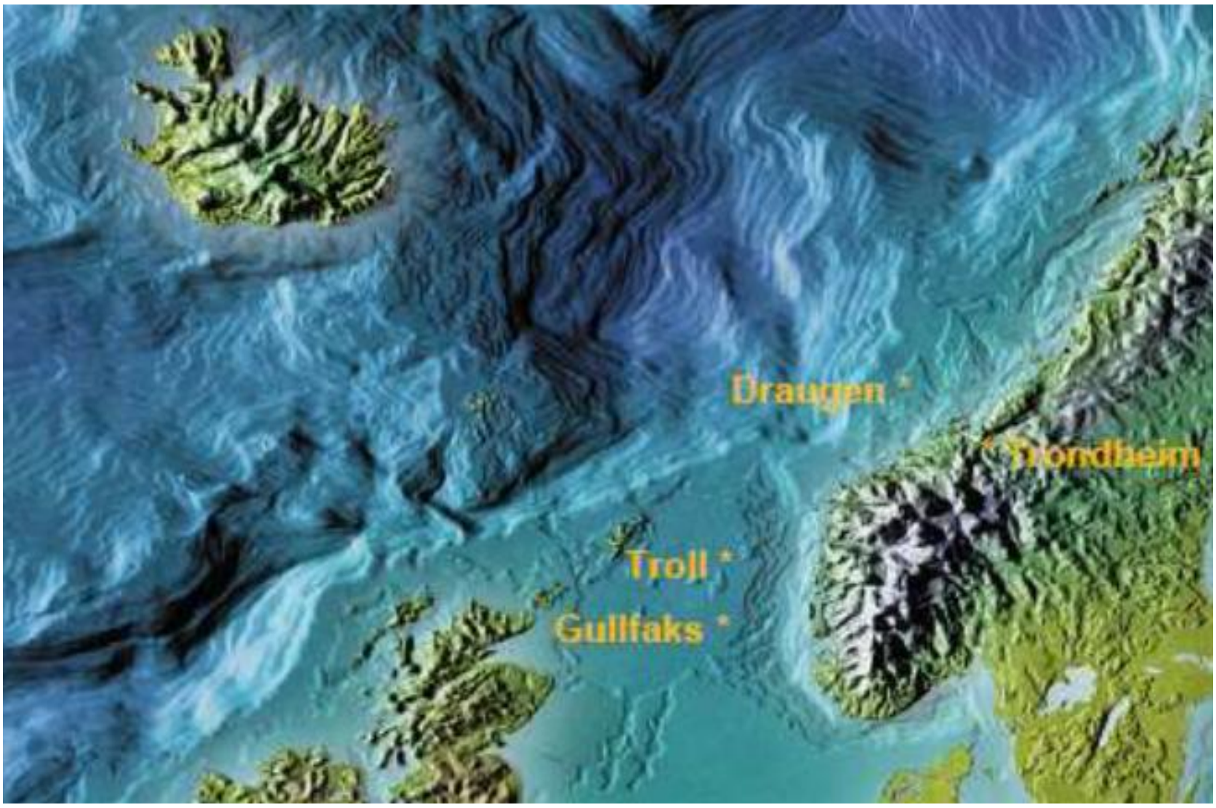
However, because of increasing gas production, total petroleum production is likely to grow in the coming years. From representing approximately 43 percent of the total Norwegian petroleum production in 2009, gas production will probably increase its share to more than 50 percent in 2013.

There have been a number of oil field explorations down the years and some of them are depleted and there are still quite a number of oil field producing at the moment. For example the Norne oil field, Grane oil ,Gyda Oil Field, Skirne gas field, Snorre oil field, Yme field , and Gullfaks oil field.

2.1 Gullfaks Main Field

Gullfaks is an oil and gas field in the Norwegian sector of the North Sea operated by Statoil. It was discovered in 1979, in block 34/10, at a water depth of 135 meters. The initial recoverable reserve is 2.1 billion barrels (330×10^6 m3), and the remaining recoverable reserve in 2004 is 234 million barrels (37.2×10^6 m3). This oil field reached peak production in 2001 at 180,000 barrels per day (29,000 m3/d). The Gullfaks reservoirs consist of Middle Jurassic sandstones of the Brent Group, and Lower Jurassic and Upper Triassic sandstones of the Cook, Statfjord and Lunde formations. The reservoirs are 1700 - 2000 meters below the sea level. The drive mechanisms are water injection, gas injection or water/alternating gas injection (WAG). The drive mechanism varies between the drainage areas in the field, but water injection constitutes the main strategy.

Oil is exported from Gullfaks A and Gullfaks C via loading buoys to shuttle tankers. The part of the rich gas that is not reinjected is sent through the export pipeline to Statpipe for further processing at Kårstø and export to the Continent as dry gas. Production from Gullfaks is in the decline phase. Efforts are being made to increase recovery, partly by locating and draining pockets of remaining oil in waterflooded areas, and partly through continued massive water circulation. Implementation of a chemical flooding pilot will be considered in 2010. A new project has also been initiated to evaluate necessary facility upgrades for lifetime extension of the field towards 2030.



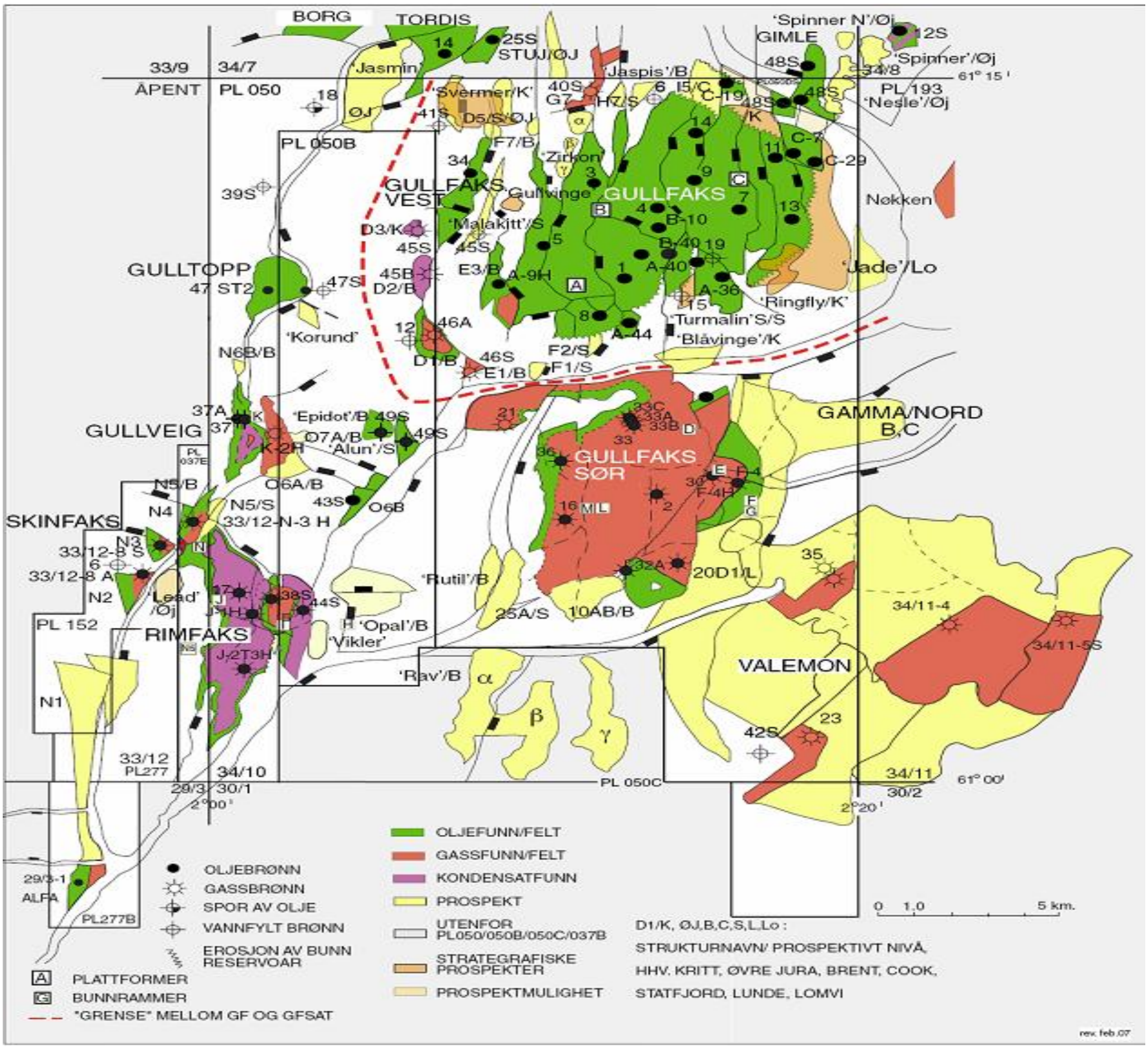
Figur 1 Map of seabed around Norway

In addition to Gullfaks main field there are six satellite fields: Gullfaks Sør, Rimfaks, Gullveig, Gimle, Gulltopp and Skinfaks . Production from the first three satellites started in 1998, while Gimle came on stream in 2005 and Gulltopp and Skinfaks in 2007. The reservoirs are similar for all fields in the Gullfaks area, but the satellite fields contain more gas than oil – often with a significant gas cap.

On the Betaridge a large aquifer is also present providing some pressure support. For the relative position of the satellite fields see Figure(1) below. In this report we will merely focus on one of the satellite field, Gulltopp. Gulltopp is almost ten kilometers long and almost completely horizontal. Never before has StatoilHydro drilled a well as complicated as the Gulltopp well on the Gullfaks field. The well provides the company with valuable knowhow and great revenues.

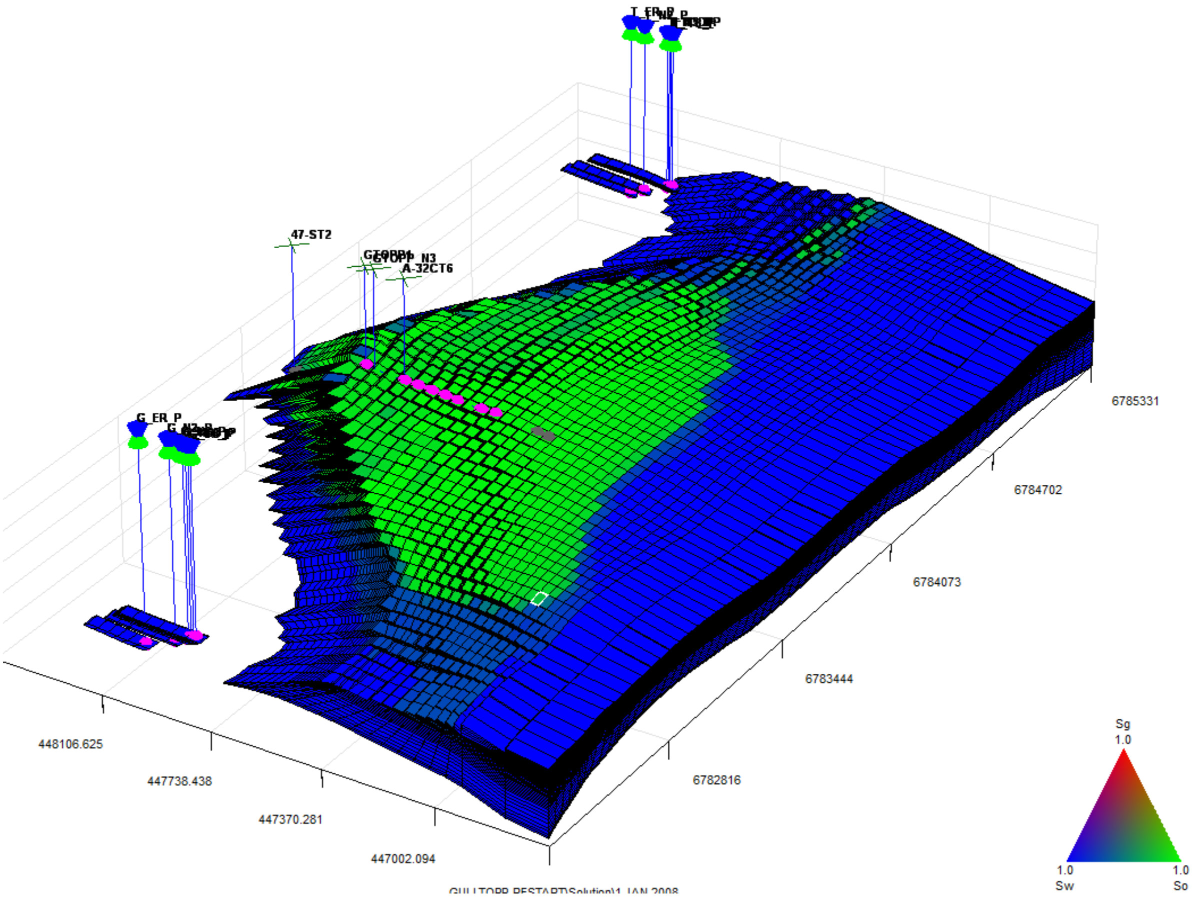
2.2 Gulltopp

“The Gulltopp structure is located along the Beta Ridge and lies 3-4 km north of Gullveig. The tilted fault block dips towards the west. The Gulltopp structure can be ascribed to an eastward protrusion of the main Beta Ridge fault. Late Jurassic Heather Formation shales provide both top and lateral seals.



Figur 2 Map of Gullfaks field and surrondings

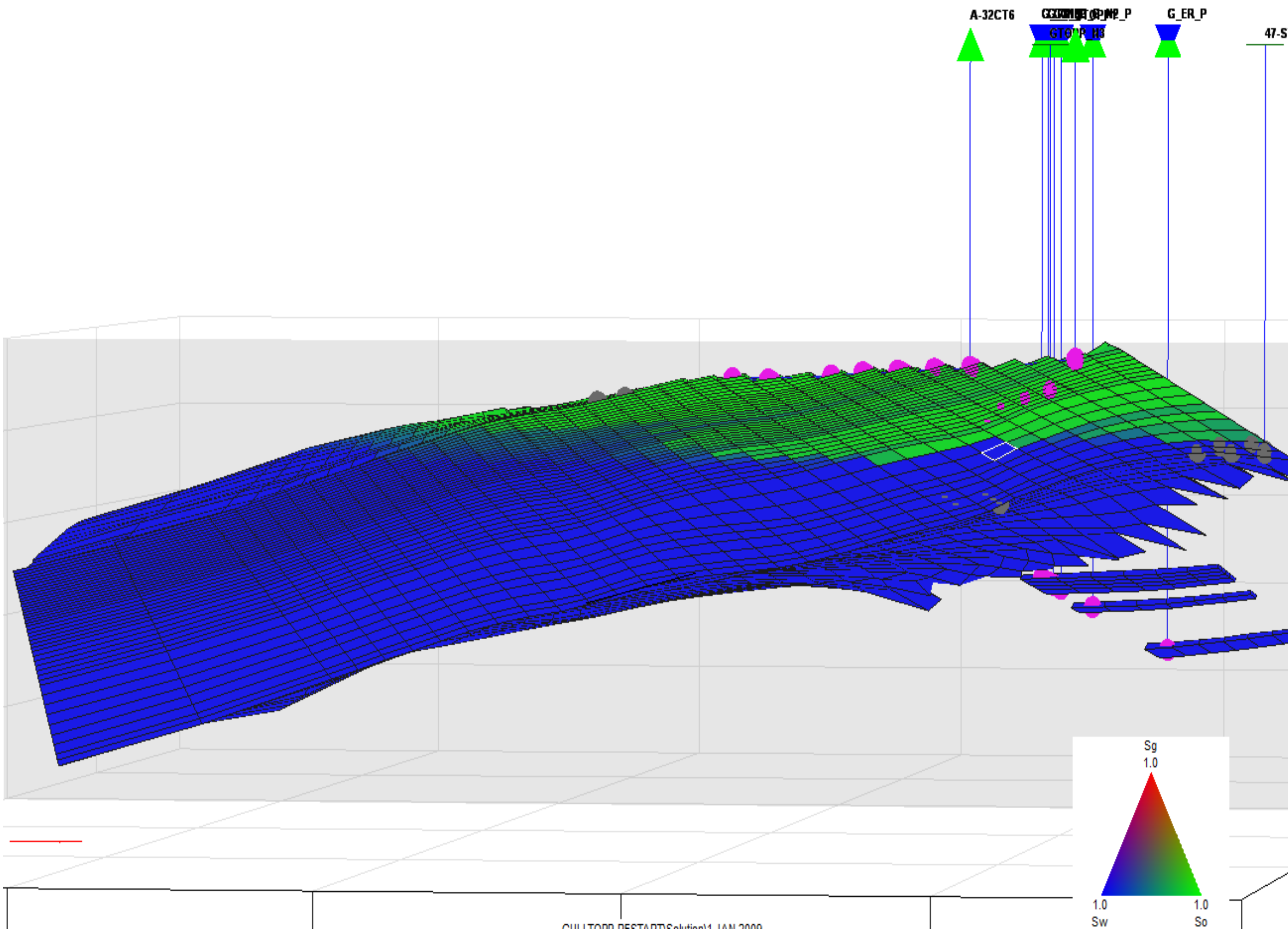
Oil was proven in the Brent Group by Well 34/10-47S/ST2 in the autumn of 2002. The Gulltopp structure is part of the Beta Ridge and lies 3-4 km north of Gullveig. The well encountered a thick Tarbert interval with excellent reservoir properties thicker and better Tarbert Formation than predicted, the absence of a gas cap and very favorable. PVT properties led to a great increase in the volume estimates in relation to expected volumes before drilling. The surface position of the well is favorable for reuse, and prior plans existed to enable the installation of a wellhead template in the future. Based on the positive results, the well has been temporarily plugged.



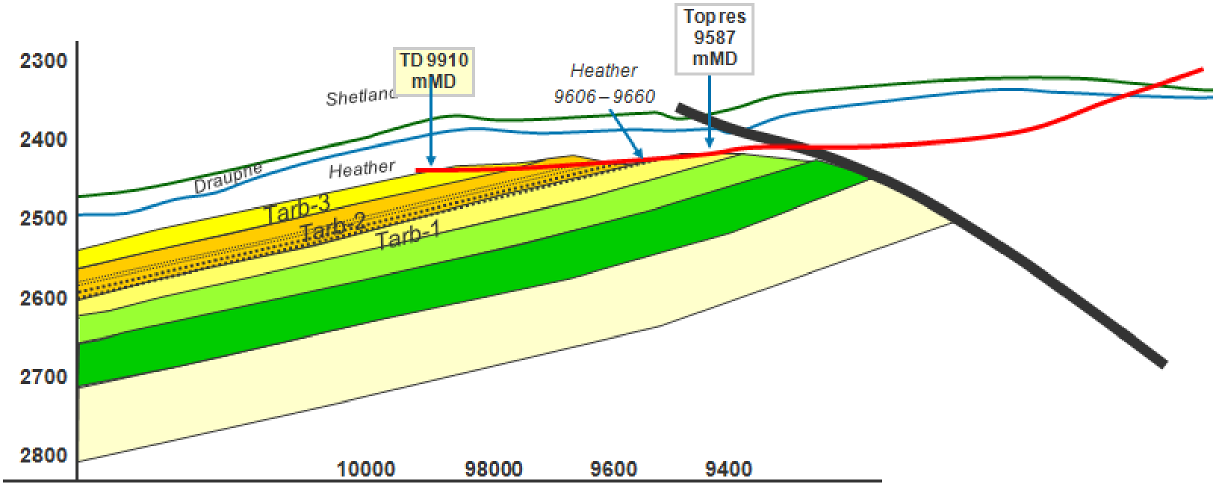
Figur 3 Gulltopp reservoir model

Tabell 1Reservoir quality and communication – Brent, Gulltopp

Reservoir parameters – Brent		Comments
Top structure (m MSL)	2,420	Considerably shallower(50-60 m) if not eroded
Datum (m MSL)	2,600	Approximately 67 m below OWC.
GOC (m MSL)	-	No free gas present in Well 34/10-47-ST2. Studies found that upflank gas was unlikely.
OWC (m MSL)	2,532.6	Petrophysical interpretation of log data from Segment O7 has an OWC at 2,507 m MSL
Pressure (bar)	327.5	Based on pressure logging in Well 34/10-47-ST2. Pressure at OWC (2,532.6 m MSL): 320.5 bar
Temperature (^{0}C)	-	-
Gas gradient (bar/m)	-	Pressure logging in 34/10-47-ST2 and petrophysical evaluation
Oil gradient (bar/m)	0.066	
Water gradient (bar/m)	0.103 [1)]	



Figur 4Well A-32CT6



Figur 5 Cross-section of A-32CT6

Well (A-32CT6) is in the Gullfaks A platform. The primary goal of this well is oil production from the Tarbert Formation, which contains approximately 80% of the volumes in place in Gulltopp. A subsequent sidetrack to the Ness Formation contributes to the total recovery. The plan is to complete the well using gas lift, which will be required when the water cut reaches 30-40%, and this was expected to occur after 3-4 years of production.

When the reservoir is penetrated, the pressure in the Tarbert Formation is expected to drop to approximately 70 bar below initial pressure as a consequence of production, mainly from Tordis, Gullveig and Gullfaks West. In the years ahead, improved recovery from Tordis and the Gullfaks Satellites is expected, which will further reduce the pressure in Gulltopp.

This has revived the wish to review the effect of injection in the Western Province. The well is a horizontal reservoir section at a depth of 2,450 m TVD MSL. Due to different pressures in Tarbert and Ness, and due to different oil/water contacts, the initial plan was to avoid opening the Ness Formation for production, in order to avoid the risk of early water breakthrough. Since then, the well path of A-32 CT6 has been raised to an even shallower level to avoid most of Ness and any problems relating to the coal horizons.

The well's 8½" x 9" section was drilled to 9,337 m MD. At this depth Statoil pulled out due topack-off tendencies and a sudden pressure loss of 80 bar. Since the BHA and 319 m of drill pipe had been lost in the hole, a cement plug was set and a new well track drilled. When inserting the 8 ½" x 9 ½" BHA to drill into the reservoir, the Eaton brake on the platform failed.

Due to repair work on the rig, it was decided to continue drilling A-32 CT6 in the beginning of 2007. However, in January 2007 a fire occurred in transformer room D11 on GFA, and it was decided not desirable to continue drilling in Gulltopp before the fire damage had been repaired. Sidetrack A-32 CT6, planned as a 2,370 m long two section sidetrack was drilled to 10,010 m MD. Production from Gulltopp as scheduled started in January 2007 at a start rate of 2,500 Sm3/Sd."

2.2.1 Source:

http://en.wikipedia.org/wiki/Petroleum_industry

http://www.ipt.ntnu.no/gullfaks/reservoir_managent_plan/Plan2007_english/2007_ch03_reservoir_description.pdf

http://www.ipt.ntnu.no/gullfaks/reservoir_managent_plan/Plan2007_english/2007_ch04_reservoir_management.pdf

3 Plot the inflow along the wellbore

We ran the data file from Statoil to get data to work with. We had to add some input to the summary file to get information from the segments. And because we were only interested in what happened on Gulltopp from 2008 and out, we made a restart file which showed the results from start-up of Gulltopp 9th of April 2008 until the simulation stopped in 2023.

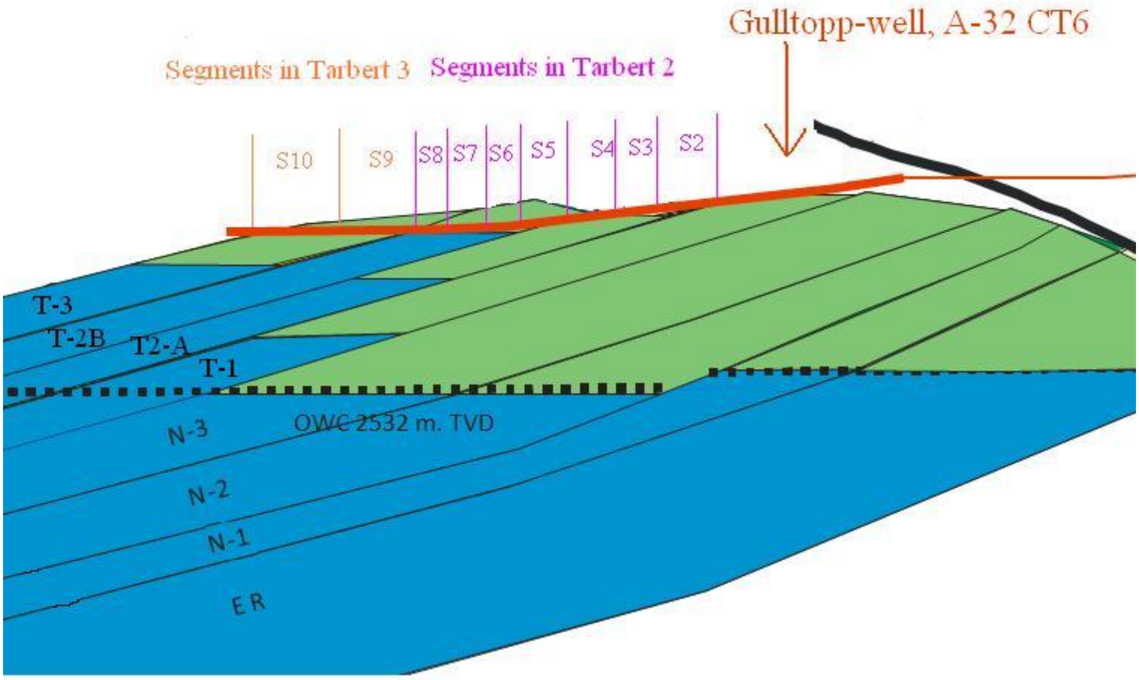
3.1 Segments

The segments are placed in series along the wellbore in the perforated interval of the well which is 38.4 % of the total length in the reservoir. The interval is divided into nine segments. Starting at the heel we find segment 2 and at the end of the interval we find segment 10. Each of the segments is of different lengths, but lies next to each other.

Using segments gives a more accurate simulation of inflow to the well. Segments are one-dimensional and have their own set of independent variables to describe the local fluid conditions. Each segment can be perforated in one or more grid blocks. In contraries to the default attribute which is blocks, you can decide where the well is located inside of the segments.

In blocks the well goes through the centre and that makes it difficult to simulate accurate reduction of the inflow due to the wells' placement in the reservoir. If the well is placed at the top of the reservoir, close to a no-flow boundary, with the intention of delaying water breakthrough, the reduced flow from the wells' boundary side is an important parameter to consider.

The SEGMENT-attribute records the total flow which pass trough were it is located in the well. To get the specific flow pattern from each segment we had to subtract the flow from higher numbered segments. Only the last segment shows data on its' own flow, and the first segment shows the cumulative flow from all the other segments.



Figur 6 Illustration of segment location

Tabell 2 Table of segment information:

WELLNAME AND SEG TYPE	SEG NO NO	BRN NO NO	MAIN INLET SEGMENT	SEGMENT OUTLET	SEGMENT LENGHT METRES	TOT LENGHT TO END METRES	RELATIVE DEPTH CHANGE METRES	T.V DEPTH AT END METRES
A-32CT6	1	1	2	0	0,0	0,0	2427,7	2427,7
	2		2	1	10,0	10,0	1,3	2429,0
	3		4	2	40,3	50,2	3,9	2432,9
	4		5	3	15,3	65,6	0,9	2433,7
	5		6	4	32,9	98,5	1,4	2435,1
	6		7	5	15,7	114,2	0,6	2435,7
	7		8	6	30,9	145,1	1,1	2436,8
	8		9	7	13,1	158,3	0,4	2437,3
	9		10	8	32,9	191,2	1,1	2438,3
	10		0	9	128,8	320,0	3,6	2442,0

Tabell 3Table of segments:

Sand	Segment
T2	2,3,4,5,6,7,8
T3	9, 10

We found the production data in the .RSM file and copied the numbers into excel. Then we subtracted the flow from the other segments and multiplied the rates with the adjacent time steps to get the production from that current time. The next step was to accumulate the production to find the total. We made the same procedure for each segment, for both oil and water production. After that we compared the total amount produced from all the segments with the total amount produced from the well, and with the initial cumulative production from segment 2.

These results gave us the basis to investigate which segments that were producing most of the oil and/or the water. Because the reservoir consists of different sands with different properties the water breakthrough will happen at different times in different segments. And early breakthrough time will affect the recovery in a negative way.

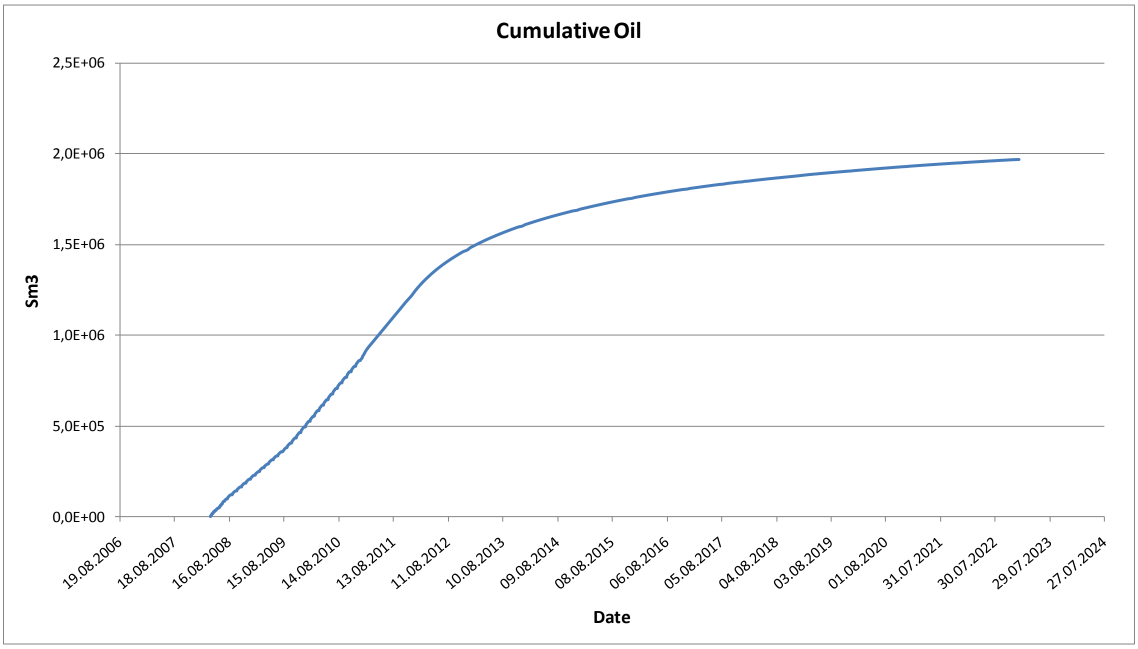
From our calculations and graphs in excel combined with the available graphs in S3GRAPH and OFFICE we could present the flow of oil and water from each segment of the well. From the graph of breakthrough times, the production graphs and the 3D simulation we could identify the layers which got early water breakthrough. We also determined the oil and water production from each segment.

In the segments description we found that there were only two of the segments that lies in Tarbert 3. The majority of the segments lie in Tarbert 2. The table below is showing the division of segments. We added the production from each segment to make a graph showing which zone is contributing the most.

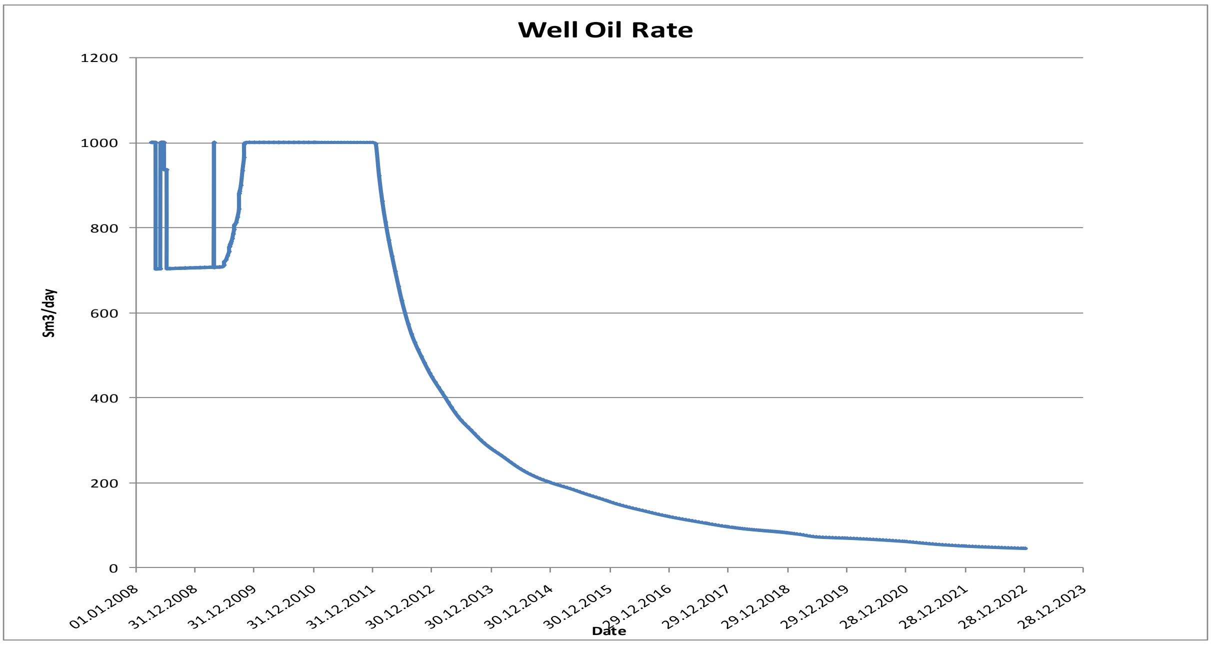
3.2 Base Case

3.2.1 Oil Production

The total oil production is limited to 1000 Sm3/day and the simulation tries to keep it this high for as long as possible. The plateau is sustained for over two years. When the water cut gets high the total flow from the well gets large, and the reservoir pressure drops fast. The large water production combined with high GOR leads to the sharp drop in oil production in 2012. The total amount of oil being produced over the lifetime is 1,97 MSm3



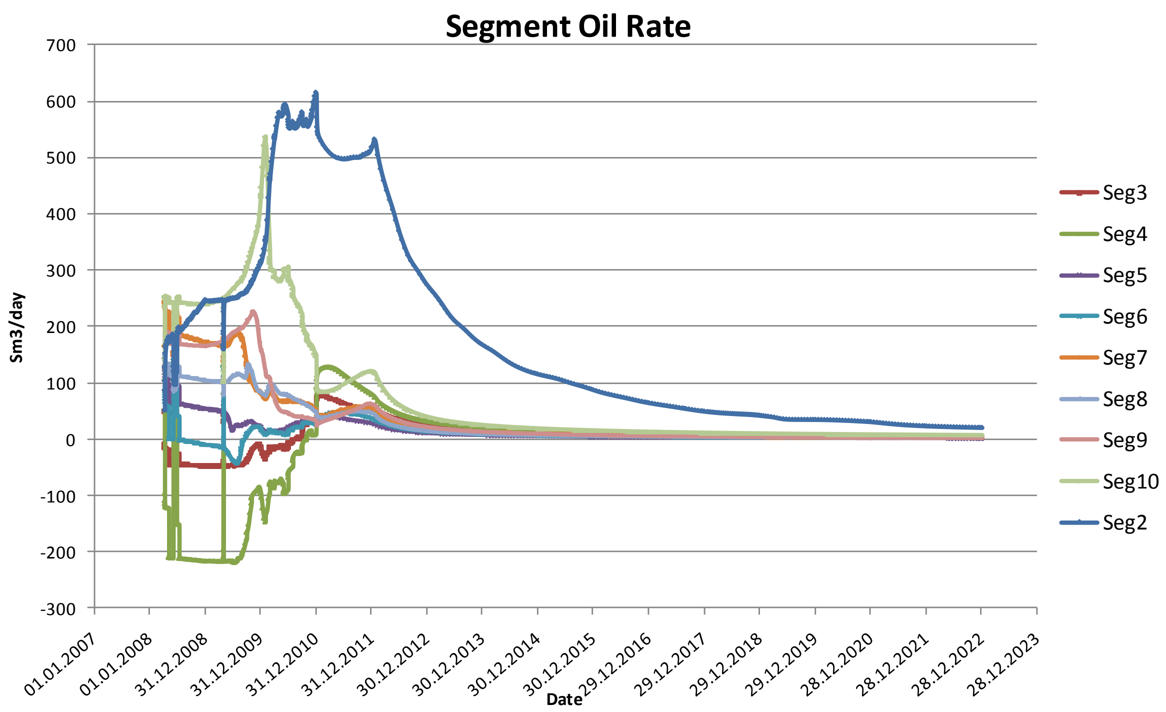
Figur 7 Cumulative Oil Production



Figur 8Well Oil Rate

3.2.2 Segment flow rate

We made a graph showing the production rate from each segment at every time. From the graph we can see that not all the segments are contributing to the total production in the same way. Most of the segments follow the same production pattern, but segment two is standing out from the others. Segment 2 has a production plateau of two years with a rate of about 550 Sm3/D. At the same time the others segments has a strong decline in production. Segment 3, 4 and 6 has a negative production rate in the first two years.

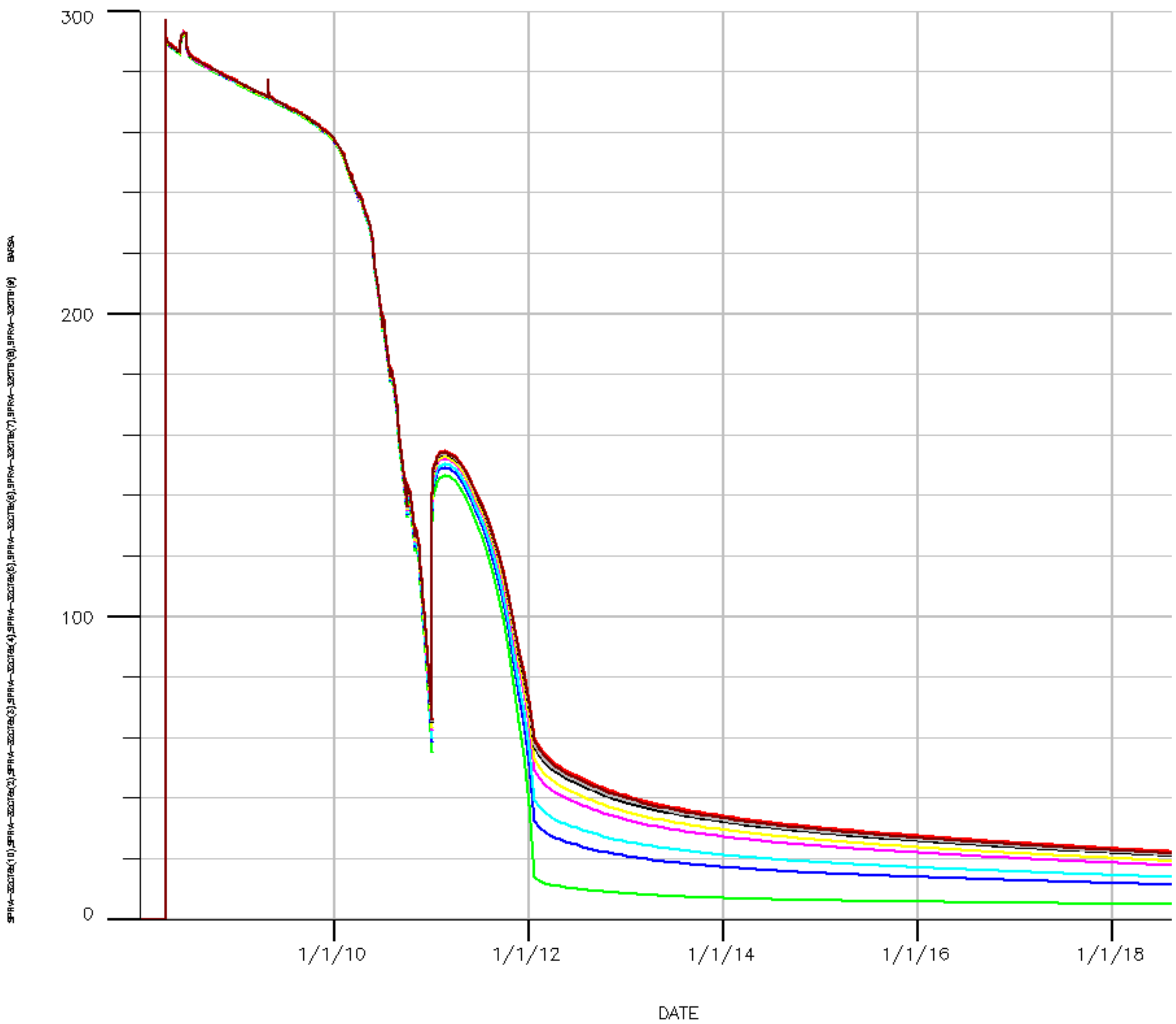


Figur 9Segment Oil Rate

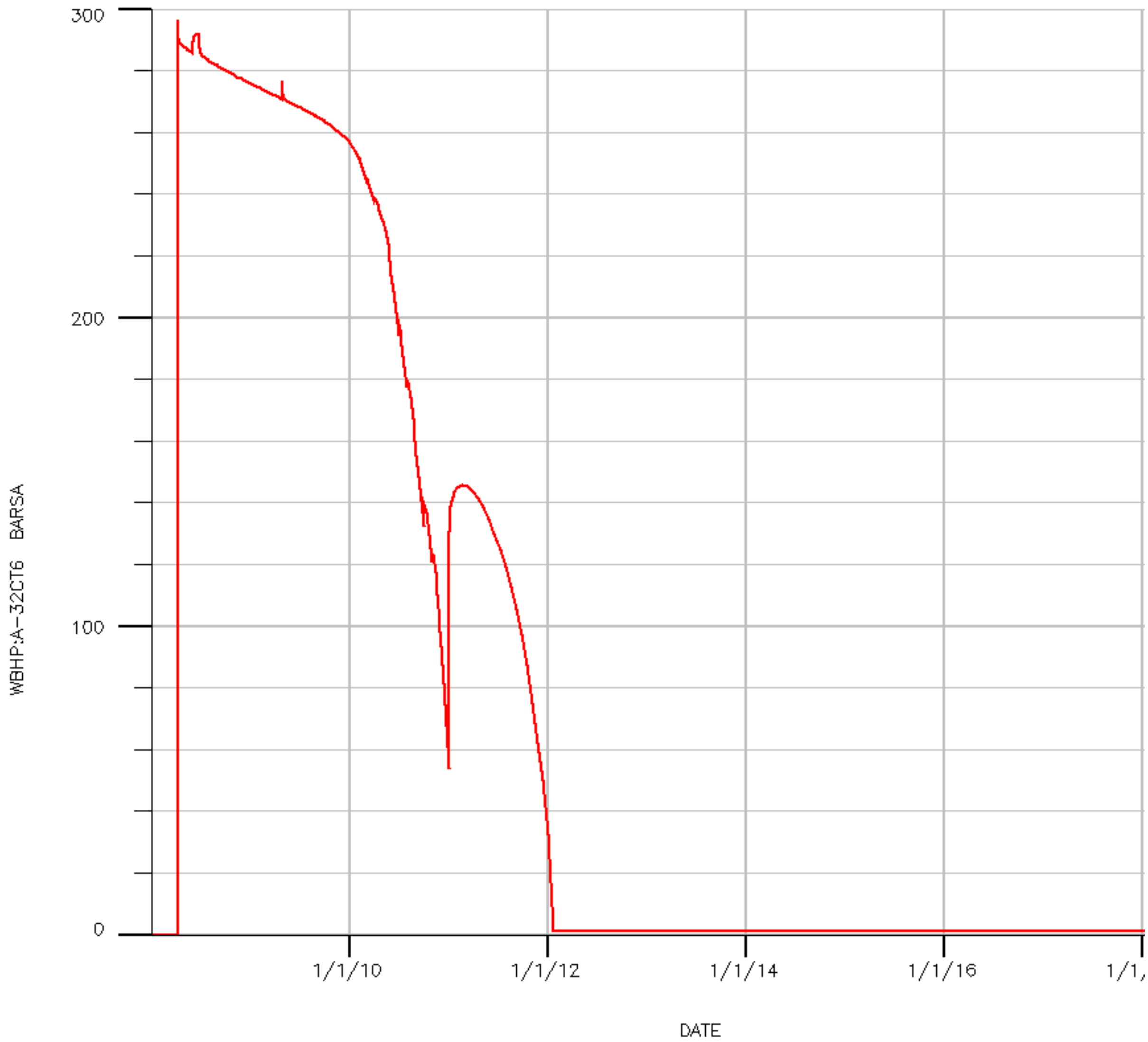
The pressure has a steady decline in the first part of the wells' production lifetime. When the plateau is reached and the water cut is increasing in early 2010 the pressure rapidly declines. Then in 2011 the pressure suddenly increases again, before it continues to sink at the same rate.

Eclipse is producing at the programmed oil rate of 1000 Sm3/day. When the water cut increases to over 90 % this oil rate is impossible to sustain. The huge total flow will cause the pressure in the reservoir to decline dramatically. In our case eclipse produces against the DEFAULT pressure which is 1 atm.

The sudden pressure increase in the well may be a consequence of aquifer activity. In our case there is a set of dummy wells to simulate this activity. From the pressure graphs we can see that in the start of 2011 there is a drop in the production and an increase in injection of these wells. This may lead to a pressure increase in this timestep.

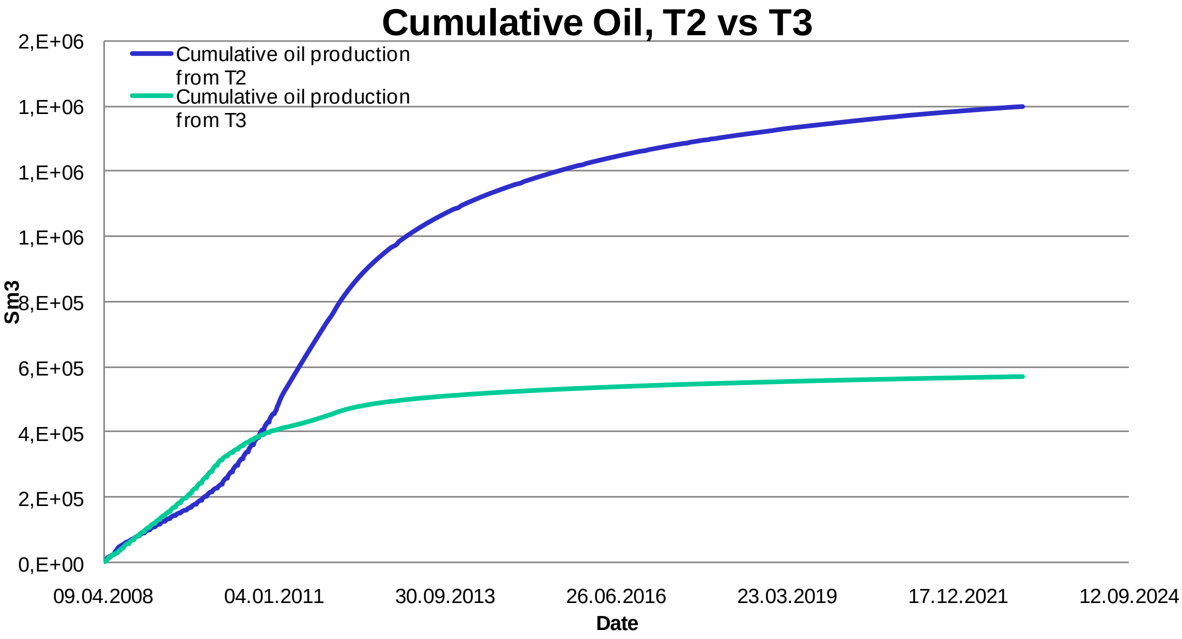


Figur 10Segment Pressure



Figur 11Bottom Hole Pressure

3.2.3 Sands



Figur 12Cumulative Oil T2 vs. T3

After calculating the production from each segment we calculated the production from Tarbert 2 and Tarbert 3. The total production from Tarbert 2 is 246% larger than the total production from T3. From the graphs we can see that the oil production from Tarbert 2 and Tarbert 3 are equal to each other until the end of 2010. In late 2010 the production from Tarbert 3 is rapidly decreasing, while the production from Tarbert 2 is still high.

The water cut is increasing dramatically in this period. And a phenomenon called water channeling, described later in this report, might be the reason for the sudden drop in production from Tarbert 3. This is one of the dangers caused by too high production rate from the reservoir. Table number 5 shows estimated OOIP and how much we are going to produce. All the numbers come from eclipse or Statoil.

We have based our recovery estimates on the reserves from DATA-file and the production we have calculated.

Tabell 4 Estimated Oil Recovery

Sone	Reserves	Produced	Recovery
	MSm3	MSm3	
T3	2,32	0,57	0,25
T2	3,00	1,40	0,47
T1	1,54	?	
Total	6,86	1,97	0,36

3.3 Production differences

There might be several reasons for this production difference. We investigated the permeability in the layers, difference in oil mobility, the perforated length of the segment, the pressure drop caused by the increasing velocity of the flow in the well, a contribution from neighboring sands and then we looked at possible differences in reserves. The figure below shows information on some of these important parameters.

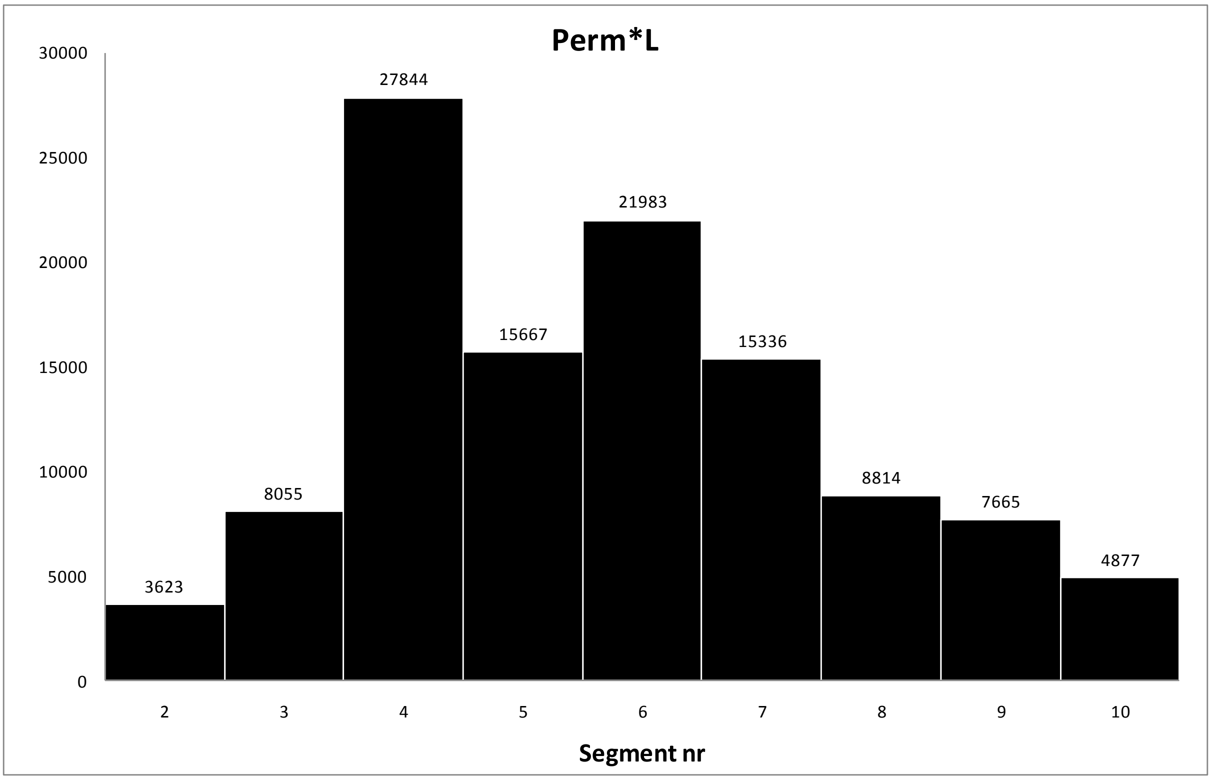
Tabell 5Cell information table.

-- L	= Perforated length of well segment in grid cell
-- Tot,L	= Total perforated length of well
-- Depth	= Middle depth for well segment in grid cell
-- Permx	= Cell value x-permeability
-- NTG	= Cell value net to gross ratio
-- Perm	= Average permeability for well transmissibility
-- Peaceman	= Pressure equivalent radius (Peaceman radius)
-- TW	= Well transmissibility
-- Rel,TW	= Relative well transmissibility, TW_Open/Sum TW_Open

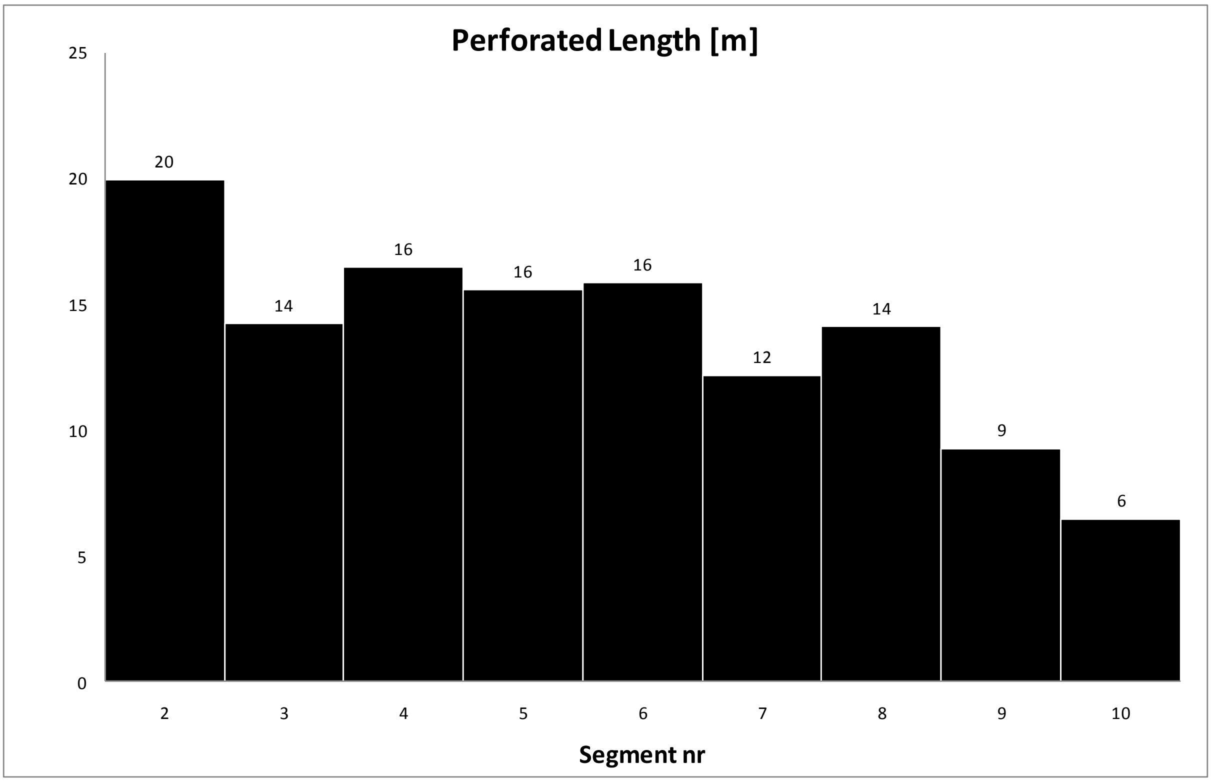
----

Cell			Segment	L	Tot,L	Depth
31	26	19	2	20	20	2429
30	26	17	3	14	34	2433
30	26	16	4	16	51	2434
29	26	14	5	16	66	2435
29	26	13	6	16	82	2436
28	26	11	7	12	94	2437
28	26	10	8	14	108	2437
27	26	8	9	9	118	2438
24	26	3	10	6	124	2442

Cell			Segment	Permx	Perm*L	TW	Rel,TW
31	26	19	2	772	3623	61	0,03
30	26	17	3	2421	8055	133	0,07
30	26	16	4	8653	27844	438	0,24
29	26	14	5	3881	15667	258	0,14
29	26	13	6	5141	21983	363	0,20
28	26	11	7	4512	15336	251	0,14
28	26	10	8	2197	8814	145	0,08
27	26	8	9	3071	7665	127	0,07
24	26	3	10	3611	4877	82	0,04



Figur 13Overview of Perm*L



Figur 14Perforated Length of segments

A good way to analyze this is to look at the product of Perm*L. Perm is the average permeability for well transmissibility and L is the perforated length well segment in the cell. The two lowest Perm*L are from segment 2 and 10 which also has the highest production rates. But segment 10 follows the production pattern of the other wells and segment 2 does not.

The perforated length in segment two is the longest in the well and might be the reason for the length of the production plateau if there is a big reserve to produce from. And the low Perm*L in both segment 2 and 10 might be the reason why they reach their plateau latest. A low Perm*L will in this case cause later water break through, and that will lead to more displacement of oil.

From eclipse we have the pressure measurement from each segment in the well. From the production starts, until 2012 the pressure in each segment is more or less equal. Before the water production grows large, the pressure drop is constant. The large production of water causes the pressure in the reservoir to drop dramatically. When the pressure drops below the boiling pressure the GOR will increase rapidly. The free gas will compromise the oil production even further. But from our simulation the gas saturation will not grow to be large.

Then afterwards the pressure is declining from the toe towards the heel. This pressure drop may be caused by the accelerating flow in the well. But the pressure drop of 40 bar as indicated in the graph is unrealistic. The total flow from the well is much larger in 2012 due to the water production. That can cause a larger pressure drop.

The production from segment 2 and 10 reaches its maximum latest of all the segments. But there is no pressure response in the segments to suggest that the production from these layers should be larger than the others.

Tarbert 2 is perforated for a longer interval than Tarbert 3. And from the cell perforation data we can see that Tarbert 2 has a larger permeability than Tarbert 3. The reserves from each formation are listed in a table below. It shows that the reserve in Tarbert 3 is around 80% of Tarbert 2, and Tarbert 1 is around 50 % of Tarbert 2. The Perm*L is much higher in most of Tarbert 2 than in Tarbert 3. This would give a better recovery of the oil in place. All these factors can be used to explain why there is a larger cumulative production from Tarbert 2 than from Tarbert 3.

Tabell 6Reservoir reserves, RMS are the figures from the geological model.

Sone	RMS	Eclipse	Diff
	MSM3	MSM3	%
T3	2,39	2,32	-2,9
T2	3	3	0
T1	1,54	1,54	0

Statoil has worked with a contribution from Tarbert 1 of 5-15%. The last uncertainty is related to the contribution from Tarbert 1. The well penetrates a small part of this formation on its way into Tarbert 2. Because we only have segments of the well in layers in Tarbert 2 and 3 we cannot make a direct calculation of the contribution from Tarbert 1. We compared the total flow recorded in the segments with the total flow recorded from the well to see if there was entering flow other places. But the numbers matched.

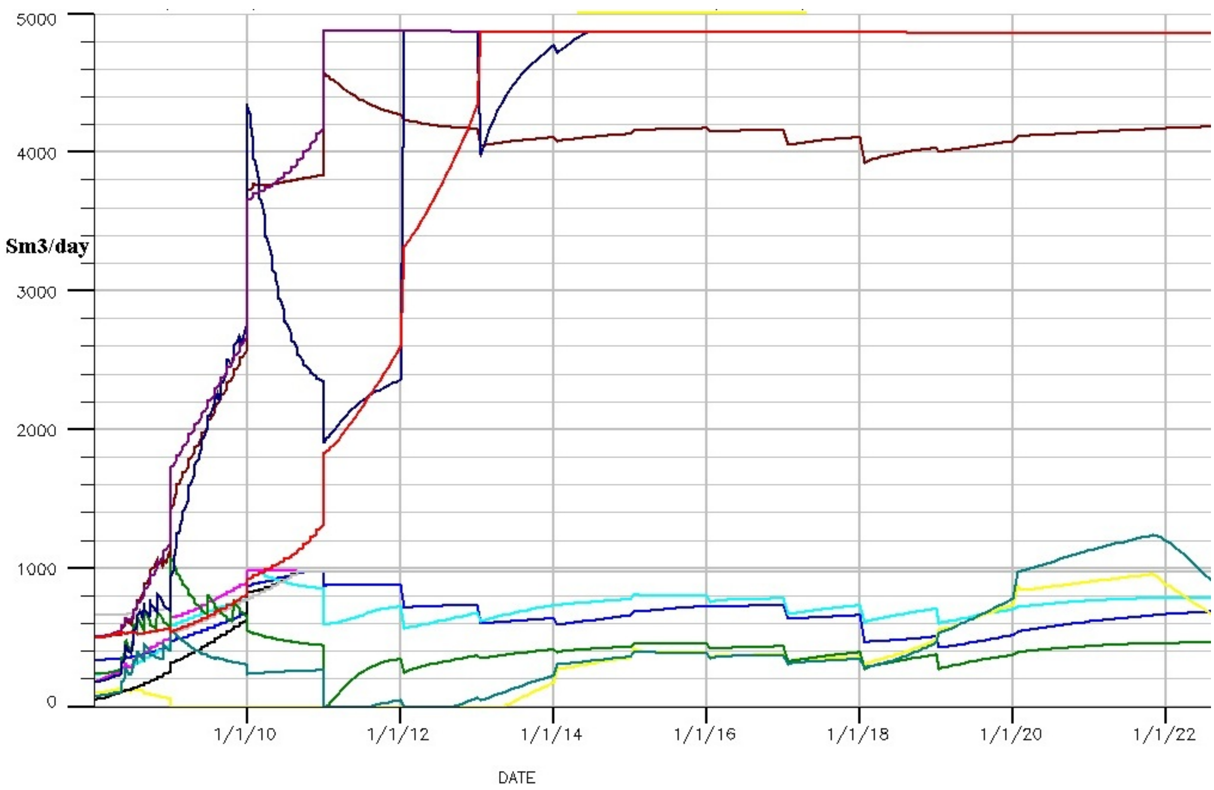
From the first year of production we have very detailed recording of the flow. Then later the recordings are made with a larger time interval. We compared the numbers for the first year of production but they also matched. We then concluded that if there is any contribution from Tarbert 1, it is recorded in segment 2. And this makes it difficult to decide the magnitude of the contribution.

There is no free gas in the reservoir. Boiling pressure is 143 bar. The Rso, (solution gas-oil ratio), is 119,6 SM3/SM3. When the pressure declines, the GOR increases rapidly to almost 540 SM3/SM3. This is while the oil production is on its' top. With declining oil production, the GOR sink but increases when the pressure sinks in the reservoir. We found no accumulation of gas in the simulation.

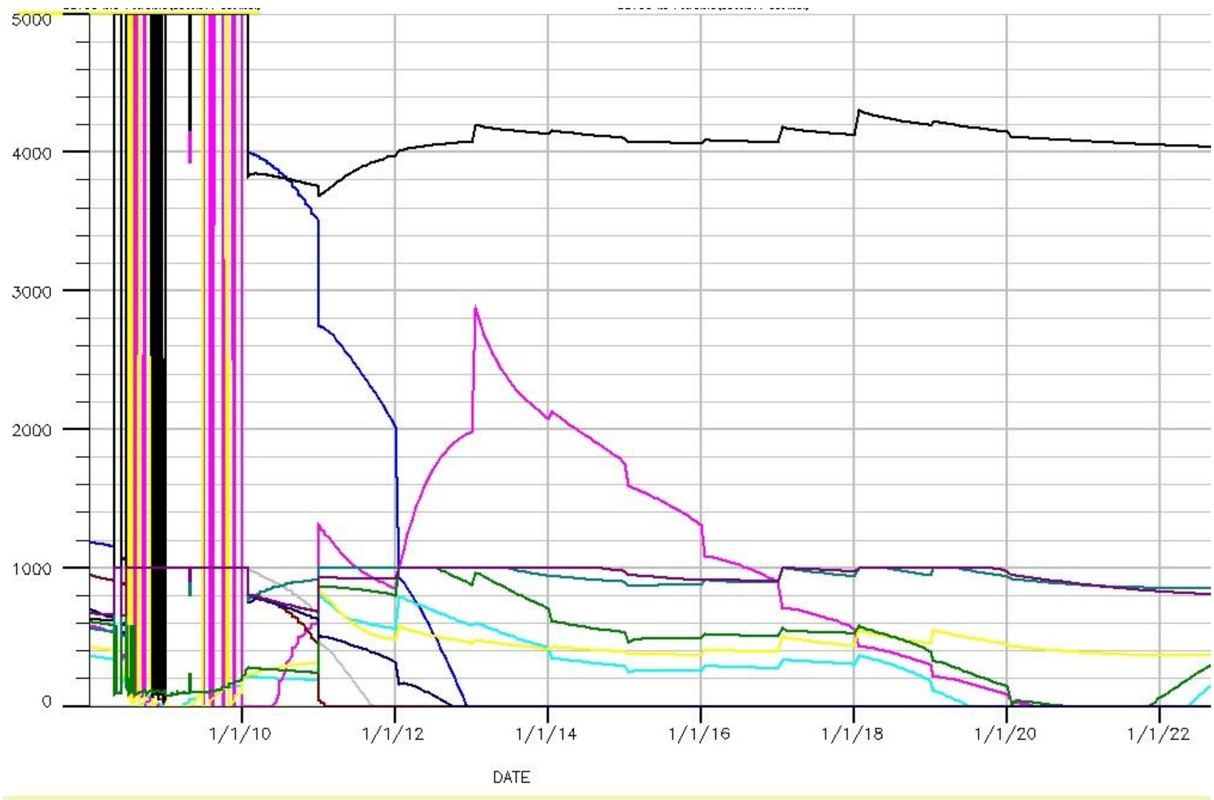
The pressure has a steady decline in the first part of the wells' production lifetime. When the plateau is reached and the water cut is increasing in early 2010 the pressure rapidly declines. Then in 2011 the pressure suddenly increases again, before it continues to sink at the same rate.

Eclipse is producing at the programmed oil rate of 1000 Sm3/day. When the water cut increases to over 90 % this oil rate is impossible to sustain. The huge total flow will cause the pressure in the reservoir to decline dramatically. In our case eclipse produces against the DEFAULT pressure which is 1 atm.

The sudden pressure increase in the well may be a consequence of aquifer activity. In our case there is a set of dummy wells to simulate this activity. From the pressure graphs we can see that in the start of 2011 there is a drop in the production and an increase in injection of these wells. This may lead to a pressure increase in this timestep.



Figur 15Dummy wells injection



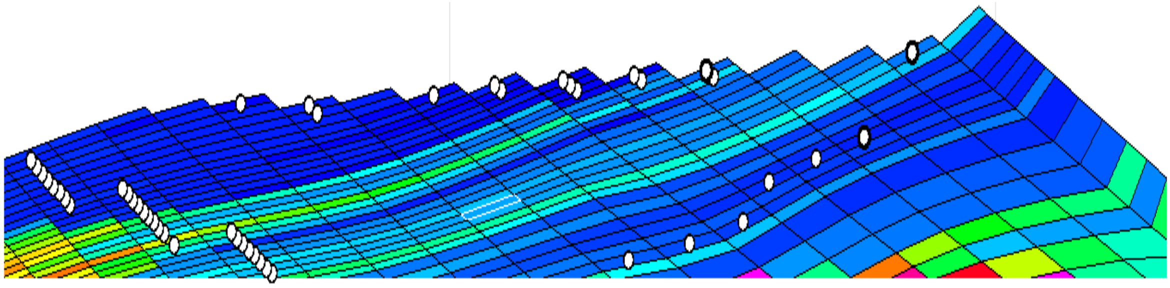
Figur 16Dummy wells production

3.3.1 Water cut

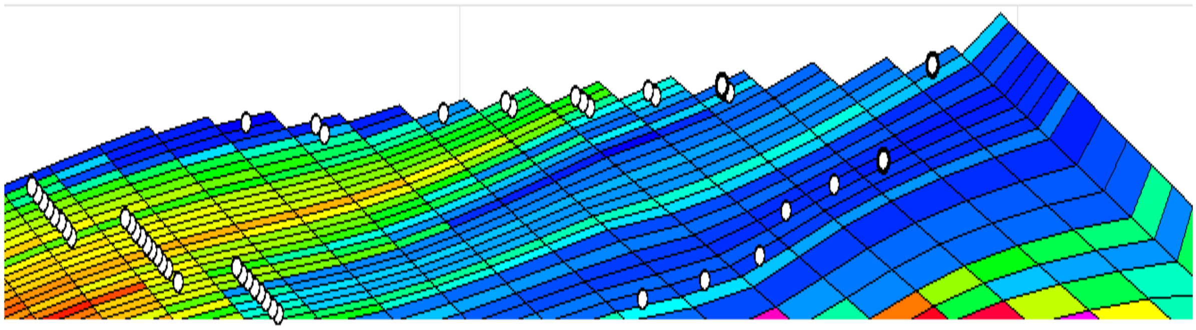
Water breakthrough is water production from underlying water. This process should be avoided or delayed since there is no value of producing water. The properties of water and oil also have a high influence on the time of the break through. If possible our main objective is to increase water break through time. Early water breakthrough will typically occur in:

- Thin oil layers
- High permeability layers (thief zones)
- Layers with good communication to water (low distance to OWC)

Observation of early water breakthrough in our reservoir model

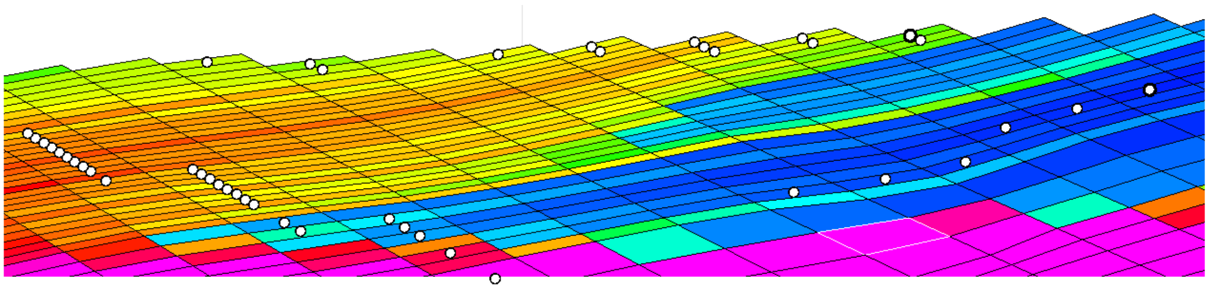


2009

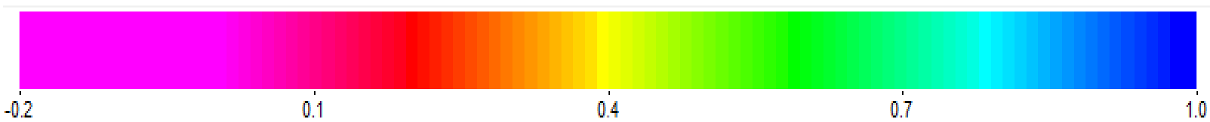


2011

From oil saturation profile along wellbore, changing time steps we can see easily that in layers number 10, 11, 12, 13 and 14 water breakthrough happens earlier than others in 2011. That is why we can eliminate these layers after this year.



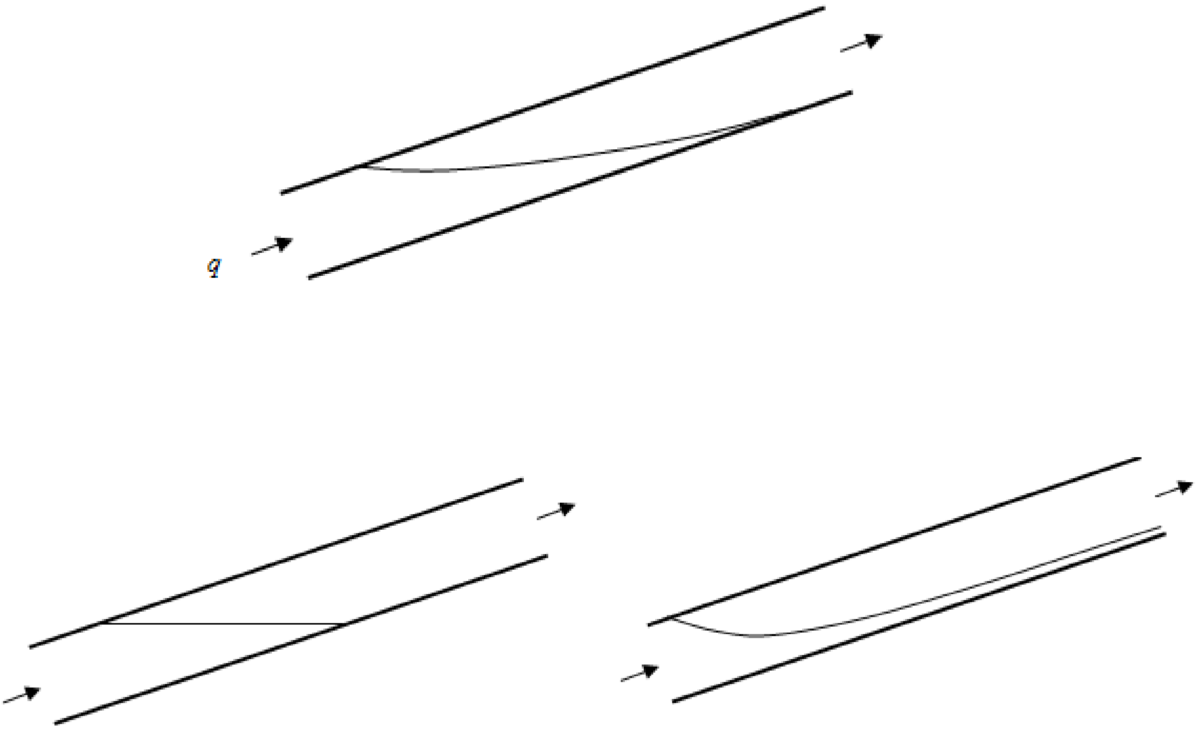
2012



Figur 17Water Break Through Development

3.3.2 Oil-Water Systems

We have displacement of oil by water in an inclined layer, porous media, as shown below, where gravity plays an important role. In this system, where the oil-water interface per definition is strongly influenced by gravity, we may identify two limiting cases; one where the injection rate is so low that the interface is horizontal (a), and one where the injection rate is so high that the interface is becoming parallel to the layer (b). For the low rate, the displacement is completely gravity stable, while the displacement in the high-rate case clearly is unstable, since the water is advancing along the bottom of the layer, bypassing the oil.



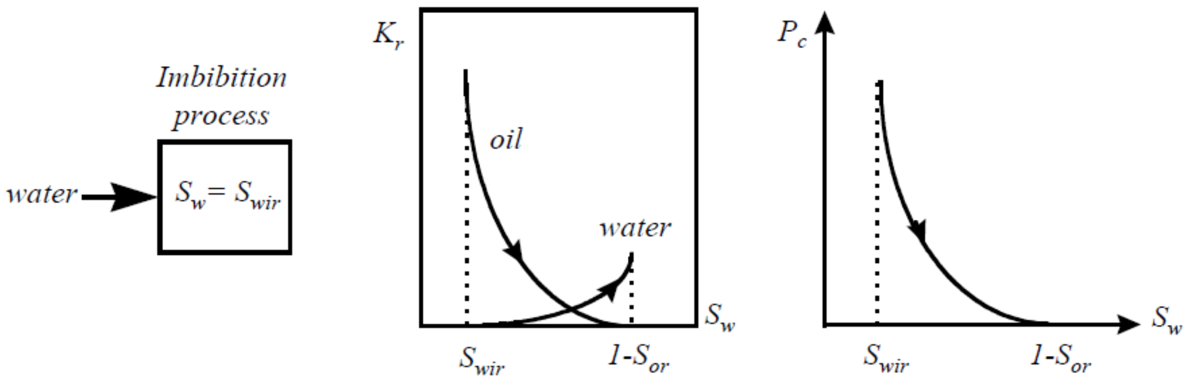
a) very low water injection rate b) very high water injection rate

Figur 18 Water displacing oil in gravity based system.

Some important points for this situation

- Increasing horizontal permeability will increase breakthrough time and, conversely, increasing vertical permeability will decrease breakthrough time.
- Increasing drainage radius will increase breakthrough time.
- Increasing oil column height will considerably increase breakthrough time.
- Increasing oil column height above perforation will decrease breakthrough time.
- Increasing perforation length will decrease breakthrough time.
- Increasing oil viscosity will decrease breakthrough time and, conversely, increasing water viscosity will increase breakthrough

When the oil is being displaced by water the mobility of oil is sinking as shown in the figure in the middle. And at the same time the water mobility is increasing, making it easier for water to move in the pores.



Figur 19 Imbibition Process

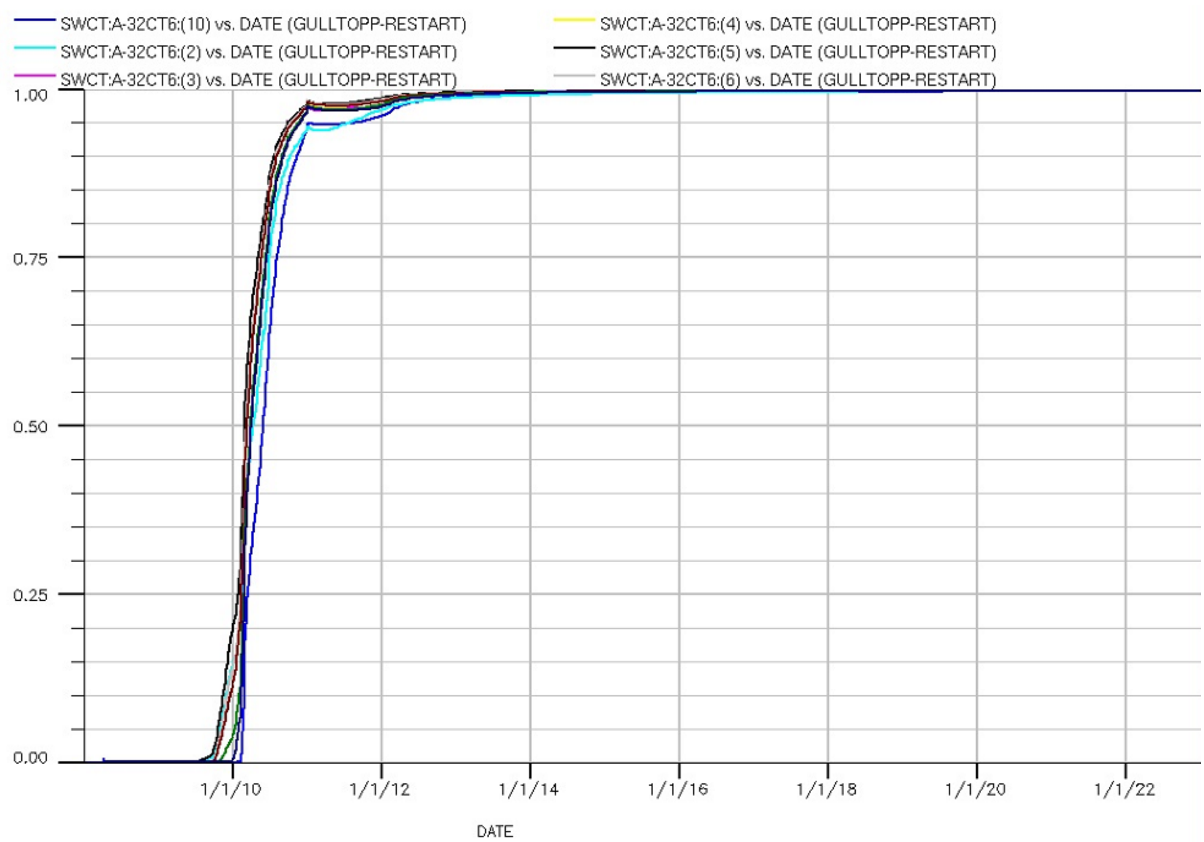
3.3.3 Source:

http://www.ipt.ntnu.no/~kleppe/TPG4150/krpc.pdf

3.3.4 Water Production

From the beginning of production around 9th of April 2008 until the middle of June 2009 there was no water production. The water brake through happened first in segment 3, 4 and 5, then just four days later in segment 2. Approximately 80 days later segment 6, 7 and 8 had water break through and the last segments some time after this.

When the water broke through, the water production rate rapidly increased in all the segments. Except segment three and four which had negative water production as well as negative oil production. These segments might have had lower pressure than the well for a while. On the 13th of April 2009 the total water rate from the well exceeded the total oil rate. The water rate was increasing exponentially, and on the 22th of September the cumulative water production reached the cumulative oil production.

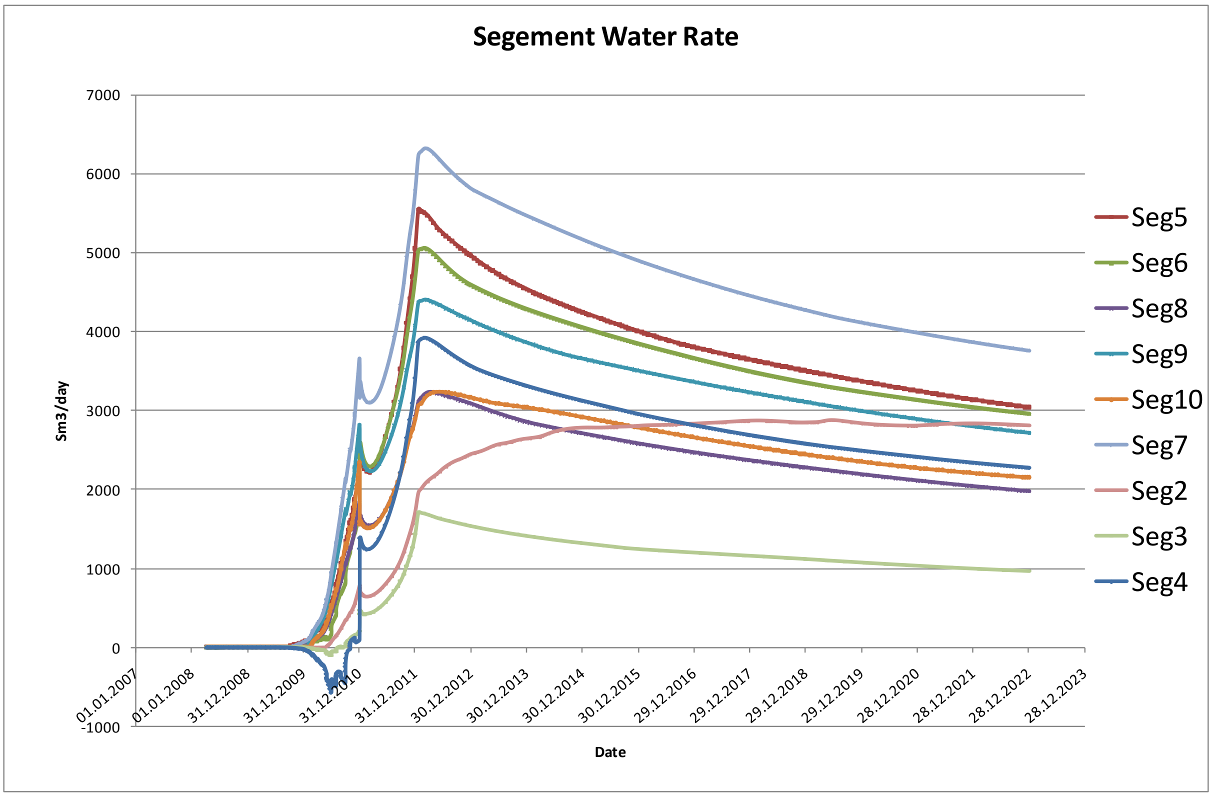


Figur 20Water Break Through

All the segments follow the same production pattern except for segment 2. Here the water production is increasing, while the others are steady declining. The largest water production is predicted to happen in segment 7 and the second largest in segment 5.

Tabell 7Cumulative Production

Segment nr	Oil Produced MSm3	Water Produced MSm3
2	0,94	11,39
3	0,04	5,16
4	-0,03	12,05
5	0,07	16,98
6	0,05	16,17
7	0,18	20,75
8	0,14	10,88
9	0,19	14,91
10	0,38	11,57
Total	1,97	119,87



Figur 21Segment Water Rate

Showing the water production from each segment versus time.

3.3.5 Discussion

There are several reasons for not wanting large water cut in the oil production. For one thing you cannot sell the water you are producing. Second of all increased water cut will reduce the waters' mobility in the reservoir. And all this can result in lower income. Water produced from the reservoir is contaminated and often more salt then the sea water. By rule made by the Norwegian government you will have to clean the produced water to acceptable levels of oil content (25 -40 ppm) and salt content before disposing of it to sea.

The deviation of segment 2 is difficult to explain. It could be because of the pressure drop due to flow in the well, but this is supposed to be gradual, and would also affect the other segment towards the heel. Another possibility is that the water is coming from somewhere else, not affected by the pressure regime in aquifer.

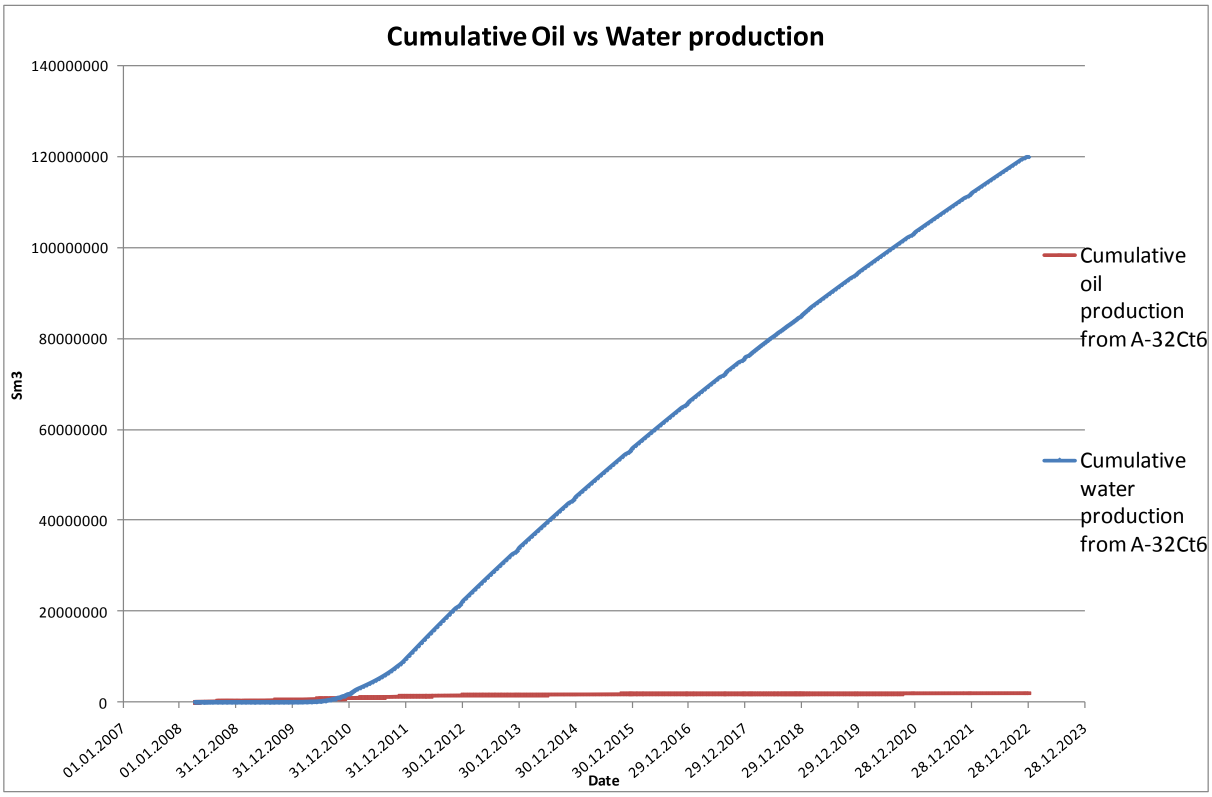
As the water starts to flow in the well the average density of the static fluid column will increase and lead to greater pressure drop to shore/platform. Combined with the declining reservoir pressure, the pressure available to transport the fluid to the surface gets smaller. This will result in a smaller production rate, reduction of the production life time and smaller recovery.

Other problems caused by liquid water in the well stream are the formation of hydrates, scaling and corrosion. In this case the temperature in the well stream would be sufficient to prevent the formation of hydrates.

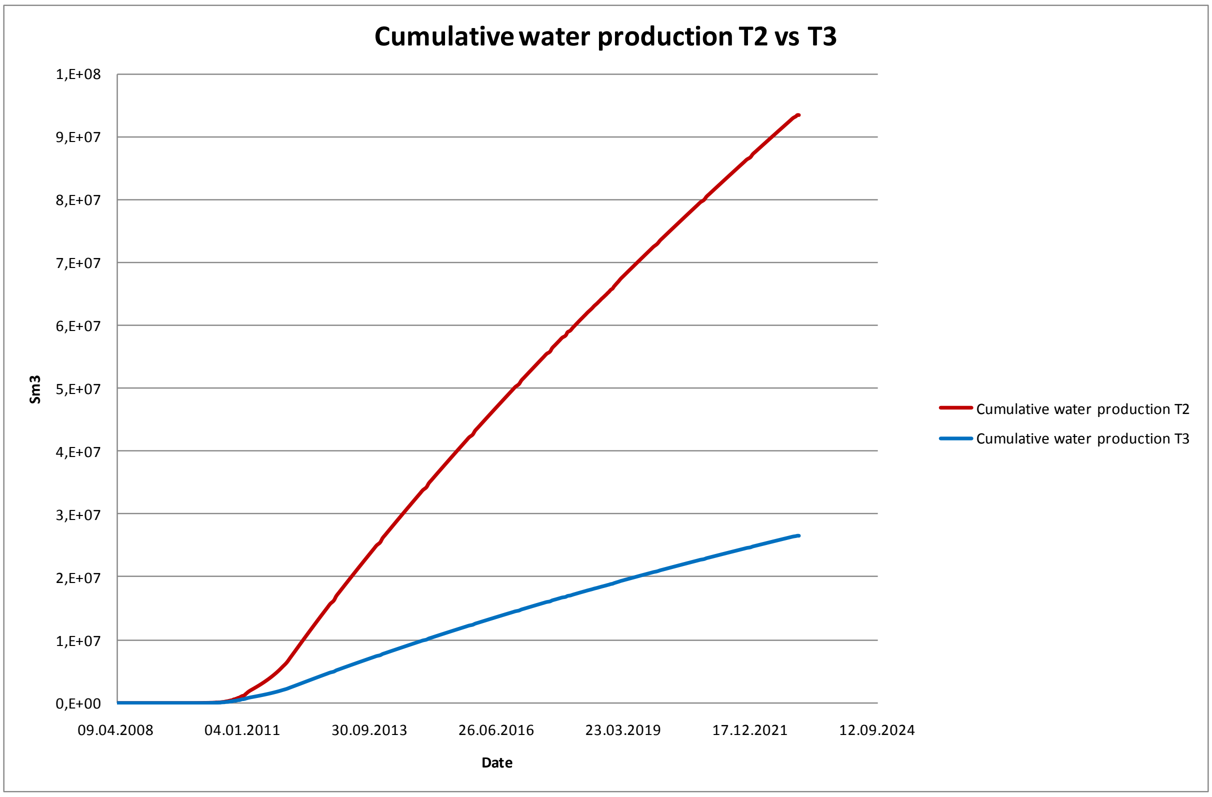
Scaling can happen when happen when formation water undergoes changes in pressure and temperature, or when to incompatible fluids are mixed. In our case it could happen in the production well when formation water is produced or in the formation. Scale-forming ions precipitate from the formation water onto the production equipment and the well. This might create plugs that reduce the flow. It is important to avoid scale forming in the well. A new oil soluble scale inhibitor made by Statoil allows the reservoir formation to be treated right after the completion of the well, and before it is sat in to interrupted production.

3.3.6 Source:

http://www.statoil.com/en/technologyinnovation/fielddevelopment/flowassurance/scale/pages/default.aspxhttp://www.statoil.com/en/technologyinnovation/fielddevelopment/flowassurance/scale/pages/default.aspx



Figur 22Cumulative Oil vs. Water production

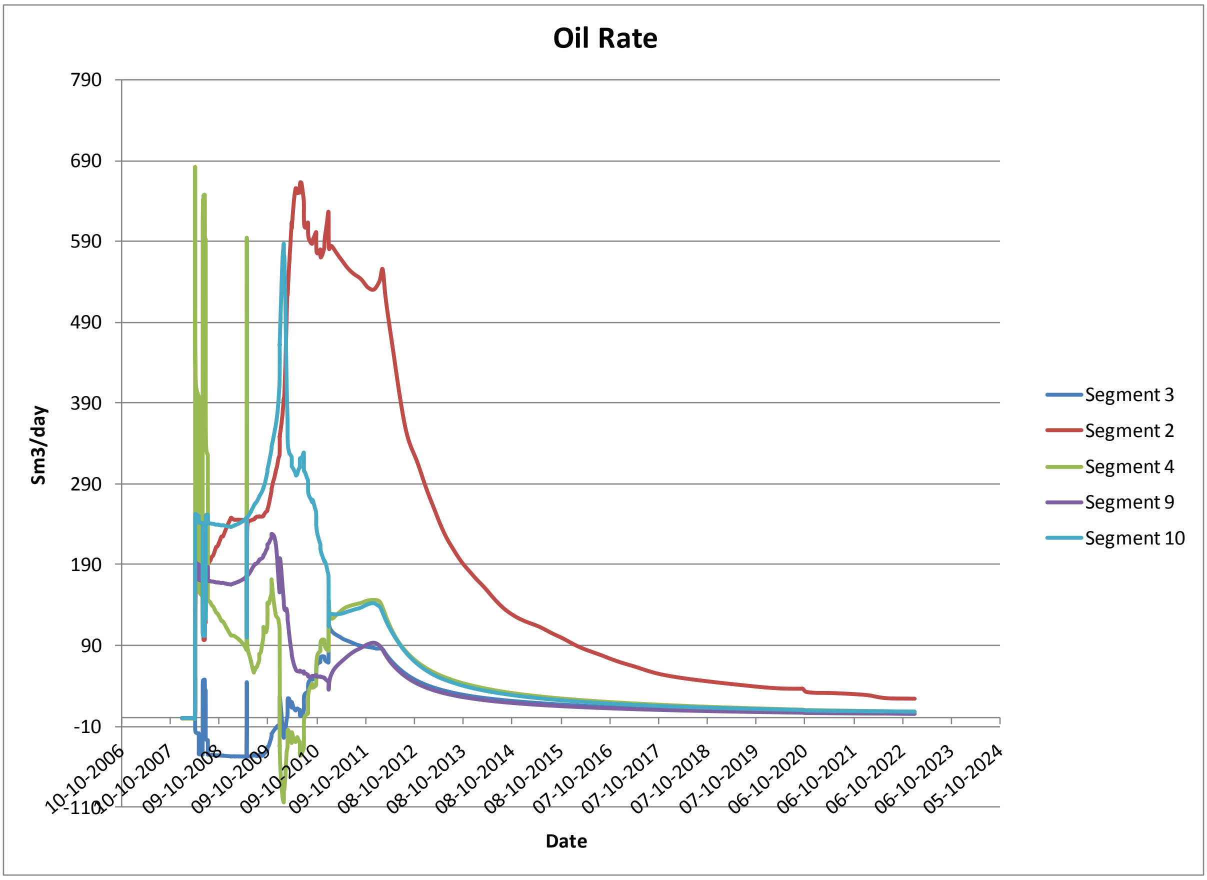


Figur 23Cumulative Water T2 vs. T3

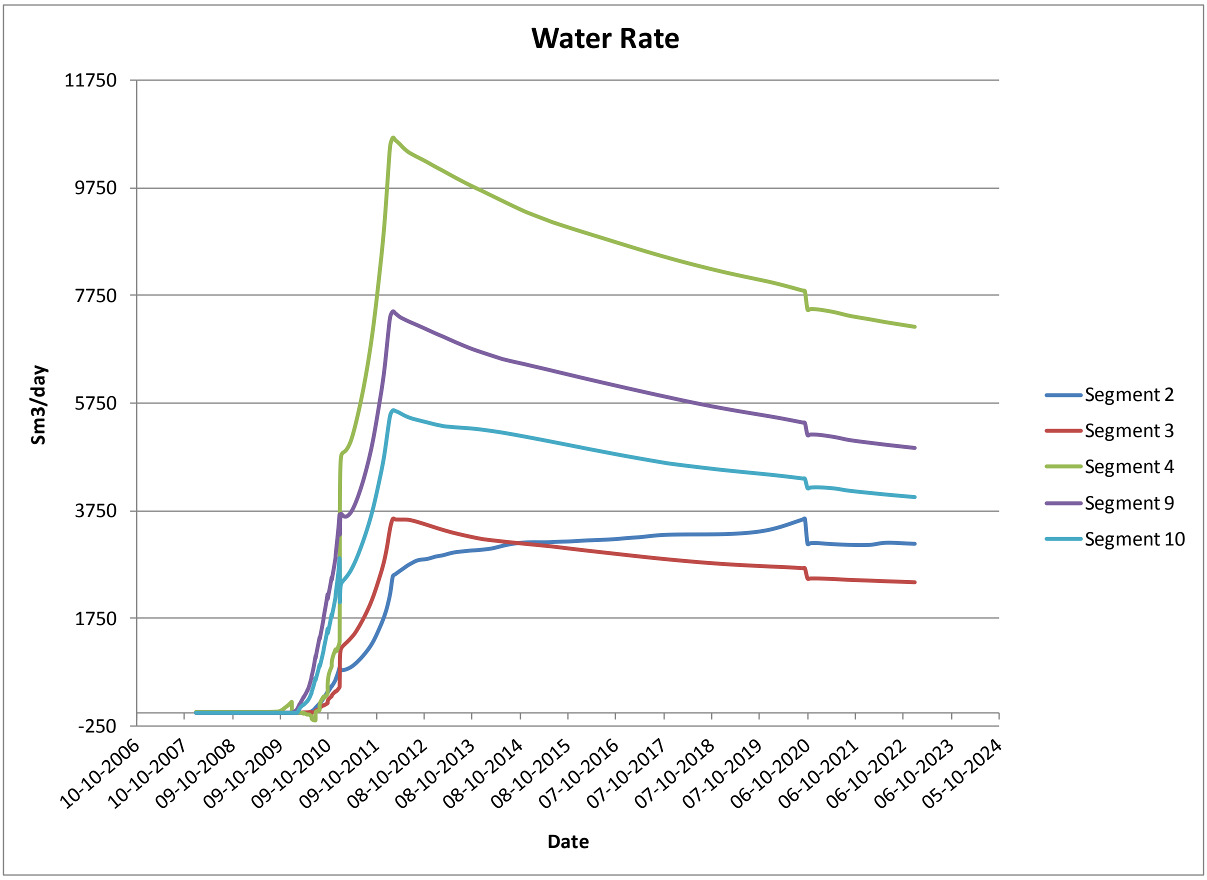
The oil in the North Sea is often rich in C02. When the C02 comes in contact with water with high temperature and pressure, and steel pipe the basis for corrosion is apparent. Corrosion of the steel pipe is a big concern for the oil company because it will destroy the production equipment. This will result in lost safety and production.

4 Sensitivity Case

Around the first result we decided to shut some segments that produced a lot of water and had less oil saturation to see if we would have greater oil recovery. We shut segment 5, 6, 7, and 8 and the results are in graphs below.



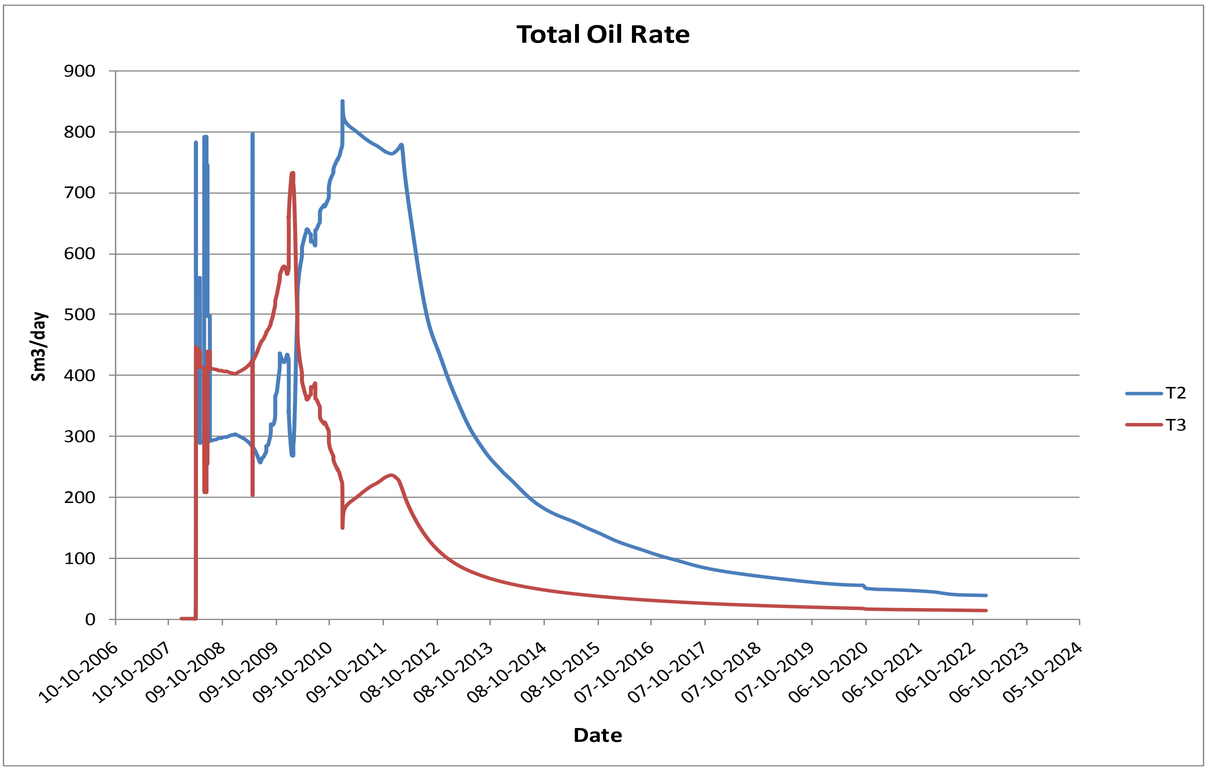
Figur 24Oil rate for each segment.



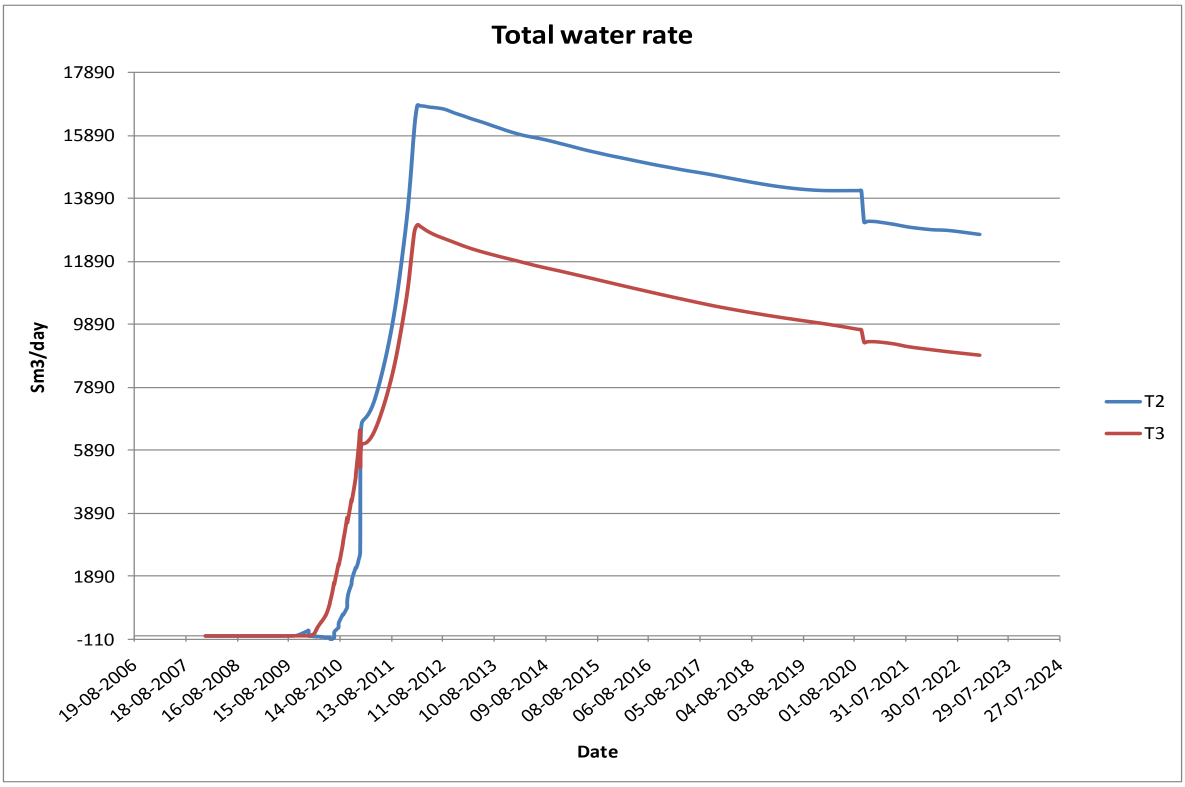
Figur 25Water rate for each segment

The figures above show the behavior of oil and water production during lifetime of well A-32CT6. We can see from the graph that the oil production starts in 09.04.2008 in all segments, segment 2 has a behavior different from the others. The production increases until it reaches a peak of 656 Sm3/day, but declines gradually and later than the others. Therefore, the segment that gives the biggest contribution of oil production is segment 2, second is segment 10, 4, 9 and the last is segment 3.

The water production began around 09.10.2009. At first the production from segment 4 increased and decreased slowly. After 04.09.2010 the production rose steeply to 15041 Sm3/day and then declined downwards 7204 Sm3/day. Segment 4 has the highest water production, the second to contribute is the segment 9, 10, and the last is segment 3. Despite of segment 3 produce less oil also it has less water production.



Figur 26Total Oil rate for each formation



Figur 27Total water rate between the formations.

These figures show the total oil and water rate which each formation produce. The oil production for Tarbert 2 and Tarbert 3 starts in the same period. However Tarbert 2 started to produce with a higher rate in comparison with Tarbert 3 and reached a peak in 02-01-2011 of 851 Sm3/day. And started to decline almost in the same period but with a bigger difference of range. The formation that produces the most oil is Tarbert 2. The reasons for the production difference are listed in the base case analyzes.

From the graph we can see that total water production for formation Tarbert 3 start early, rise sharply and then decline gradually, this formation produce less water than Tarbert 2. Regarding that we have larger water production in segment 4 in comparison with the others, this result is reasonable.

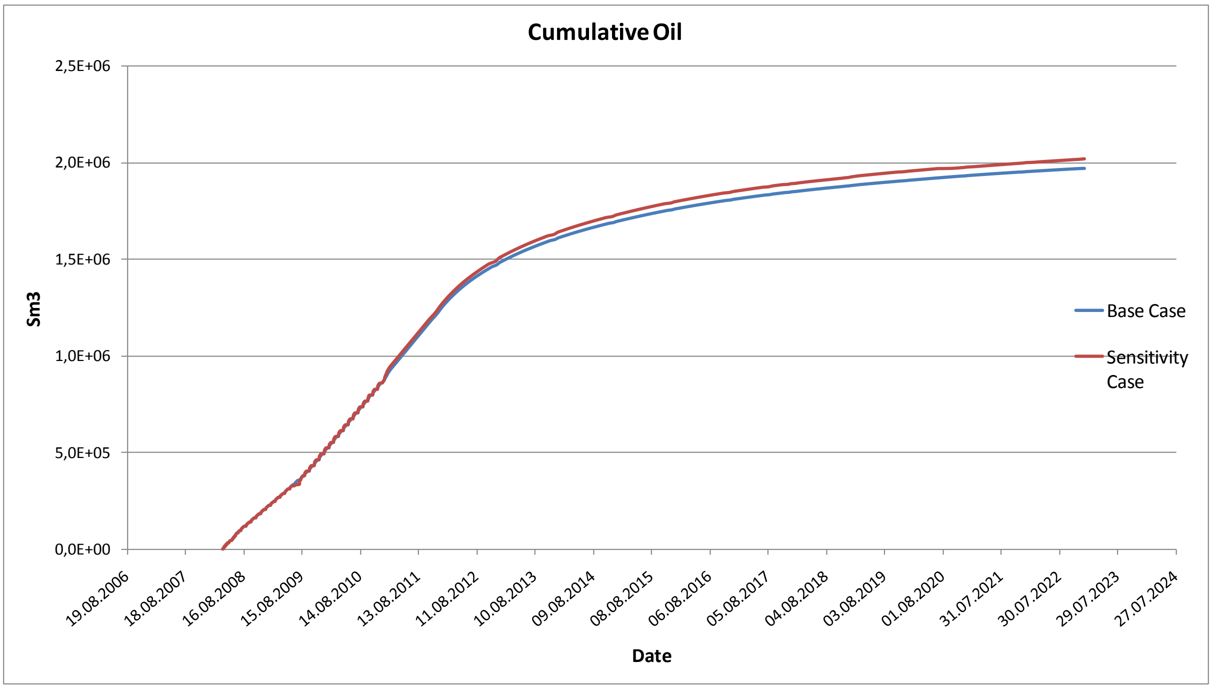
Tabell 8The oil and water production for each segment

Segment nr	Oil Produced MSm3	Water Produced MSm3
2	1,00	13,21
3	0,10	12,44
4	0,26	37,17
5	0,00	0,00
6	0,00	0,00
7	0,00	0,00
8	0,00	0,00
9	0,24	26,13
10	0,43	20,53
Total	2,02	109,48

The table above show the total production of oil and water for each segment and the total produced during lifetime of well. This is comparative table regarding the graphs above.

5 Comparison

After interpretation of our data we could identify which layers who had earliest water break through, produced the largest amount of water and the least amount of oil. We choose to shut down the production from these layers to look at the consequences.



Figur 28Cumulative Oil Production Comparison

It turned out that we had the same arrangement of which layers that produced most of the oil. But when we added the production from segments from each of the formations it turned out that we had increased oil production from Tarbert 3 and decreased production from Tarbert 2. And we also got a higher total recovery. The total volume of oil increased from 1, 96 MSm3 to 2,02MSm3. That is an increase in production of 2,76 %.

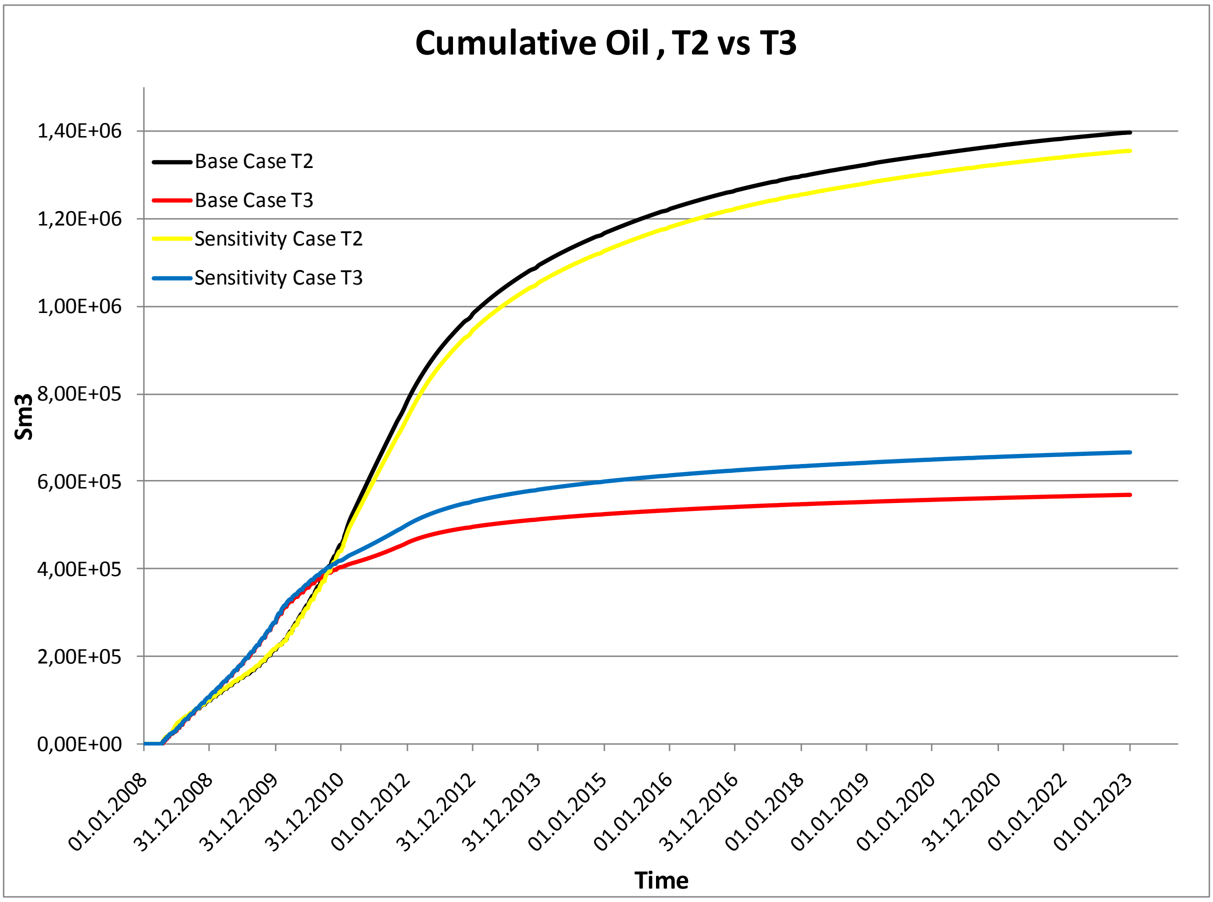
Tabell 9Oil Production Comparison

	Base Case Oil Production			Sensitivity Case Oil Production		
Segment	Tarbert 2	Tarbert 3		Tarbert 2	Tarbert 3	Difference
	MSm3	MSm3	MSm3	MSm3	MSm3	MSm3
2	0,94			1,00		0,06
3	0,04			0,10		0,05
4	-0,03			0,26		0,29
5	0,07					0,07
6	0,05					0,05
7	0,18					0,18
8	0,14					0,14
9		0,19			0,24	0,04
10		0,38			0,43	0,05
Total formation	1,40	0,57		1,36	0,67	0,05
Total reservoir		1,97			2,02	
% Difference						2,76 %

The water production decreases from 120 MSm3 to 109 MSm3. That is reduction of 8,66 % in water production. Even though this is a substantial reduction in produced water, there will not be possible to save a lot of money on water processing equipment because the processing is a centralized operation on Gullfaks A.

Tabell 10Water Production Comparison

	Base Case Water Production			Sensitivity Case Water Production		
Segment	Tarbert 2	Tarbert 3		Tarbert 2	Tarbert 3	Difference
	MSm3	MSm3	MSm3	MSm3	MSm3	MSm3
2	11,39			13,21		1,82
3	5,16			12,44		7,28
4	12,05			37,17		25,12
5	16,98					16,98
6	16,17					16,17
7	20,75					20,75
8	10,88					10,88
9		14,91			26,13	11,21
10		11,57			20,53	8,97
Total formation	93,39	26,48		62,82	46,66	
Total reservoir		119,87			109,48	-10,38
% Difference						8,66 %



Figur 29Comparison of oil production from sands

We shut down the production from segment 5, 6, 7, and 8, which all dwell within Tarbert 2. Not surprising the total production from Tarbert 2 sank. At the same time the total production from Tarbert 3 increased, and extra the production exceeded the drop in Tarbert 2.

After closing the production from the segments 5-8, the migration of water will stop in this zone. This means more oil close to the well, and more oil to be produced from segment 9 and 10.

6 Economic part

We made a simple economic analyze to see if the sensitivity case was economical feasible. The analysis is based on the assumed numbers from Gulltopp – introduction and the production data from our simulation. We assumed the inflation to be included in the discount factor, and the price of gas oil equivalent to be half the price of oil.

The analysis was made over the simulated lifetime of Gulltopp, from 2008 to 2023. And we assumed a constant oil price of 90 $ /STB.

Tabell 11 Economical ssumptions

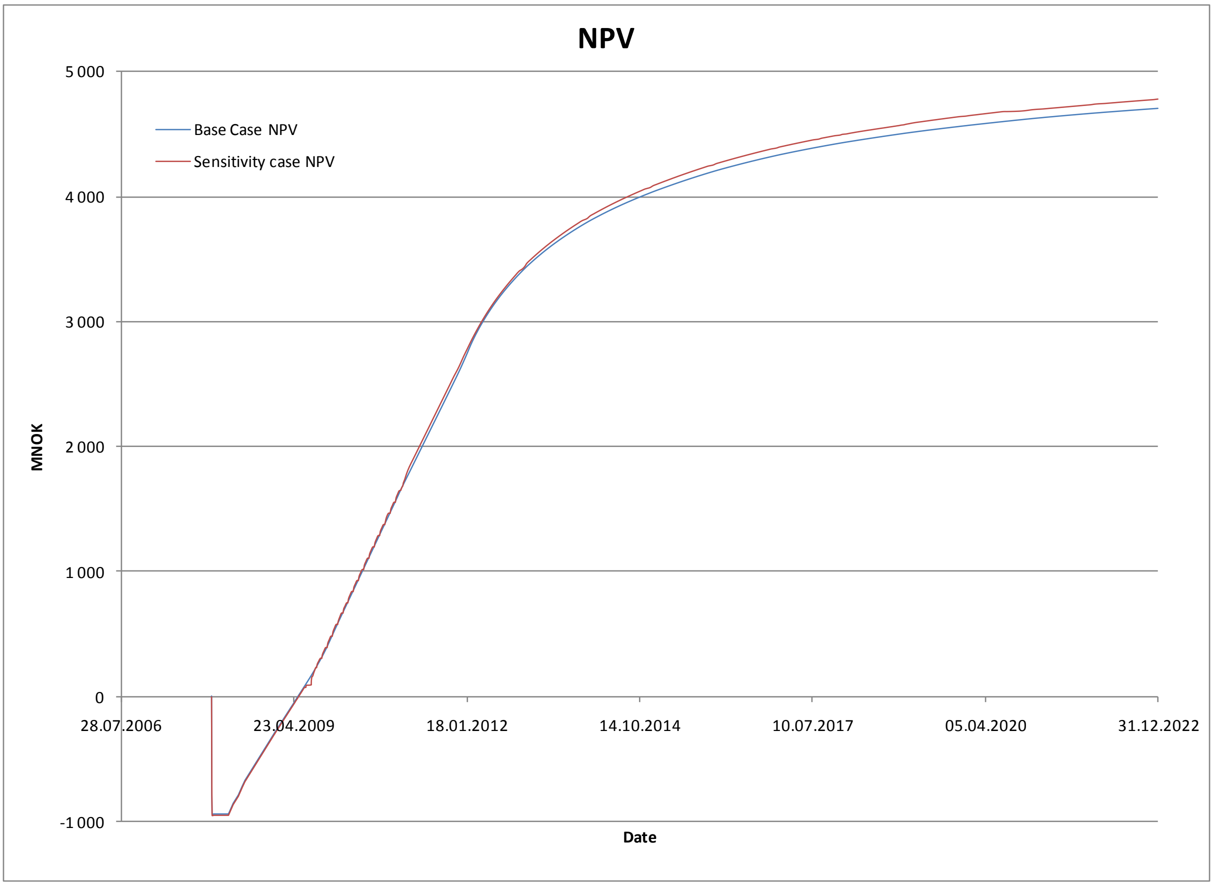
Assumptions:		
Oil price	90	USD/bbl
Gas price	0,045	USD/bbl
Inflation rate	1 %	p.a
Discount rate	5,00 %	
Dollar exchange rate	5,7	NOK/USD

Tabell 12 Net Present Value

Net present values		
Base case	4709	MNOK
Sensitivity Case	4789	MNOK
Difference	1,70 %	

In the sensitivity case we included the well intervention costs of three MNOK with the capex, because we did not have information about the daily rate and the length of the operation.

From table two we see that the sensitivity case is more economical viable than the base case. The Net present value is 80 MNOK, 1,7%, higher in the sensitivity case. An evaluation base sole on these data makes the sensitivity case a preferable choice.



Figur 30NPV comparison

7 Measuring the Flow from the Different Segments

7.1 Introduction

The water cut on the Gulltopp well is increasing, as we have seen from the results of the Eclipse simulation. Especially segment 2 has a high water production. To check if this is true, measurements have to be done.

There are different tools made to record the flow profile down hole. We contacted several companies that have knowledge on this topic, and gave them some restricted input data for the well.

Tabell 13

WELLDATA, GULLTOPP AC-32 CT6		
Oil Production	1600	sm3/d
Water Production	2400	Sm3/d
Gas Production	52200	Sm3/d
Oil Viscosity	0,5	cp
Bottom Hole Pressure	145	bar
Bottom Hole Temperature	93	C

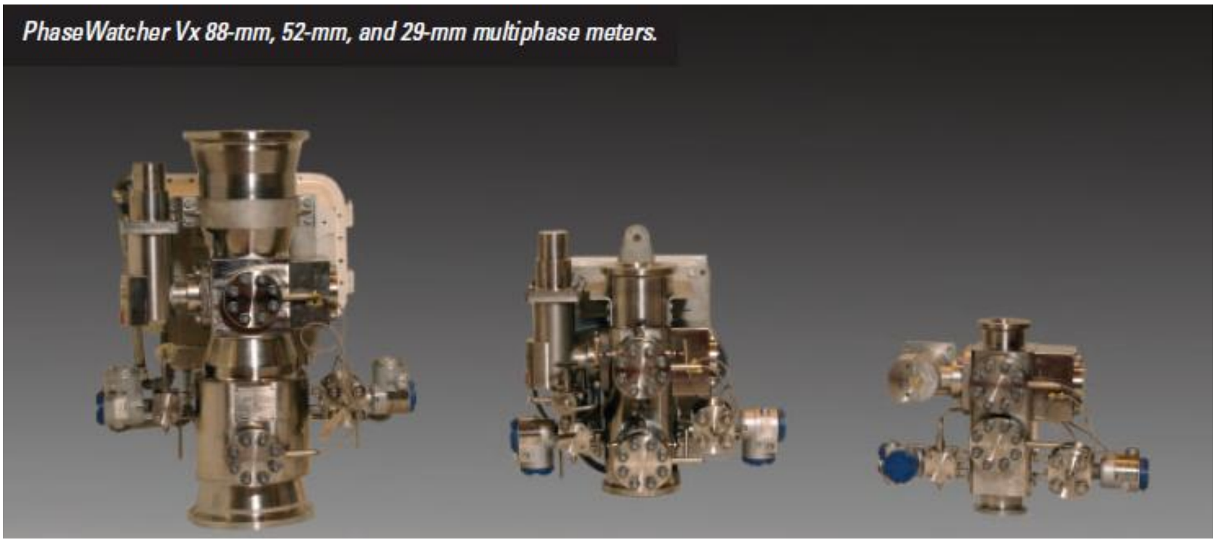
7.2 Flow meters

A flow meter is a device used to measure volumetric or mass flow. There are many different types of flow meters for different services. The working principle of a venturi flow meter is that pressure loss is made by different cross section areas within the flow meter. The pressure loss is measured, and combined with Bernoulli's equation for incompressible flow and the continuity equation, it is possible to calculate the volumetric flow.

A dual energy fraction density meter is using two different gamma ray energy levels to estimate the mixture density and the phase hold ups. By using a radioactive source, gamma rays are attenuated differently due to the type of liquid in the flow meter.

First, we were thinking of placing flow meters down hole recording in different sections of the production tubing. But, according to Schlumberger, it does not exist three phase flow meters that works properly down hole. Since the bottom hole pressure in the Gulltopp well is lower than the bubble point pressure, and therefore we are dealing with three phase flow. Because of that, there might be a problem having flow meters down hole.

Instead Schlumberger are proposing another idea, which is to use geochemical fingerprinting to identify the oil from the different layers. Liquid samples are taken from each segment of interest, and tests are done in the lab to investigate the different compounds of the liquid from the different layers. This is combined with using a flow meter topside to measure the volumetric fraction of the three phases. For this job, Schlumberger recommend the Vx PhaseWatcher flowmeter, and 4D GCMS (gas chromatography-mass spectrometry). The PhaseWatcher is using a combination of venturi and dual energy fraction to measure three phase flow.

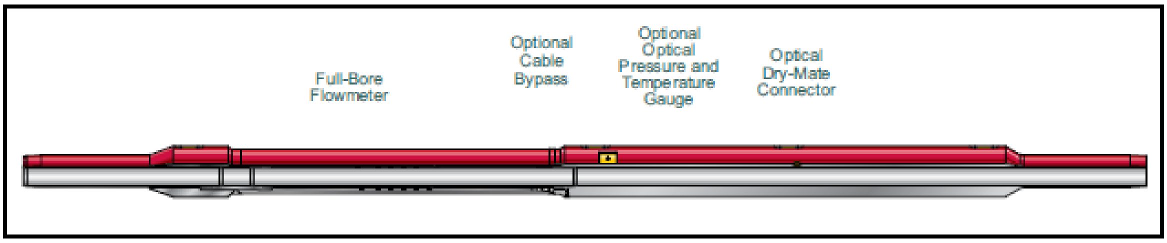


Figur 31

Schlumberger are suggesting to use the Vx PhaseWatcher flow meter combined with 4D GCMS to measure the down hole flow regime. Photo: Schlumberger

Gas chromatography is method where the components in the mixture are separated with respect to different vapor pressures. In mass spectrometry, the particles in the mixture are charged, and then separated due to different mass to charge ratio. Both these methods are combined in 4D GCMS. 4D means 4 dimensions, and two columns are used to separate the chemicals in the gas chromatography part

Weatherford claim that their Optical Multiphase Flowmeter is well fitted for down hole measurements. The technology is based on measurements of the velocity and the speed of sound. The speed of sound is proportional to the volume fraction of oil, water and gas. Weatherford have previously used up to three flow meters in the same production tubing.



Figur 32

By using a optical working principle, Weatherford claim that their flow meter is working fine in a three-phase environment down hole. Photo: Weatherford

Tabell 14

DATASHEET, Schlumberger's Vx PhaseWatcher		
Maximum Operating Liquid Flow (low gas flow)	2051	sm3/d
Maximum Operating Temperature	150	C
Maximum Operating Pressure	344	bar
Liquid Viscosity Range	0,1-2000	cp
Water/Liquid Ratio	0-100	%
Gas Volume Fraction	0-98	%

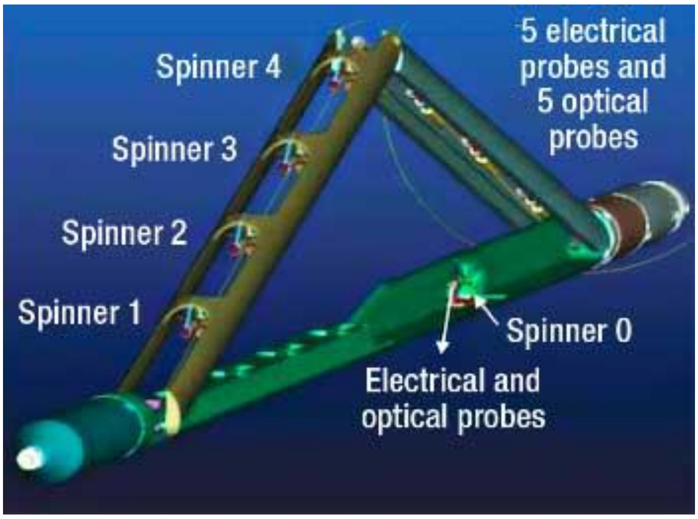
Tabell 15

DATASHEET, Weatherford Optical Multiphase Flowmeter		
Volumetric flow rate accuracy(of measurement)	+/- 1	%
Flow rate accuracy, oil-water(0-100% WLR)	+/- 5	%
Flow rate accuracy, liquid-gas(<30% or >90% GVF)	+/- 5	%
Flow rate accuracy, liquid-gas(30% to 90% GVF)	+/- 20	%
Pressure Rating	690	bar

7.3 Production Logging Tool

Another way to measure the down hole flow regime is to use a production logging tool(PLT). It is a device which uses spinners as sensors to measure the flow of the different fluids.

For our case, Schlumberger is recommending their Flow Scanner to log the flow. It is using electrical devices to differentiate hydrocarbons from water. Since water is a conductor and oil and gas are not, the tool is able to distinguish between water and hydrocarbons. The Flow Scanner has optical equipments to distinguish between liquid and gas phase. This can be done, since light travels faster through gas than through water or oil.



Figur 33

Illustration of the Flow Scanner from Schlumberger. The PLT is using spinners to measure the flow of the different fluids and electrical and optical probes to distinguish

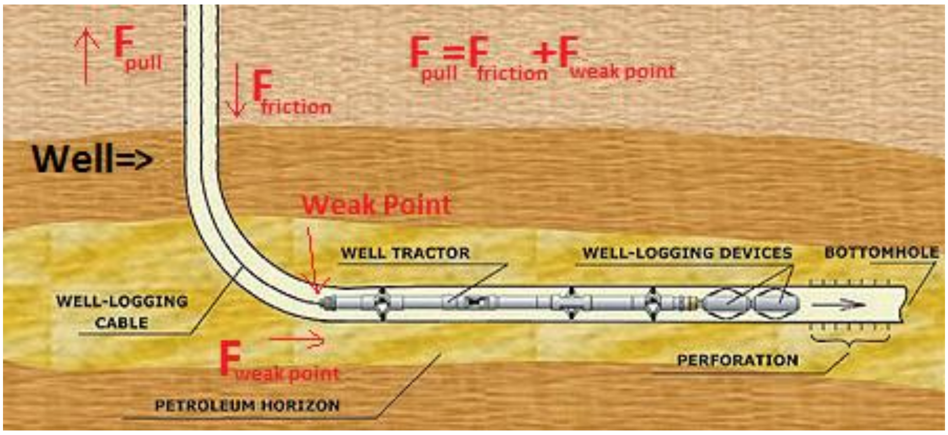
Tabell 16

DATASHEET, Schlumberger's Flow Skanner		
Maximum Operating Pressure	1034	bar
Maximum Operating Temperature	150	C
Hole Size Operating Diameter	from 2 7/8 to 9	inches
Three Phase Holdup Accuracy	+/-10	%
Velocity Accuracy	+/-10	%
Outer Diameter	1,668	inches
Weight	49	kg
Length	4,9	m

7.4 Well Tractor & Wire Line

Since the Gulltopp well is nearly horizontal, gravity alone will not be able run the production logging tool in hole. It is possible to use a tractor to help pulling the tool. By using a tractor it is possible to perform light well intervention with the PLT connected to wire line. This is less expensive than intervention with coiled tubing. It is possible to reach longer with wire line than with coiled tubing. This is because helical lockup is an issue with coiled tubing, but it is not a problem with well tractors and wire line.

One of the limitations with wire line is the strength of the cable. When the work of the tractor is done, a certain force is needed to release the wire from its weak point. The wire line must also withstand forces due to friction. A standard 7/16” wire line cable has a maximum suggested working tension of approximately 40 kN. If the weak point strength is 20 kN, only half of the maximum working tension can be used to overcome friction.



Figur 34

The force needed to pull the cable out of hole might be bigger than the cable can withstand. The problem can partly be solved by using a electrically releasable weak point. Illustration: taris.ru

The Gulltopp well is very long, and there might be a problem with pulling the wire line out of hole due to friction. The wire line might get stuck, and trying to recover it will not be easy. Part of this problem is solved by Schlumberger, since they have electrically releasable weak point on their tractor; MaxTRAC.*9.1.6* This means that all the force applied on the wire line can be used to overcome friction. To be sure that it is possible to use wire line and tractor in the Gulltopp well, modeling the friction in well has to be done. The friction modeling will not be covered in this report.

Figur 35

Illustration photo of the MaxTRAC well tractor from Schlumberger, using a electrically releasable weak point.

Tabell 17

DATASHEET, Schlumberger's MaxTrac		
Maximum Operating Pressure	1034	bar
Maximum Operating Temperature	150	C
Hole Size Operating Diameter (tractoring)	from 2,4 to 9 5/8	inches
Maximum Dogleg	45	degrees/30,5m
Maximum Pull	454	kg
Maximum Tool Diameter	2,125	inches
Maximum Reach	Has to be modeled for each well	

7.5 Compositional Fingerprinting

A new technology is developed by Schlumberger called compositional fingerprinting. By measuring the asphaltene level in the oil topside with 4D GCMS, it is possible to determine which layers the oil is coming from. The philosophy is that the level of asphaltene is increasing with increasing depth. This is because the asphaltenes have higher density than lighter hydrocarbon compounds. Because of that, it can be determined which layers the well is producing from.

7.6 Tracers

Another way to investigate the flow from the different segments is to use radioactive fluids, called tracers. The wanted property is supported by adding a radioactive mineral to the solution. Carnotite, which is a mineral containing uranium, is often used. The tracer is injected into the reservoir, most commonly by a injection well. The fluid can then be monitored as it is flowing into the production tubing. By using a gamma ray tool down hole, it is possible to determine which segments are producing the tracer first, giving indications of higher flow ability.

Since there are no injection wells on the Gulltopp field, injection of the tracer has to be done in another way. One idea is to inject the tracer in the annulus of well A-32 CT6. A part of the annulus of the production tubing is closed, so the tracer will be flowing into the reservoir. A second idea is to inject the tracer via the exploration well on Gulltopp, 47ST2. The third idea is to drill a sidetrack in the existing well, A-32 CT6. The planned sidetrack to the sand Ness 3 might be useable for injecting tracer. is already been planned. Due to lack of time, none of these ideas were simulated in Eclipse, so more investigation has to be done.

7.6.1 Sources:

www.slb.com

http://www.omega.com/prodinfo/flowmeters.html

http://www.efunda.com/formulae/fluids/venturi_flowmeter.cfm

http://www.onepetro.org/mslib/servlet/onepetropreview?id=00063118&soc=SPE

http://www.se-source.com/varianGCMS.htm

http://www.leco.com/products/sep_sci/pegasus_4d/pdf/PEGASUS%204D%20GCxGC-TOFMS%20209-183.pdf

http://www.taris.ru/eng/img/img_product/transporter.jpg

http://www.acronymfinder.com/Water_In_Liquid-Ratio-(multiphase-flow-metering)-(WLR).html

http://www.eng-tips.com/viewthread.cfm?qid=188726&page=10

www.worldoil.com

8 Conclusion

Segment 2 is the largest contributor to the total oil production in both cases. And the production pattern does not fit with the other segments' pattern. This may be caused by a contribution from another formation.

After comparing the production recordings from different sources we concluded that an eventual contribution from Tarbert 1 is being recorded in segment 2, which makes the magnitude difficult to determine.

Because of the pressure drop in the reservoir there will be a great increase in GOR. We have seen this as one of the reason for the rapid decline of cumulative oil rate from the well, combined with the large water production.

After analyzing the pressure development in the reservoir due to production we would recommend a pressure support program for the reservoir.

We made the decision to shut out segment 5, 6, 7 and 8 by investigating the migration of water in the reservoir. The water break through happened first in these segments. And they were also the layers who produced the most water during the fields' life time. The result of shut-in was that we produced more oil and less water.

To investigate the flow from the reservoir in to the production tubing, we recommend the use of a production logging tool combined with a well tractor. We choose the Flow Scanner PLT from Schlumberger with a MaxTRAC well tractor because this combination has proved to be suitable in a similar task. It is uncertain if flow meters will work down hole in a three-phase situation. However, the friction in the wellbore has to modeled to check if the wire line cable can take the load.

If the question on how to select which zones to produce from in the well I solved, and the cost is low: The sensitivity case is to preferred compared to the base case because of higher net present value of the project.

According to Schlumberger, a well intervention using a PLT and a tractor will cost approximately 3 million NOK. This number might be bigger since issues related to the extreme length of the Gulltopp well might occur.

The problem with how to close in the parts of the production tubing for real is not solved. This might be a very complex operation with significantly high unknown costs.

List of figures and tables

9 Appendix

9.1.1 Report, part A

9.1.2 Excel-sheet, part A

9.1.3 Excel-sheet, Base Case

9.1.4 Excel-sheet, Sensitivity Case

9.1.5 Excel-sheet, Economical Part

9.1.6 Case Study: Flow Scanner PLT and MaxTRAC used for well intervention in horizontal well

Schlumberger

Accurate Three-Phase Quantification Using Flow Scanner Toolstring in a Horizontal Well

Case Study: Downlog capability improves data quality

Challenge

StatoilHydro required an inflow profile of a horizontal oil producing well in the Omega Nord structure. They wanted to identify any significant differences in the reservoir pressure between the Middle and Lower Tarbert areas.

Solution

The MaxTRAC* downhole well tractor system was used to convey the Flow Scanner* horizontal and deviated well production logging system to a 6,040 m MD.

Results

The combination of the MaxTRAC system and the Flow Scanner toolstring made it possible to measure and quantify three-phase flow and led to a saving of three trips across the logging interval.

Dedicated software created multiphase quicklook images for quality control.

Profiling flow to plan intervention in a horizontal well

In January 2009, StatoilHydro required an inflow profile for a horizontal oil producing well in the Omega Nord structure. The well TD is 6,390 m MD. It is perforated in Middle Tarbert 2 and in Lower Tarbert. A total of 641 m has been perforated at three intervals.

A production logging profile in February 2004 revealed that the 30 m perforated section in the toe of the Lower Tarbert contributed to 68% of the total inflow of water cut. In October 2008, the production rate declined rapidly, and water influx was suspected. Although normal production was later resumed, a decrease in production shortly following shut-ins suggested possible water loading in the liner.

Complex operation

Because of the limited rig-up height, the toolstring was deployed using three deployment bars. It took 30 hours to rig-up and deploy the toolstring into the well, which demanded seamless coordination between the service providers.

In a total of three consecutive descents, the MaxTRAC system conveyed the Flow Scanner toolstring to 6,040 MD.

Real-time monitoring

Data was available in real time for analysis through the InterACT* connectivity, collaboration, and information system. This made it possible to monitor internal and tubular changes and compressions exerted on tools below the tractor while it was run in hole, to avoid equipment damage and stuck tool. The capability to record data against the flow while tractoring down the well improved data quality. Multiphase flow profile quicklook images from the inflow profiler aided data quality control.

Case Study: Downlog capability improves data quality

Operation and results

The combination of the MaxTRAC system and the Flow Scanner toolstring made it possible to

- retain constant logging speed
- perform cumulative tractoring: ~6,000 m
- maintain proper Flow Scanner system orientation
- log down passes in real time
- identify water and gas entry points
- obtain multiphase flow profile across the logging interval at multiple rates.

E-mail govil@slb.com or contact your local Schlumberger representative to learn more.

"Platform management conducted an inspection where the area for Interventions received special praise. The word was that this was an area which was extremely good and 'a joy to inspect.' The deployment and logging job went very well, so also technically this was a very good job. When working with positive and motivated workers one gets a job flow which I feel was particularly good this time. The job gets top marks!"

Jan Fosshagen
Well Intervention Supervisor
Oseberg

www.slb.com

Schlumberger