Universitetet
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Faculty of Science and Technology

MASTER'S THESIS

Study program/Specialization: MSc Petroleum Engineering/ Reservoir Technology	Spring semester, 2012 Restricted access
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Title of thesis: *Developing a full field geological model with subsequent reservoir numerical simulation on the Krafla field.*	
Key words: Geological model, Reservoir numerical simulation, Field development, Petrel, Eclipse,	Pages: 95 + Appendix: 11 Stavanger, 15.06.2012

Acknowledgements

This report is the result of a Master Thesis which is written for, and together with, Det Norske Oljeselskap in Harstad during the spring term 2012.
The thesis concludes the degree of Master in Petroleum Engineering at the University of Stavanger, with specialization in reservoir technology.

Writing the thesis has provided me with insight and valuable experience in reservoir technology as being part of the everyday life of a professional reservoir engineer.
It has been a challenging, exciting and educational experience which has clearly increased my personal interest of working with reservoir simulation and technology.
However, the thesis could never have been accomplished without the help and support from several individuals.

First of all, I would like to thank my supervisor at Det Norske Oljeselskap, reservoir engineer Pål Skillingstad. Your passion about reservoir engineering and your professionalism through this thesis has been an inspiration to me. Thanks for all your guidance and motivational talk, and for making me a part of the Det Norske Oljeselskap.
I would also express my graduate to the rest of the people at Det Norske Oljeselskap which has provided me with additional information to the thesis and who made the days at the office light and bright. Thank you.

Finally, thanks to my professional supervisor at the University of Stavanger, Professor Leif Larsen who also contributed as my lecturer during my education at the university. Your incredible knowledge has provided me with high educational insight in the reservoir technology study which I am grateful for.

Last but not least, my dearest greetings go to my beloved family and friends who believed in me not only through this thesis but through my whole education. You have been a huge support through ups and downs and I will for always be grateful to you.

Best regards,

Tonje Edvardsen, 15.06.2012

Abstract

The Krafla field is newly discovered in production license PL 272/035 which is located in the North Sea where Statoil is the operator and Det Norske Oljeselskap is one of the partners. Exploration wells are drilled on the structure where the aim is to prove existence of commercial hydrocarbons in the Tarbert Formation and to collect sufficient data needed to assess the development of the prospect.
Development solutions are evaluated and production platforms nearby is able to assist in producing the field.

A full field geological model is developed with petrophysical data provided as input from the exploration wells. A grid is constructed in Petrel with reservoir properties and computational saturation functions simulated throughout the grid.
The geological model are imported into Eclipse are the remaining initialization are performed.

A total of 5 scenarios are initialized and simulated by the use of reservoir numerical simulation, where total fluid production and rate is evaluated in addition to gas oil ratio and bottom hole pressure. The scenarios consisted of differing number and types of wells, perforation heights, well placement and water injection.

The first scenario is considered the base case where the well placement, number and types of wells are initialized by knowledge from similar structures as the Krafla field and from development strategies performed on earlier basis.
The previous two scenarios are observing the difference by the addition and removal of an oil producer on Krafla Main which also contained a water injection well.
The remaining two scenarios are performed on Krafla West are the difference in providing a vertical well in relation to a horizontal well is observed.

As the base case only represents the base wireline log interpretation and one set of maps, there are a significant uncertainty and source of errors. However, the model will be a basis for further simulations and detailed studies.

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1. Introduction

1.1 Background

New fields are explored on continuous basis and the development of both new and existing fields require careful planning and good structuring to find the best possible development solution concerning safety, environment and economic values.

The international oil company Statoil, together with its partners including Det Norske Oljeselskap, is developing a newly discovered field in the North Sea.
Exploration wells are drilled where the primary objective is to prove the existence of commercial hydrocarbons in the middle Jurassic Tarbert Formation and to collect sufficient data needed to assess the development of the prospect.

As a part of the development process, Det Norske Oljeselskap is building a geological model with the petrophysical properties from the field in Petrel and a reservoir simulation model with initialization in Eclipse.
The different aspects of building a full field model requires understanding about the petrophysical behavior and knowledge about the reservoir engineering technology, including the ability to evaluate advantages and disadvantages for different production options.

1.2 Problem statement

The aim of the thesis is to take part in the development process of a newly discovered field in the North Sea by constructing a geological model with available petrophysical properties and initialization of a reservoir simulation model with associated data.
The thesis gives an insight of the model construction in accordance to the data required to make the model as vivid as possible and contribute to provide a foundation for future elections in the development process.

Reservoir numerical simulation is provided to simulate scenarios regarding well numbers and placement after construction and initialization of the model, where water injection is considered due to lack of natural fluid lift.

Advantages and disadvantages are discussed in the different scenarios where total oil and gas production and high recovery factor are essential for the different outcomes.

In accordance to the construction of both the geological model and the reservoir simulation model, the topics investigated and discussed in the simulated scenarios are:

- What impact will the number of production wells have on the total oil and gas production from a field?
- What type of well (vertical/horizontal) will give an optimizing effect on the production?
- Will the location of the wells provide any difference in reservoir volumes produced?
- Would the outcome of the results have been affected due to what type of scale on the grid blocks are chosen?

The thesis is written and based on a real discovery in the North Sea, and the results provided may contribute as a crucial factor for development decisions to be made.
Building a reservoir simulation model is an important aspect of the development process, and the thesis may work as a guideline to help achieve the optimal solution for future fields.

1.3 Solution

The geological model is built by the use of Sclumberger's '*Petrel 2011.2*' version and the reservoir model is initialized and simulated by the use of Schlumberger's '*Simulation Launcher, Reservoir simulation launcher version 2012.2.*' where the softwares Eclipse, FloViz and Office are used.
Input data needed to build a full field geological model is provided from the operator of the field, but given that the field development is in the early stages it is experienced some lack of data where default parameters from the software programs are used as a substitute.

1.4 Limitations

In order to limit the scope of the thesis some fundamental topics and simulation scenarios are not covered in the study. These topics are given in the following and may be of importance in a developing process:

- The use of gas lift versus water injection as artificial lift.
- Optimizing dimension of pipe lines considering friction and pressure drop for fluid transport to production template.
- Investigating range of uncertainty (P10, P50, P90) in model parameters such as porosity, permeability, fluid contacts and endpoint scaling to determine the extreme values.
- The use of a finer grid scale with higher resolution versus a coarse grid scale to compare the accuracy of the results provided.

It is preferred that the reader of the thesis has fundamental knowledge in petroleum technology and reservoir simulation, although some theory concerning the petrophysical properties and the basics of reservoir simulation is provided throughout the thesis.

1.5 The report

The study which has been performed is presented in the following report and consists of 11 chapters in addition to references, nomenclature and appendices.

- Chapter 1 states the background and aim for the problem statement provided in the thesis including the limitations for the work.
- Chapter 2 gives a brief introduction to the field discovered and provides an insight in the geological structure and the development strategy for the field.
- Chapter 3 provides the reservoir description and fluid properties from the field.
- Chapter 4 gives an introduction to the reservoir simulation theory where the main topics are covered to provide an understanding of the behavior and knowledge about the various aspects related to the simulation.
- A brief presentation of the software used in this thesis is given in Chapter 5.
- The construction of the geological model is provided in Chapter 6, where the aspects of building a full field model with petrophysical data are defined and implemented.
- Chapter 7 describes the initialization of a reservoir numerical simulation model and considers model input parameters not provided in the geological model.
- Chapter 8 address the different simulation scenarios performed during the study.

- The results from each scenario and the discussion related to the study are presented in Chapter 9. Graphs are provided to illustrate the results which are evaluated and interpreted followed by a conclusion in each scenario.
  Problems and challenges encountered through to the study are explained, and possible sources of error are discussed at the end of the chapter.
- Chapter 10 summarizes the conclusions withdrawn from the study.
- Recommendations for further work are suggested in Chapter 11.

2. The Field

2.1 History

Statoil Petroleum AS drilled in 2011 exploration wells on the Krafla Main and Krafla West structures located in the Norwegian part of the North Sea, where Det Norske Oljeselskap is one of the partners.

The first well 30/11-8 S discovered oil in the Tarbert Formation and gas condensate in the Ness Formation of the Brent group, and a sidetrack 30/11-8 A is drilled which encountered oil in the Heather Formation and gas condensate in the underlying Tarbert Formation. [1]

The exploration wells are formation tested, logged and cored. In addition there are a total of twenty samples taken for PVT analysis by the use of a Modular Formation Dynamics Tester (MDT) which identifies and collects high-quality reservoir fluid samples for downhole fluid analysis and further laboratory analysis. [2]

Data acquired from the well are:

- Logs and Cores from both wells
  - Miniperm is run on both cores taken in the Tarbert Formation
- Mini-DST
- MDT samples (12 samples in well 30/11-8 S and 8 in well 30/11-8 A)
- VSP from well 30/11-8 S

An extensive SCAL study is initiated but the result is not ready when building the model.

2.2 Location

The Krafla Main and Krafla West discoveries are located within production license (PL) 272/035 in the north Northern Sea, approximately 36 km southwest of the Oseberg Field Centre and 30 km north of the Frigg Gamma and Frigg Delta discoveries. [3]

The prospects are seen as being time critical due to future gas blow-down of the nearby Oseberg Field. [1]

The location of the Krafla discoveries in relation to nearby fields, discoveries, license boundaries and facilities are shown in figure 2-1. [1] The image recessed in the figure shows the depth map of the Top Tarbert level illustrating the outline for Krafla Main (blue) and Krafla West (red). The area around Krafla is characterised by a large number of SSW-NNE faults intersected by smaller East-West trending faults that form a large number of fault bounded closures. [1]
A large North-South fault which holds more than 100 bars is separating the two fields and constitutes as a barrier together with coal/shale layers. Due to this elevation and sealing between layers there are 5 PVT-regions in total for the two fields; three in Krafla Main and two in Krafla West.

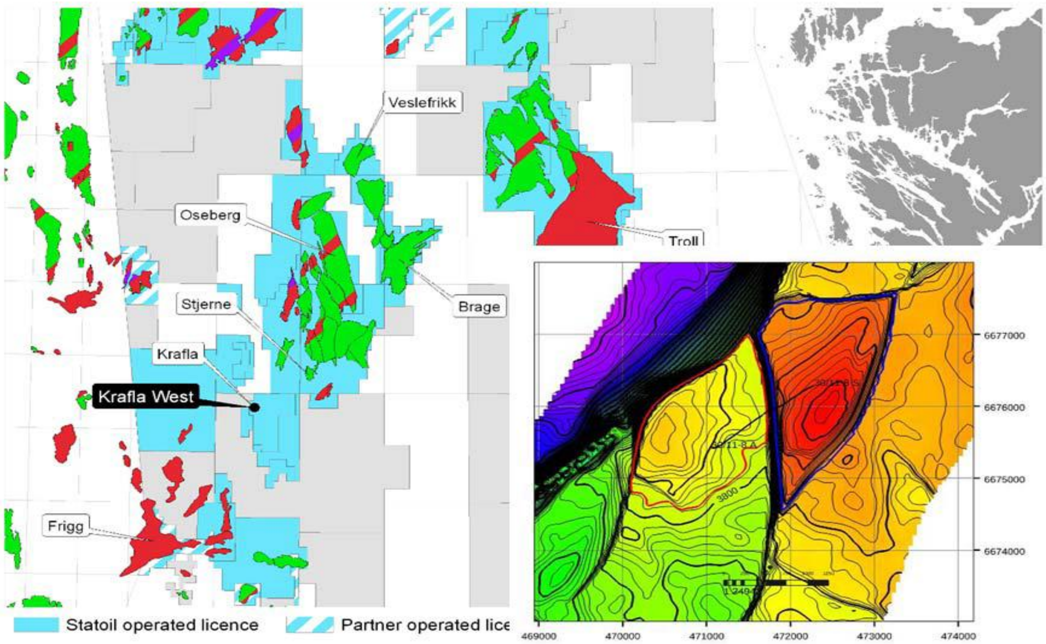

Figure 1-1: Location of the Krafla discoveries and depth map of the Top Tarbert level.

2.3 Geology

2.3.1 Depositional environment

The lithology on Krafla Main and Krafla West generally consists of coal beds, over bank deposits and channelized sandstones that form the only potential reservoir in the formation.

Hydrocarbons are detected in sandstones belonging to the Ness, Tarbert and Heather Formations. Figure 2-2 illustrates the stratigraphic location of the discoveries for Krafla Main and Krafla West. [1]

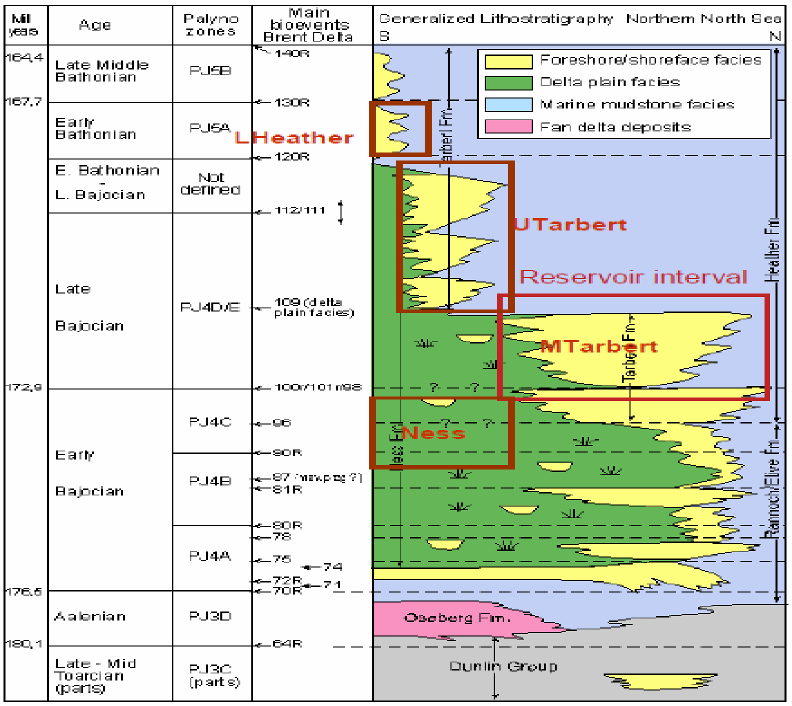

Figure 2-2: Stratigraphic column of the Brent Group in the northern North Sea illustrating key reservoir intervals.

Table 2-1 gives an overview of the formation deposition on the Krafla fields and the reservoir quality of the different formations.

The Tarbert Formation has been subdivided into three zones; lower Tarbert, middle Tarbert (1 and 2) and upper Tarbert based on correlations with nearby Oseberg South field.

Ness Reservoir	The Ness formation has reservoir potential in both Krafla Main and Krafla West although it is only filled with hydrocarbons in Krafla Main. The formation consists of a complex reservoir with a low net to gross which is composed of channelized sands and crevasse splays. [1] *<u>The reservoir is concluded as non-producible due to low reservoir quality and is not considered in the further model-building.</u>*
Middle Tarbert 1 and lower Tarbert (Ness/Tarbert transition)	Further to the north, near Oseberg South area, the lower Tarbert formation is a good shore face reservoir, but the shore face pinches out into coastal plain deposits in the Krafla area. [1] This is also considered for the middle Tarbert 1 Formation which essentially is a coastal plain deposit. Due to this, the zone is a non-reservoir interval in both wells and forms a major barrier across the area.
Middle Tarbert 2 Reservoir	The reservoir in middle Tarbert 2 is considered to be a regressive-transgressive wedge where the deposition took place in a major estuary system. [1] The depositional system forms a significant high-quality reservoir across a large part of the region. The sands of the middle Tarbert are expected to contain excellent properties suggesting that the zone will be a major volumetric contributor. *Figure 2-3 illustrates the regressive-transgressive Tarbert wedge.*
Upper Tarbert Reservoir	From the deposition of the middle Tarbert zone, the sea-level rise which caused a coastal plain to dominate by alternating environments of extensive coal-generating coastal swamps and widespread estuaries. [1] But due to continued sea-level rise, the swamp environment is absent from the upper part of the unit where estuary channels, mouth bars and lagoonal sediments dominate the area around the Krafla wells.

	The sand in the upper Tarbert is expected to have the same good properties as middle Tarbert 2, and will also be a major volumetric contributor.
Lower Heather Reservoir	From deposition of the upper Tarbert, another major flooding caused a transgression which led to a succession of upward coarsening shore face, and delta-front sediments are deposited across a large part of the region. [1] The coarsest sands are deposited in the southern part of the region (Krafla West) where the succession is sand-dominated, while in the northern part (Krafla Main) the succession is so silt-dominated that it does not have reservoir quality.

Table 1-1: Formation deposition and reservoir quality on Krafla Main and Krafla West.

By evaluation of the reservoir quality in table 1-1, only 3 PVT-regions are considered in the following when constructing the geological model;
The Tarbert Formation on Krafla Main, and the Heather and Tarbert Formation on Krafla West.

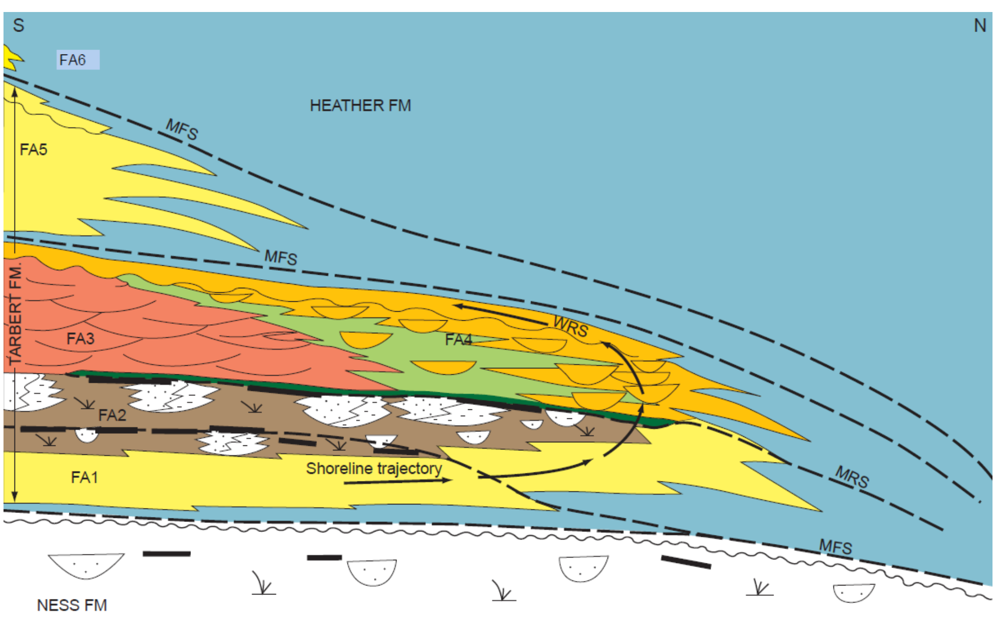

Figure 2-3: Regressive – transgressive Tarbert wedge.

2.4 Development

2.4.1 Development strategy

Krafla Main and Krafla West are discoveries with commercial potential and the evaluated development solutions of the fields consists of two potential scenarios where economic circumstances and recovery factor plays a particular important role.
The Krafla discovery could be developed by either a direct subsea tie-in to the Oseberg Field Center or via a connection to Stjerne subsea manifold and a tie-back to Oseberg South.

The base case at time being is a direct tie-in 36 km to Oseberg Field Centre and figure 2-4 illustrates the development scenario where to subsea templates are constructed on Krafla Main and West and water injection is delivered from Stjerne and Oseberg South.

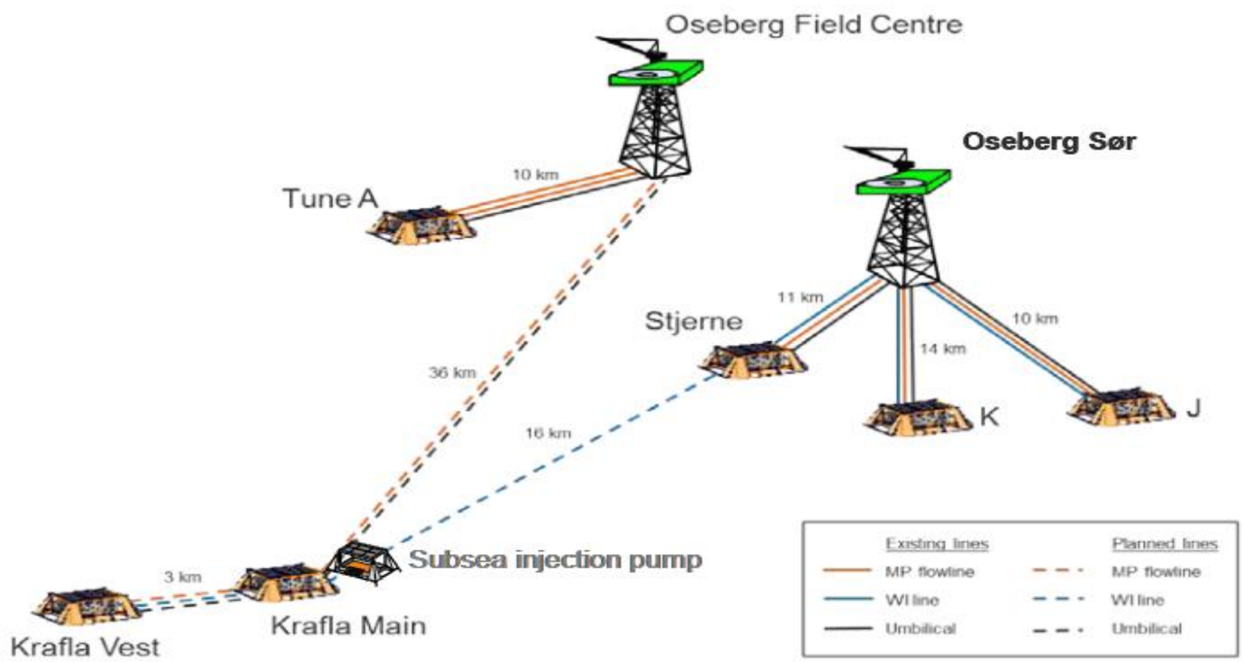

Figure 2-4: Krafla base case scenario with 2 subsea templates and tie-in to Oseberg Field Centre.

The area surrounding the Krafla discovery contains a number of interesting prospects that will represent interesting additions to the potential development.

One part of the development evaluation is to investigate if smaller discoveries and prospects in the area could be developed together with Krafla. [1]

The drainage strategy preferred to develop Krafla is pressure maintenance by water injection, and simulation studies performed in this thesis examines the use of this to increase the oil volume production.

Other simulation scenarios which should be considered but not developed in this thesis consists of comparing gas lift to water injection and evaluating optimum dimensions of pipelines between Krafla templates and tie-in.

3. Reservoir description and fluid properties

The chapter provides an insight in how the reservoir quality is defined due to contacts and existing faults. It will also provide information about the pressure evaluation and fluid properties contained in the reservoir.

3.1 Defining contacts

3.1.1 Krafla Main

The Krafla Main discovery includes oil within the Tarbert Formation and gas condensate within the Ness Formation, but the two hydrocarbon columns are not in communication.
An ODT (Oil Down To) exists within the Tarbert Formation, located at 3454 m TVDSS.
The hydrocarbon filling is thought to be controlled by the spill point across the eastern fault (3550 m TVDSS), although deeper filling might exist if fault seal is effective.
The deeper Ness filling supports this observation, giving an expected (mean) OWC at 3534 m TVDSS.

The Ness formation contains a number of isolated channels where the upper 3 channels contain gas condensate and a GDT/WUT (Gas Down To/Water Up To) exists at 3593/3607 m TVDSS. As the GDT/WUT levels are in close proximity, and due to the isolated nature of the Ness channel it is unlikely that an oil leg is present, and an expected (mean) GWC is set at approximately 3600 m TVDSS.
The Ness Formation is juxtaposed against the Tarbert, across the bounding fault in east to the Krafla West discovery, suggesting that cross-fault seal is working. [1]

3.1.2 Krafla West

The Krafla West discovery includes oil within the lower part of the Heather Formation and gas condensate in the upper part of the Tarbert Formation.
Pressure measurements indicate that the lower Heather and upper Tarbert accumulations are not in communication with each other or any of the Krafla Main hydrocarbon bearing zones.

A GDT/WUT is encountered in the Tarbert Formation at 3771/3777 m TVDSS, but as the GDT/WUT is so similar, the prospect for finding an oil leg is unlikely and the expected (mean) GWC is set at 3774 m TVDSS.

In the Heather Formation an ODT exists at 3593 m TVDSS, but the hydrocarbon filling is thought to be controlled by a spill point arising from the juxtaposition across the Krafla West eastern boundary fault giving a mean contact of 3675 m TVDSS. [1]

Table 3-1 summarizes the identified fluid observation levels on both Krafla Main and Krafla West while table 3-2 gives an overview of the expected (mean) contacts set for both fields. An illustration of the Krafla Main and Krafla West structures with the expected contacts are given in figure 3-1.

Fluid observations [m TVD MSL]		
	ODT	GDT/WUT
Krafla Main, Tarbert fm.	3454	-
Krafla Main, Ness fm.	-	3593/3607
Krafla West, Lower Heather fm.	3593	-
Krafla West, Tarbert fm.	-	3771/3777

Table 3-1: Fluid observation depths on Krafla Main and Krafla West [m TVD MSL]

Expected (mean) contacts [m TVD MSL]		
	OWC	GWC
Krafla Main, Tarbert fm.	3534	-
Krafla Main, Ness fm.	-	3600
Krafla West, Lower Heather fm.	3675	-
Krafla West, Tarbert fm.	-	3774

Table 3-2: Expected contacts on Krafla Main and Krafla West [m TVD MSL]

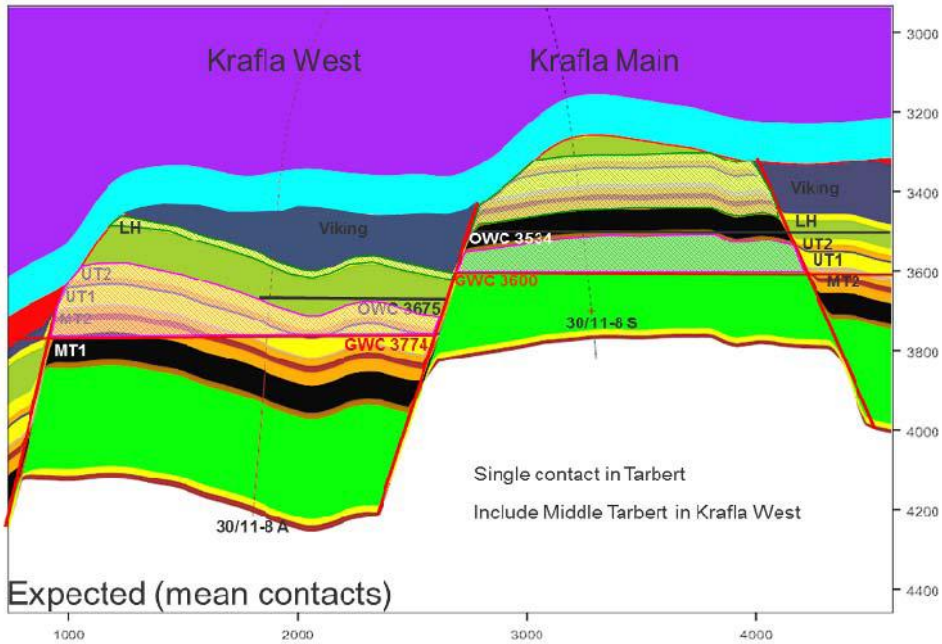

Figure 3-1: Schematic illustration of Krafla Main and Krafla West with fluid expected contacts [m TVD MSL]

3.2 Formation pressure evaluation

Due to the sealing fault that is separating the two fields, both reservoirs in the Tarbert formation on Krafla Main and Krafla West are experiencing an overpressure. Initial pressure is about 90 bars above hydrostatic pressure on Krafla Main, and about 210 bars above hydrostatic pressure on Krafla West.

The reservoir pressures and temperatures on the Krafla field are given in table 3-3. [1]

Reservoir	Pressure [bars]	Temperature [˚C]
Krafla Main Upper Tarbert	426,3	123,5
Krafla Main Middle Tarbert	426,3	127,4
Krafla Main Ness	445,0	130,5
Krafla West Lower Heather	576,8	132
Krafla West Tarbert	614,5	137,6

Table 3-3: Krafla Main and West reservoir pressures and temperatures.

Both well 30/11-8 S and 30/11-8 A consists of water filled shale, and due to lack of pressure points in poor formation, an OWC/GWC cannot be seen from wireline logs.
Only ODT and GDT can be identified.

3.2.1 Well 30/11-8 S, Krafla Main

Pressure plots showed two gradients in the Tarbert Formation; 0,734 and 0,748 which indicated oil within the main formation. The pressure difference between the two gradients is relatively small but may represent a significant production barrier. In the Ness Formation a gas gradient of 0,380 is identified. There is also several water gradients proved further down in the well. Pressure points from the well with additional oil gradients are shown in figure 3-2.

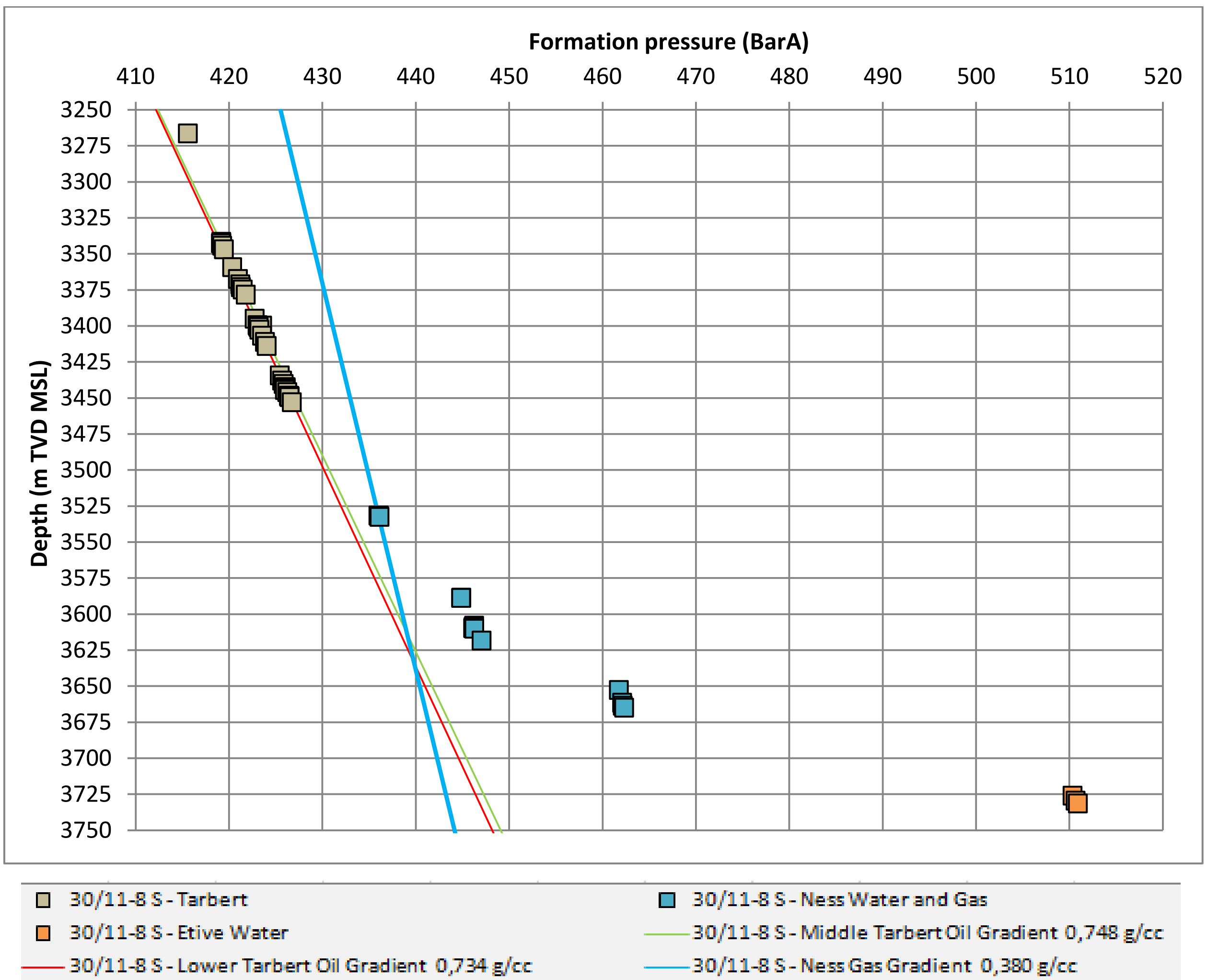

Figure 3-2: Pressure plots from well 30/11-8 S, Krafla Main

3.2.2 Well 30/11-8 A, Krafla West

Within the middle Tarbert Formation a pressure gradient of 0,535 is found which indicated oil. In the main part of the reservoir (Upper Tarbert) a gradient of 0,377 is found indicating gas. Both gradients are confirmed by sampling. [1]

By seen on figure 3-3, the pressure points at 3767,2 m TVD MSL may indicate a possible GWC in the Tarbert Formation, however; this depth coincides with a pressure point in the gas column, and a gas-condensate sample is taken at 3767,4 m TVD MSL.

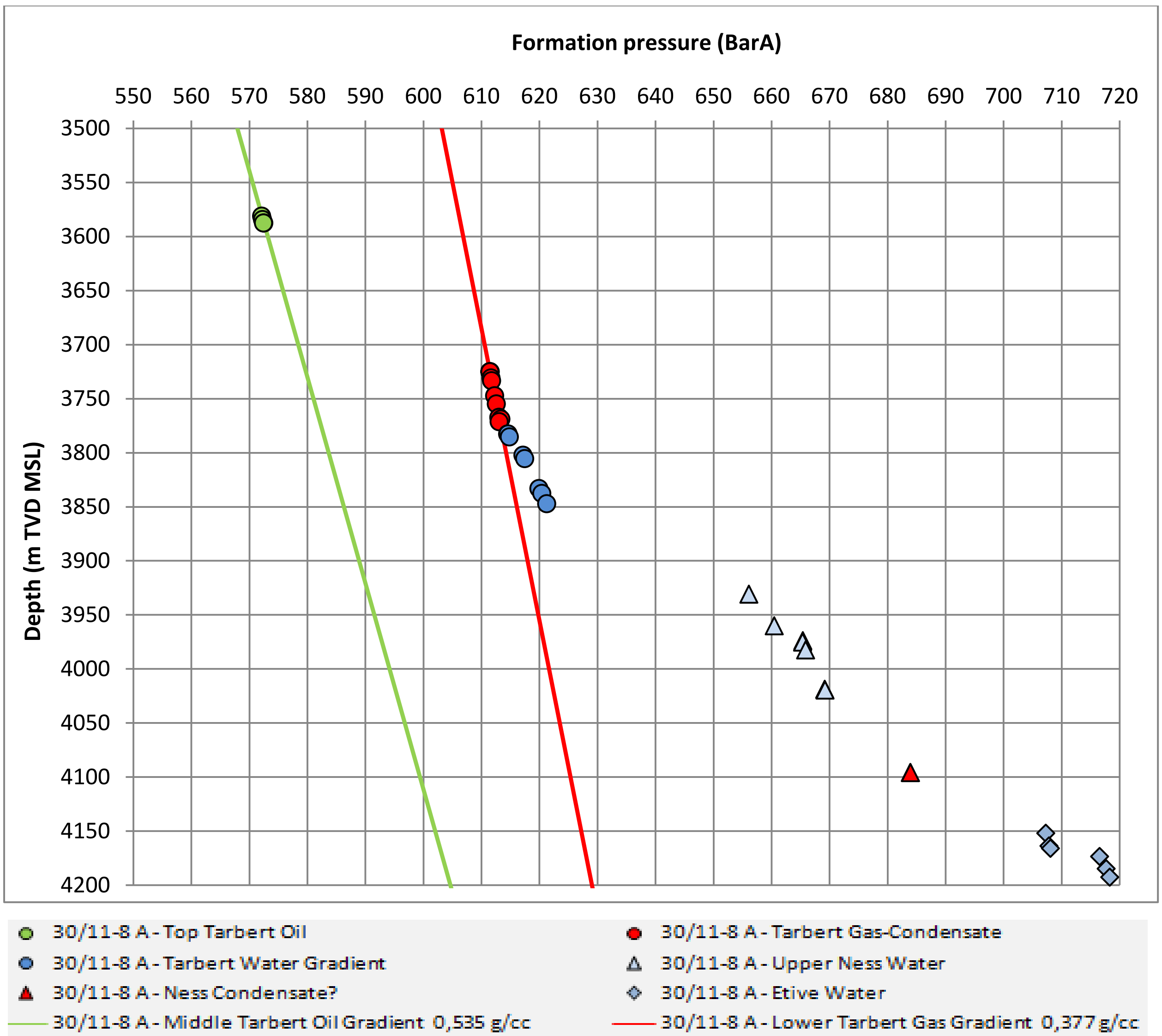

Figure 3-3: Pressure plot from well 30/11-8 A, Krafla West.

A pressure plot comparison between well 30/11-8 S and 30/11-8 A showing the gradients and the pressure differences is illustrated in figure 3-4. [1]

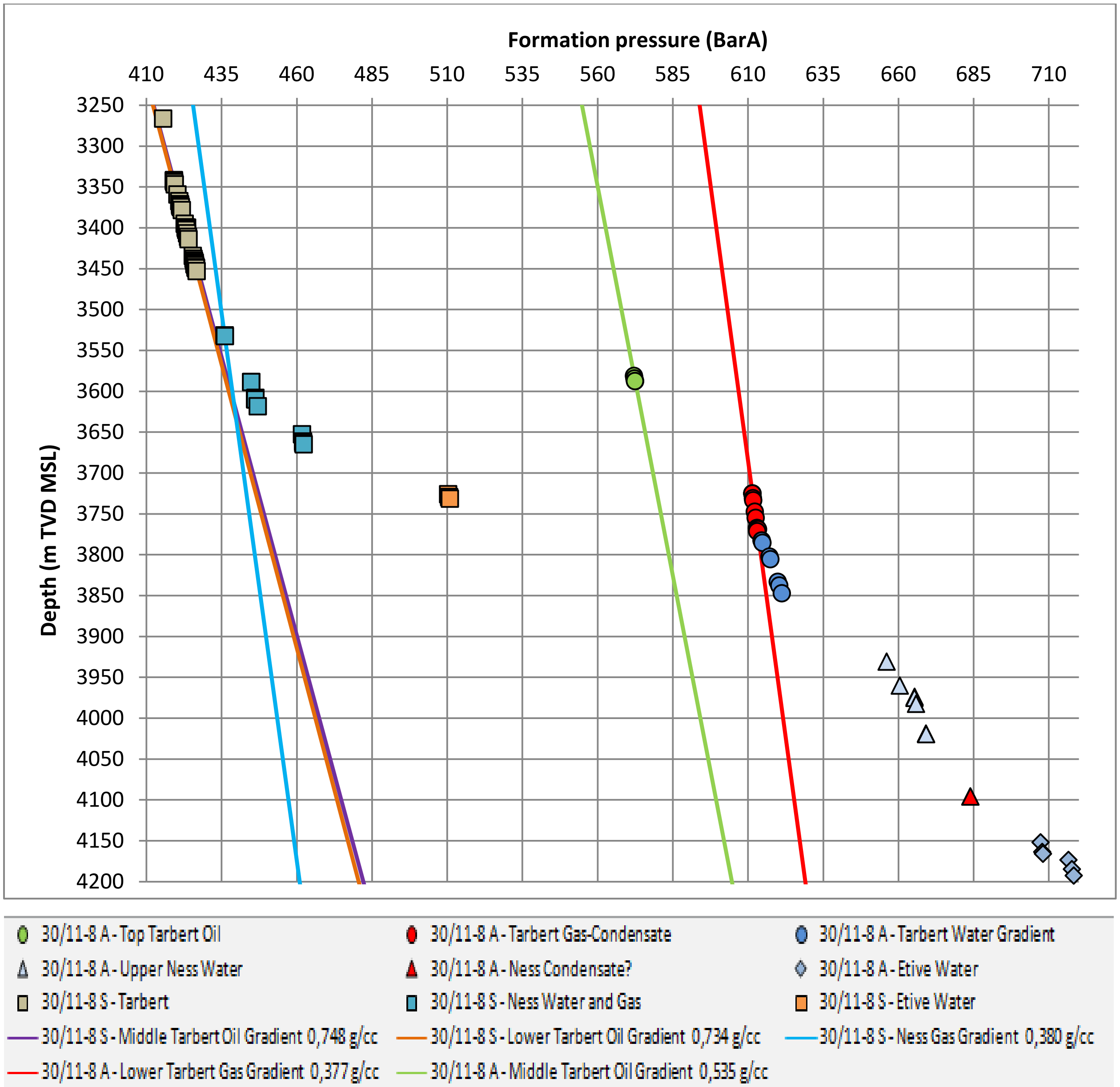

Figure 3-4: Pressure plot of comparison between well 30/11-8 S and 30/11-8 A.

3.3 Fluid properties

3.3.1 Hydrocarbon characteristics

Oil and gas samples are taken from both well 30/11-8 S and 30/11-8 A and further analyzed. Due to the complexity of the reservoir it is important to secure hydrocarbon-samples from each pressure regime.

Large volume chambers are sampled in the major HC bearing zone for flow assurance analysis. The analysis showed that the oil and the gas condensate in Krafla Main and Krafla West consist of different properties. [1]

In Krafla Main Tarbert (Upper and Middle) the two reservoir oils are a moderate-GOR black oil. They are both highly under saturated and quite similar, while the oil in Krafla West is a high GOR-volatile oil. These are therefore completely different oils.

Krafla Main Ness has a rich gas condensate, while the gas in Krafla West Tarbert is also fairly rich in liquid content but contains slightly more methane. **[3]**

Since the properties of the oil and gas condensate from Krafla West are significantly different from Krafla main, this is pointing to a complicated migration history involving multiple sources.

4. Reservoir simulation theory

This chapter gives an introduction to the numerical reservoir simulation performed in this thesis and defines the aspects related to the initialization of a simulation.

4.1 Introduction

By the use of soft-ware driven computer tools, engineers and geoscientists are allowed to build dynamic models that predict the movement of oil and gas flowing in reservoirs under the surface of the earth. [5]

For optimal reservoir management it is critical to capture the reserves as quickly and economically as possible. Reservoir simulation is able to forecast a range of production and depletion scenario based on different variables. The more quality information used as input for simulation, such as seismic data, well data and production figures, the better the model forecast will be.

Modeling a large-scale system such as an entire petroleum reservoir will require a mathematical approach where the physical system to be modeled is expressed in terms of equations. Reservoir simulation is used for solving these equations which models flow in reservoirs and the solution produces pressure and saturation distribution at different time steps.

Cumulative production, production rates, water cuts and similar entities are important simulation output, but the accuracy of the output data will be limited by the following: [5]

- The description of the physical process given by basic equations and boundary condition is only approximate.
- The equations are solved by numerical techniques and hence, only approximation to the exact solution is computed.
- Reservoir data are estimated at a limited number of reservoir locations, and due to this the methods used for measuring data may be inaccurate.
- Information may be lost during upscaling since reservoir properties usually vary on a smaller scale than the size of a grid block.

4.2 Model input data

In order to do simulation studies on a reservoir, field simulations require a huge amount of input data. Petrophysical data such as permeability and porosity consist of strong heterogeneity and a grid is needed to represent this kind of data. [6]

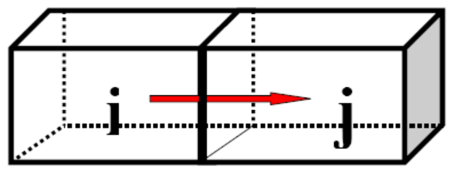

Figure 4-1: Liquid flow between grid block i and j.

In a reservoir numerical simulator, the mass flow rate [q] of liquid [l] between grid blocks *i* and *j* (figure 4-1) is computed by using Darcy's Law: [6]

$$q_l = \frac{A k_a k_r \rho}{\mu} \frac{P_j - P_i}{\Delta x_{ij}} \tag{4.1}$$

Here:

A	=	Cross sectional area between the blocks
k_a	=	Absolute permeability
k_r	=	Liquid relative permeability
μ	=	Fluid viscosity
Δx_{ij}	=	Distance between block centers
P_j-P_i	=	Pressure difference between grid block j and i

4.2.1 Grid data

The reservoir model is a numerical model and the main purpose of constructing a grid of the reservoir is the need to solve the differential equations for mass balance numerically. Heterogeneous reservoir properties such as permeability and porosity are used for input in the grid and should be selected to reflect realistic heterogeneity variations.

The grid is supposed to represent the size and geology of the reservoir and the available data used for reservoir description, and irregular geometry such as faults requires advance gridding technique. [7]

Another consideration when constructing a grid is the type of fluid displacement or depletion process to be modeled.

The grid consists of grid blocks where many grid blocks represent a fine grid and few grid blocks are considered a coarse grid. By using a fine grid, the accuracy of the simulation increases but the simulation study is time-consuming and requires higher costs than using a coarse grid.

An example showing the results of numerical dispersion when using coarse and fine grid blocks are illustrated in the following. Consider a piston like water flooding process like the one illustrated in figure 4-2: [7]

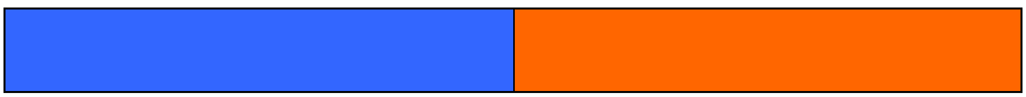

Figure 4-2: Illustration of a piston like water flooding process.

By the use of a coarse grid simulation the result of the numerical dispersion will smear the front of the water flood like shown in figure 4-3:

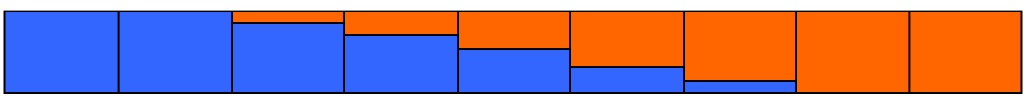

Figure 4-3: Result of numerical dispersion in coarse grid simulation.

When using better grid resolution the numerical dispersion will be reduced and the simulation will perform more accurate results as shown in figure 4-4:

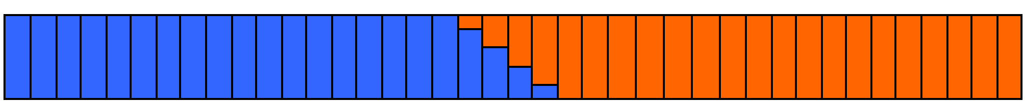

Figure 4-4: Result of numerical dispersion in fine grid simulation.

Absolute permeability usually exhibits strong variations between regions in the reservoir and is directional dependent. It is also considered time dependent and will not experience variation with pressure. An upscaling procedure is required to import fine scale permeability data from core analysis, well logging and well testing, into a coarse simulation grid.

The fluids occupy only a fraction of the reservoir volume and this fraction is called *porosity*.
The porosity is considered isotropic, meaning that the geometry is the same in all direction, but it is still strongly heterogeneous and will depend on pressure P.
Model input data for reference porosity is obtained from core analysis and well logging. [6]

Another input parameter is the *saturation functions* which change the effective permeability with varying saturation.
If there are several phases flowing simultaneously through the grid, the effective permeability of each phase depends on the saturation distribution. This dependency between saturation and effective permeability are modeled by relative permeability, and capillary pressures are also considered a dependent parameter.
Saturation functions will influence all parts of simulation such as ultimate recovery and initial fluid distribution. Fluid flow characteristics and well rate computations are also dependent of the saturation functions. [6]

4.2.2 Well data

Well positions are specified using grid block indices, but it is difficult to manually locate the blocks penetrated by the well for deviated wells.
The driving force for flow is pressure difference between block-pressure P_i and well-pressure P_{well}.
Well flow rates are proportional to the difference between block pressure and well pressure and distribution of individual rates are obtained using phase mobilities in the block.
The block well connection factor [WI], also called well index, is a constant factor which is related to block parameters and well parameters. It is computed using block characteristics like absolute permeability and block dimensions for flow between grid blocks. The well index is also composed of well radius and skin factor and the formula is given as: **[6]**

$$WI = \frac{2\pi kh}{\ln\left(\frac{r_e}{r_w}\right) + S} \tag{4.2}$$

Here:

k	=	Average horizontal permeability
h	=	Perforation height
r_e	=	Dependent on grid block parameters
r_w	=	Well radius
S	=	Skin factor

A function called *cross flow* may appear when a well is completed in two or more poorly communicating regions of the formation with significantly differing pressures.
As a result, the fluid flows into a well from high-pressure regions while some flow back into low-pressure regions even if the whole well is producing. The simulator must then be able to compute both the reinjection rate and the composition of the injected fluid mixture to model the cross flow.
Fluid composition may vary considerably along the well bore and it is not adequate to use an average composition through the whole well bore. [8]
Well operation constraints, such as pressure limits, must be specified and individual well rates, restrictions on well pressure, production water cut and gas oil ratio is crucial factors in the simulation study.
Wells can also be grouped together during simulation to identify operation constraints and producible volumes as a network. [6]

4.2.3 Runtime steering parameters

The time which is required to perform a simulation is divided into intervals, and the numerical solution is computed at certain time steps lengths which are automatically based on user defined parameters like size of time discretization error and maximum/minimum time step lengths.
A numerical solution procedure consists of iteration processes, and model parameters such as tolerances and maximum number of iterations are needed to monitor iterations. [6]

5. Available software

5.1 Petrel

Petrel is a software modeling tool from Schlumberger which is used for seismic interpretation and reservoir characterization and is frequently used on a daily basis by geologists, petrophysicists and reservoir engineers. Through this thesis the Petrel software are used to build the geological model and to distribute petrophysical data throughout the grid that is made for reservoir simulation. A lot of settings and properties is provided in the software, but each feature has an economic value and it is up to the oil companies which feature meets their benefits. Petrel has the ability to perform reservoir simulations, but another software program is used instead for the initialization and simulation of the geological model.

5.2 Eclipse

Eclipse is a simulation parameter from Schlumberger's reservoir simulation launcher and is used to construct the simulation model with the initially geological model as input.
The initialization is performed by use of Eclipse keywords described in an Eclipse manual to provide a correct and smooth simulation.
The Eclipse keywords used for initialization of the model are given in Appendix A.

5.3 FloViz

Another parameter in the simulation launcher called FloViz is provided to observe the scenarios performed in the thesis. The geological model is simply imported into FloViz where the field is illustrated with the given petrophysical data and the well placement.
The software tool made it possible to observe how the depletion of the reservoir would develop and due to the illustration of structure and heights, the location of the wells are easier to choose for simulation studies.

5.4 Office

The results of the reservoir simulation scenarios are observed by the use of the *Office* parameter in Eclipse where the results are presented in a graph showing cumulative oil/gas production and rate, water injection rate, gas/oil ratio and bottom hole pressure.
The results are evaluated and compared to conclude which scenario appeared as the optimal solution for the reservoir development.

6. Geological model

In order to build a reservoir simulation model, a geological model had to be constructed.
The construction of the grid is performed in Petrel with well data and calculated characteristics as input.

6.1 Model input parameters and method

6.1.1 Depth maps and fault sticks

Selected seismic horizons from the Krafla field had been interpreted by Statoil and these are given as depth maps derived in Petrel.
Interpreted faults surrounding the Krafla area are also available and these are converted to fault sticks to be used as input in the geological model.

6.1.2 Well data

Volume parameters like porosity, permeability and net-to-gross ratio is derived from petrophysical analysis based on core data and composite logs. These data is up-scaled in the grid blocks which the wells is penetrating and is further simulated throughout the whole grid.

6.1.4 Saturation functions

The Krafla area consists of 3 reservoirs/PVT-regions which are considered commercial and due to this, one water saturation function is derived for each of the three zones.
A log-derived J-function is used for water saturation calculation, which derived from the Leverett's J-function, and this calculation is performed in Petrel.
The basis Leverett's J-function formula is a dimensionless function that allows capillary pressure function to be correlated to rock properties and is defined as: [9]

$$J\,(S_w) = \frac{Pc\ (S\mathrm{w})}{\sigma \cos\theta}\sqrt{\frac{k}{\phi}} \qquad (6.1)$$

Here;

S_w = water saturation measured as a fraction

p_c	=	capillary pressure [Pascal]
k	=	permeability
ϕ	=	porosity [0-1]
σ	=	surface tension
θ	=	contact angle

6.2 Grid building

6.2.1 Constructing the grid

The construction of the geological model is performed in Petrel by making a grid with all available petrophysical parameters as input, and the Petrel-grid is then converted to Eclipse-grid to be used for reservoir simulation.

Depth maps from selected horizons of the Krafla field together with interpreted fault sticks made it possible to make a pillar grid, i.e. sort of a base-case for the model.

The whole Krafla area consists of 6 faults which are surrounding and separating the area, and these faults are used as a frame for the grid.

The depth map of Top Heather which contributed as a top map for the grid is shown in figure 6-1. The outline of the Krafla field can clearly be seen by the faults surrounding the area.

The closures of Krafla Main and Krafla West are easily visible as 4-way structures where the wells have been drilled.

Faults that are converted to fault sticks are shown in figure 6-2.

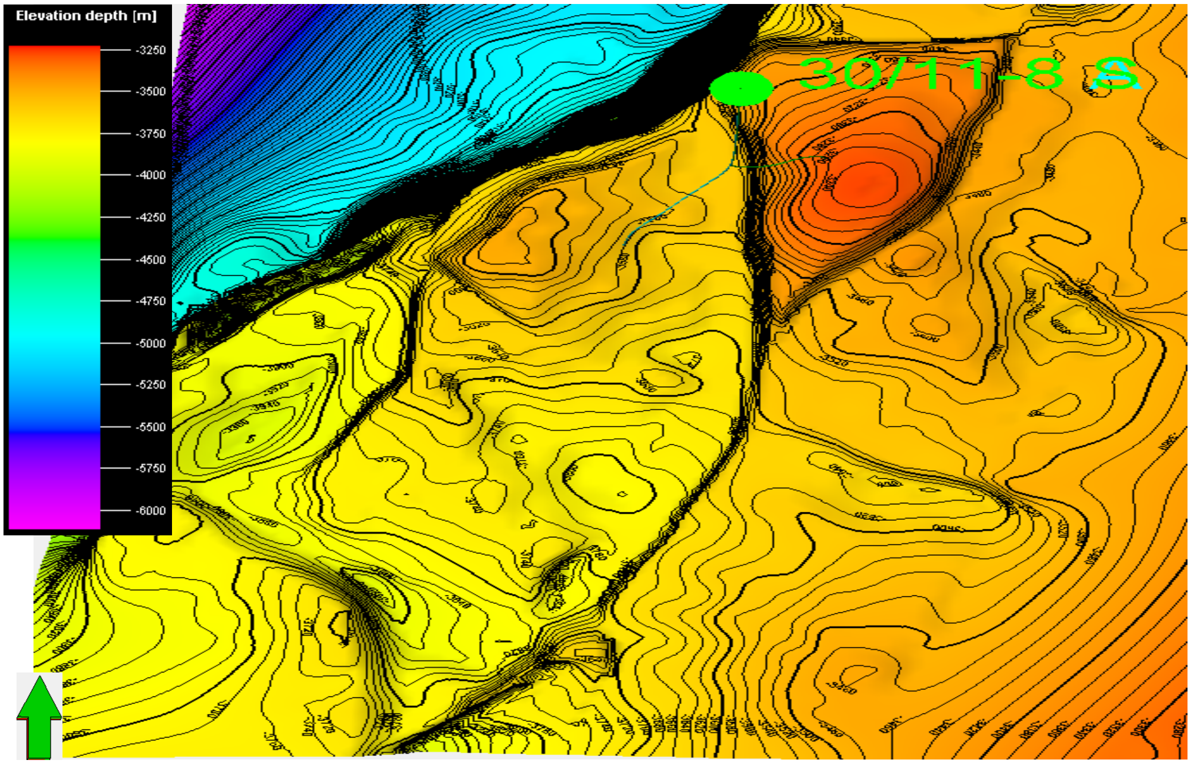

Figure 6-1: Depth map of Top Heather showing the structures and outlines of the Krafla field.

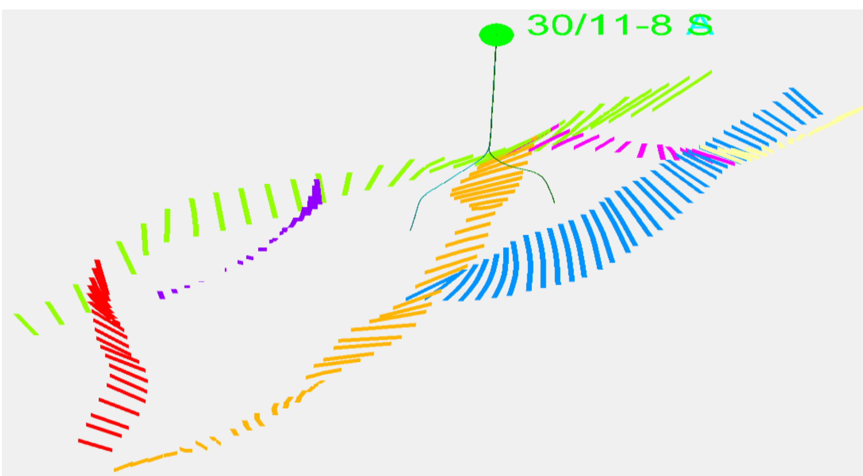

Figure 6-2: Faults stick from the Krafla faults provided in the geological model.

The pillar gridding-settings made it possible to adjust the distance between the grid nodes and the increment of the grid in i- and j-direction is set to 100 m x 100 m, which amounted as a coarse grid. This grid dimension is chosen to make the simulation in Eclipse go faster due by limiting the number of grid cells. It is also crucial that such a grid dimension will not decrease the resolution of the simulations due to extensive lateral extension of the petrophysical properties.

Another setting is to make zig-zag faults of the fault sticks which also contributed to low-time simulation and to decrease bugs, but this setting would also serve as a source of error for volume calculations. Still, by not making zig-zag faults the grid blocks near the faults would be much smaller than the grid blocks further in the grid which would cause trouble in the simulation. During simulation, one pore volume per grid block per time-step is simulated and smaller grid blocks would then cause the larger grid blocks to never be completely filled.

By making zig-zag faults the grid blocks near the faults would even each other out and be the same size as the other blocks. This would make each grid block equally filled during simulation.

There are six faults surrounding the Krafla area and due to these faults it became possible to divide the grid into seven segments, where each segment is surrounded by one or more of these faults. Since Krafla Main and Krafla West is only a small part of the whole area only 3 of these segments, which contained the fields, are of relevance for the model. The segments that did not include any structure of the fields are excluded when converting the Petrel-grid to Eclipse-grid. The seven segments which made up the whole Krafla area are shown in figure 6-3, but only the segments labeled 1, 2 and 3 are the ones taking further to simulation.

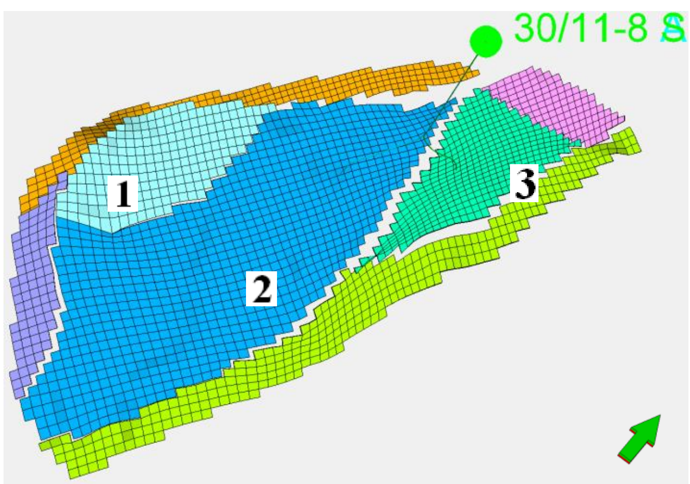

Figure 6-3: The labeled segments from the Krafla field provided in reservoir simulation.

6.2.2 Reservoir zoning and upscaling well logs

The Petrel-grid is further divided into reservoir zones in z-direction to focus on where the reserves are and to make the simulation in Eclipse easier by using zone division. The zones are divided according to information from well-logs and the depth maps given, which became a total of 4 zones;

Zone 1A;	Lower Heather
Zone 1B;	Transition of Lower Heather and Upper Tarbert (Dry zone)
Zone 2;	Upper and Middle Tarbert
Zone 3;	Transition between Middle and Lower Tarbert

The transition zone between Lower Heather and Upper Tarbert are considered a dry zone where no hydrocarbons are present.

The division of zones in the reservoir logs and the interpreted fluid distributions are given in figure 6-4 and 6-5. [1]

The reservoir zones are further divided into layers with a thickness of approximately 3-5 meters per layer. This layer division contributed to a more accurate simulation by precisely indicating where to drill and perforate wells.

A suggested value of 1-2 meter thickness is recommended for an even more accurate simulation, but this value is tried later on and it is concluded that the output data in the simulation is not affected by a higher thickness value. It would only limit simulation time by using a higher value. **[10]**

Since the zone labeled 1B between Lower Heather and Upper Tarbert are considered a dry zone, the whole zone is set as one layer. The division of zones and layers in Krafla Main are shown on figure 6-6 are the well 30/11-8 S is penetrating the zones.

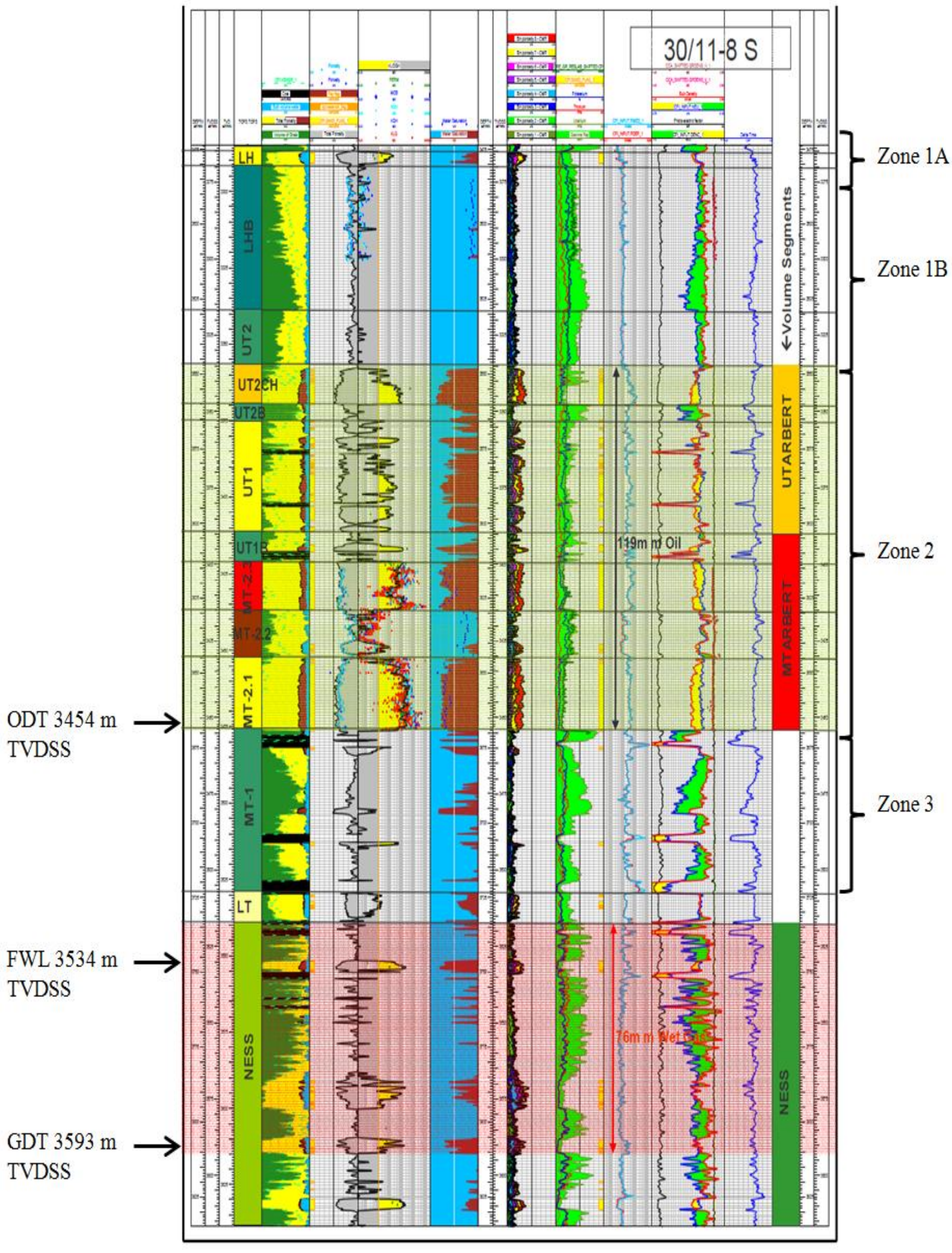

Figure 6-4: Reservoir logs and interpreted fluid distribution for Krafla Main well 30/11-8 S

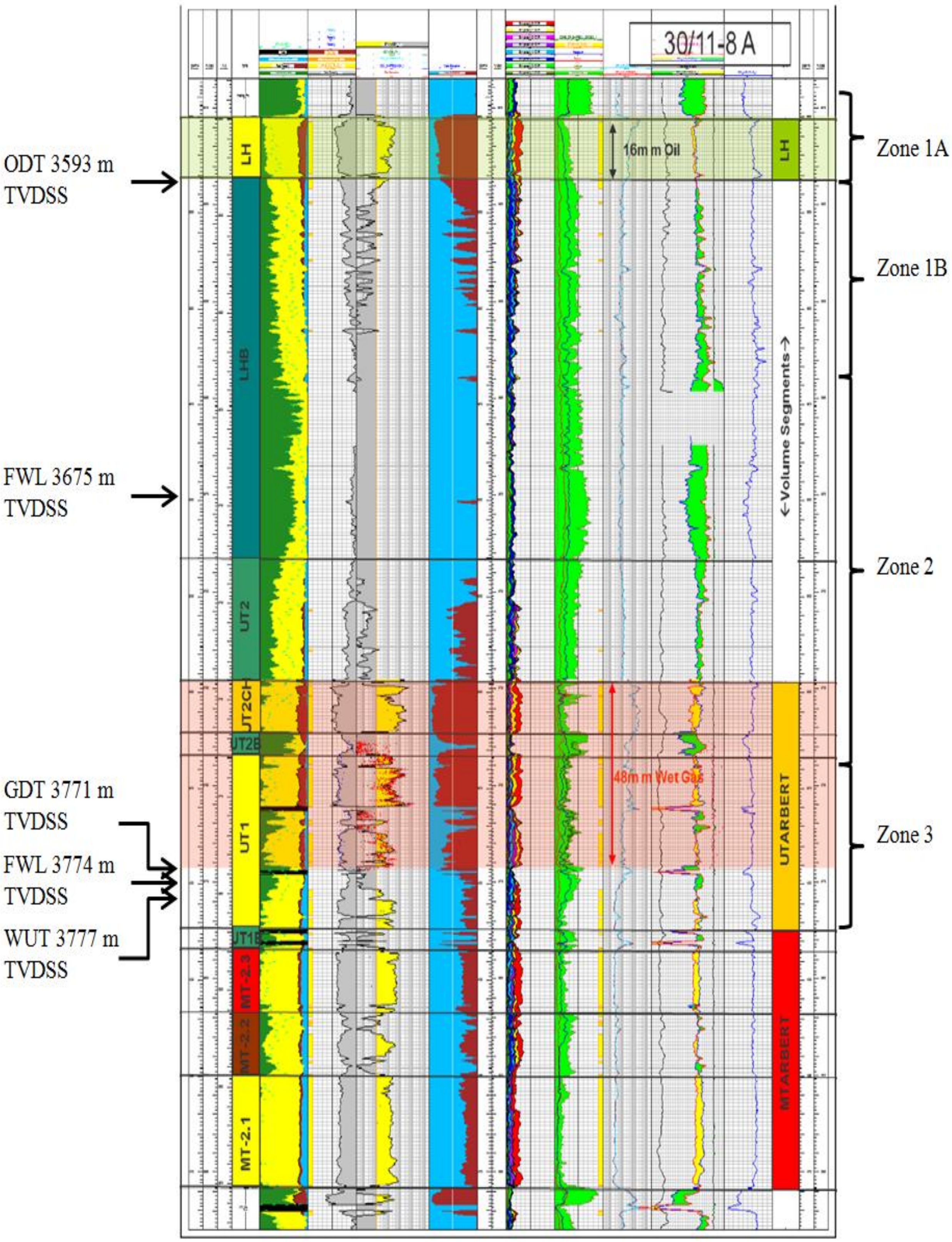

Figure 6-5: Reservoir logs and interpreted fluid distribution for Krafla West well 30/11-8 A

The well in Krafla West has the same zone- and layer distribution as illustrated in figure 6-6. The four zones made a total of 46 layers which are distributed as follows:

Zone 1A:	3 layers
Zone 1B (dry zone):	1 layer
Zone 2:	32 layers
Zone 3:	10 layers

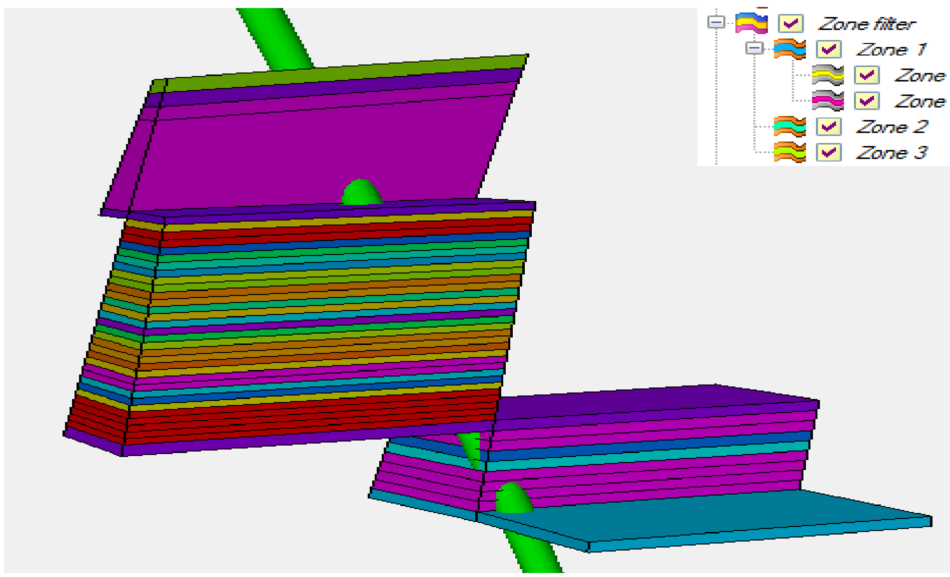

Figure 6-6: Division of zones and layers on the Krafla Main structure

Input values from raw logs such as effective porosity, permeability and net sand is imported to the Petrel-model and the data is then upscaled in the grid cells penetrated by the wells.
This means that each grid cell has a single value for each property, but since the grid cells often are much larger than the sample density for well logs, the well log data must be scaled up before it can be entered into the grid. [11]
A method called “Neighbor Cell” is then used where cells immediately adjacent to the upscaled cell and belonging to the same layer as the upscaled cell are given average log values.

Two average methods are used: *Arithmetic* and *Geometric*.

The Arithmetic mean [A] is calculated by summarizing all the values in a collection and then dividing this sum on the number of values.
It is defined as:

$$A = \frac{1}{n}\sum_{i=1}^{n} a_i \tag{6.2}$$

Here a_i is the value $\{a_1,....,a_n\}$. [12]

The arithmetic mean is typically used for properties such as porosity, saturation and net/gross because these are additive variables. [11]

The geometric mean [G] is calculated by multiplying values and then taking the *nth* root of the product where *n* is the count of numbers. It can also be calculating by summarizing the log value for each number and divide the sum on the number of values. [12]

$$G = \sqrt[n]{X_1\, X_2 \ldots \ldots X_n} \tag{6.3}$$

$$\log G = \frac{1}{n}\sum_{i=1}^{n} \log x_i \tag{6.4}$$

The geometric mean is normally a good estimate for permeability if it has no spatial correlation and is log normal distributed. The geometric mean is sensitive to lower values, which will have a greater influence on results, and is not defined for negative values. [11]

6.2.3 Population of reservoir properties

When the reservoir properties are upscaled in the grid blocks near the wells, a simulation function called "Gaussian Random Function Simulation" is used for distributing the average values throughout the grid.

The simulation function is an algorithm that contains the parameter *Kriging* which is defined as an estimation technique that uses a variogram for expressing the spatial variability of the input data.

It is based on the principle that closely spaced samples are likely to have a greater correlation than those located far from one another, and that beyond a certain point a minimum correlation is reached and the distance is no longer important.

The algorithm will not generate values larger or smaller than the min/max values of the input data. [11]

In the variogram setting, a range parameter is adjusted for how far out in the grid a specific average value are distributed before another average value is chosen to be further distributed due to correlation between the values. The range value is the maximum distance where sample values are dependent of each other while spread out in the grid. [11]

By using a small range value in the x- and y-direction, the data is unevenly distributed leading to *incorrect* values far out in the grid. It is for instance discovered that porosity is increasing with depth, which is not the case.

With higher range value, such as 40 000, a value is simulated 40 000 meters before a new average value is chosen. Since the Krafla area is limited to a smaller distance than 40 km, this value simulated the data more evenly and correct.

In the z-direction the range value is set to 5 so that the grid blocks would not be dependent in the vertical direction. Only dependency in x- and y-direction is needed.

The value 5 is indicating a range of 5 meters which is an approximate value for the thickness of one grid block.

Another function called *Co-kriging* is performed between porosity-permeability and porosity-net/sand to make the values more or less proportional so that they would match each other in the grid.

The Co-kriging parameter uses a correlation coefficient between primary and secondary data, together with the secondary variable (porosity), to calculate the contribution of the secondary variable at each point in the grid. [11]

A coefficient of 0,8 is used in a linear regression function meaning that the correlation between the data is approximately proportional which indicated good permeability when good porosity. The petrophysical modeling setting is shown in figure 6-7 A & B, where the adjusted range value is set at 40 000 in the x – and y-direction and 5 in the z-direction in each reservoir zone.
In the Co-kriging setting, effective porosity is set as the secondary variable with a correlation coefficient at 0,8.

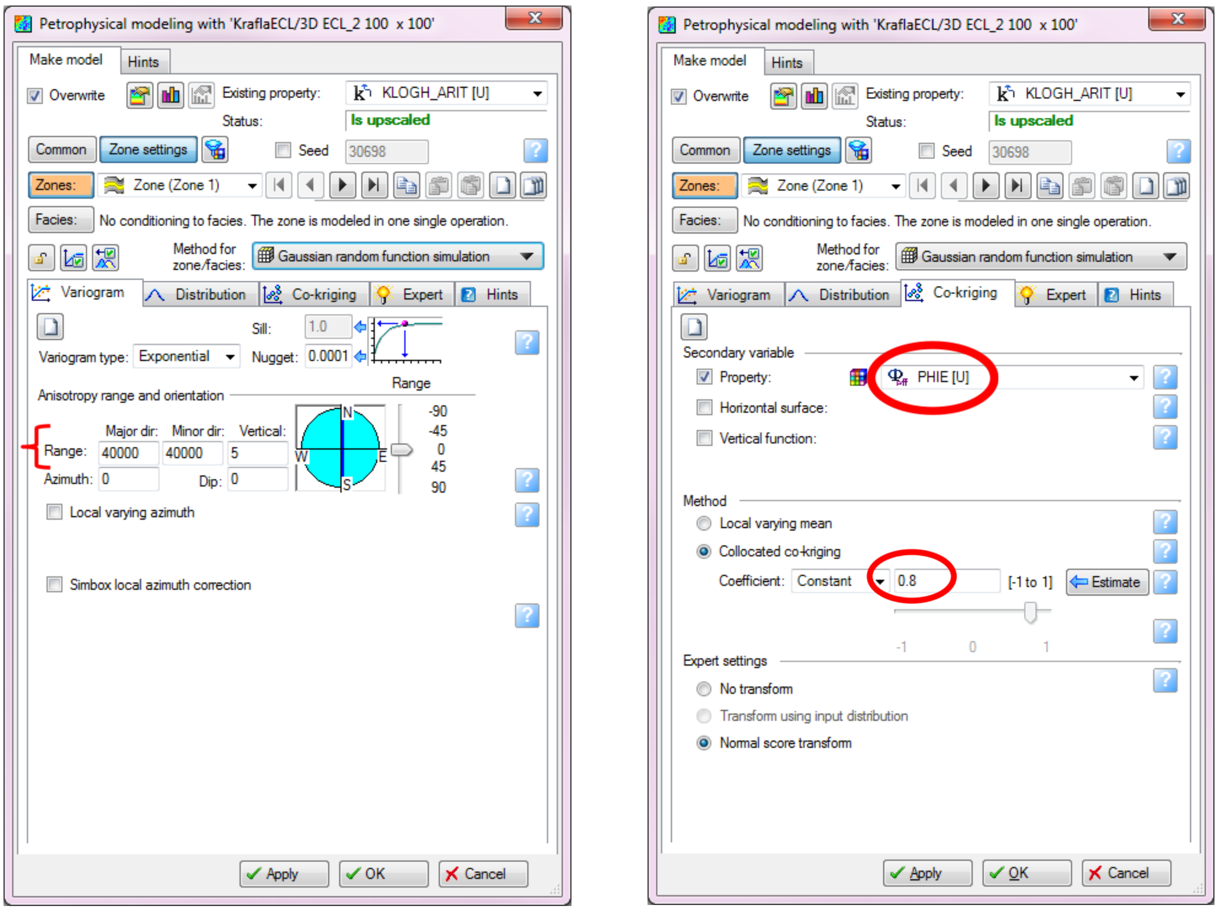

Figure 6-7: Petrophysical modeling setting showing A) the variogram range value B) the Co-kriging variable and the linear regression coefficient.

When the population of reservoir properties is performed, a histogram showing the simulated distribution in each zone could be compared to well data for the same zone.
It is important to get the simulated values approximately the same as the well data. If the values are different from each other, the simulated values had to be corrected.

This is the case after the first geological model simulation, where the main problem is that mean and standard deviation of the porosity values are too low, leading to lower values for permeability and net/sand since these are collocated with the porosity.

During the upscaling of well data, the extreme values from well data are eliminated and only the average values are set as upscaled values. These values and the simulated values are approximately the same, since it is the upscaled values that are used for simulation.
The well data would therefore show peaks on a histogram indicating extreme values while the upscaled and simulated values are more or less the same and showing average values.
This error in neglecting extreme values could be stimulated by use of a distribution parameter in the Petrophysical modeling setting which adjusted the simulated values to correspond to the well data values.
The mean and the standard deviation of the simulated data is set approximately the same value as the well data, and a right-hand movement in the histogram led to a fair match between the simulated and the raw values which can be seen in figure 6-8.

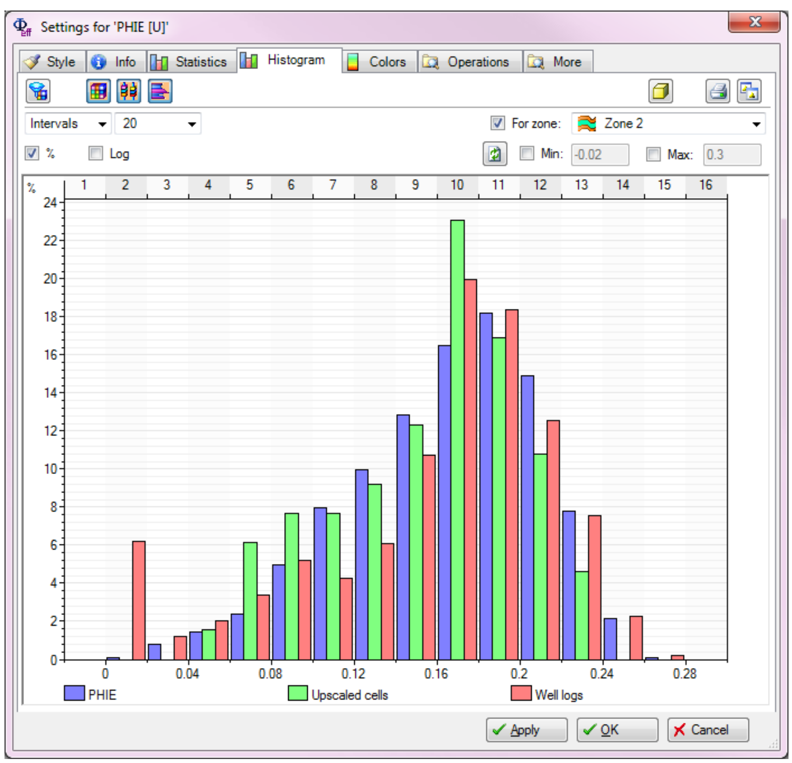

Figure 6-8: Porosity distribution from Upper/Middle Tarbert showing simulated values [PHIE] in relation to upscaled and raw log values.

This adjustment indicated that the grid now had the same properties far out in the grid as nearby the wells, correlated to reservoir properties.

The simulated grid can be seen in figure 6-9, which illustrates the porosity distribution in Upper/Middle Tarbert in Zone 2. The distribution shows good porosity values in Krafla West and slightly lower values in Krafla Main.

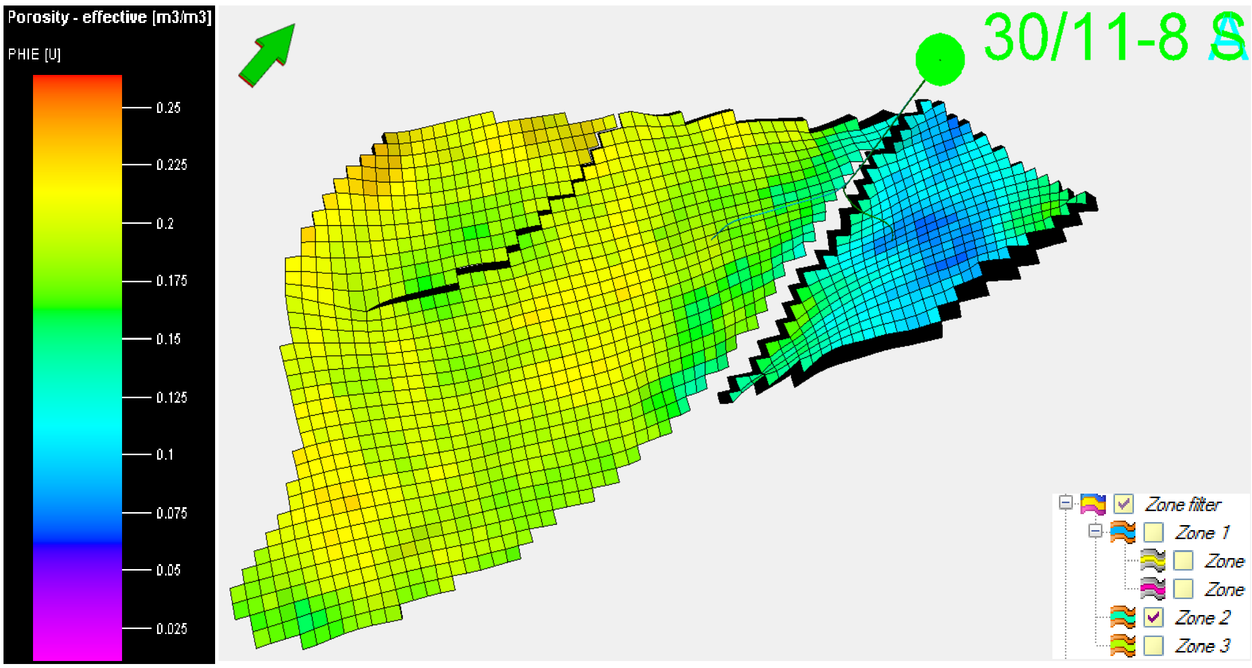

Figure 6-9: Porosity distribution in Upper/Middle Tarbert, Zone 2.

6.3 Saturation functions and relative permeability

6.3.1 Water saturation calculation

Due to lack of SCAL-studies when the geological model is built, the log-derivative Leverett's J-function is used for water saturation calculation which is performed in Petrel.

If wells are drilled through transition zone and contacts are identified (here: FWL) the log-derivative function can be established based on the saturation profile from raw logs. The surface tension and contact angle is then neglected, and the formula is abbreviated down to: [13]

$$J = h_{\mathrm{FWL}}\sqrt{\frac{k}{\emptyset}} \tag{6.5}$$

Here;

h_{FWL}	=	Height above free water level
k	=	Log-permeability
$\emptyset$	=	Porosity

The term [J] is generated as a log-curve and is plotted against saturation function [Sw] where Sw is the log-derivative saturation curve. By regression the function can be adjusted to: [13]

$$J = h_{\mathrm{FWL}}\sqrt{\frac{k}{\emptyset}} = aS_w^{-b} \tag{6.6}$$

Where: [a] and [b] are regression coefficient from the regression line through the plotted values. The water saturation [Sw] as a function of the height above free water level (expected contacts) can then be expressed as: [13]

$$Sw = \left(\frac{h_{\mathrm{FWL}}}{a}\sqrt{\frac{k}{\emptyset}}\right)^{-\frac{1}{b}} \tag{6.7}$$

One saturation function is derived for each PVT-region according to the height above free water level (FWL), porosity, permeability and by the plotted [J] / [Sw] curve for each region.
The plotted [J] / [Sw] curve from the three reservoir regions are shown in figure 6-10, 6-11 and 6-12.
The parameters used for water saturation calculation (formula 6.7) are summarized in table 6-1.

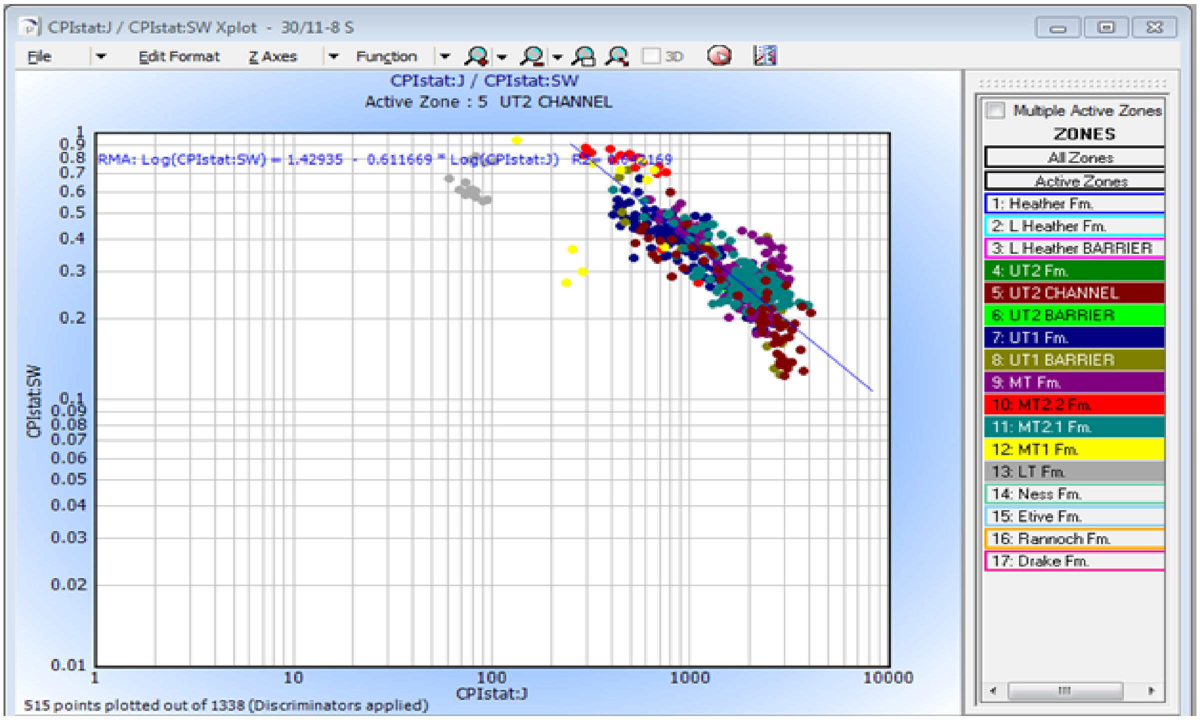

Figure 6-10: [J] / [Sw] curve for Krafla Main, Tarbert Formation

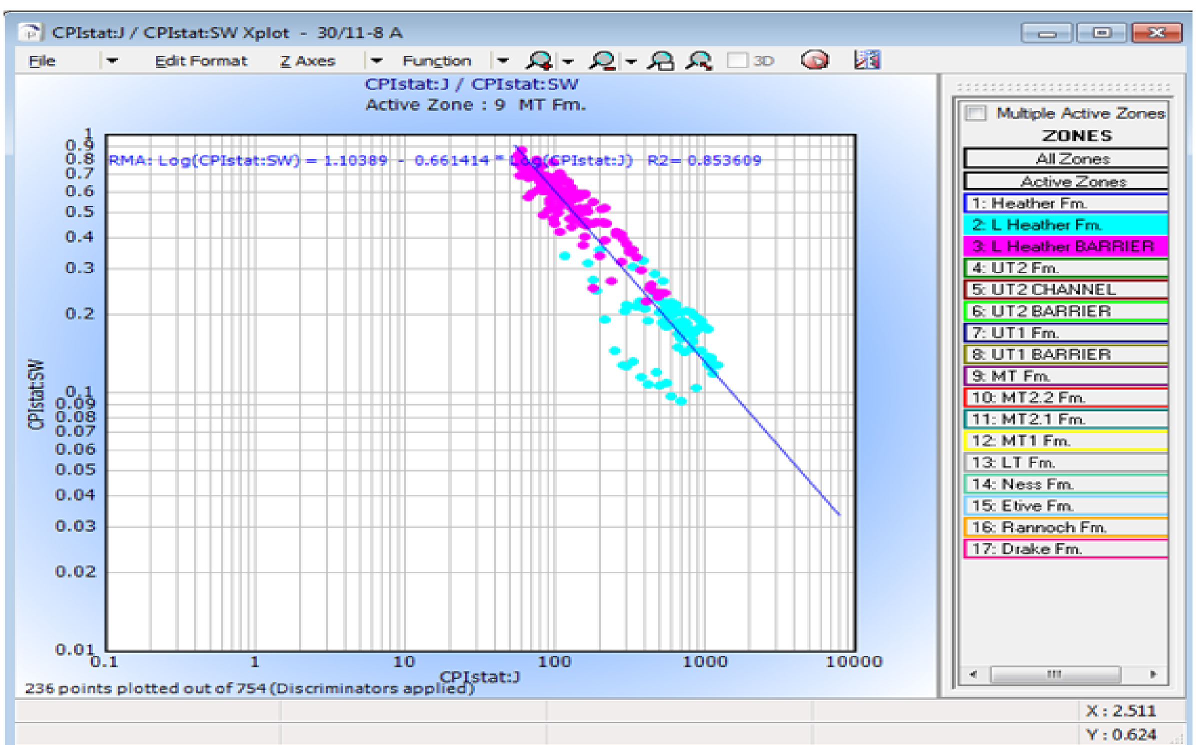

Figure 6-11: [J] / [Sw] curve for Krafla West, Heather Formation

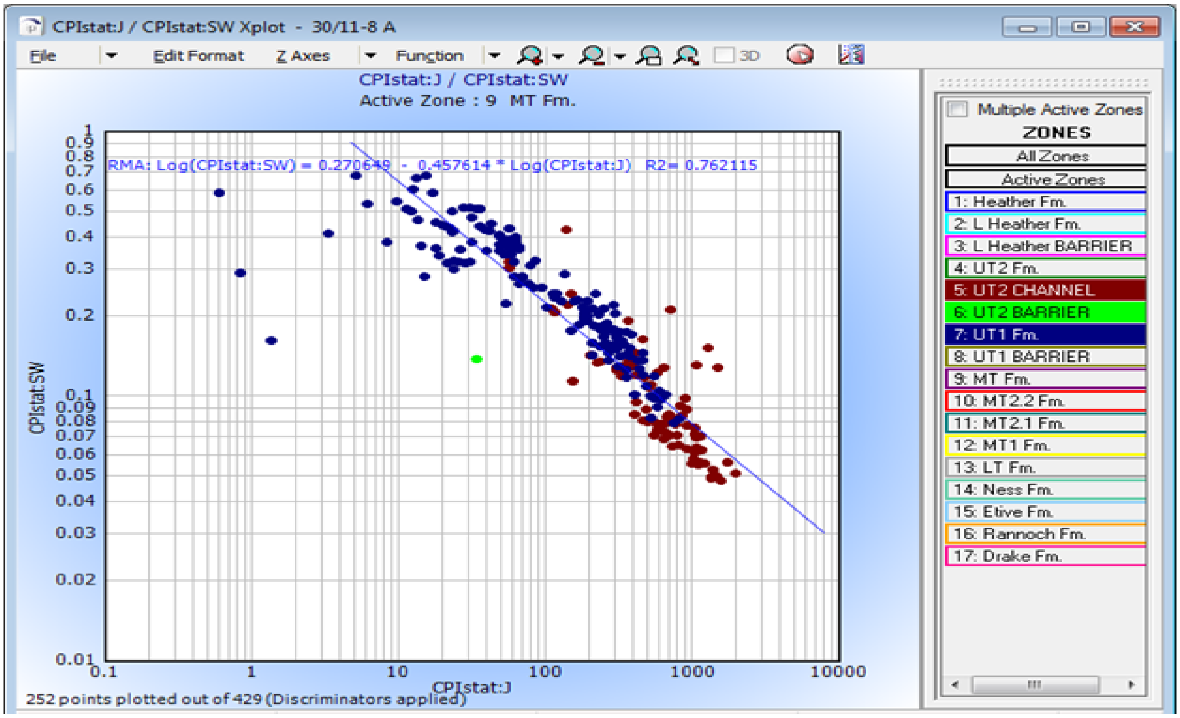

Figure 6-12: [J] / [Sw] curve for Krafla West, Tarbert Formation

	Krafla Main; Tarbert	Krafla West; Heather	Krafla West; Tarbert
FWL	3534	3675	3774
a	217,1	46,79	3,91
b	1,634	1,51	2,183

Table 6-1: Parameters used for water saturation calculation

The calculation of water saturation is performed by a setting in Petrel which calculated the water saturation for the 3 different segments according to h_{FWL} and relevant layers.

The Tarbert Formation in Krafla Main is located on segment 3 (from figure 6-3)

While the Heather Formation in Krafla West is located above layer K=4 on segment 1 and 2, the Tarbert Formation lies within the same segments but is located beneath K=4.

The formulas used for water saturation calculation is defined in the table (6-2) below.

The formulas are based on the principle: X = IF (Y), then (Z), if not; then (X).

Location	Calculation formulas
Krafla Main, Tarbert fm.	SWL = If (Segments = 3, Pow ((Hfwl / 217.1 * Sqrt (KLOGH_ARIT/PHIE)), -0.612), SWL)
Krafla West, Heather fm.	SWL = If (Segments = 1 Or Segments = 2 And K<4, Pow ((Hfwl / 46.79 * Sqrt (KLOGH_ARIT/PHIE)), -1 / 1.51), SWL)
Krafla West, Tarbert fm.	SWL = If (Segments = 1 Or Segments = 2 And K>=4, Pow ((Hfwl / 3.91 * Sqrt (KLOGH_ARIT/PHIE)), -1 / 2.183), SWL)
Common	SWL = If (SWL >= 0.6, 0.6, SWL)

Table 6-2: Formulas used for water saturation calculation.

In order to initializate the Eclipse simulation model, the connate water saturation, SWL, is set to a maximum value of 0.6. The reasons for this are:

- The total connate saturations for all phases cannot exceed 1, thus a SWL<=0.6 will avoid this.
- As scaled endpoints are used in the initialization of Eclipse, a SWL>0.6 will cause some very steep relative permeability functions. These steep functions can cause numerical convergence failure due to unlikely interpolation through the relative permeability curves.

As the volume of hydrocarbons in range 0.6 to 1 are likely to be very low, this simplifying will not cause a significant disagreement in volumes calculated in the geological model versus Eclipse.

6.3.2 Saturation initialization

The saturation function initialization for Eclipse is also calculated in Petrel.

The parameters are given default values (table 6-3) and calculated according to default formulas.

Parameters	Default values
Critical oil/water saturation; SOWCR	0,15
Critical oil/gas saturation; SOGCR	0,03
Maximum water saturation; SWU	1
Connate gas saturation; SGL	0
Critical gas saturation; SGCR	0,03

Table 6-3: Saturation parameters given default values for calculation

The saturation initialization formulas are given in table 6-4.
Here; segment 3 is set as PVTNUM 1, segment 1 and 2 above [K=4] is set as PVTNUM 2 and beneath [K=4] is defined as PVTNUM 3.
The PVTNUM keyword specifies the PVT region to which every grid block belongs, and is defined in the Eclipse definition in appendix 1.

Location	Calculation formulas
Common	Maximum gas saturation SGU = - 1 * Water saturation SWL + 1
Krafla Main, Tarbert fm. (Segment = 3) (PVTNUM = 1)	Maximum gas saturation SGU = If (PVTNUM = 1 And Depth ( ) > -3534, - 1 * Water saturation SWL – Critical oil gas saturation SOGCR + 1, Maximum gas saturation SGU) Maximum gas saturation SGU = If (PVTNUM = 1 And Depth ( ) < -3534, - 1 * Water saturation SWL + 1, Maximum gas saturation SGU) Maximum water saturation SWU = If (PVTNUM = 1 And Depth ( ) > -3534, - 1 * Critical oil water saturation SOWCR + 1, Maximum water saturation SWU) Connate gas saturation SGL = If (PVTNUM = 1 And Depth ( ) > -3534, 0.01, Connate gas saturation SGL)

Krafla West, Heather fm. (Segment = 1 & 2) (PVTNUM = 2)	Maximum gas saturation SGU = If (PVTNUM = 2 And Depth ( ) > -3675, - 1 * Water saturation SWL – Critical oil gas saturation SOGCR + 1, Maximum gas saturation SGU) Maximum gas saturation SGU = If (PVTNUM = 2 And Depth ( ) < -3675, - 1 * Water saturation SWL + 1, Maximum gas saturation SGU) Maximum water saturation SWU = If (PVTNUM = 2 And Depth ( ) > -3675, - 1 * Critical oil water saturation SOWCR + 1, Maximum water saturation SWU) Connate gas saturation SGL = If (PVTNUM = 2 And Depth ( ) > -3675, 0.01, Connate gas saturation SGL)
Krafla West, Tarbert fm. (Segment = 1 & 2) (PVTNUM = 3)	Critical gas saturation SGCR = If (PVTNUM = 3 And Depth ( ) > -3774, 0.35, Critical gas saturation SGCR) Maximum gas saturation SGU = If (PVTNUM = 3 And Depth ( ) > -3774, - 1 * Water saturation SWL – Critical oil gas saturation SOGCR + 1, Maximum gas saturation SGU) Maximum water saturation SWU = If (PVTNUM = 3 And Depth ( ) > -3774, - 1 * Critical gas saturation SGCR + 1, Maximum water saturation SWU)
[K=4]	Water saturation SWL = If (K = 4, 0.55, Water saturation SWL) Maximum gas saturation SGU = If (K=4, 0.3, Maximum gas saturation SGU) Critical water saturation SWCR = If (K=4, 0.55, Critical water saturation SWCR)

	Connate gas saturation SGL = If (K=4, 0, Connate gas saturation SGL) Critical gas saturation SGCR = If (K=4, 0.35, Critical gas saturation SGCR)

Table 6-4: Saturation initialization formulas calculated in Petrel

6.3.3 Relative permeability and end point scaling

The reservoir simulation model must be capable of simulating flow of at most three phases; oil, water and gas.

Relative permeability is a function of saturation distribution and is given for phase [l]:

$$k_{rl} = \frac{k_l}{k_a} \tag{6.8}$$

At a reservoir location where several phases are flowing simultaneously, the effective permeability [k_l] of each phase will be smaller than the absolute permeability [k_a]. [6]

In the lack of relative permeability values, industry default parameters are used and end point scaling is performed to adjust the range of saturation functions between differing saturation and relative permeability end points.

Relative permeability can differ from one grid block to another and the differences may be concerning different function shapes, different mobile saturation intervals and change in function values by a multiplication factor.

Tables are used to import saturation function data to the numerical model and since the reservoir is divided into a small number of saturation regions each region has a specified saturation table. [6]

The end point scaling function allows you to use one saturation function table over a large extent of the reservoir model grid where saturation values vary with grid block location. [14]

The end point scaling option is enabled by the ENDSCALE keyword in Eclipse which is defined in appendix 1.Relative permeability input to a simulation model will be four tables reflecting the four measured two-phase curves.
The scaling process preserves relative permeability at two saturation nodes, and the following end points are assumed for the relative permeability for each phase: [15]

Krw: SWCR AND SWU
Krg: SGCR AND SGU
Krow: SOWCR AND (1.0 –SWL-SGL)
Krog: SOGCR AND (1.0 –SWL-SGL)

Here:

Krw	=	Relative permeability of water. Scales the K_r at the maximum water saturation. In Eclipse this value is set to 0,8
Krg	=	Relative permeability of gas. Scales the K_r at the maximum gas saturation. In Eclipse this value is set to 0,9
Krow	=	Relative permeability of oil relative to water. Scales the K_r at the critical water saturation. In Eclipse this value is set to 0,9
Krog	=	Relative permeability of gas relative to oil. Scales the K_r at the critical gas saturation. In Eclipse this value is set to 0,8

The definition of the saturation functions are defined in table 6-4.
The oil, water and gas saturation tables, for each particular saturation table number region, must obey certain consistency requirements in the end point scaling function.
These requirements are performed in Petrel and are defined in the following:

1) SGU must not exceed 1.0 – SWL
   The condition is set to prevent negative oil saturation. Normally if there is no oil in the gas cap the condition fulfilled.
2) SGL must not exceed 1.0 – SWU

The condition is set to prevent negative oil saturation. Normally there is no initial free gas below the gas cap and the water zone is fully saturated with water. In that case the condition is fulfilled.

Both consistency requirements are met before continuing with the initialization of the model.

The relative permeability curve for oil [Krow] is calculated by formula: [16]

$$Krow(Sw) = (1 - Swn(Sw))^{Co} \tag{6.9}$$

where [Swn] is defined as:

$$Swn\ (Sw) = \frac{Sw - Swi}{1 - Swi - Sorw} \tag{6.10}$$

Here:

Sw	=	Water saturation to be plotted
Swi	=	Initial water saturation
Sorw	=	Residual oil saturation in oil/water system
Co	=	Corey oil exponent

The Corey parameter describes the lower part of the curve and can be adjusted between different values where lower values, for instance 1, will give a linear curve and higher values will give a creeping type of curve. [17]
In calculation of [Krow] a Corey parameter of 3 is used.

The relative permeability curve for water [Krw] is calculated by formula:

$$Krw(Sw) = Krw' * Swn(Sw)^{Co} \tag{6.11}$$

where [Krw] is the end point of the water relative permeability and is defined as:

$$Krw' = Krw(1 - Sorw) \tag{6.12}$$

In calculation of [Krw] a Corey parameter of 4 is used.

If a higher value, for instance 5, of the Corey parameter for Krw is used, then the relative permeability for water saturation will decrease. This would influence the ability for water to flow and reduce the time of water breakthrough. The low permeability would cause better sweep efficiency, but may be a disadvantage during water injection.

Opposite would a parameter of 3 increase the relative permeability for water and may cause *fingering* of the oil during production caused by higher mobility ratio of water relative to oil.

The water saturation table [SW] is plotted against relative permeability for oil [KROW] and relative permeability for water [KRW] in figure 6-13.

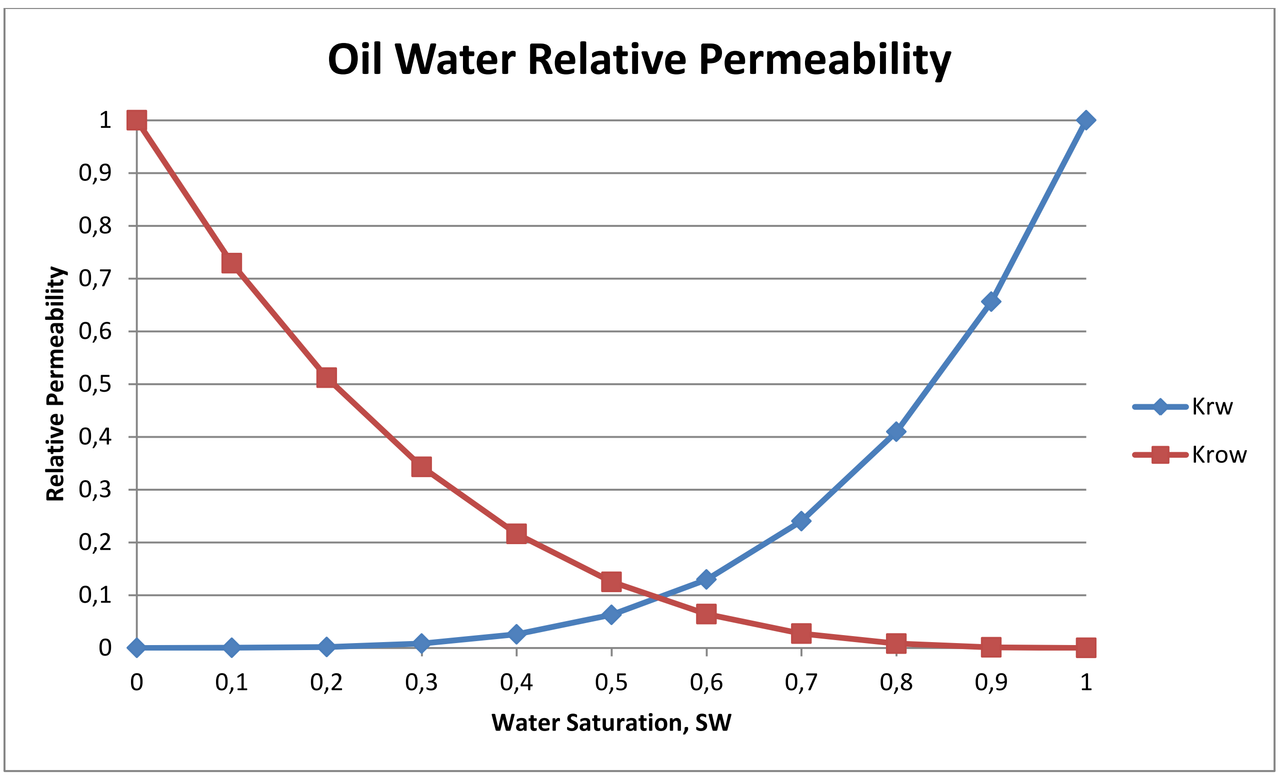

Figure 6-13: Unscaled oil water relative permeability curve

The endpoints Swr, Sorw, Sgr and Sorg are of critical importance for initial fluid distribution and final recovery since they control the fluid flow and saturation through the grid blocks.

7. Simulation model

When the input parameters containing porosity, permeability, net/sand and water saturation is imported and distributed in the Petrel grid, the grid is taken further as input to be converted to Eclipse grid.

7.1 Model input parameters

7.1.1 PVT analysis

Data regarding PVT for the one region in Krafla Main and the two regions in Krafla West, including rock compressibility and density are given from the operator of the field.
The PVT data consisted of Gas/Oil Ratio (GOR), Pressure [P], Formation Volume factor (Bo/Bg/Bw) and fluid viscosity [cP] for oil, gas and water.
In addition there is available data regarding dissolved gas/oil ratio versus depth given in Eclipse with keyword RSVD and vaporized oil/gas ratio versus depth given with keyword RVVD.
Pressure is plotted against the formation volume factor Bo on Krafla Main Top Tarbert (main oil zone) on figure 7-1 where the development of GOR for each value is shown.
When oil is brought to surface conditions, some natural gas will always bleed out of the solution due to pressure depletion.
The gas oil ratio is the ratio of the volume of gas that bleeds out of the solution, to the volume of oil produced at standard conditions.
Oil consists of high pressure and temperature which decreases to surface conditions when oil is produced. This will cause the gas to bubble out of the oil and the volume of oil will then decrease.
The formation volume factor gives the ratio of volume at reservoir condition to volume at the surface condition and is defined as:

$$Bo = \frac{[Vo]rc}{[Vo]stc} \qquad (7.1)$$

Similar volume factors can be provided for water and gas: [6]

$$Bw = \frac{[Vw]rc}{[Vw]stc} \qquad Bg = \frac{[Vg]rc}{[Vg]stc} \qquad (7.2 \ \& \ 7.3)$$

The graph is illustrating that the GOR from a field is given as a function of surface pressure and the Bo-factor.

As the pressure decreases, the composition of the reservoir fluid changes in a way that light hydrocarbon components increase and the heavier components decrease.

GOR is defined as the gas evaporated from oil, so naturally the GOR increases with decreasing pressure indicating higher gas production relative to oil production, and as a function the formation volume factor increases.

A high formation volume factor indicates high-shrinkage oil, meaning that the volume of oil at standard conditions is considerably lower than at reservoir conditions due to natural gas depletion at surface conditions. This is identified in the graph where the GOR value at the same pressure condition increases with the formation volume factor.

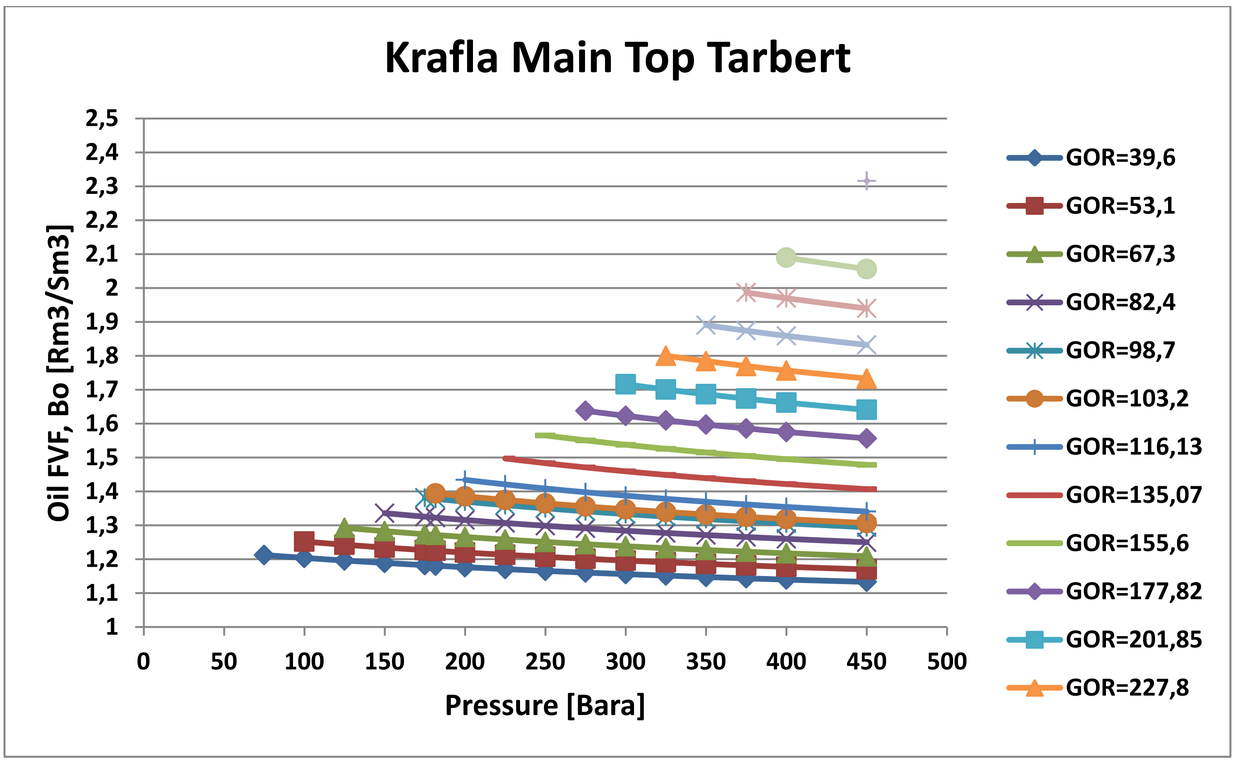

Figure 7-1: Pressure plot versus Bo factor, illustrating development of GOR on Krafla Main, Top Tarbert.

The graph shown in figure 7-2 illustrates the GOR development relative to pressure and oil viscosity on Krafla Main Top Tarbert and it is seen that high pressure together with low ability for oil to flow will hence give a high gas oil ratio.
A fluids viscosity is defined as the resistance for the fluid to flow, indicating a slower movement of fluid containing high viscosity. As the pressure increases, the load-carrying capacity of the oil increases meaning higher composition of heavier hydrocarbons and the movement of fluid in the reservoir will be reduced.
When reservoir pressure depletion occurs during production, the reservoir fluid becomes lighter and more volatile, and the resistance to flow, hence the viscosity, will decrease. This in order will lead to more natural gas depletion as the gas is evaporating out of the oil at pressures lower than the dew point.

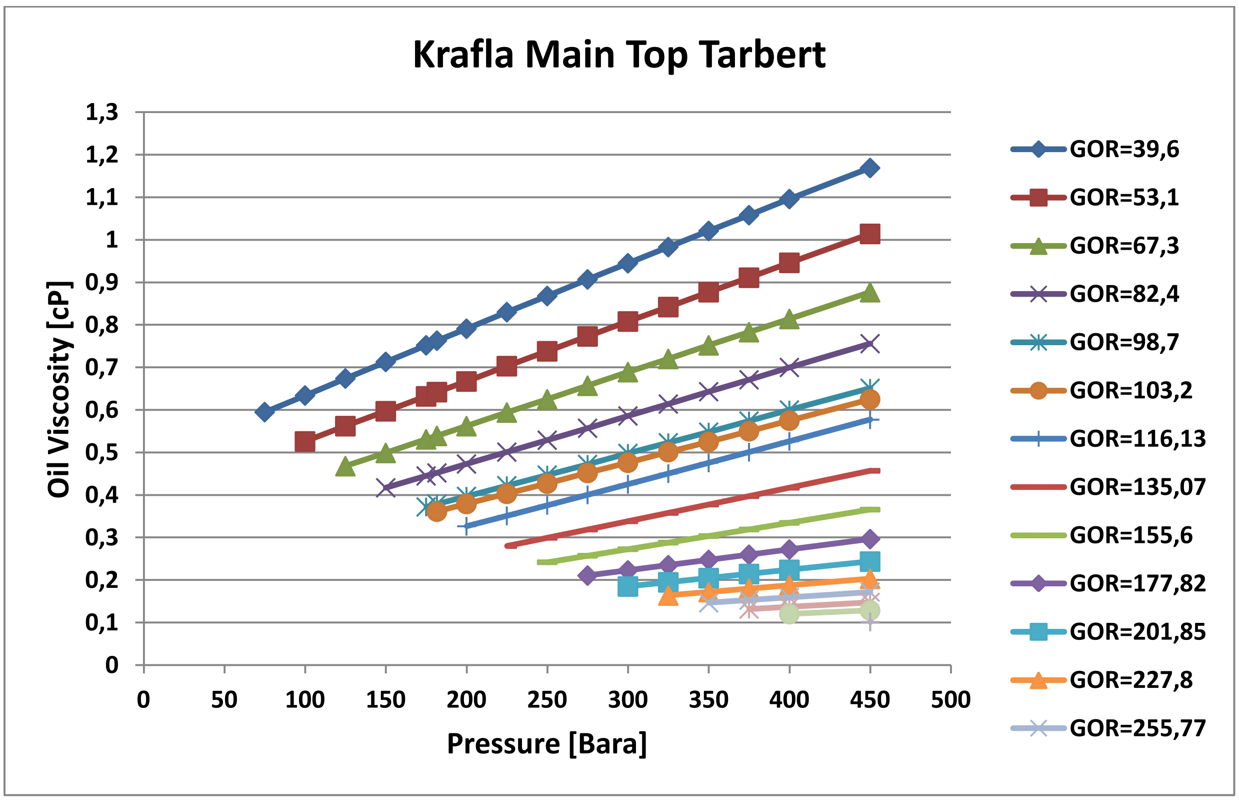

Figure 7-2: Pressure plot versus oil viscosity, illustrating development of GOR on Krafla Main, Top Tarbert.

GOR analysis is a valuable feature in the oil production as it is essential for an oil company to produce fields with low GOR. Fields with lower containment of natural gas will have an economic impact on the production as heavy oil components are more profitable on the sales marked than lighter components.

Even so, the worldwide development proceeds towards renewable energy, and natural gas is becoming more and more attractive as it contains less heavy hydrocarbon components. [18]

The theory behind the gas depletion can be described by the use of the phase envelope [19] in figure 7-3.

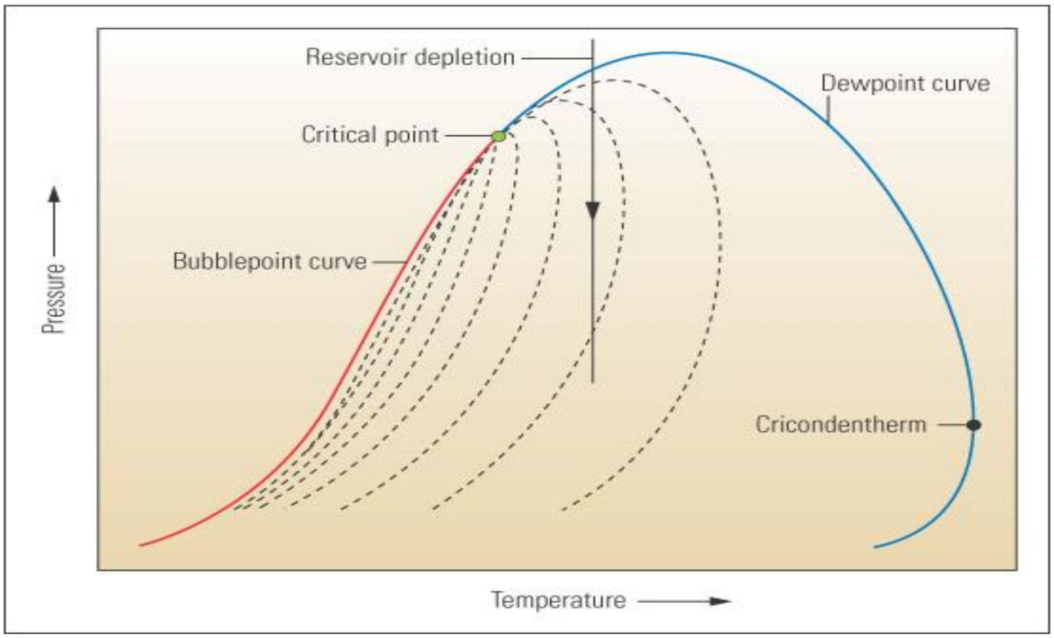

Figure 7-3: Hydrocarbon phase envelope for a retrograde condensate.

The curve describes the phase behavior for a reservoir fluid in relation to pressure and temperature. At low pressure and temperature, the bubblepoint curve builds up where one phase fluid is on the left side of the curve and two phases is on the right side.

A critical point is reached at a certain pressure and temperature at the curve and fluids entering the two-phase region on the right side of the critical point are termed retrograde condensate. The fluid entering due to pressure depletion at initial reservoir conditions, for instance gas, are then starting to condensate into a liquid under isothermal conditions instead of expanding or vaporizing when pressure is decreased. [20]

The dewpoint curve shows at which pressure and temperature the two phase fluid has to exceed in order to become one phase. At temperatures higher than the point called cricondentherm the fluids will remain single-phase at all pressures and similar for a certain point called cricondenbar (not shown on the figure) the fluids remain single-phase at all temperatures.

The oil/gas ratio from the Top Tarbert formation on Krafla West is plotted in figure 7-4 together with the formation volume factor [Bg] and the viscosity relative to pressure.

The reservoir is mainly contained of gas with some oil components present, and the oil/gas ratio is defined as the liquid content of the gas phase.

Evaluation of the figure shows that the dew point is located at approximately 445 barsa, where the graphs are experiencing a certain "break" on the line.

This pressure indicates the point where the reservoir fluid is going through the dew curve from one phase to two phases. The composition of lighter components increases and oil relative to gas decreases. As a function of increasing amount of lighter hydrocarbons due to pressure drop, the formation volume factor [Bg] increases which means that the gas expands at reservoir conditions. The fluid viscosity will also experience a decrease with pressure depletion and become more volatile, i.e. lighter and less viscous.

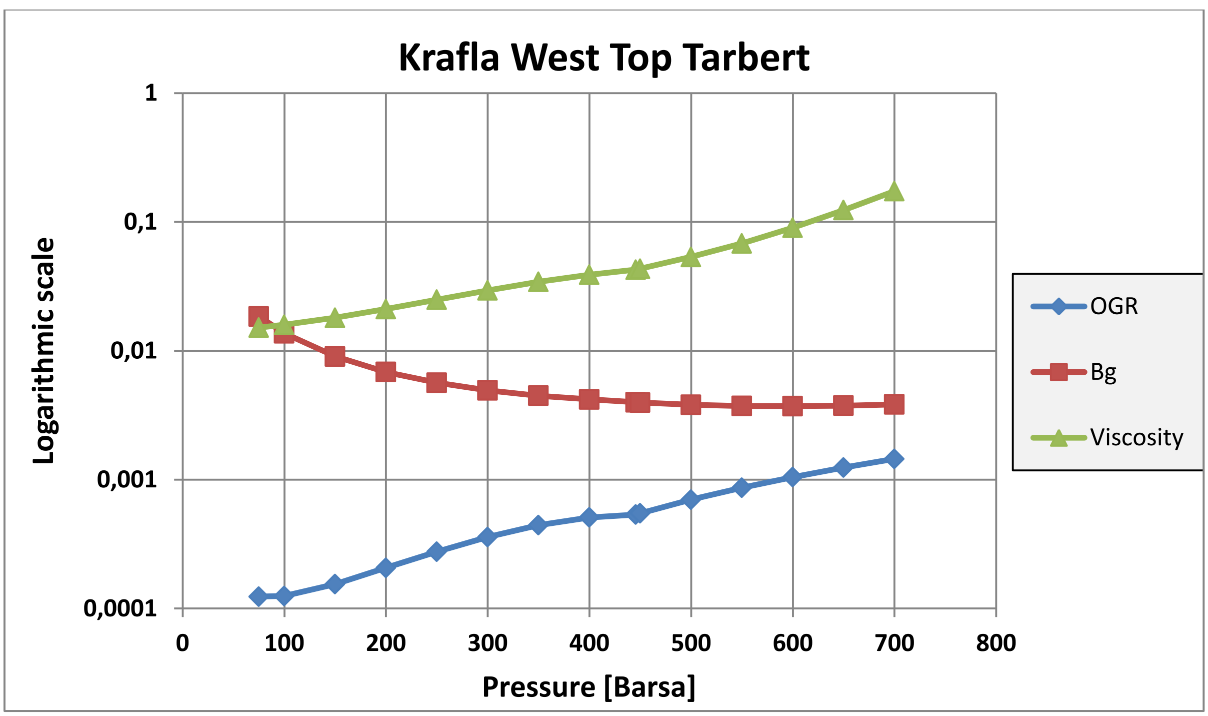

Figure 7-4: Pressure plot versus log-scale, illustrating development of OGR, Bg and viscosity on Krafla West, Top Tarbert.

The composition of a gas in a reservoir varies from one formation to another, and the gas may be compared to an ideal gas to see the deviation in thermodynamic property.
An ideal gas can be defined from the equation of state (EOS) which states that all gases at given T, P and n occupy the same amount of volume and expressed by the formula: [21]

$$P\,V = Z\,n\,R\,T \tag{7.4}$$

Here; P is the reservoir pressure, V is the volume occupied, Z is the compressibility factor (deviation factor), n stands for number of moles in the composition, R is a universal gas constant and T is the absolute temperature, respectively.

The compressibility factor may be thought of as the ratio of the volume of a real gas relative to the volume predicted by an ideal gas at the same pressure and temperature.
For an ideal gas, the compressibility factor [Z] is always 1, but for real gases the value may deviate positively or negatively depending on the effect of intermolecular forces on the gas.
The forces, sometimes referred to as Van der Waals forces, act between stable molecules and give rise to bonding energies which causes the composition of the gas to change. [22]
In general all gases at standard conditions, given as T_{SC} = 15˚C (60˚F) and P_{SC} = 1 bar (14,7 psia), are supposed to be ideal and can be treated by the ideal gas law.
However, this is not the case in reservoirs since temperature and pressures deviate from these conditions, and the closer a real gas is to its critical point or to its saturation point, the larger the deviation from ideal gas behavior.

The compressibility factor for the gas reservoir on Krafla West is not calculated in this thesis, but it is possible to use the formula to predict volumes in place by knowing the remaining parameters.

7.1.2 Rock compressibility

The rock compressibility used in the simulation model is derived from Hall et. all.
The rock compaction equation for consolidated sandstones are given as: [23]

$$C_r = \frac{7{,}89792*10^{-4}}{2} P_{Ra}^{-0{,}687} \frac{\phi}{0{,}17-0{,}42818} \tag{7.5}$$

Where;

$$P_{Ra} = \frac{(D*S_o+14{,}7-Pa)}{2} \tag{7.6}$$

ϕ = Average porosity from the field

P_a = Rock reference pressure

D = Vertical depth

S_o = Overburden gradient

The overburden gradient is the weight of the rocks and fluids above the reservoir and varies in different regions and formations. It is expressed by the formula: [24]

$$S = \rho_b * d \tag{7.7}$$

Where

$$\rho_b = \phi * \rho_f + (1 - \phi)\, \rho_m \tag{7.8}$$

(Abbreviations on page 86)

The overburden gradient is normally set to 2 psi/ft = 0,14 bar/ft. [10]

Rock compressibility is given in Eclipse by the use of keyword [ROCK] which also expresses the reference pressure, and is described in Appendix A.

7.2 Eclipse keywords

The initialization for reservoir numerical simulation in Eclipse demand keywords for each parameter to be simulated.

These keywords are given in the Appendix A at the end of the thesis and are provided in the simulation scenarios described in the preceding chapter.

The initialized DATA-file with the provided keywords is enclosed as an attachment in Appendix B.

7.3 Volume calculation

The volume of hydrocarbons contained in a reservoir is of main interest for every partners of a producing field.

The original oil in place (OOIP) and gas in place (OGIP) is the total hydrocarbon content of a reservoir before the commencement of production.

Oil in place is often abbreviated to *STOOIP* which stands for *Stock Tank Original Oil In Place* and is calculated in m^3 by using the formula:

$$STOOIP = \frac{Vb * \emptyset * (1 - Sw)}{Bo} \tag{7.9}$$

Here:

Vb	=	Bulk volume of the reservoir
$\emptyset$	=	Fluid filled porosity of the rock
S_w	=	Water saturation – water-filled portion of this porosity
B_o	=	Oil formation volume factor

Stock tank refers to the storage vessel containing the oil after production and the formation volume factor is a dimensionless factor for the change in volume between reservoir and standard surface conditions.

Each PVT-region from the geological model is given an identical FIPNUM region.

By use of the Eclipse keyword FIPNUM, the fluid in place and cumulative flows from the wells simulated in the different scenarios are given for each fluid-in-place region in a PRINT-file or as output from SUMMARY keywords.

The volumes original in place and currently in place after production for oil, gas and water could then be observed in the file and calculation of produced fluid and recovery factor are performed.

The results for total oil and gas production from each scenario and the recovery factor given as a percentage of produced reservoir volumes relative to OOIP are given in the preceding chapter.

8. Simulation scenarios

The simulation model described in chapter 7 is used to simulate five different scenarios for finding the optimal solution for oil and gas production according to producing economic volumes. The scenarios contained different well placement and production zones in Krafla Main and Krafla west and adjusted number of wells for production.

A support software in Eclipse called *Office* is used to evaluate oil and gas production rate, total oil and gas production, water injection rate, gas oil ratio and bottom hole pressure for the different wells and the field in total.
The evaluation part is contributing to the conclusion of which scenario gave the best outcome and which is observed as the optimal solution for oil and gas production.
A detailed description of the scenarios performed in this study is addressed in the following.

8.1 Scenario 1; Base Case

The first scenario is introduced as the Base Case scenario where all the adjustments performed in the following scenarios are done according to scenario 1.
Figure 8-1 gives a schematic illustration of the Base Case imported in Eclipse; FloViz which shows the oil saturation on Krafla Main and Krafla West with associated wells from first time step.

8.1.1 Krafla Main; Two producers and one injector

Considering the structure of Krafla Main, two oil producers are placed on the height of the structure and one water injector is set on the north side of the area.
The first producer, KM-1, is set more or less on the top height producing from layer 5-36 (zone 2 & 3) at an approximate vertical distance of 125 meters.
The second producer, KM-2, is placed on the south side of the height producing from layer 5-30 (zone 2 & 3) giving an approximate vertical distance of 100 meters.
It is assumed that natural flow would not be sufficient to produce this section due to pressure depletion, so water injection is considered.

The injector, WI-KM, is placed north on the Krafla Main structure at the bottom of the height, and water injection is applied from layer 5-46 (zone 2 & 3) with layer 46 being the bottom layer of the grid.

Layer 1-4 (zone 1A & 1B) is considered non-producible with layer 4 (zone 1B) as a total dry zone. No production would therefore occur from these layers in Krafla Main.

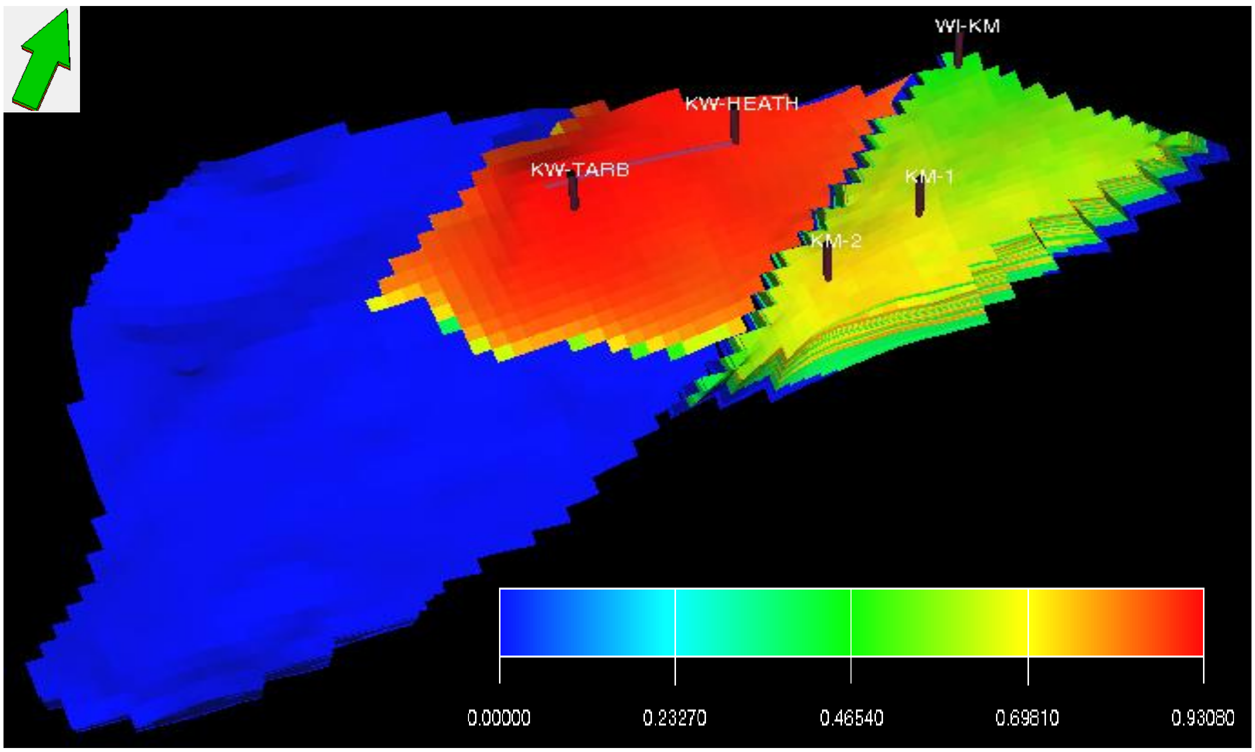

Figure 8-1: Scenario 1; Base Case: Initial oil saturation on Krafla Main and Krafla West with well producers and injector.

8.1.2 Krafla West; Two producers

The Lower Heather formation in the top structure of Krafla West is considerably narrow in vertical direction, so a horizontal gas producer, KW-HEATH, is placed on the north side of the field extending down to the west side producing from one top layer (layer 2) in zone 1A.

The well is penetrating 12 grid blocks in horizontal direction which is an approximate distance of 1200 meters with one grid block defined as 100x100 meters in the x- and y-direction.

A vertical gas producer, KW-TARB, is placed further south on the Krafla west structure on a small height. The well is penetrating 21 layers but is only producing from layer 5-21 (zone 2).

8.2 Scenario 2: Krafla Main; Three producers and one injector

The effect of using three producers on Krafla Main is investigated in scenario 2.
A third oil producer, KM-3, is placed between the existing wells on the east side of the height, producing from layer 5-30 (zone 2 & 3). The objective is to observe if adding an extra oil producer had any effect on how much volume would be produced from the field.
The 2.scenario is also used to simulate oil production from layer 5-36 in KM-3 to observe differences in volume production from different layers.
No changes are made on Krafla West.

8.3 Scenario 3: Krafla Main; One producer and one injector

The difference in using one oil producer vs. two oil producers on Krafla Main is simulated in scenario 3. One oil producer, KM-2, is removed leaving one oil producer (KM-1) and one water injector (WI-KM) left unchanged on Krafla Main. The objective is to observe if one producer could manage to produce the field alone with complementary help from one water injector.
No changes are made on Krafla West.

8.4 Scenario 4: Krafla West; One producer with 5 months delayed production start

The fourth scenario consisted of removing the horizontal well, KW-HEATH, on Krafla West and doing simulation with only one gas producer.
The gas producer, KW-TARB, started the production from layer 5-21 (zone 2) in the Tarbert Formation and after 5 months, the top layers 1-3 (zone 1A) in the Heather Formation is opened for oil production. The objective is to produce the lower layers with high pressure first and delaying the top layer production until the pressures are even. It is then observed if the pressure drop in the well had any effect on the volume production from the top layers.
No changes are made on Krafla Main.

8.5 Scenario 5: Krafla West; One producer with 1 year and 5 months delayed production start

The fifth scenario is a follow-up of scenario 4 to delay production of the top layers in the Heather Formation on Krafla West by using one gas producer.

The gas producer, KW-TARB, started the production from layer 5-21 (zone 2) in the Tarbert Formation and after 1 year and 5 months, the top layers 1-3 (zone 1A) in the Heather Formation is opened for oil production. The objective is to delay the production from the top layers at a longer time step than in scenario 4 to observe if an even lower pressure drop would manage to increase oil production from the top layers.

No changes are made to Krafla Main.

9. Results and discussion

This chapter provides results from the simulation scenarios described in the previous chapter. Results from each scenario are given in production profiles to provide an overview of the development over time for each well.
The parameters of valuable interest from the simulation is the oil and gas production rate, total oil and gas production and water production rate, in addition to gas oil ratio and bottom hole pressure.
The profiles made it possible to compare the differences that are made in each scenario and to analyze how the changes affected the production.
Findings are summarized at the end of each scenario and the recovery factor is calculated from each scenario are given at the end of this chapter.

9.1 Scenario 1; Base Case

The first simulation is the construction of the base case which is based on experience and knowledge on earlier productions with similar structure as Krafla Main and West.
The scenario consist of two oil producer and one water injector on the Main structure, and one gas producer and one oil producer on the West structure.

9.1.1 Krafla Main, KM-1

The evaluation of well KM-1 from figure 9-1 shows that the total oil production (green line) for the first well on Krafla Main is economic valuable with a production of approximately 1 680 000 Sm^3. As an opposite approach to the increasing oil production, the rate of the oil production (light blue) is decreasing with time.
In the beginning of the production, the GOR (red line) increases slightly due to a decrease in reservoir pressure leading to production of light hydrocarbons.
The GOR then experience a drop when the BHP (purple line) is increasing indicating production of heavier components reflected in a steady oil production rate.
As the GOR is starting to rise again due to pressure drop, the water production rate development is steep (blue line) leading to a rapidly increase in BHP until the pressure evens out and stabilizes throughout the production.

The GOR and water production rate then reach a certain value which is held more or less constant to the end of production.

It is not observed a relatively high GOR at this well, indicating that the production mainly consists of oil which is not influenced with natural gas.

The bottom hole pressure reflects the hydrostatic pressure of the wellbore fluid and may also be affected by backpressure held at the surface when the well, for instance, is shut in. This is not the case here, and the BHP only applies to the wellbore fluid.

The increase in BHP for KM-1 indicates good reservoir properties as the BHP reflects the production rate. The definition of production rate is referred to section 4.1, where it is shown that the pressure difference (drawdown) between the reservoir pressure and the bottom hole pressure influence the production rate. The drawdown must be adjusted to this field's permeability, and low drawdown indicates high fluid flow.

It is also observed that the water production rate increases with decreasing oil production rate which is true to the fact that water replaces oil at same speed.

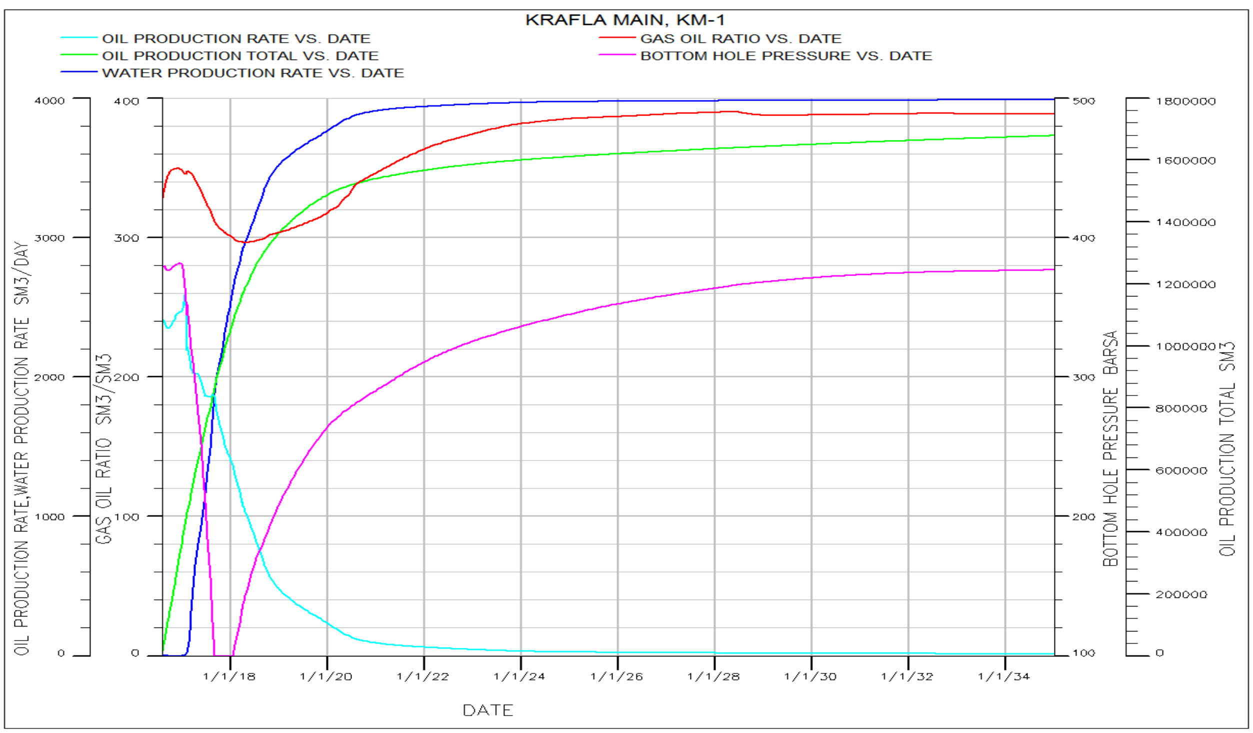

Figure 9-1: Base Case scenario showing cumulative oil production and rate, water production rate, GOR and BHP in KM-1.

9.1.2 Krafla Main, KM-2

The second well on Krafla Main, KM-2 (figure 9-2) shows considerably good oil production (green line) with a value of 3 150 000 Sm^3 which is almost twice as much as the first well. The location of the well may be a good reason for the high production since the well is placed on the high structure on Krafla Main.

A moderately level on the GOR (red line) is observed, indicating that the production contains mostly oil with low containment of natural gas.

The GOR experiences a peak due to the pressure drop at the production start before the BHP (purple line) decreases and evens out.

The GOR then increases slowly while the BHP is held constant at a pressure of 100 barsa. This BHP value is defined in the initialization in Eclipse where the BHP target or lower limit should be set to a value not less than the lowest pressure in the PVT tables to ensure the tables are not extrapolated in the well. [25]

The low BHP reflects poorer reservoir properties in well KM-2. The well must produce with high drawdown to optimize a good production rate. However, the BHP cannot drop below 100 barsa

The oil production rate (light blue line) increases rapidly into a peak when the BHP decreases, but as the production precedes the oil production rate decreases with increasing water production when the BHP is held constant.

The water production rate (blue line) is observed to be much lower in KM-2 which means less water produced per day. This is obviously the case since well KM-2 is placed further away from the water injector than KM-1.

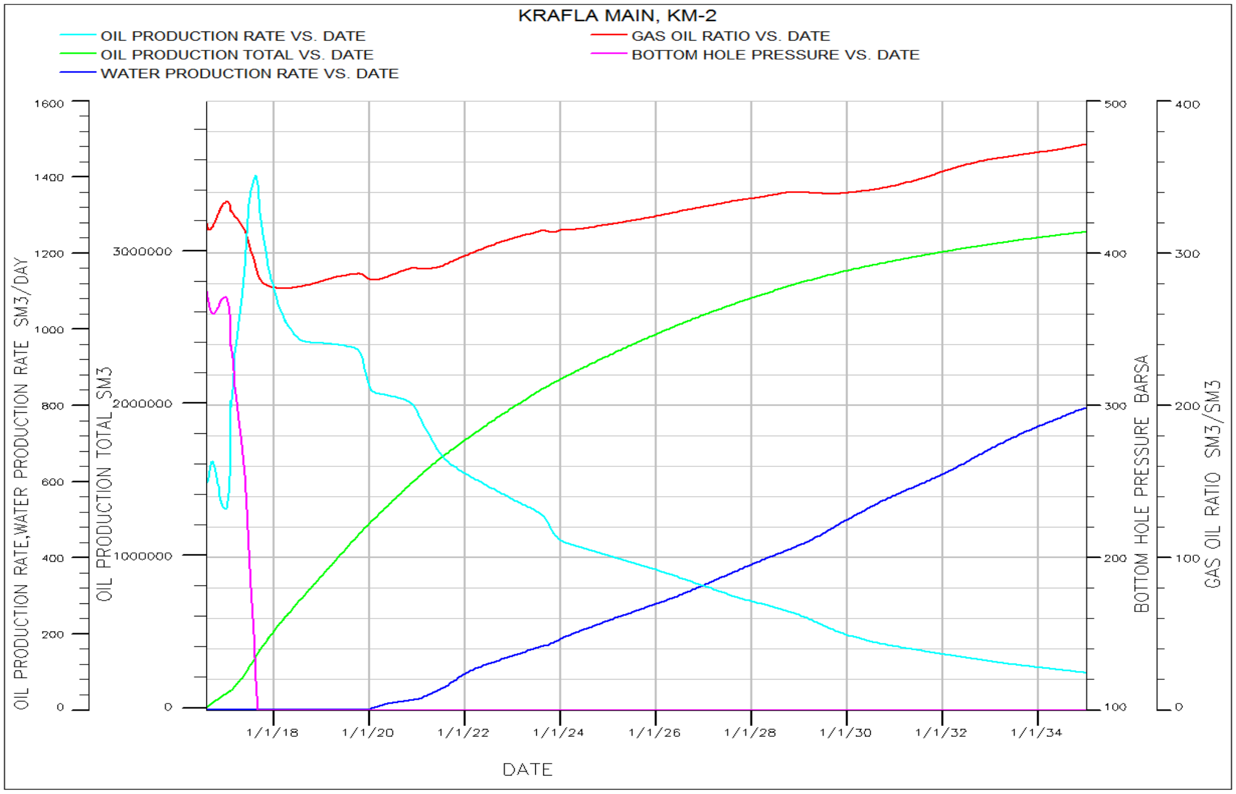

Figure 9-2: Base case scenario showing total oil production and rate, water production rate, GOR and BHP in KM-2.

9.1.3 Krafla Main, WI-KM

One water injector is placed on the Krafla Main structure to perform artificial lift to the oil producers. Through experience and logical reasoning, the injector is placed on the low side of the height to perform hydrostatic lift to the hydrocarbons.

The water injection rate (blue line) is set through initialization in Eclipse to be controlled by the BHP (red line) at an upper rate of 600 barsa. This pressure is held constant through the whole simulation to secure stabile injection rate as the oil production develops.
As can be observed from figure 9-3 the water injection rate has a sharp decline at the start of the production. This may be caused by low permeability and porosity which prevents the water from flowing rapidly to reach the oil and the viscosity of the oil for water breakthrough.
After some time the water production develops and the rate stabilizes throughout the production.

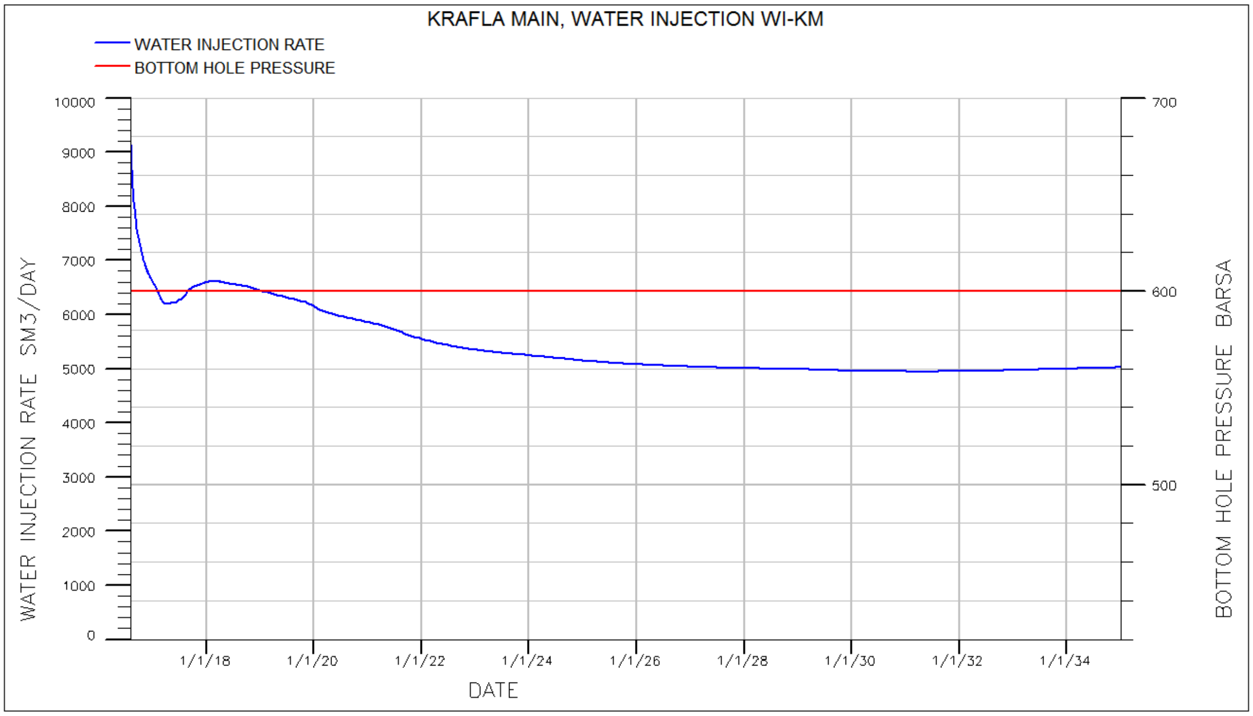

Figure 9-3: Base case scenario showing water injection rate and BHP on WI-KM.

9.1.4 Krafla West, KW-Heath

One horizontal oil producer, KW-Heath is placed on Krafla West which produces from the top layers on the structure. The production profile from the well is shown in figure 9-4.

The well experience a total oil production (green line) of approximately 940 000 Sm^3 and no water production from depletion of the Heather Formation.

The oil production rate (light blue line) is decreasing evenly through the whole process except in the start of the production where the production need time to stabilize due to pressure drop in BHP (purple line).

The GOR (red line) has a steep development curve that reaches a value of approximately 3200 Sm^3/Sm^3 that indicates a high containment of natural gas in the produced oil which is naturally since the oil in the Heather Formation is very volatile.

The BHP drops significantly to a 100 barsa where it stays constant through the whole production as observed in well KM-2.

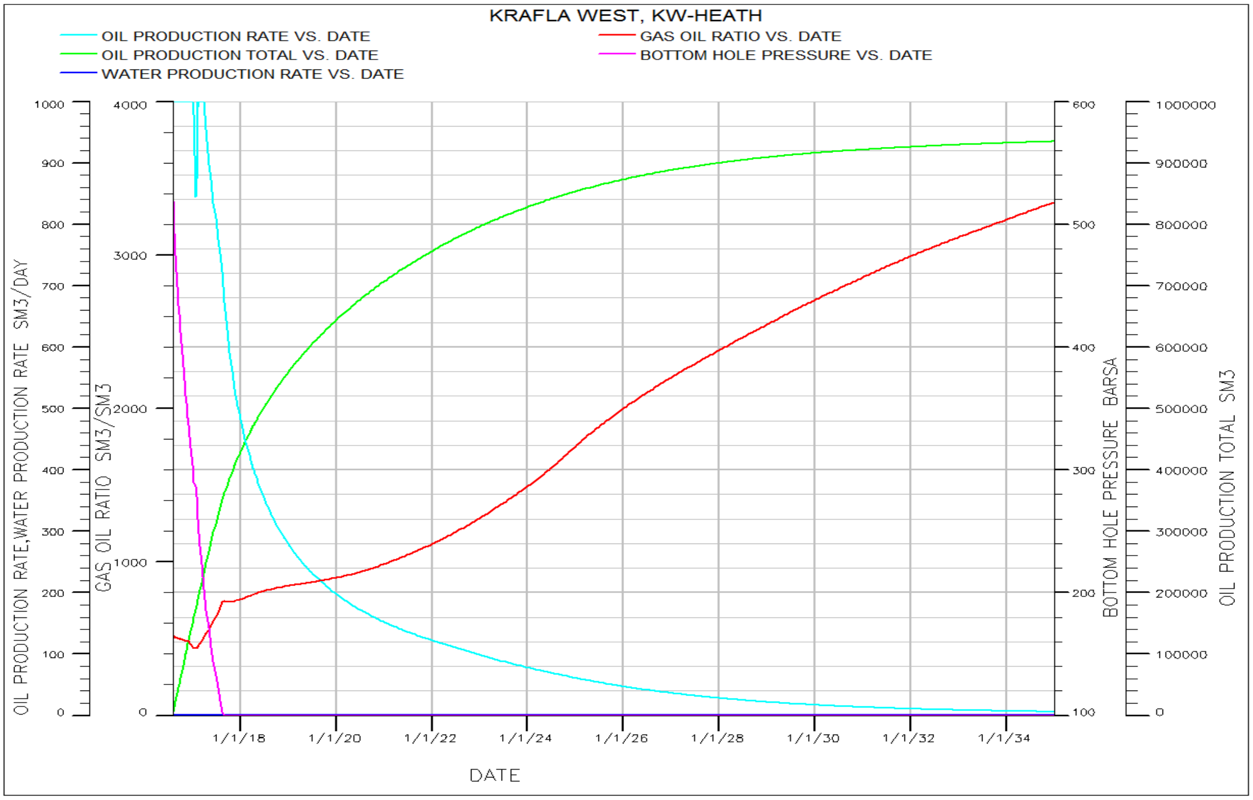

Figure 9-4: Base case scenario showing total oil production and rate, water production rate, GOR and BHP on KW-Heath

9.1.5 Krafla West, KW-Tarb

The second well on Krafla West is the gas producer, KW-Tarb which has a total gas production (red line) of approximately 3 200 000 000 Sm^3.

No water production is observed in the well, and the GOR is normally high in this production due to lot of gas production.

The gas production rate (green line) together with the GOR (light blue line) experiences a peak where the BHP (purple line) is low because of increased production. The BHP then builds up leading to a sharp decline in production rate, before both stabilizes throughout the production. The production profile for well KW-Tarb is shown in figure 9-5.

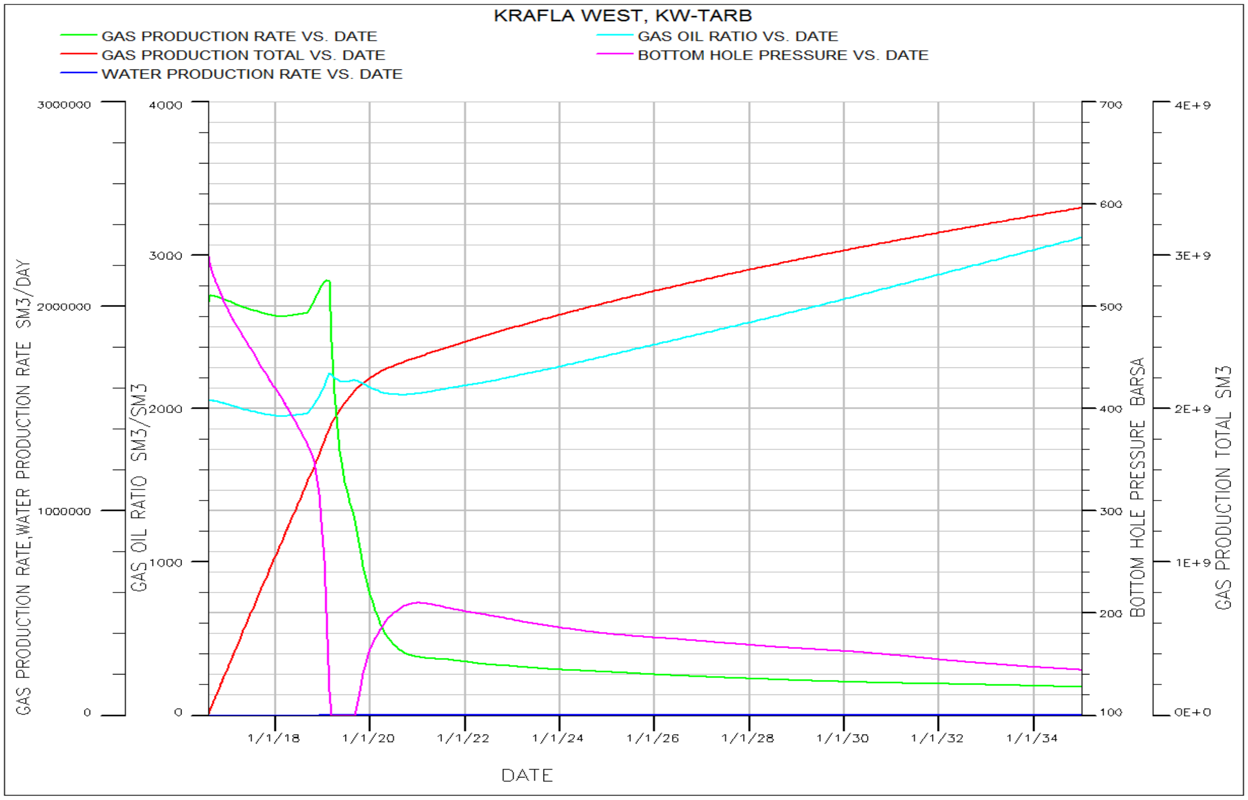

Figure 9-5: Base case scenario showing total gas production and rate water production rate, GOR and BHP on KW-Tarb

9.1.6 Summary of Scenario 1

Conclusions that can be withdrawn from the analysis of Scenario 1:

- Wells that are placed near an injector provided to perform artificial lift may be subject to interference in the production by early breakthrough of injected fluid.
- Knowledge of the reservoir structure and how the reservoir is drained is important aspects of finding the location of producers and injectors.
- The perforation heights in wells are crucial for good production and play an important role considering early water cut. Good perforation leads to postponement of coning which will have an economic value since it may reduce the water production.
- The bottom hole pressure contribute to stabilize the production by maintaining a backpressure to the formation. As the oil/gas production rate drop, the reservoir pressure decreases leading to a fall back on the bottom hole pressure. If water injection is

provided, the bottom hole pressure will maintain its value since there will be no decrease in reservoir pressure.

- Keeping the production rate at a stabilized value is crucial to prevent the well from dying. The BHP contributes to stabilize the production and keeping a high production rate as long as possible.

9.2 Scenario 2

9.2.1 Krafla Main; Three producers and one injector

Initial state from the Base Case scenario is two oil producers and one water injector on the Krafla Main structure.

Scenario 2 explores the possibility of three oil producers and how it will affect the total volume production. One might imagine that the idea of adding an oil producer to the field may have a beneficial advantage for increasing the volumes produced, but for a new well to be economic valuable for an oil company the well have to produce at least 300 000 Sm^3/day. This value will cover the expenses that entail to develop and operate a new well on the field. [10]

By evaluating the production profile from Scenario 2 in figure 9-6 it is possible to compare the Base Case scenario from Krafla Main with two oil producers versus the new case with three oil producers.

The figure shows the total oil production and the oil production rate for the whole Krafla Main structure in both cases.

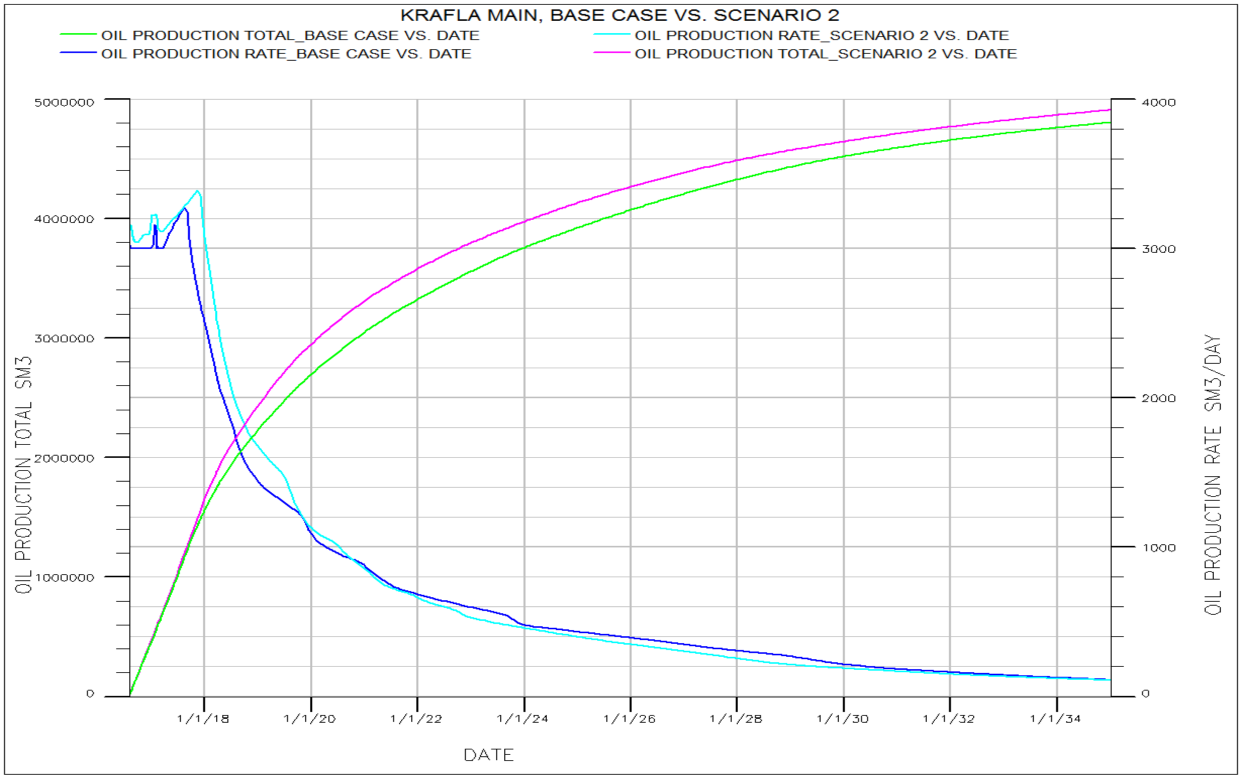

Figure 9-6: Base Case scenario vs. Scenario 2 showing total oil production and rate from Krafla Main

The total oil production from the Base Case scenario (green line) shows that the whole field produced by only two injectors provide a volume of approximately 4 800 000 Sm^3/day.
By adding the extra producer in scenario 2 (purple line), the volume increases to 4 900 000 Sm^3/day meaning an increase of approximately 100 000 Sm^3/day which will not pay off economically.
The oil production rate in Scenario 2 (light blue) will naturally increase at the start of the production due to more oil producers and will continue with higher rate than the base case (blue line) in about five years before it drops and slows out throughout the production.

9.2.2 Summary of Scenario 2

Conclusions that can be withdrawn from the analysis of Scenario 2:

- Adding an extra oil producer to the field may not necessarily pay off economically even though the total oil production increases. There are high expenses related to a new production well and the net present value has to be considered.
- It should be considered other possibilities to recover the remaining volumes, either by relocation of the existing wells or perforation in different heights.
- The oil production rate has a lower development towards the end of the production in Scenario 2 which is not optimal in preventing the well from dying at an early stage.

9.3 Scenario 3

9.3.1 Krafla Main; One producer and one injector

As an opposite approach to Scenario 2 where the case is simulation of three oil producers, the third scenario consisted of simulating the field with only one oil producer to observe the effect on produced volume.
Well KM-1 which experienced lowest oil production in the Base Case scenario is removed, leaving the well KM-2 left to see if it could manage to produce the same amount of volumes covered from both wells.

KM-2 is placed on the south side of the height structure on Krafla Main and is perforated to a certain level described in the Base Case scenario.
Figure 9-7 shows the comparison between development of the Base Case scenario (same as in Scenario 2) and Scenario 3 on the field.

It is observed that the total oil production from Scenario 3 (purple line) is slightly less than the oil production from the base case (blue line) and the difference is approximately 50 000 Sm^3. This means that the oil producer KM-2 is capable of producing almost the entire field alone with artificial lift from one water injection. In spite of this, it is preferable with one more oil producer since it is observed in Scenario 2 that adding a producer may lead to higher produced volumes. The location of the second well should in that case be reconsidered since it clearly causes poor production where it is located at the time. The second producer may then be able to cover the expenses of adding a new well.

It is also observed that the oil production rate from Scenario 3 (light blue line) has a more evenly approach than the base case scenario (green line) indicating a good and steady production from the single producer even though it falls a bit towards the end.

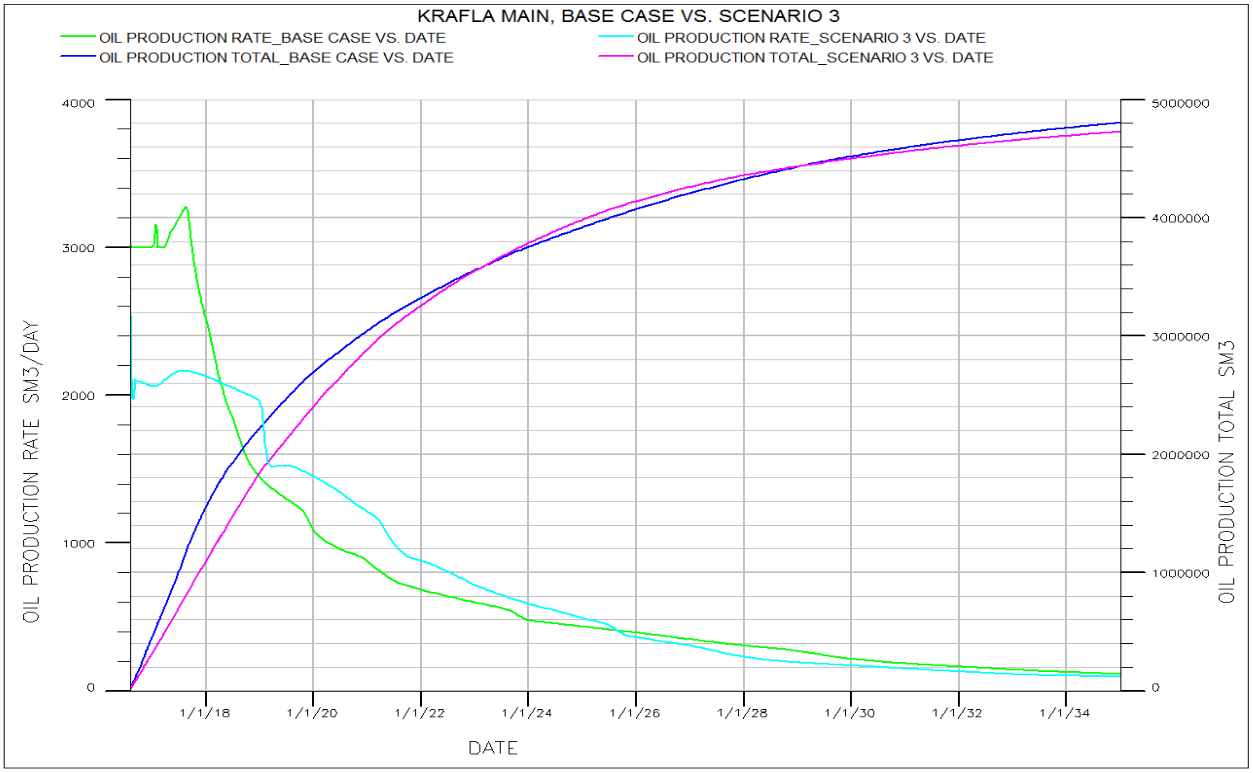

Figure 9-7: Base Case scenario vs. Scenario 3 showing total oil production and rate from Krafla Main

9.3.2 Summary of Scenario 3

Conclusions that can be withdrawn from the analysis of Scenario 3:

- Due to the location and perforation of the single well producer on Krafla Main, the well is capable of producing almost the same amount of volumes as from two producers.
- The results evaluated leads to a reconsidering of the second well simulated in the Base Case scenario (KM-1) with poor production which may be caused of the location placement and the deep perforation performed on the well.

  The case where the second well is relocated is not simulated in this thesis, but should be considered in the development stage of the field.

- The production rate is kept higher in Scenario 3 which is an advantage for the life time of the field, but increases more towards the end than the Base Case scenario.

9.4 Scenario 4

9.4.1 Krafla West; One producer with 5 months delayed production start

Krafla West consists of an oil filled reservoir at the top of the structure and a gas filled reservoir in a zone further down.

The case simulated in Scenario 4 involves removal of the horizontal well, KW-Heath, which produced the oil from the reservoir in the top layers, and instead use one well to produce from both the oil and the gas reservoir. The well would then start by producing from the gas reservoir located deep on the structure, while delaying the production from the oil reservoir at the top layers by 5 months.

The pressure and temperature increases with increasing depth, but the reservoir pressure decreases as the production proceed.

The main task in Scenario 4 is to start the production from the reservoir further down with high pressure and continue production until the pressure had decrease to approximately the same value as the reservoir above. Then the production of the top layers would be initiated and the well would produce both oil and gas at different petrophysical properties.

The aim with delayed production start is to optimize the production from the top layers by the use of pressure drop in the well and to observe if it would have any effect on the volume produced.

Figure 9-8 A & B shows the total oil/gas production and oil/gas production rate, respectively, for the Base Case and Scenario 4 on Krafla West.

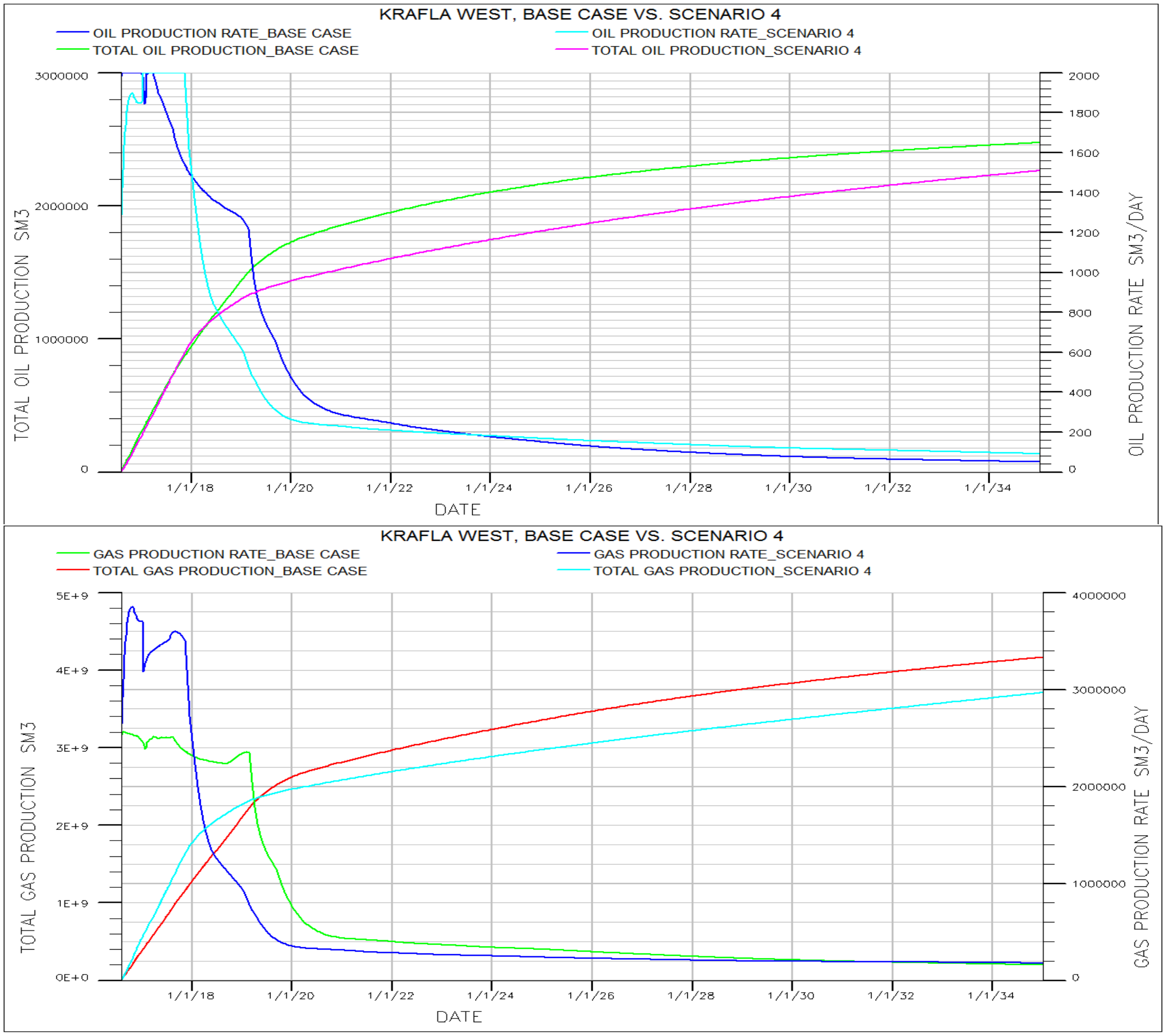

Figure 9-8: Base Case scenario vs. Scenario 4 showing A) total oil production and rate and B) total gas production and rate from Krafla West

The evaluation of Scenario 4 indicates a reduction in reservoir volumes produced in relation to the Base Case scenario for both oil and gas.

The total oil production for the Base Case in figure A (green line) produces oil volumes at an approximate volume of 2 450 000 Sm^3 in relation to Scenario 4 (purple line) which has a total oil production of 2 220 000 Sm^3. This reduction is of a considerably volume which indicates that the vertical well do not manage to produce as efficiently as the horizontal well and that makes the Base Case scenario preferred over Scenario 4.

The oil production rate from the Base Case scenario shows a steady decreasing slope (blue line) except from the first year of production where the instability may be caused by the volatile oil located at Krafla West in the Heather Formation.
A pressure drop is common in volatile oil reservoirs at the beginning of production from tight reservoirs [26], but the rate stabilizes as the pressure evens out throughout the production.
The oil production rate from Scenario 4 (light blue) is set at an upper limit target of 2000 Sm^3/Day which is the increased value at the start of the production until the delayed limit is reached and the production starts from the top layers in the Heather Formation. The rate then experience a relatively steep drop and produces with constant rate throughout the simulation which indicates good flow.

The total gas production simulated in Scenario 4 is experiencing a decrease from approximately 4,2 MSm^3 from the Base Case scenario (red line) to approximately 3,6 MSm^3 (light blue line) This indicates that the gas production must yield for the oil production
The gas production rate from Scenario 4 (blue line) is experiencing a high naturally increase at the start of the production, and another high peak is observed after 5 months, due to the start of the delayed production. But after some months of production, the rate drops quickly and falls under the rate from the Base Case scenario (green line) where it is held constant towards the end of production.

Note: The gas production rate is of considerably difference relative to oil production rate, and the cause is that erosion is a disadvantage with high fluid production rate.
The gas production rate is therefore adjusted relatively high in the Eclipse initialization in Appendix B while the oil and water production rate is set at a considerably lower value.

9.4.2 Summary of Scenario 4

Conclusions that can be withdrawn from the analysis of Scenario 4:

- The oil production and the gas production are both experiencing a decrease in this scenario, indicating that the horizontal well, KW-Heath is a valuable producer. It seems like the pressure drop that occurred in the well is not optimizing the production in the expected way.

- The rate in both cases drops dramatically which is not a good circumstance for the life time of the well.

9.5 Scenario 5

9.5.1 Krafla West: One producer with 1 year and 5 months delayed production start

As an extension to the case simulated in Scenario 5, the horizontal well, KW-Heath is removed and the remaining well, KW-Tarb, is producing from both reservoirs with a delayed production start of the top layers.

Scenario 5 simulated a delayed production start of 1 year and 5 months from the oil reservoir in the Heather Formation on Krafla West while producing from the gas reservoir in the underlying Tarbert Formation.

The aim is to see if the effect of decreasing the pressure even more than in Scenario 4 would increase the reservoir volumes produced (described in more detail in Scenario 4).

Figure 9-9 A & B shows the total oil/gas production and oil/gas production rate, respectively, for the Base Case and Scenario 5 on Krafla West.

It is observed that delaying the production start from the top layers from 5 months (Scenario 4) to 1 year and 5 months (Scenario 5) had no considerably impact on the cumulative oil production (purple line). A slight decrease in the total oil production rather occurred.

The oil production rate (light blue line) reached the maximum value at the start of the production but decreased naturally after 1 year before it experienced a high narrow peak when the production started from the top layers after 5 more months.

After a short production it decreased again due to pressure drop and fell below the Base Case production rate. The rates intersected again after 1/3 of production and the rate from Scenario 5 is held constant throughout the production.

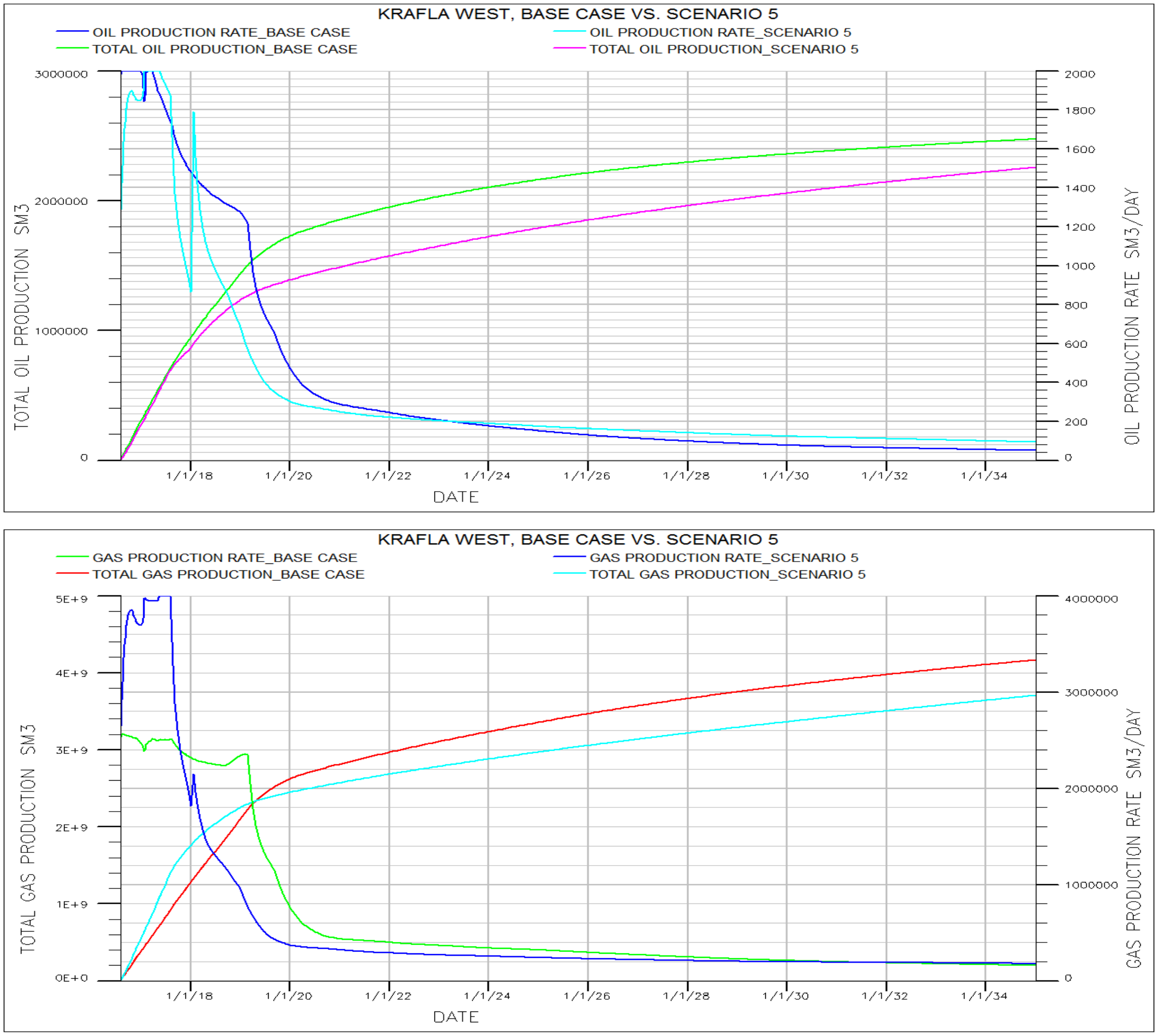

Figure 9-9: Base Case scenario vs. Scenario 5 showing A) total oil production and rate and B) total gas production and rate from Krafla West

No particularly changes are discovered on the cumulative gas production (light blue line) either which indicated that increased pressure drop would not affect the well to produce more volumes. The gas production rate for Scenario 5 however (blue line), experienced a change during the time when the production start at the top layers occurred. Due to this, the gas rate drops quickly after the time delayed, but rises slightly again as the pressure stabilizes in the well.

The rate then experience a continuous drop and produces with a low rate towards the end of the production.

The evaluation of the Base Case scenario is naturally identical for both Scenario 4 and 5 where both the total oil and gas production rate are experiencing steady increase and decrease, respectively.

9.5.2 Summary of Scenario 5

Conclusions that can be withdrawn from the analysis of Scenario 5:

- The relatively same conclusion can be withdrawn from both Scenario 4 and 5. The single producer on Krafla West does not manage to produce both reservoirs alone, and the horizontal well is needed for production from the top layers.
- The oil and gas production rate is also experiencing a lower value in relation to the Base Case scenario and is not optimal for production.

9.6 Recovery factor

The recovery factor is of main importance during development process of a field.
It is defined as the recoverable amount of original or residual hydrocarbons in place in a reservoir, expressed as a percentage of total hydrocarbons in place. [27]

The main interest is to achieve the highest recovery value as possible to ensure that no hydrocarbons are left behind in the reservoir.
Observation of the recovery factor from each scenario in table 9-1 contributes to the evaluation of what development strategy that would be contributing to the highest NPV.
It is seen that the recovery factor for Scenario 2 has increased relative to the recovery factor in the Base Case Scenario, but then again it is important to evaluate the reason for why it has increased. It may not increase the NPV although more hydrocarbons are recovered.
As expected, the recovery factor for Scenario 3 is lower due to lower production.

By comparing the recovery factor for the Base Case Scenario from Krafla West relative to Scenario 4 and 5, the recovery factor is naturally higher in the case of one oil and oil gas producer as in the Base Case scenario. But, it is important to look at the expenses of having two producers relative to one, or if other options should be considered like artificial lift.

Scenario	Oil reserves [MSm^3]	Gas reserves [MSm^3]	Recovery factor oil	Recovery factor gas
1 **Base Case, Krafla Main**	4,8	1507,9	0,59	0,52
1 **Base Case, Krafla West**	2,3	4166,0	0,40	0,57
2 **Krafla Main**	4,9	1515,2	0,60	0,53
3 **Krafla Main**	4,75	1586,7	0,57	0,55
4 **Krafla West**	2,2	3709,0	0,39	0,50
5 **Krafla West**	2,2	3707,6	0,39	0,50

Table 9-1: Oil and gas recovery factors from simulated scenarios

9.7 Problems and challenges

Many challenges had to be overcome to fulfill this thesis and one of them is the construction of the geological model in Petrel. Building the model required insight in all the functionalities of the software and knowledge about the data available to use as input.

The grid construction had to be done accurately to prevent errors in the proceeding work and the data had to be distributed as realistic as possible.

The field is surrounded by many faults and it is important that there is no simulation of fluid movements between them since they are sealing faults. This is especially important between the main fault between Krafla Main and Krafla West and a keyword is used in Eclipse to set the transmissibility between faults to zero.

The distribution of porosity throughout the grid required time and effort since it is the basis for further data distribution. It is important that the petrophysical data simulated throughout the grid matched the data from raw well logs. Many settings are tested to see how the distribution is performed and adjustments are made until a logically realistic decision came through.

The calculation and initialization of all the saturation functions is also time-consuming and the fact that the field consisted of 3 PVT-regions did complicate the task. Each region had its own requirement of data, and the complexity of the saturation functions needed a clear mind. Adjustments are performed until the consistency requirements are met.
A lot of time is spent on learning the Eclipse software better and understanding the behavior of the keywords to be able to initialize a simulation with this kind of complexity.
The reservoir fluid located in the Heather Formation is a very volatile oil, and Eclipse had problems believing that this fluid is oil and not gas.

9.8 Uncertainty and source of error

The results provided in this thesis contain some degree of uncertainty due to the complexity in constructing a geological model and the reliability of the data simulated. These uncertainties and the source of error are listed below and are should be considered with great care since they are crucial for determining a good development solution.

9.8.1 Geological model

The construction of the geological model is accomplished due to a variety of settings on how to build the model. The field contained a lot of faults which are made into zig-zag faults to ease the simulation, and that may have had an impact on the reservoir volumes.

The petrophysical data distribution throughout the grid is performed by the use of a Gaussian random function simulation similar to kriging which simulated the data from the well into the grid. The porosity distribution is a crucial factor for the permeability and the net-sand since the parameters are set to match the porosity behavior by the use of a regression line.
A source of error may have been developed during this distribution since the process of getting the well data to match the simulated data where prevented since the simulated data are developed by upscaling. By upscaling the well data, only the average data are considered leaving the extreme values behind, and simulated data would therefore never fully match the original data.

The grid is divided into reservoir zones and layers, where certain layers are indicated to be dry and therefore excluded from further simulation. There is an uncertainty related to the height of each layer and decreasing the height would attain a more accurate simulation.
The increment on the grid blocks would also have given more accurate results on the simulation since finer grid blocks use smaller time steps and provide more sensitive data. But using finer grid blocks is more time consuming than the use of coarser grid blocks and will affect the economy related to the production.

9.8.2 Reservoir simulation model

It possesses an uncertainty in the petrophysical data collected from the well logs, and if more time are remained then sensitivity analysis would have been performed.
Parameters that are subject to uncertainty are porosity, permeability, net-sand and fluid contacts and a suggested approach is to perform a simulation to investigate the range of uncertainty (P10, P50 and P90). The parameters are then simulated with both increased and decreased values to predict the extreme cases.

Another approach to decrease the uncertainty during the development of the field is to adjust the endpoints related to the relative permeability and saturation functions applied.
By adjusting the endpoints, the fluid flow through the grid blocks are affected.
The ability for water to flow through a grid block may be held back by the limit of the water saturation endpoint, meaning that the water will not move from one grid block to the next until the saturation in the grid block is reached.
The adjustments of the endpoints should be simulated to observe any effect on the residual oil and water saturations.

10. Conclusions

The aim of this thesis is to develop a full field geological model on a newly discovered reservoir in the North Sea, with performance of subsequent reservoir numerical simulation.

The geological model is built by constructing a grid in Petrel with petrophysical data and computational saturation functions provided as input.

Initialization to prepare for reservoir numerical simulation is performed in Eclipse.

The geological model resulted in a total of 5 scenarios that are initialized and simulated to evaluate the differences related to fluid production.

The importance of the thesis is to observe which scenarios provided the best outcome due the number and types of wells, perforated layers, well placement and artificial lift.

The main conclusions made from the study are in the following:

- Hydrocarbons are located in different PVT zones. This differing between the zones made the area a complex system and a total of 5 PVT regions are discovered.
  Only 3 of this PVT regions contained economic amount of producible hydrocarbons, and are used further in the simulation study.
- The grid is divided into layers and reservoir zones to focus on producible volumes and to provide an easier numerical simulation. Petrophysical data is upscaled and distributed throughout the grid, and slight problems had to be overcome in the process of making the grid realistic.
- Fluvial contacts are not able to be identified from pressure tests. Expected (mean) contacts are provided in this thesis.
- SCAL studies are not available, and in the lack of data there is providence of default values in saturation calculations and end point scaling.
- Naturally high structures provide an optimal placement of wells, especially when the field is produced with artificial lift.
- Perforation in high layers prevents coning, i.e. early water breakthrough, and increase the hydrocarbon production.
- To prevent the well from dying at an early stage it is of main importance to keep the production rate at an acceptable level throughout the production.

- The bottom hole pressure stabilizes the production rate and contribute to extend the life time of a well.

Developing a drainage area consists of many aspects which should be considered critically to avoid uncertainty. Investigation of range of uncertainty must be taken into consideration during development since it may influence the economic value of the field at a high level.

11. Recommendations for further work

- Investigate the range of uncertainty (P10, P50 and P90) by performance of numerous simulations on model parameters (porosity, permeability, net-gross and fluid contacts).
- Performance of numerous simulations related to adjustments to endpoint scaling regarding saturation functions and relative permeability.
- Identify the difference in results by the use of smaller grid blocks (fine grid) versus the coarse grid blocks.
- Evaluate the performance of multiple simulation scenarios with various number and types of wells (vertical, horizontal and sub-horizontal).
- Consider alternatives to artificial lift, i.e. gas lift versus water injection.
- Decide which development scenario is optimal regarding the production of the field (Oseberg Field Center or Oseberg South).
- Evaluate lift curves for each field and find the optimum dimension of pipeline for transporting the produced fluid to the production template.

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Nomenclature

Symbols

A	=	Cross sectional area between the blocks
k_a	=	Absolute permeability
k_l	=	Effective permeability
k_{rl}	=	Liquid relative permeability
μ	=	Fluid viscosity
Δx	=	Distance between block centers
$Pj\text{-}Pi$	=	Pressure difference between grid block j and i
h	=	Perforation height
r_e	=	Dependent on grid block parameters
r_w	=	Well radius
S	=	Skin factor
p_c	=	capillary pressure [Pascal]
ϕ	=	porosity [0-1]
σ	=	surface tension
θ	=	contact angle
h_{FWL}	=	Height above free water level
k	=	Log-permeability
Sw	=	Water saturation
Swi	=	Initial water saturation
$Sorw$	=	Residual oil saturation in oil/water system
Co	=	Corey oil exponent
P_a	=	Rock reference pressure
D	=	Vertical depth
S_o	=	Overburden gradient
ρ_b	=	Average formation bulk density
d	=	Vertical thickness of the overlying sediments
ρ_f	=	Formation fluid density
ρ_m	=	Rock matrix density

Vb	=	Bulk volume of the reservoir
P	=	Pressure
V	=	Volume
Z	=	Compressibility factor
n	=	Number of moles
R	=	Universal gas constant
T	=	Absolute temperature
B_o	=	Oil formation volume factor
B_g	=	Gas formation volume factor
B_w	=	Water formation volume factor

Abbreviations

BHP	=	Bottom Hole Pressure
DST	=	Drill Stem Test
EOS	=	Equation Of State
FWL	=	Free Water Level
GDT	=	Gas Down To
GOR	=	Gas Oil Ratio
GWC	=	Gas Water Contact
HC	=	Hydrocarbon
MDT	=	Modular Formation Dynamics Tester
MSL	=	Mean Sea Level
PL	=	Production License
ODT	=	Oil Down To
OGR	=	Oil Gas Ratio
OOIP	=	Original Oil In Place
OWC	=	Oil Water Contact
SCAL	=	Special Core Analysis
STOOIP	=	Stock Tank Original Oil in Place
TVDSS	=	True Vertical Depth Sub Sea
VSP	=	Vertical Seismic Profile

WUT	=	Water Up To

Units

Ft	=	Feet
Rm^3	=	Reservoir cubic meters
Sm^3	=	Standard cubic meters

Appendix A: Eclipse keywords

Data file section	***Keyword***	***Meaning***
RUNSPEC	ENDSCALE	Indicates that end point scaling is being performed on relative permeability curves for each cell.
	WELLDIMS	The dimension of well data, such as maximum number of wells and the maximum number of grid blocks connected to any well.
	EQLDIMS	Equilibration regions by keyword EQLNUM which are used to initialize different parts of the reservoir that is not in mutual hydrostatic equilibration. Also defines the maximum number of depth nodes in keyword RSVD and RVVD.
GRID	EQUALS	Assign and replace the value of a property for a box of cells within the grid. The keyword sets the transmissibility of flow through the fault between Krafla Main and West to zero, indicating that the fault is 100% sealing.
PROPS	SWFN	Comprises a table of water saturation functions with 3 columns; The water saturation, the corresponding water relative permeability and the corresponding water-oil capillary pressure.
	SGFN	Comprises a table of gas saturation functions with 3 columns; The gas saturation, the corresponding gas relative permeability and the corresponding oil-gas capillary pressure.
	SOF3	Comprises a table of oil saturation functions with 3

		columns; The oil saturation, the corresponding oil relative permeability for regions where only oil and water are present and the corresponding oil relative permeability for regions where only oil, gas and connate water are present.
REGIONS	ROCKNUM	Used together with the ROCK keyword for specifying rock compressibility.
	SATNUM	A saturation function region number that specifies which set of saturation functions should be used to calculate relative permeabilities and capillary pressures in each grid block.
	PVTNUM	Specifying the PVT region to which every grid block belongs. All grid blocks within a particular equilibration region must have the same PVT region number.
	FIPNUM	Fluid in place and cumulative flows to and from wells and other regions is produced for each fluid-in-place region at every report time.
	EQLNUM	Specifying the equilibration region to which every grid block belongs. All blocks with the same equilibration region number must have the same PVT region number.
SOLUTION	EQUIL	Sets the contacts and pressures for conventional hydrostatic equilibrium.
	RSVD	Comprises tables of dissolved gas-oil ratio versus depth for each equilibration region.

	RVVD	Comprises tables of vaporized oil ratio versus depth for each equilibration region.
	RPTRST	Controls the output of data to the restart file. Here; restart files are created every n^{th} report time.
	RPTSOL	Controls the output of SOLUTION section data to the print file. Here; Initial fluid in place are reported for each fluid in place region and the inter block flows of each phase are written to the restart files.
SCHEDULE	TUNING	Sets simulation control parameters such as maximum length of time step and maximum/minimum number of Newton iterations in a time step.
	RPTSCHED	Controls the output of SCHEDULE section data to the print file. Here; a balance sheet is produced for each fluid in place region which shows current and initial fluids in place and also gives a report of well and connection flow.
	WELSPECS	Introduces the well, the position of the wellhead and the phase of the well.
	COMPDAT	Specifies the position and properties of one or more well completions.
	WCONPROD	Controls data for production wells which sets the phase rate target or upper limit and BHP target or lower limit.
	WCONINJE	Defines if the injector is open and what pressure it is controlled by (here BHP).

	GCONPROD	Sets the upper limit on fluid production rate targets
	GCONINJE	Sets the upper limit on surface injection rate target
	GECON	Sets the minimum fluid production rate

Appendix B: Initialization file in Eclipse

```
RUNSPEC

TITLE
KRAFLA

START
  1 AUG 2016 /

WATER

OIL

GAS

VAPOIL

DISGAS

UNIFOUT

METRIC

DIMENS
79 43 46 /

TABDIMS
1 3 11 137 4 137 137 5* 1 /

ENDSCALE
  /

WELLDIMS
8 70 5 4 /

EQLDIMS
3 1* 23 /

NSTACK
40 /

GRID

GRIDFILE
0 0 /

GRIDUNIT
METRES /
```

```
PINCH
  /

NOECHO

GDFILE
KRAFLA_INPUTGRID.EGRID /

INCLUDE
'..\PoroPerm\Poro_Perm_NTG.GRDECL' /


COPY
PERMX PERMY /
PERMX PERMZ /
/

MULTIPLY
PERMZ 0.1 /
/

EQUALS
MULTZ 0.0 1 79 1 43 3 4 /
/

NOECHO

EDIT

INCLUDE
KraflaW_NNC_EQLNUM_2_3.INC /

PROPS

INCLUDE
'Endpoint_saturation.INC' /

KRW
156262*0.8 /

KRORW
156262*0.9 /

KRG
156262*0.9 /

KRORG
156262*0.8 /


INCLUDE
'Statoil_PVT_DG0.INC' /
```

```
ROCK
500 4.4388E-005 /


SWFN
--    SW      KRW          PCOW
       0       0            0
       0.1     0.0001       0
       0.2     0.0016       0
       0.3     0.0081       0
       0.4     0.0256       0
       0.5     0.0625       0
       0.6     0.1296       0
       0.7     0.2401       0
       0.8     0.4096       0
       0.9     0.6561       0
       1       1            0     /


SGFN
--    Sg    Krg         Pcg
      0     0           0
      0.1   0.000001    0
      0.2   0.000064    0
      0.3   0.000729    0
      0.4   0.004096    0
      0.5   0.015625    0
      0.6   0.046656    0
      0.7   0.117649    0
      0.8   0.262144    0
      0.9   0.531441    0
      1     1           0     /

SOF3
--    So    Krorw       Krorg
      0     0           0
      0.1   0.001       0.001
      0.2   0.008       0.008
      0.3   0.027       0.027
      0.4   0.064       0.064
      0.5   0.125       0.125
      0.6   0.216       0.216
      0.7   0.343       0.343
      0.8   0.512       0.512
      0.9   0.729       0.729
      1     1           1      /

REGIONS

INCLUDE
PVTNUM.GRDECL /
```

```
COPY
PVTNUM EQLNUM /
/

INCLUDE
 FIPNUM.GRDECL /

ROCKNUM
156262*1 /

SATNUM
156262*1 /

NOECHO

SOLUTION

EQUIL

3534        426.3         3534              0          2000      0 1 1 0 /
3675        576.8         3675              0          2000      0 2 2 0 /
3774        614.5         3774              0          3774      0 3 3 0 /


RSVD
          3300        131.5
        3310.5        129.3
        3321.1        127.1
        3331.6          125
        3342.1        122.8
        3352.6        120.8
        3363.2        118.7
        3373.7        116.7
        3384.2        114.7
        3394.7        112.7
        3405.3        110.8
        3415.8        108.9
        3426.3          107
        3436.8        105.2
        3447.4        103.4
        3448.5        103.2
        3457.9        101.6
        3468.4         99.9
        3478.9         98.1
        3489.5         96.4
          3500         94.8
  /
          3550        542.6
        3553.9        535.6
        3557.9        528.6
        3561.8        521.8
        3565.8        514.9
```

```
        3569.7        508.2
        3573.7        501.5
        3577.6        494.9
        3581.6        488.3
        3585.5        481.8
        3587.6        478.4
        3589.5        475.4
        3593.4          469
        3597.4        462.7
        3601.3        456.5
        3605.3        450.3
        3609.2        444.2
        3613.2        438.2
        3617.1        432.2
        3621.1        426.3
          3625        420.4
  /
          3780          162
          3790          164
  /

RVVD
          1990   0.00014254
          2000   0.00015086
  /
          1990    0.0007655
          2000    0.0013582
  /
          3700    0.0004872
        3706.6   0.00049938
        3713.2    0.0005121
        3719.7   0.00052542
          3725   0.00053654
        3726.3   0.00053938
        3732.9   0.00055404
        3739.5   0.00056947
        3746.1   0.00058573
        3752.6   0.00060292
        3759.2   0.00062114
        3765.8   0.00064049
        3772.4   0.00066111
        3778.9   0.00068315
  /



RPTRST
BASIC=3 /

RPTSOL
RESTART=2 FIP=2 /
```

```
SUMMARY

INCLUDE
'KRAFLA_SUMMARY.INC'   /

SCHEDULE

TUNING
 0.5  20 /
  /
 2*  50 /

RPTSCHED
FIP=2 WELLS=2 /

RPTRST
BASIC=3 /

WELSPECS
KM-1 KM-T 54 25 1* OIL /
KM-2 KM-T 47 27 1* OIL /
WI-KM SUB-INJ 60 11 1* WATER /
KW-HEATH KW 46 12 1* OIL /
KW-TARB KW 36 14 1* GAS /
/

COMPDAT
KM-1 54 25 5 36 OPEN 2* .21 3* Z /
KM-2 47 27 5 30 OPEN 2* .21 3* Z /
WI-KM 60 11 5 46 OPEN 2* .21 3* Z /
KW-TARB 36 14 5 21 OPEN 2* .21 3* Z /
KW-HEATH 35 12 2 2 OPEN 2* .21 3* X /
KW-HEATH 36 12 2 2 OPEN 2* .21 3* X /
KW-HEATH 37 12 2 2 OPEN 2* .21 3* X /
KW-HEATH 38 12 2 2 OPEN 2* .21 3* X /
KW-HEATH 39 12 2 2 OPEN 2* .21 3* X /
KW-HEATH 40 12 2 2 OPEN 2* .21 3* X /
KW-HEATH 41 12 2 2 OPEN 2* .21 3* X /
KW-HEATH 42 12 2 2 OPEN 2* .21 3* X /
KW-HEATH 43 12 2 2 OPEN 2* .21 3* X /
KW-HEATH 44 12 2 2 OPEN 2* .21 3* X /
KW-HEATH 45 12 2 2 OPEN 2* .21 3* X /
KW-HEATH 46 12 2 2 OPEN 2* .21 3* X /
/
WCONPROD
KM-1       OPEN  GRUP  3000  4000  1E6   4000  1*    100   /
KM-2       OPEN  GRUP  3000  4000  1E6   4000  1*    100   /
KW-TARB    OPEN  GRUP  1000  100   4E6   1000  1*    100   /
KW-HEATH   OPEN  GRUP  1000  2000  1E6   2000  1*    100   /
/
WCONINJE
WI-KM WATER OPEN BHP 10000 1* 600 /
/
```

```
GCONPROD
FIELD ORAT 5000 7000 6E6 8000 RATE NO /
/

GCONINJE
FIELD WATER RATE 10000 /
/

GECON
FIELD 50 /
/

DATES
1 JAN 2018 /
1 JAN 2020 /
1 JAN 2022 /
1 JAN 2024 /
1 JAN 2026 /
1 JAN 2028 /
1 JAN 2035 /
/

END
```