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Abstract:

The Depletion of oil production and the low recovery rate are major challenges faced in oil production at Norwegian continental self. Several studies have shown that considerable amount of oil still remains after the well shutdown. Heavy oil reservoirs occupy more than two third of globally oil reserves. Therefore, extensive studies are undergone to optimize the oil recovery in heavy oil reservoirs. Water flooding and Enhanced Oil Recovery (EOR) methods are successfully implemented. Water breakthrough strongly affects on the recovery factor in heavily oil reservoirs and water cut is exponentially increased after the breakthrough. Inflow Control Devices (ICDs) are becoming handy in controlling water cut of the inflow. The water coning effect of the reservoir is also reduced by ICDS. Water coning depends on reservoir properties and recovery techniques. Hence, a better understanding about them are needed to observe and develop oil production. Literature review is provided useful information over and affecting factors of water breakthrough in heavy oil reservoirs. Moreover, the oil production is needed to be optimized within the handling capacity of offshore platforms. ICDs are used to control the multiphase flow behavior in production flow. Furthermore, multiphase flow behavior can be used to describe most of the characteristics in oil production. The reservoir flow simulator, Rocx in combination with OLGA is used to simulate heavy oil reservoirs with water drive. Simulations are carried out to observe the influence of reservoir properties on oil recovery and the inflow controlling mechanisms. Results obtained can be utilized to increase the oil recovery factor and to regulate the multiphase flow within the limitations.

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Preface

The thesis, “Near well simulations of heavy oil reservoir with water drive” has been carried out at Telemark University College (TUC) in co-operation with InflowControl AS. The thesis work has been a mandatory part of the Process Technology master programs at (TUC) and this has been carried out under the close supervision by Britt Halvorsen (TUC). The report mainly concerns the developments of oil extraction and the simulation results from OLGA and Rocx. I gained lot on offshore oil recovery process at the end of the task.

During this journey, the support and the guidance given by Britt Helvorsen (main supervisor) with close observation was remarkable. Hence I would like to give my unconditional thank to Britt Halvorsen for being with me from the beginning to the end with continues developments. The task would never have been a reality without your tremendous support.

Explanation from Vidar Mathisen (co-supervisor) about the project at the beginning was excellent. It made me motivated to persuade myself completely in to the thesis work throughout the period. I would like to give my utmost thank to Vidar Mathisen without any hesitation.

Finally I would like to thank Anushka Perera for giving me valuable advices and immense support on technical writing.

Porsgrunn, June 2nd 2014

Mahesh Ediriweera

Overview of tables and figures

1 Introduction

The offshore petroleum industry is continuously looking for new technology to enhance and optimize the production process. There are two types of technologies are used in reservoir drilling: horizontal and vertical well. The horizontal well technology has been the most common approach used in Norwegian oil fields since the North Sea oil reservoirs exhibit as thin layers. Horizontal wells have many attractive features over vertical wells with respect to oil recovery factor, gas and water coning.

Simply, the oil recovery factor is the amount of oil can be extracted from a reservoir. Water can enter to the wellbore during the oil production and the conical shaped profile is known as the water cone. The coning phenomenon significantly affects to the oil recovery factor. When the water cone reaches the wellbore, water starts to mix with oil and inflow behavior turns into multiphase flow. Moreover the water coning effects on economic factor in many ways after the water breakthrough.

Current separation process used in offshore industry includes expensive systems. If the water separation can be done in subsea with simple and effective equipment, it would definitely be profitable than existing offshore process systems or upcoming subsea compact separation mechanisms. The oil recovery with Inflow Control Devices (ICD) is becoming popular since it offers economical and effective smart solutions for oil extraction. Presently, there are many studies and researches is been done on ICD technology and its development. When retrofitting the existing process plant, new requirements and features are demanded hence simulation study is really important, to get a close look into its performance and to operate at most economical conditions. Even though there are many types of ICDs are used in industry only the standard ICD is discussed with in the report. The standard ICD is not easily replaceable or manipulatable during the operation once it has been installed at the starting stage of the process. ICDs are very useful in long horizontal wells which is commonly practiced in Norwegian offshore oil production due to its ability to eliminate early breakthrough. ICDs currently used to increase the pressure restriction in term of reducing local flow rate since flow rate depends on the pressure drop. However still the coning can be affected the process at the later stage of the production.[1]

The Recovery factor is a strong function of reservoir properties and extraction techniques. Recovery mechanisms have been developing for years. An overall understanding over the reservoir properties and recovery procedures is desired before going deeper into the inflow control technology developments. Therefore, the report discusses the reservoir properties and the oil recovery methods currently implemented in the industry. The demand of oil and gas would remain until a cost effective feasible energy source is found. Hence, the industry always looking for new reservoirs and new methods to extract as much as possible oil and gas in efficient and effective ways.

Reservoir model simulations can be used to quantitatively analyze the characteristics of reservoir process. The simulation results will give data for comparison among different extraction techniques and provide information to select the optimal recovery operation. OLGA-Rocx[1] module used for the simulations. The report consists of different flow models with ICDs and respective simulations to observe the characteristics of different properties of the reservoir and the controlling mechanisms. The initial project proposal is given by Inflowcontrol AS with the collaboration of Telemark University College.

The primary objective of the project is to build an OLGA-Rocx model for a typical Norwegian oil production process to investigate the dynamic properties. Only horizontal wells are modelled in this project due to the fact that horizontal wells are the most common technology implemented in Norwegian offshore fields. OLGA-Roxs module has been used throughout this report as the modelling and simulation tool. TECPLOT[2] is used as the supporting software to plot the reservoir simulation results.

The problem description can be divided into two main tasks; (1) developing an OLGA-Rocx models for oil fields, and (2) simulate and observe the results of different reservoir and well scenarios.

1.1 Structure of the report

The project is divided into two main parts, literature review and the simulation study using OLGA and Rocx. The report contain five chapters. Introduction describes the project tasks and gives a general interpretation for the oil extraction technologies. Chapter 02 mostly contains information over reservoir properties, obstacles faced in oil recovery and recovery methods currently used in industry. Then the chapter 03 introduces the flow modelling and simulation tool. The reservoir and production well modelling with OLGA and Rocx also discusses under this chapter. The main objective of the report is then described with chapter 04. Simulations are carried out on interested properties and multiphase flow controlling. Detailed descriptions over the simulation results are given under the sub chapters. Finally, discussion on important observations through the simulations and conclusion are provided under the chapter 05. An overview about the completed project task is also given within the discussion. Moreover, chapter 05 gives suggestions for improvements of the simulations and proposals for future work.

[1] OLGA-Roxs is a modelling software dedicated for oil field simulation. http://www.prod.software.slb.com

[2] http://www.tecplot.com

2 Petroleum reservoirs

A petroleum reservoir is a hydrocarbon storage accumulated in a porous or a fractured rock medium which is a mixture of water, oil and gas. The crude oil mixture is conserved in a reservoir exerting very high pressure and consequently a large quantity of gas is embedded within the liquid phase. One third of the world's oil production is done at offshore reservoirs. Swallow reservoirs consist of relatively low pressure and low gas dispersion compared to deep reservoirs. Generally, oil rim is sandwiched by an overlain gas cap and underlain aquifer. A typical reservoir is consist of sand, sandstone, lime stone or dolomite. Oil and gas flow through porous media or fractures to the surface due to its low density over water. This flow can be restrained by traps --- a trap is a storage that is overlain by a dense cap of rock --- which prevents the movement of hydrocarbons. Petroleum is extracted by drilling wells into a reservoir and wells are designed so that fluid inflow is controlled. Typically, the lifetime of a reservoir is consist of three different stages; buildup, plateau production and the depletion. In order to maintain the production effective for a longer period of time, a good understanding of the recovery process and the reservoir properties is essential. The production profile varies from field to field in relation to reservoir properties and the operational conditions.

2.1 Oil Recovery methods

Production rate depends on several factors such as reservoir geometry, reservoir pressure, depth, number of wells, well locations, rock properties, extent of fracturing, fluid saturation, relative permeability and viscosity. Hence, the oil recovery can be enhanced effectively by these factors. There are common methods used to enhance the oil production for instants: providing new channels to the fluid flow; increasing the reservoir pressure by means of external fluids; reducing the viscosity by thermally and chemically. Oil recovery can be done in three distinct phases namely primary, secondary and tertiary. However, these strategies cannot be considered in a chronological order due to many differences in production sequence. The primary recovery of high viscous heavy oil reservoirs might not be economical so that primary phase would be skipped. For such reservoirs, even the secondary recovery processes may not give an economical solution, hence the thermal recovery method could be the only feasible way to extract a considerable amount of oil. In such cases tertiary method is utilized at first.[2] Even though, the extraction is carried out with all possible techniques, abandoned reservoirs often contained substantial amount of oil left which is known as residual oil. It is very important to make sure to handle extraction methods to keep residual oil volume at a minimum level.

During the primary recovery, the natural pressure of the reservoir is higher than the pressure inside the well and thereby it is used to drive hydrocarbons in to wellbore. The pressure drop from reservoir to wellbore must exceed the viscous forces to maintain a continuous flow.

The driving energy is derived from: the liberation and expansion of dissolved gas; from the expansion of the gas cap or of an active aquifer; from the gravity drainage; or from a combination of these effects.[3] The Figure 2-1 shows the primary recovery process in a typical reservoir. The most effective forcing method is the water drive where the pressure of the aquifer pushes lighter oil from the reservoir to the wellbore. If the reservoir pressure is not high enough to transport the crude oil mixture to the surface then an external pump system will be used to provide additional pressure head. Since no artificial pressure is applied to increase the reservoir pressure during primary recovery, production rate will be declined with the time. This depletion rate is one of the mainly concerned drawbacks in current ongoing studies. Some reservoirs are capable to replace the displaced oil volumes with water supply. However, almost all wells are not able to supply enough water flow rate to compensate the oil production, therefore pressure continuously decrease with the time. Previous experiences have been shown the recovery factor not more than 20 percent of total reservoir oil in place is produced by the primary method.[4]

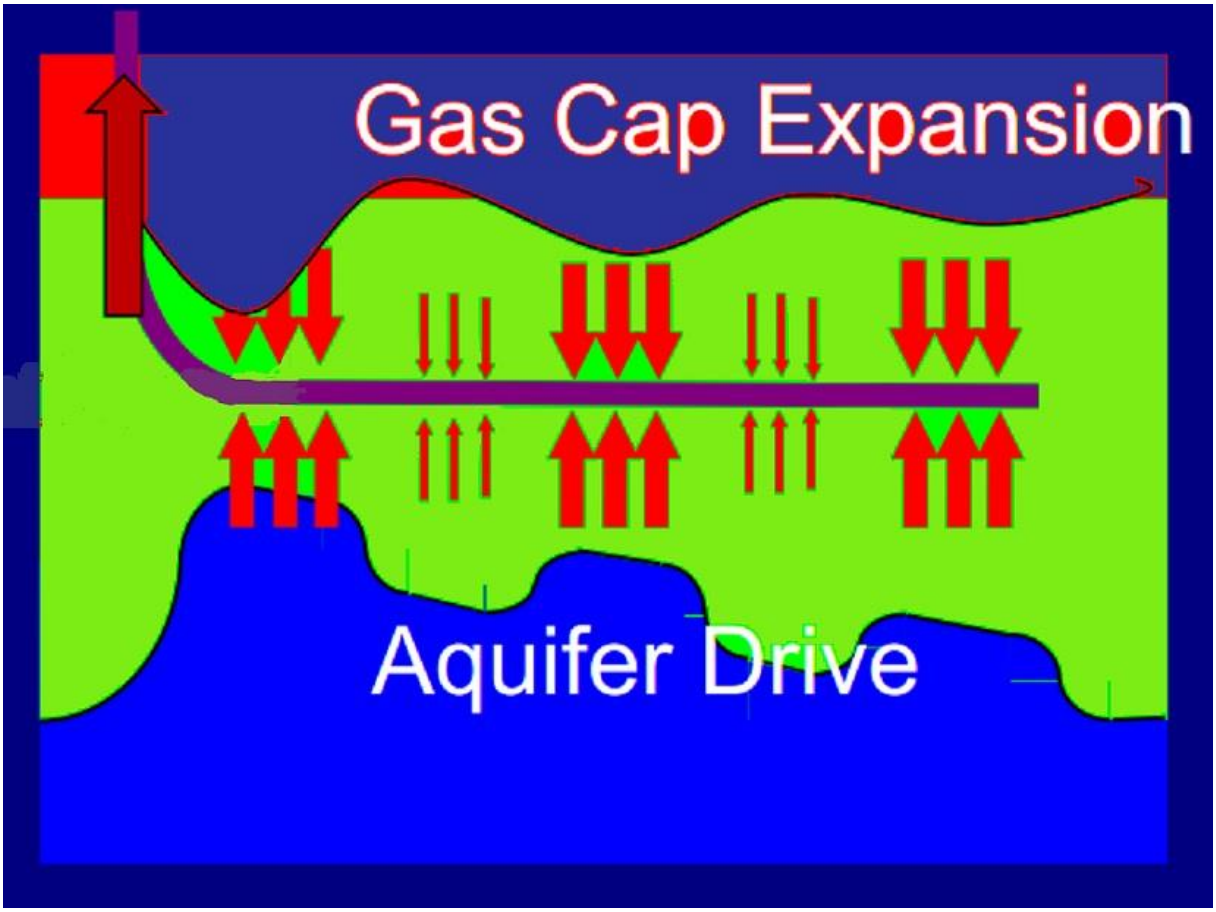

Figure 2-1: Typical primary recovery with water aquifer and gas cap

2.2 Improved Oil recovery

An additional drive mechanism is needed to optimize the oil extraction followed by the primary energy drive, as considerable amount of hydrocarbon always left in the reservoir. There are two types of improved Oil Recovery (IOR) methods broadly used in industry, categorized as the secondary and the tertiary recovery. The tertiary process is so called the Enhance Oil Recovery (EOR) method.

The secondary recovery is simply based on the external fluid injection to replace the produced crude oil, aiming to increase the reservoir pressure in order to enhance the production in depleting or low presser reservoirs; fluid are injected through the secondary wells to maintain pressure so that the economical extraction is assured. Another objective of the injective method is to sweep crude oil towards the production well from the injection well. This method includes the natural gas injection, the water injection and the gas lift. In particular gas lift method associate with injecting air, carbon dioxide or some other gas into the reservoir.[5] Water flooding (water injection) is the most common secondary recovery method due to its simplicity, availability and the cost effectiveness. With secondary techniques, the state of the hydrocarbon is not changed. The overall recovery factor generally lies between 35% and 40% after both the primary and the secondary recovery. In some cases, it is possible to have a very low recovery factor or even very high values, depending on the various rock properties and stored natural energy at the reservoir.

Tertiary methods are implemented to extract remaining oil where reservoir energy has been diminished during the primary and secondary methods. The main objective behind the EOR method is to increase the mobility of residual oil throughout the entire reservoir by decreasing the viscosity. The oil viscosity can be decreased by using thermal flood and the capillary effect reduction can be achieved with chemical floods, both in turns cause to increase the oil displacement efficiency.[4] In the tertiary recovery techniques external energy or material are used to efficiently capture hydrocarbons and this mechanism is able to recover oil that is economically impossible by conventional methods. The tertiary methods are classified as thermal and non-thermal approaches.

The steam injection is the widely used technique under the thermal enhanced oil recovery where oil is heated to reduce the viscosity. Steam drive injection is a method used a set of secondary wells to inject steam and then the production is carried out through another set of wells. In the cyclic steam injection, the same well is applied for injection and production. The produced oil contains steam condensate. The Figure 2-2 shows the steam drive injection field with two different wells. The steam injection has the least uncertainty when it comes to predicting the flow characteristics of the well. [5] In situ combustion is another recovery method practiced under the thermal recovery where some of oil is burned to heat up oil beside.[5] In this method air, oxygen enriched air or oxygen is injected to sustain the combustion of oil in the reservoir.

The gas injection is one of non-thermal EOR methods. Gases such as carbon dioxide, nitrogen, natural gases, flue gases, alcohol are used to yield the production.[5] These miscible and immiscible gases increase the mobility of the fluid with different mechanisms. Once miscible gases spread into the reservoir oil, oil swells and reduce the viscosity and change of fluid properties causes to capillary force reduction. Chemical agents such as polymers, surfactants, and caustics are also commonly used techniques under non-thermal recovery method.[5] Such chemicals change the reservoir fluid properties and as a result enhance the mobility. The selection of the chemicals and gases is decided after comparing the rock properties as well as cost effective amount of oil to decrease the residual oil in the abandoned reservoir.

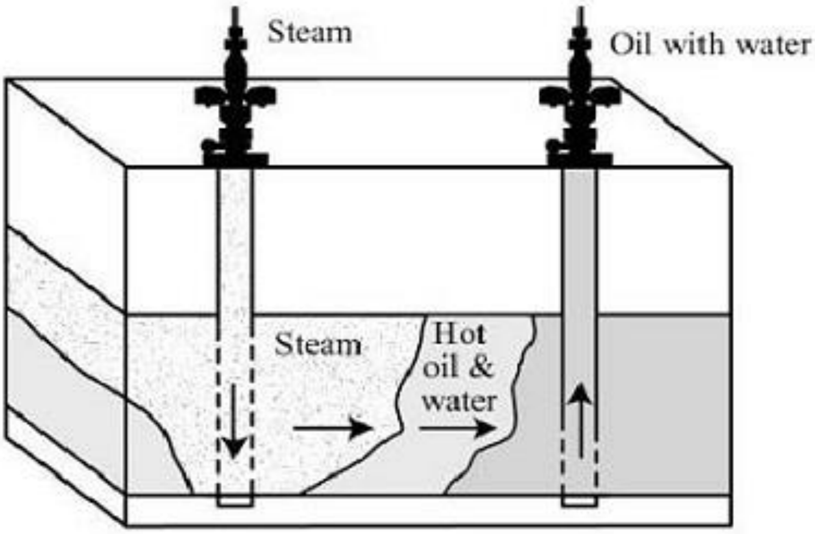

Figure 2-2: steam injection with two different wells. [5]

2.3 Water Coning

Usually oil reservoirs exhibit with a gas cap and/or water aquifer, having Gas-Oil Contact (GOC) and/or Water-Oil Contact (WOC). The water coning phenomena as shown in Figure 2-3 occurs in oil wells with aquifer. During the production the water cone is formed, raised towards the well and entered to the wellbore. Once the water cone reaches the wellbore, water breakthrough occurs and the duration where breakthrough occurs is known as the breakthrough time. The imbalance between gravity, viscous and pressure forces causes the water coning which shows some deformation of WOC. The cone formation potential in high viscous fluids is higher than low viscous fluids. Therefore, heavy oil water breakthrough may happen early compared lighter oils. Both production rates and the pressure gradients will be constant, if the steady state condition is achieved. At this conditions, if the viscous forces created by the pressure gradient are lower than the gravitational forces, the developed cone will not expand or decline and configuration known as stable cone. Conversely when pressure gradient is not steady, unstable cone will be obtained. In vertical wells this deformation is known as cone and horizontal wells crest or cone. The propagation of the water cone is a critical issue in petroleum industry as it causes to produce oil and water simultaneously which adds additional operational cost to separate oil. The water coning causes water cut --- the amount of water in the multiphase flow --- to increase rapidly and yielding reduced oil rate accordingly. The water coning effects in reducing the recovery amount in the total oil in place. Moreover, water is a corrosive media accounts in expensive disposals, additional maintenance and shutdowns.

Hence it is very important to delaying water coning phenomena to obtain total economic recovery and several techniques are used to increase the production efficiency. The pressure drawdown should be reduced to eliminate or minimize the coning. Water can easily enter to the wellbore if the oil layer is very thin. Which is a common occurrence in northern sea offshore oil fields. The horizontal well technology is a good solution to mitigate the coning effect while maintaining an effective production flow rate. The critical production rate is higher in horizontal wells over vertical wells. The critical rate is the maximum flow rate which can be imposed on a well to prevent cone break through.[6] At the critical rate, the cone is stable and the peak is at the initial state of the break through. Typically, an oil well has a production flow rate than its critical flow rate. However, high flow rates become disadvantageous since the water cut tends to increase rapidly after the break through. With the nature of viscous fluids some other challenges appeared so that the pressure drop along the horizontal wells is higher than conventional wells. The pressure drop along the well causes to produce oil with a high flow rate at the heel compared to the toe. [1] Therefore, particularly in homogeneous reservoirs, the water coning shows up early at the heel before the toe. On the other hand at heterogeneous reservoirs, the properties of the inflow might vary along the well. These conditions lead to early break through, lower sweep efficiency and lower recovery factor than expected. By varying the perforated density on outer well surface, uniform inflow along the well can be achieved where lower perforated density near to heel and higher at the toe.

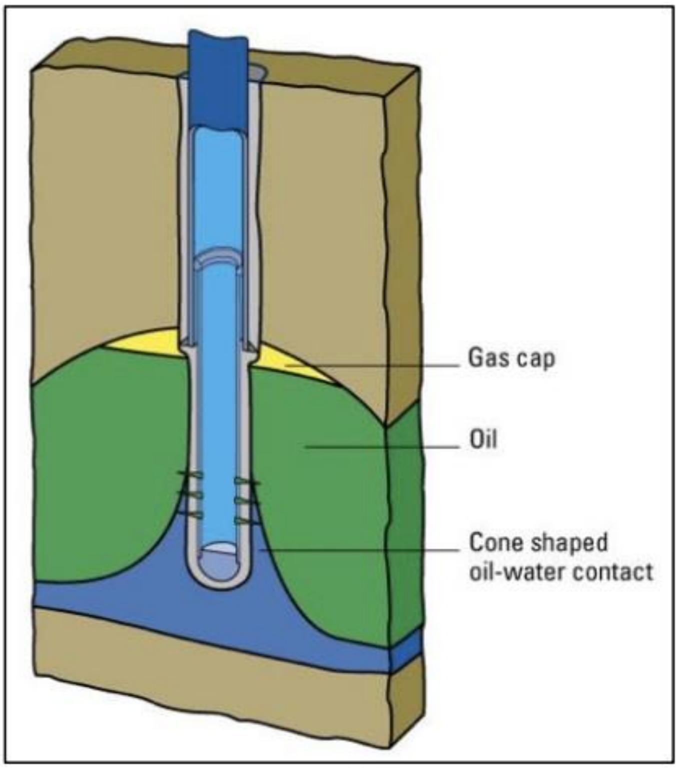

Figure 2-3: Water coning in a vertical well. [1]

2.4 Inflow Control Devices

Even the drilling technology is more difficult and comparatively expensive, the horizontal well installation is rapidly increasing due to its more efficient oil extraction over vertical wells. Lower pressure drop is enough to recover a huge amount of oil compared to the vertical well since the horizontal well produces high contact with thin oil layer. The water coning is a challenge in long horizontal wells in Norwegian offshore industry. Therefore, the water breakthrough controlling is a highly demanding research study in the horizontal wells.

The conventional ways of controlling water breakthrough is to build packers at the water-oil transition region in horizontal wells. Generally, a horizontal well consists of a well tube and an annulus. The dense perforation is designed in the distance of outer surface in between 0.5 to 2m. A packer is placed between the annulus and the well, then the blocking agent such as silica gel, chromium gel and phenolic resin is injected from the tube to the annulus.[7] Even though the packers give positive impact on the controlling water coning, placing packers at the accurate location is not easily determined especially when there is a very thin oil layers.

Installation of Inflow Control Devices (ICD) at proper places along a horizontal well is a successful practical solution under inflow control techniques. Installation of Inflow Control Valves (ICVs) on horizontal well has been an established method during last decade which permits an active control while the ICD provide a passive control. [8] Some of positive impacts of ICD technology are: compensate uneven flow variation due to the heterogeneity and pressure drop from heel to toe; decrease water/gas flow rate after breakthrough and improved well cleanup. There are different types of ICDs are used according to the field applications such as channel type Spiral Inflow Control Device (SPID), nozzle-type ICD, Autonomous Inflow control Device (AICD), Orifice ICD, annular chamber ICD and integration of several.[1] The Figure 2-4 shows a helical channel and a nozzle type ICD. Modern Autonomous Inflow Control Devices overcome most of the drawbacks in inflow controlling due to its ability to weaken the influence appears after the breakthrough. AICD is designed such that it is able to response actively and choke the low viscous flow while opening the orifice for viscous flow.

The static ICD, also known as the standard ICD, is an open valve which is selected and installed subsequently according to the predicted reservoir characteristics at the beginning of the process. However, the actual behavior might deviate from the predicted one over the lifespan of the reservoir so it is impossible to anticipate the complete characteristic of the process. The static ICD is not able to adjust easily after the installation and another drawback of static ICD is that it has no any mechanism to cut off flow when water break through occurs.

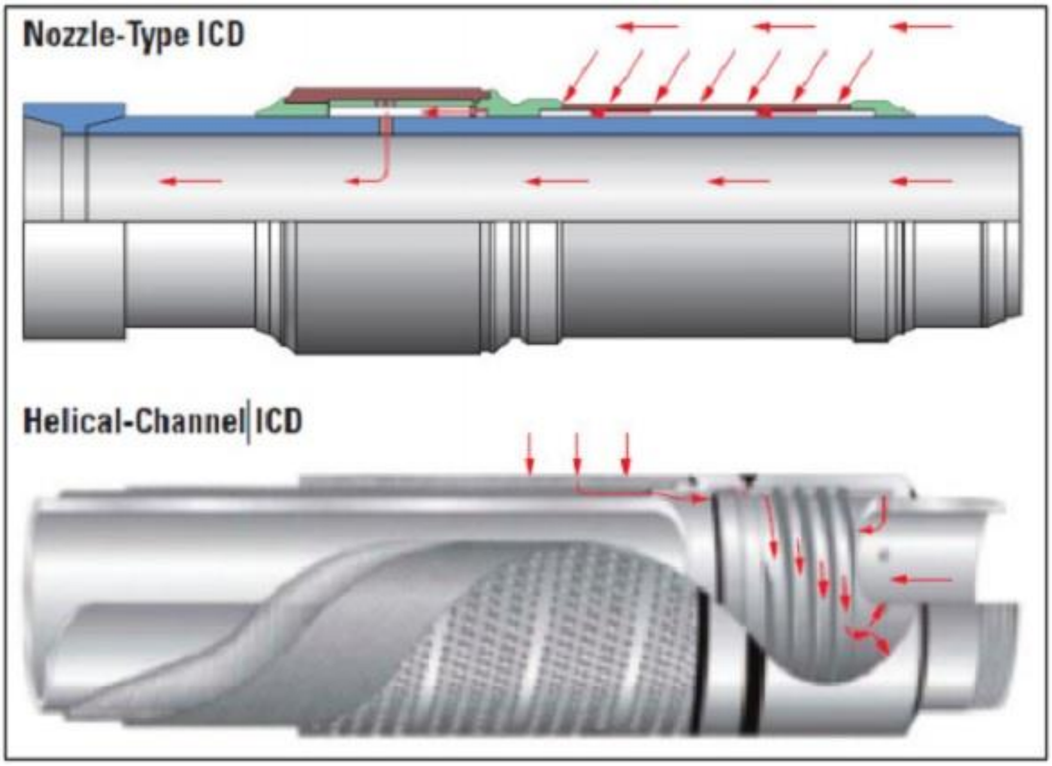

Figure 2-4: Different types of ICDs. [1]

2.5 Reservoir properties

Every petroleum reservoir has its own distinct properties and better understanding over the properties is needed to analyze the reservoir characteristics. These properties are distinguished as rock properties and fluid properties. Porosity, permeability and relative permeability are the most critical rock parameters. Pressure, temperature, viscosity, specific gravity, oil and gas concentrations are some of the useful fluid properties for the analysis. Conventionally, crude oil is brownish green or black with the specific gravity 0.801-0.985 and has boiling ranging from 20^0C to 350^0C which active decomposition ensures when distillation is attempted. [5]

2.5.1 Porosity and Permeability

Porosity and Permeability are very important oil and gas reservoir properties. Most of the petroleum reservoir volumes are consist of sandstones. Sandstones are generally considered as high porous and high permeable media. Porosity is a measurement of the amount of spaces in a rock which is expressed as a volume fraction in the equation (2-1). Tiny spaces consist in sandstones hold hydrocarbons and water in the reservoir. Therefore, indirectly Porosity is a dimension of reserved petroleum quantity of the reservoir. Porosity can be categorized as primary and secondary Porosities. Gaps and spaces developed during the sedimentation process is called the primary porosity and the secondary porosity is formed in later stages as dissolving of minerals. Reserved hydrocarbons can only be produced if interconnected pores are available within the reservoir rock. The ratio between the interconnected pores and total rock volume is equal to the effective porosity.

$$Porosity\ (\phi) = \frac{Volume\ of\ the\ Viod\ space\ (V_V)}{Total\ or\ Bulk\ Volume\ of\ the\ Rock\ (V_T)} \qquad (2\text{-}1)$$

Permeability describes the conductivity of the fluid flow though a porous media, also known as "absolute/intrinsic permeability". If high pressure is needed to extract hydrocarbons, it is called low permeable reservoirs and vice-versa. Permeability is directly related to the porosity, it depends on the porous connectivity and the size of the porous volumes. Absolute permeability could be determined by laboratory experiments with the use of inert gases (frequently used nitrogen).[9] Permeability can be calculated by Darcy's law which was developed semi empirically by Darcy in the 19^{th} century for single phase and in 20^{th} century for multiphase flow.[10] The permeability coefficient depends on both material and the fluid properties. Greater the K value higher will be the flow rate.

$$Q = \frac{K\ \Delta P}{\eta\ \Delta L}\ A \qquad (2\text{-}2)$$

Where,

Q = flow rate

K = Permeability coefficient

ΔP = Pressure difference

A = cross sectional area of the flow

η = Fluid viscosity

ΔL = flow length

In petroleum industry, permeability is expressed in *millidarcys* and most of the oil reservoirs are in the range of ten to several hundreds of *millidarcys*. The Figure 2-5 shows the permeability of different types of commonly available rocks.

Two concepts has introduced to increase the permeability of shale rock wells where high porosity and low permeability exists;[11]

- horizontal drilling – the drill bit is made to turn from vertical to horizontal and continue horizontal drilling.
- advances in hydraulic fracturing (Fracking) – Advances in fracking techniques in horizontally drilled holes, particularly in shale formations, has led to a tremendous increase in shale gas production.

Permeability	Pervious				Semi-Pervious				Impervious				
Unconsolidated Sand & Gravel	Well Sorted Gravel		Well Sorted Sand or Sand & Gravel			Very Fine Sand, Silt, Loess, Loam							
Unconsolidated Clay & Organic					Peat		Layered Clay			Unweathered Clay			
Consolidated Rocks	Highly Fractured Rocks				Oil Reservoir Rocks			Fresh Sandstone		Fresh Limestone, Dolomite		Fresh Granite	
κ (cm^2)	0.001	0.0001	10^{-5}	10^{-6}	10^{-7}	10^{-8}	10^{-9}	10^{-10}	10^{-11}	10^{-12}	10^{-13}	10^{-14}	10^{-15}
κ (millidarcy)	10^{+8}	10^{+7}	10^{+6}	10^{+5}	10,000	1,000	100	10	1	0.1	0.01	0.001	0.0001

Source: modified from Bear, 1972

Figure 2-5: Permeability of common rocks [11]

2.5.2 Relative permeability

The relative permeability is defined for multiphase flows. It relates with the effective permeability of a particular fluid which is a component of the multi-phase flow. Darcy's law can be modified for a multiphase flow as expressed in the equation (2-3). (2-3)

$$Q_i = \frac{K_i \, \Delta P_i}{\eta_i \, \Delta L} A \qquad i = 1,2, \dots \dots, n \tag{2-3}$$

The subscript i indicates the parameters of i th phase and the K_i is the of phase permeability of the component i. In a numberer of laboratory experiments, it has been observed that a sum of effective permeability's is less than the absolute permeability.[9]

$$\sum_{i=1}^{n} K_i < K \tag{2-4}$$

Relative permeability is the ratio between effective permeability of the respective phase and the absolute permeability as shown in the equation (2-5). Therefore, some of the relative permeabilities of all phases must be lesser than 1. Even though the effective permeability is a function of several parameters such as rock property, fluid property, absolute permeability fluid saturation and reservoir condition (pressure, temperature), the relative permeability depends on the fluid saturation and structure of the porous medium.[9] However, the relative permeability can be assumed as a function of only saturation due to its strong correlation with saturation.

$$K_{ri} = {}^{K_i}\!/_{K} \qquad (2\text{-}5)$$

Saturation of a particular fluid is denoted as a factor of a porous volume and the fluid quantity which is shown in the equation (2-6).

$$Saturation\ of\ Oil\ (S_o) = \frac{Volume\ of\ Oil}{Pore\ Volume} \qquad (2\text{-}6)$$

Though there are several attempts have been made to calculate the relative permeability on a theoretical basis, thus by far the commonly available data has been taken from experimental investigations. For two phase flows typical permeability curves are shown in the Figure 2-6.

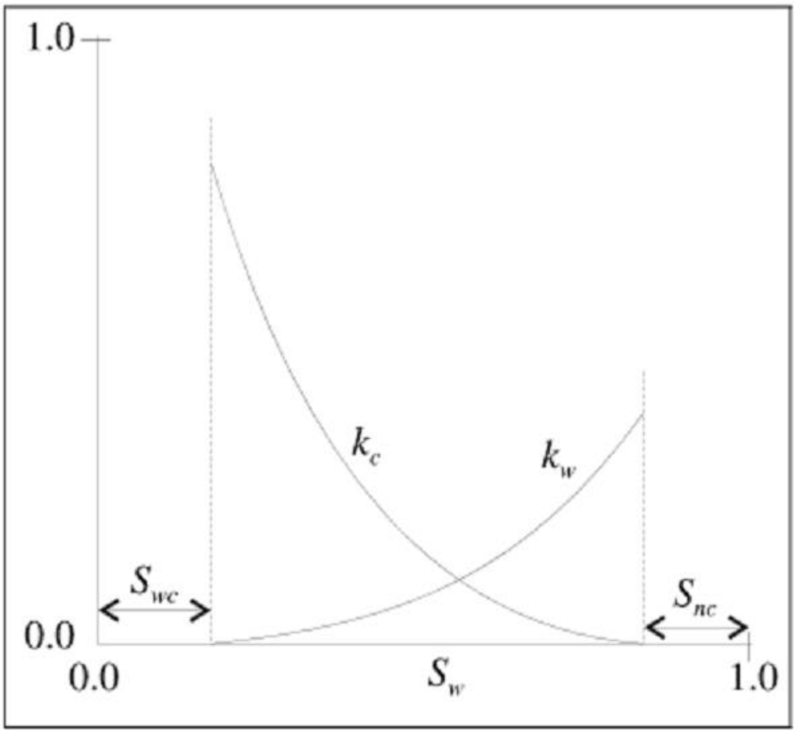

Figure 2-6: A typical oil-water relative permeability curve [9]

One important remark on the given curve that the relative permeability becomes zero if the saturation of the corresponding phase lesser than a specific value. The value is then said to be the residual saturation of the respective phase. Moreover, mobility of the phase is interrupted by the reduction of the phase saturation after residual value. The residual saturation depends on several factors such as pressure, temperature, number of phases, type of the rock, etc.

It is clear rock wettability has certain impact on the relative permeability. The wettability is the tendency of one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids. Typically, water-oil relative permeability is present for strong water-wet and oil-wet is given in the Figure 2-7. Non-wetting phase generally occupies the center of the porous, while the wetting phase occupies the cavities between the solid and coats the surface.

Therefore two phases disturb flow of each other and the non-wetting phase to be the dominant obstacle to the wetting phase.

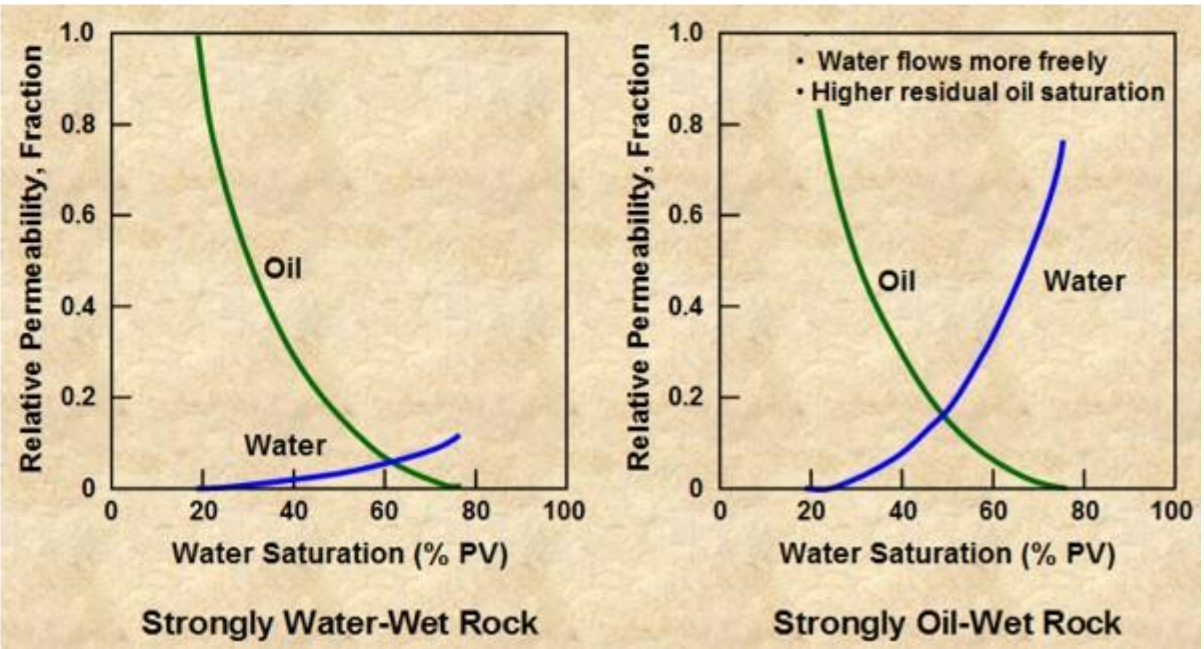

Figure 2-7: water-wet and oil-wet relative permeability curves [9]

3 Flow Modelling

Since the oil well drilling is a highly expensive process, a preliminary study is very crucial in order to predict the behaviors of the real process. Preliminary studies have been developed over the years. Presently petroleum companies often create mathematical models written in computer aided tools such as OLGA and Rocx to the simulations. After discovering the possible extracted amount of hydrocarbon by the simulation. The next challenge is to implement the optimal recovery methods at the best age of well life to extract maximum possible quantity with the available recovery processes. However, the real world experiences have shown that economic success is by far different from theoretical values, since the parameter uncertainty is there as well as in general, most of the para meters are not known preciously. [5] Even though the real world process behaviors deviate from the simulations, it is very important to model and simulate oil reservoir and multiphase flow to evaluate economical perspectives and optimize the operation before apparatus is built up.

OLGA-Rocx module is a good candidate to simulate well bore and reservoir which has been continuously developing as a commercial software by Schlumberger. The multiphase flow modelling and simulation can be successfully performed with the tool from reservoir rock to process facility.[12] Apart from its practically closed enough results, the tool has some attractive features when it comes to plotting. The results from the simulations can be used to find the maximum production, figure out the best design, optimize the operation and introduce the safety concepts. Dynamic flow simulations with OLGA provide built in models of reservoir components and using those components it is possible to create complete well model. Most of the report content depends on simulations, hence better understanding about the software has been given later in this chapter. Reservoir modelling, horizontal well modelling and 3-dimensional plotting have been discussed under subchapters respectively. Most of the simulations under this report are modeled based on the properties found in the Grane field in the North Sea which is the Statoil's largest heavy oil field. The Table 3-1 shows the reservoir properties of the Grane field.

Table 3-1: Reservoir properties in Grane oil

Property	Value
Pressure (bar)	176
Temperature (C)	76
Porosity (%)	33
viscosity (cP)	12
Thickness (m)	31
Permeability (D)	10

3.1 Reservoir Model

Reservoir is modelled by Rocx module provided with OLGA. Field's geometry is divided into a 3-dimentional mesh and the selection of the grid size is a very important factor to obtain accurate results. Later in the report, grid selection for a better solution is discussed with simulations. Reservoir properties such as permeability, porosity and relative permeability are included as inputs for the model. Permeability is given for the respective control volume along all three directions. A model allowed to store more than fluid together with their specific characteristics since some reservoirs are available with several oil phases. Rocx is allowed to include concentrations, specific gravity values, viscosities, ratio of the phases, temperatures and the pressure of fluids. However, some of fluid properties must also be included into the OLGA model as well. Different properties between OLGA and Rocx models cause to obtain simulation errors. All the cases used in the report has selected Rocx inbuilt Black oil model. Two another critical data are given to the reservoir model, are initial conditions and boundary conditions. Under the boundary conditions, the properties concentrations beyond the reservoir margins are given. Content of the report only focused on the water drive reservoirs so that aquifer is given as the only one boundary condition. If the aquifer is large enough, pressure at the lower boundary can be considered as a constant. Therefore, when creating the model the aquifer is infinite so that it gives same pressure drop across the reservoir over the simulation. Installed well position in the reservoir block is also given under boundary conditions and ICD placement is denoted with assigned grid as a pressure point. The fluid concentration and saturation at time zero are given under the initial conditions. Rocx provides executed flow rate data at the each state and transferred to the OLGA model. The modelled file is saved with the *.rocx* extension. See Appendix 2 for the interface of the Rocx.

3.2 OLGA Model

A horizontal oil well is modeled with the use of OLGA for the simulation and then file is saved with the *.opi* extension. It is essential to modeled *.opi* file is saved in the same folder as *.rocx* file is located. Both OLGA-Rocx simulators interact each other while the simulation is going on. The OLGA module consist of several in-built component models which are commonly used in industry and very useful to build a more realistic models. Generally used components are valves, subsea pumps, transmitters and also controllers such as PID, switch, algebraic controllers are available. Near-well source is available to enter in to the model under the boundary and initial condition. Flow components are used to access fluid properties at the specific boundary.

All the component specification founded in literature are able to enter through the *model browser* in order to tally with realistic values used in industry. The cases used in the report are modelled for black oil and unsteady operation, options are selected under the *OPTION* key. In the report tube and the annulus have been modelled as two different pipes named as *PIPELINE* and *FLOWPATH* where annulus and tube respectively. The oil reservoir interface, ICD, the connection between casing and the tube are denoted by source, valve and leak respectively. The pressure along the wellbore is presented by the pressure node at the end of the *FLOWPATH*. Initially the pressure difference is provided to drive fluid from casing to well tube under the initial conditions before dynamic values are obtained during the simulation. Interested plotting variables are selected during the modelling and it is not possible to observe additional variables, unless it is entered before the simulation. This feature can be categorized as a drawback of the tool. The Figure 3-1 shows a OLGA model used in simulation.

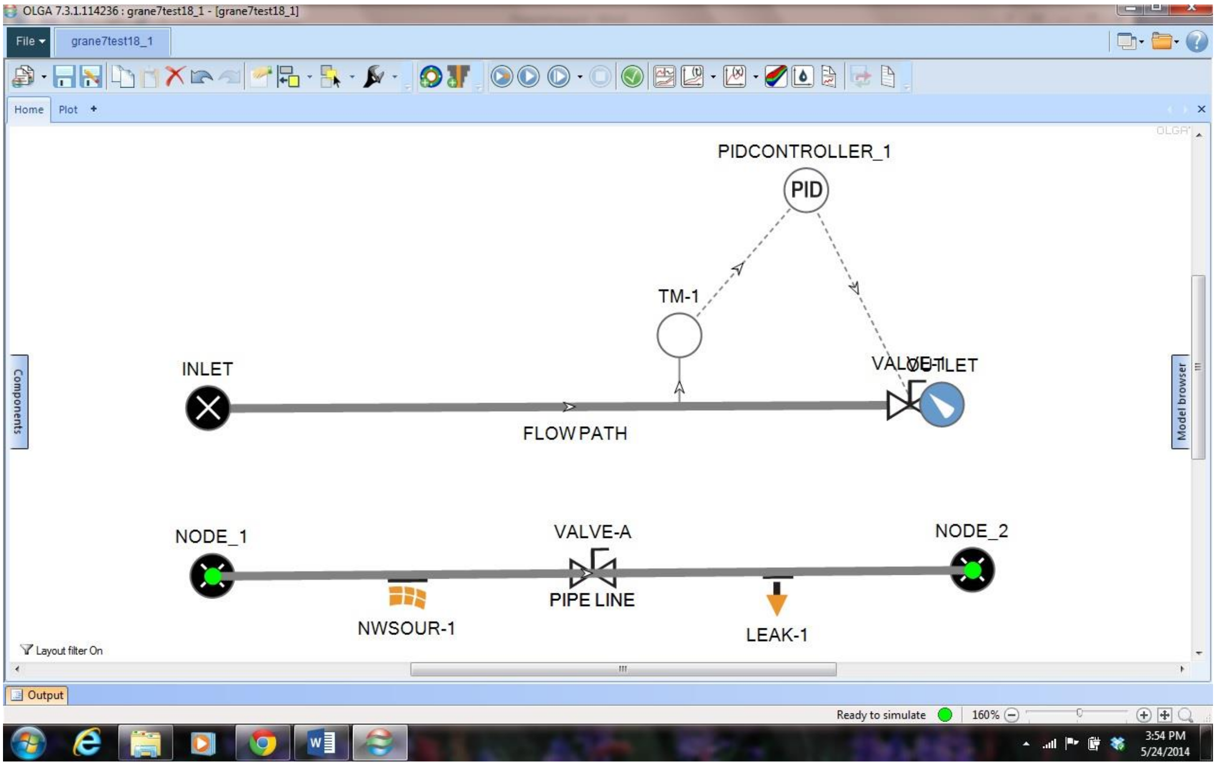

Figure 3-1: OLGA Model with perforated pipe and the tube

3.3 Tecplot RS

A clear 3-D reservoir profile can be mapped with the Tecplot RS which is used throughout the report to observe reservoir properties. *.egrid* extensional file is created during the simulation which is able to open with Tecplot RS. By the way, it is important to start the simulation with the *Run Batch* mode to make *.egrid* file to be compatible with the Tecplot RS.

4 Simulation

This chapter consists with the simulation results and comparisons. Several models are created under the project tasks by varying the reservoir properties and the well properties in order to observe the dynamic behavior of the process. The variation along the horizontal well profile is also interested within the report. Once the model building is completed, system can be checked with *verification* button which shows the errors, warnings and missing variables.

Most of comparisons and simulations have been carried out with only one ICD due to its simplicity. Based on the simple model results, complex models can be simulated later with less effort. When it comes to the comparison, only one variable is changed in order to avoid the impacts from the other variables. Simulation results of the complete model and used components can be distinguish clearly even though simulation is done as one. This feature is useful to identify errors and appropriate parameters of individual components. The trial and error method is used throughout the report to find better parameters. When the reservoir model is updated it is important to recall the *Rocx* file in each case.

Saving the simulation time and the memory space are highly focused areas in any kind of simulation. Simulation can be done with relatively large time steps in order to minimize the simulation time. Even though precise results are not given with large time steps, those integration are useful to get a general information and to cut down errors before going for the final simulation. The selection of plotting variables is also a critical factor to reduce the computer time. Data plotting with short time intervals consume lot of memory. So the plotting with large intervals utilize low memory capacity although it doesn't provide smooth accurate curves. Rest of the chapter is discussed the selected model building, simulation results and different approaches used to obtain the accuracy.

4.1 Effect of the grid resolution

Most of the cases discussed in this report has considered the cuboid shaped reservoirs with 100m length, 201m width and 30m height. In the multiphase flow analysis, it is a common practice to partition a whole volume into a mesh with several control volumes. The analysis with the finer grids is always giving better results than coarser grids. By the way, finer grid simulations consume more execution time over coarser grid cases. Therefore when selecting the grid size, it should be careful to choose the correct size to compromise both the computer time and the accuracy of the results.

To make comparisons, a reservoir is divided into different grid sizes in each case. However, the grid size in Z direction and X direction is kept constant 3m and 100m respectively while changing the size along Y direction only. Grids are numbered from the top and aquifer is at the 10^{th} grid. The well is installed at the 4^{th} grid in Z direction and the middle grid along the

Y direction. Perforated area of the pipe is assumed to be homogeneous and laid along the X direction. The Figure 4-1 shows the 3-D view if the reservoir.

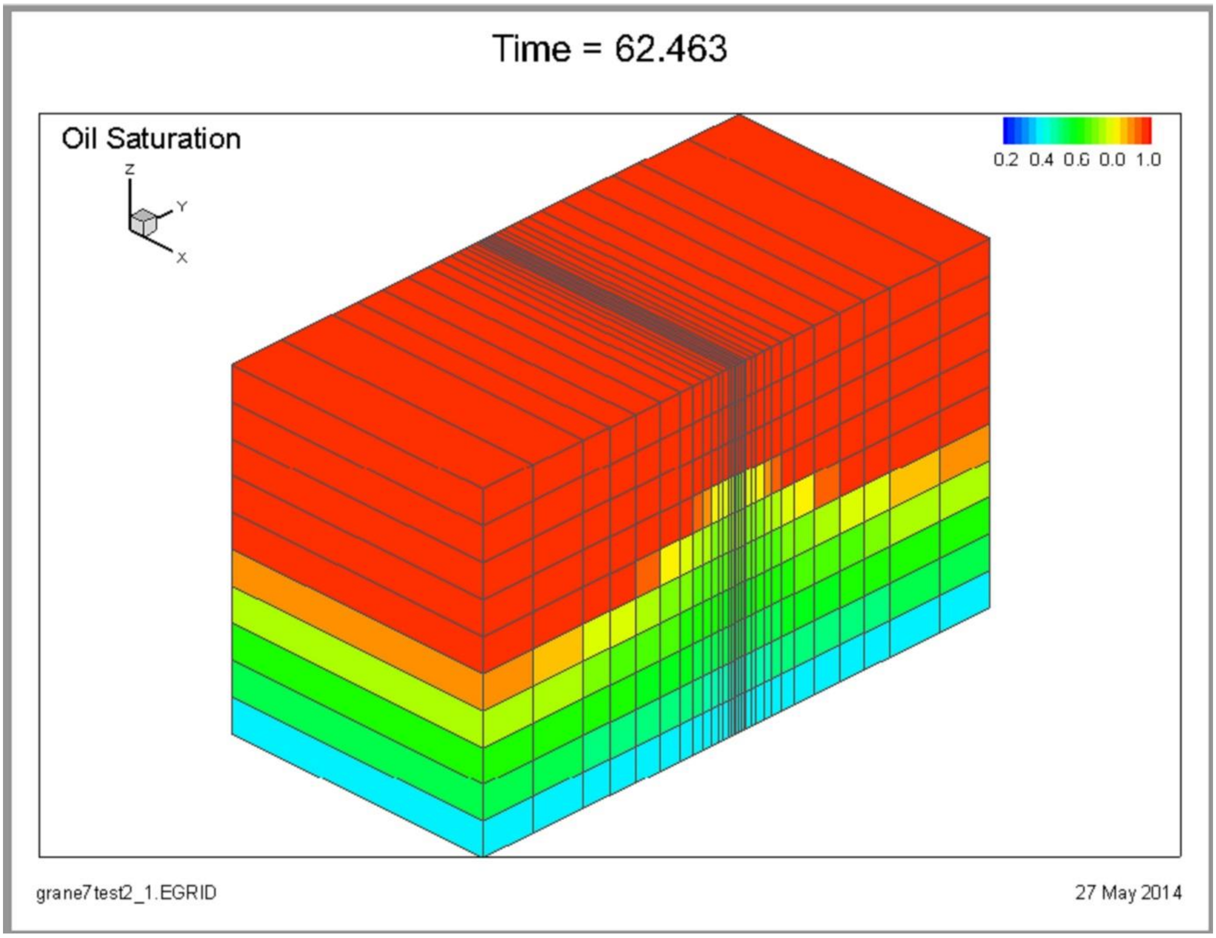

Figure 4-1: 3-D view of Oil saturation after 62.463 days

Table 4-1 shows the grid size data for 4 cases which are used to analyze the effects of the reservoir resolution over multiphase flow behaviors. The grid size is changed along the Y axis to be coarser to finer from case 1 to case 3. In the case 4, the grid size is converged towards the petroleum well so that coarser grids away from the well and finer ones closer to the well. Grid sizes along the Y axis in the case 4 are as follows: 20, 20, 10, 10, 10, 8, 5, 4, 3, 3, 2, 2, 1, 1, 1, 1, 1, 1, 1, 2, 2, 3, 3, 4, 5, 8, 10, 10, 10, 20, 20. Number of grids of the mesh significantly affect the simulation time. In the case 4, due to its convergency pattern, the amount of grids along the Y axis could be reduced up to 31. The comparison mostly concerned on water breakthrough, flow rates, accumulated liquid flows and the reservoir oil saturation profiles. All the cases are simulated for 250 days.

Table 4-1: Grid sizes

Case	NO. of Grids	Grid size (m)
Case 1	25	8
Case 2	51	4
Case 3	201	1
Case 4	31	Converged

The simulation results give different values/profiles for each case so that the effect of the control volume size is reflected. Some important results is shown in Table 4-2 which shows, a clear comparison. According to the grid size, the case 3 gives the most reliable results among all other cases even though it takes maximum simulation time. Values given in the table show that the results are deviated from the case 3 when the number of grids are reduced. However, the values in the case 4 are closer to the case 3 values even though it has less amount of grids. This means the effect of the grid size closer to well is higher than the grids away from the well. The Figure 4-2 shows the reservoir profiles at the same operational time and it can observe that the case 04 has the approximately similar profile for finest grid case.

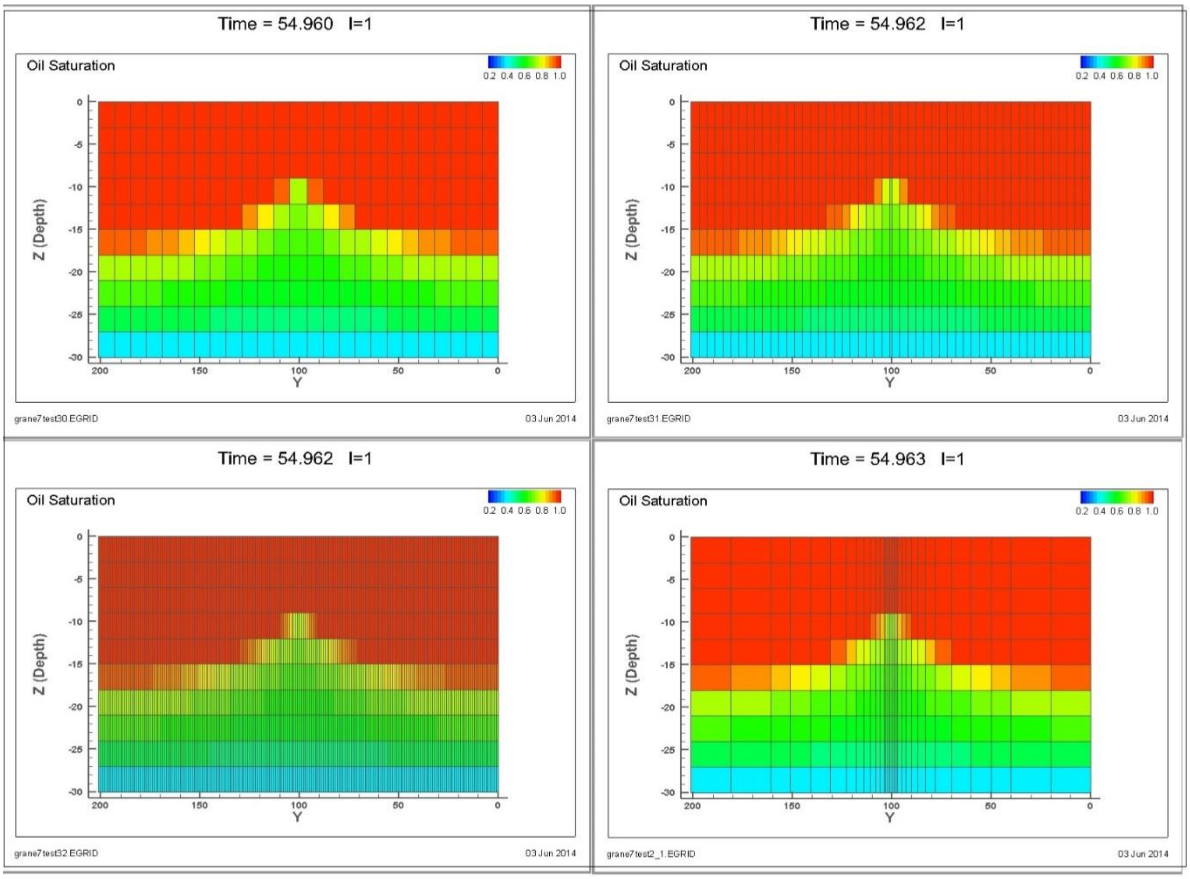

Figure 4-2: reservoir profiles with different grid sizes i) case 01 ii) case 02 iii) case 03 iv) case 04

Table 4-2 : Several simulated results over Grid size

Case	Breakthrough time (days)	volume at Breakthrough (m3)	Accumulated liquid after 200 days (m3)	Accumulated Oil after 200 days (m3)
Case 1	54.7398	18476.1	53475	37498.5
Case 2	54.7024	18459.7	53228.2	37055.8
Case 3	54.1341	18270.6	55455.6	38189.6
Case 4	53.8833	18187.4	55711.4	38459.4

4.2 Influence of the reservoir size

Simulations discussed under this subchapter are to investigate impacts of the reservoir size on oil production. Four cases are used for the observation and only the reservoir width is changed while keeping the length and the height as constants. When changing the width, grid size along the Y direction is changed in each case, however the grid pattern is kept almost the same in every cases. All the simulations are carried out for 100 days. Table 4-3 shows the reservoir volumes in different cases. Case 04 reservoir size is more than twice of case 01 reservoir. Same data collection is used to observe simulation results with two different ICD diameters, 9mm and 15mm.

Average total liquid flow rates are represented by the gradients of the graphs. The total flow rates for two cases in 9mm and 15mm are approximately 325 and 650 in $m^3/_{Day}$ respectively. Even though there are slight variations over the life span of the well, total flow rates can be rounded up as constants in both cases. Figure 4-3 and Figure 4-4 show the accumulated liquid volumes for two different cases. However, the ratio between two valve areas is 1: 2.77 and the ratio of total flow rates is 1:2 which is an important observation from the results. Obtained results also showed that the total flow rates are not vary in considerable amounts with respect to the reservoir size, if the valve area is the same. The valve diameter is an indicator of the pressure drop from reservoir to wellbore. If flow rates through the ICDs at both cases are in the bottle neck state, the constant total flow rates for particular valve are clear. So more simulations with different valve diameters are needed to confirm that the reservoir size has very little influence on total flow rate.

Table 4-3 : Reservoir dimensions

Case	Width (m)	height (m)	Length (m)
case 01	141	30	100
case 02	201	30	100
case 03	251	30	100
case 04	301	30	100

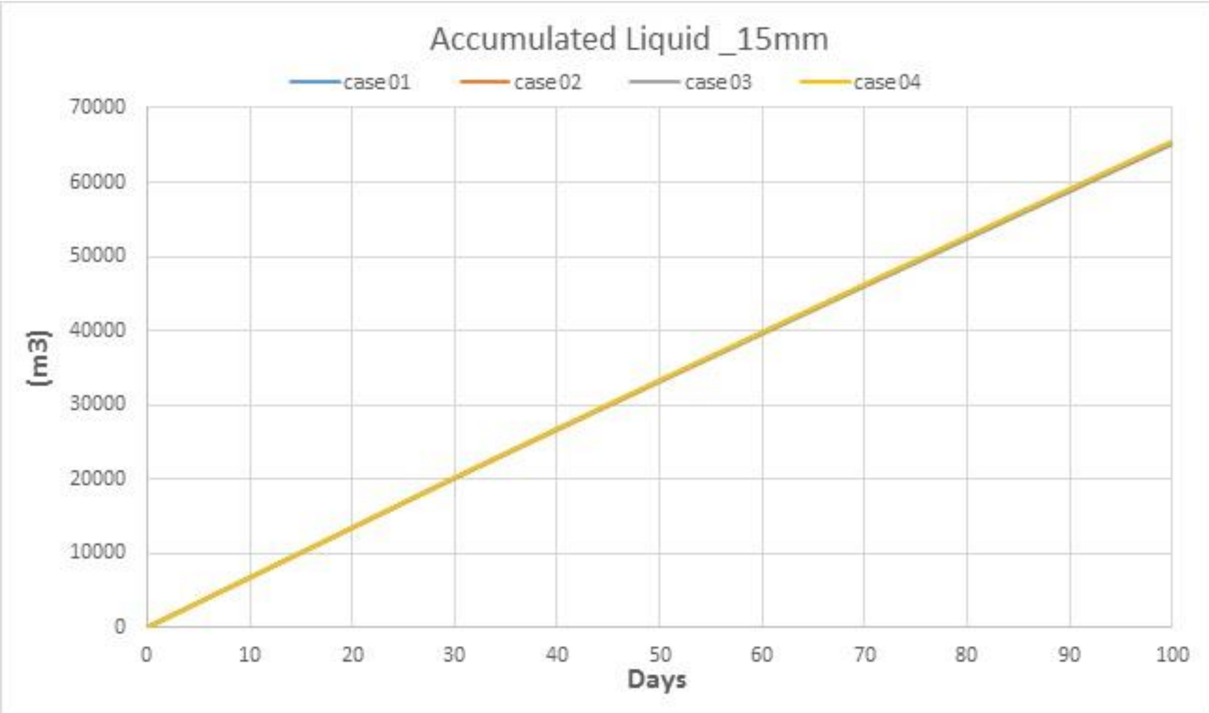

Figure 4-3: Accumulated Liquid profile for grid size case-15mm Valve diameter

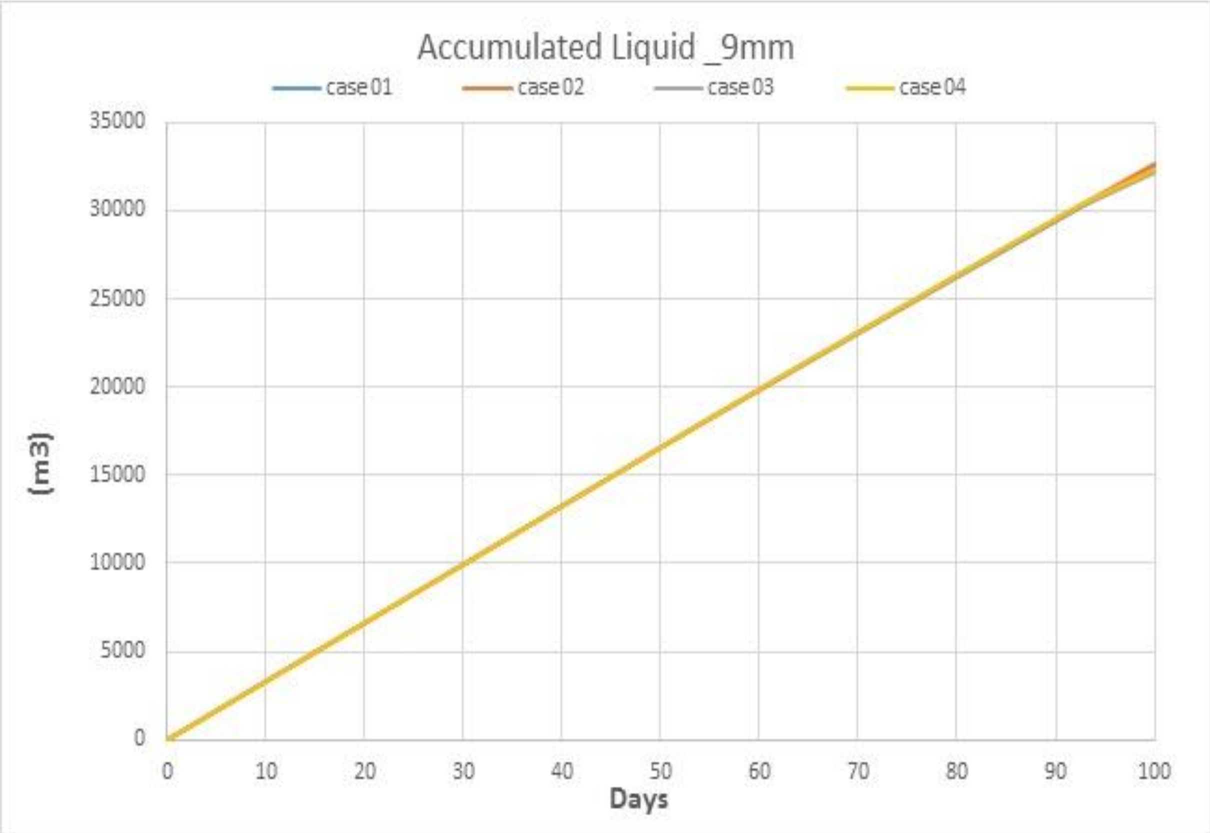

Figure 4-4: Accumulated Liquid profile for grid cae-9mm Valve diameter

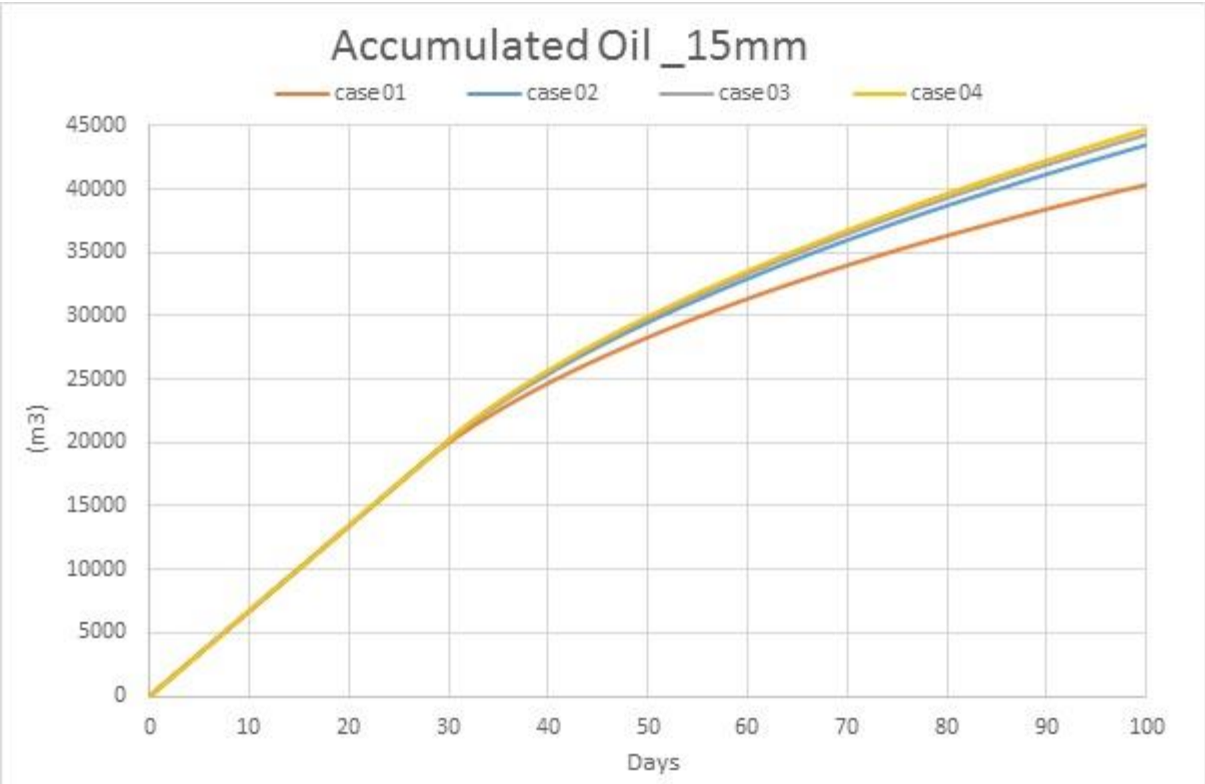

Figure 4-5: Accumulated Oil profile for grid cae-15mm Valve diameter

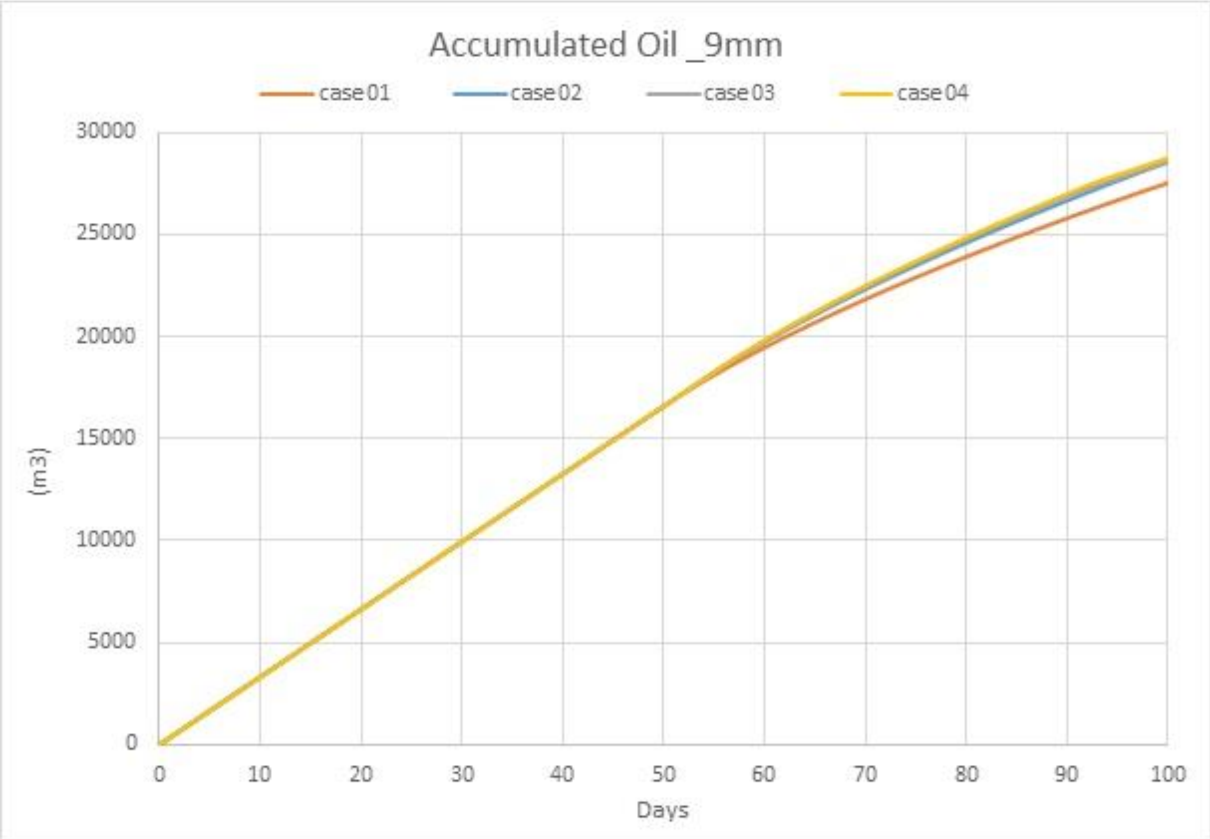

Figure 4-6: Accumulated Oil profile for 9mm Valve diameter

Even though the total flow rates are not changed over different reservoir sizes, oil flow rates have been changed upon both life time and the reservoir size. Figure 4-5 and Figure 4-6 show the simulation results of accumulated oil volume over the time. The gradient of the oil curves are changed with the time. At the beginning, the flow rate is maintained at constant level and after some time the oil flow rate start to deviate from its constant value. Then the oil flow rate is gradually going down with decreasing flow rate change.

Graphs show that the accumulated oil amount seems to converge for a stable value with the time. This behavior represents the oil depletion of the reservoir with respect to the time and later no more oil to be extracted. The point starts to deviate from the constant flow rate indicates the water breakthrough. Thereafter total flow rate and oil flow rate have different values due to the multiphase flow after the breakthrough.

Table 4-4 shows the breakthrough time and the flow rate at the water breakthrough. The breakthrough time difference between first two cases is higher than all other adjacent cases and the difference seems to be converged. Therefore it is conclude that after some reservoir volume, water breakthrough time is not expanded even though the reservoir volume is increased further. Moreover, with these results, it can be commented that the oil mobility is highly active at closer reservoir areas to the well. The reservoir volume influence is getting reduced with the increment of the distance to the well. The well is not able to active the mobility of oil after a particular distance and oil saturation data profiles on reservoirs provide better information to assure this property. Figure 4-7 shows the oil saturation profiles of the reservoirs at the break through in specific case. The variation of the profile along the Y direction can be clearly noticed between case 01 and 04 where case 02, 03 and 04 have similar profiles. The decreasing gradient represents the flow rate is reduced over the well life. Another important observation is that the oil depletion rate is highest in the smallest reservoir and vice-versa. Even though depletion rate is various in different cases, the changed is very little compared to the reservoir volume difference. Therefore it can be conclude that having a one well for a big reservoir is not efficient in extraction and number of wells should be increased with reservoir volume expansion. Further investigations are needed to find the optimum reservoir size for one well. The well installation cost, maintenance cost and increment of the oil extraction after placing several wells are the main factors to calculate the profit of the operation. Those factors all together decide the economic aspects over the number of wells for a particular reservoir volume.

Table 4-4: Breakthrough data

Case	Breakthrough days		Liquid Volume (m3)	
	9mm	15mm	9mm	15mm
Case 01	51.5554	27.6348	17087	18542.5
Case 02	55.1238	29.6286	18285.3	19918.5
Case 03	56.1121	30.263	18618	20356.5
Case 04	56.5095	30.4536	18751.2	20488

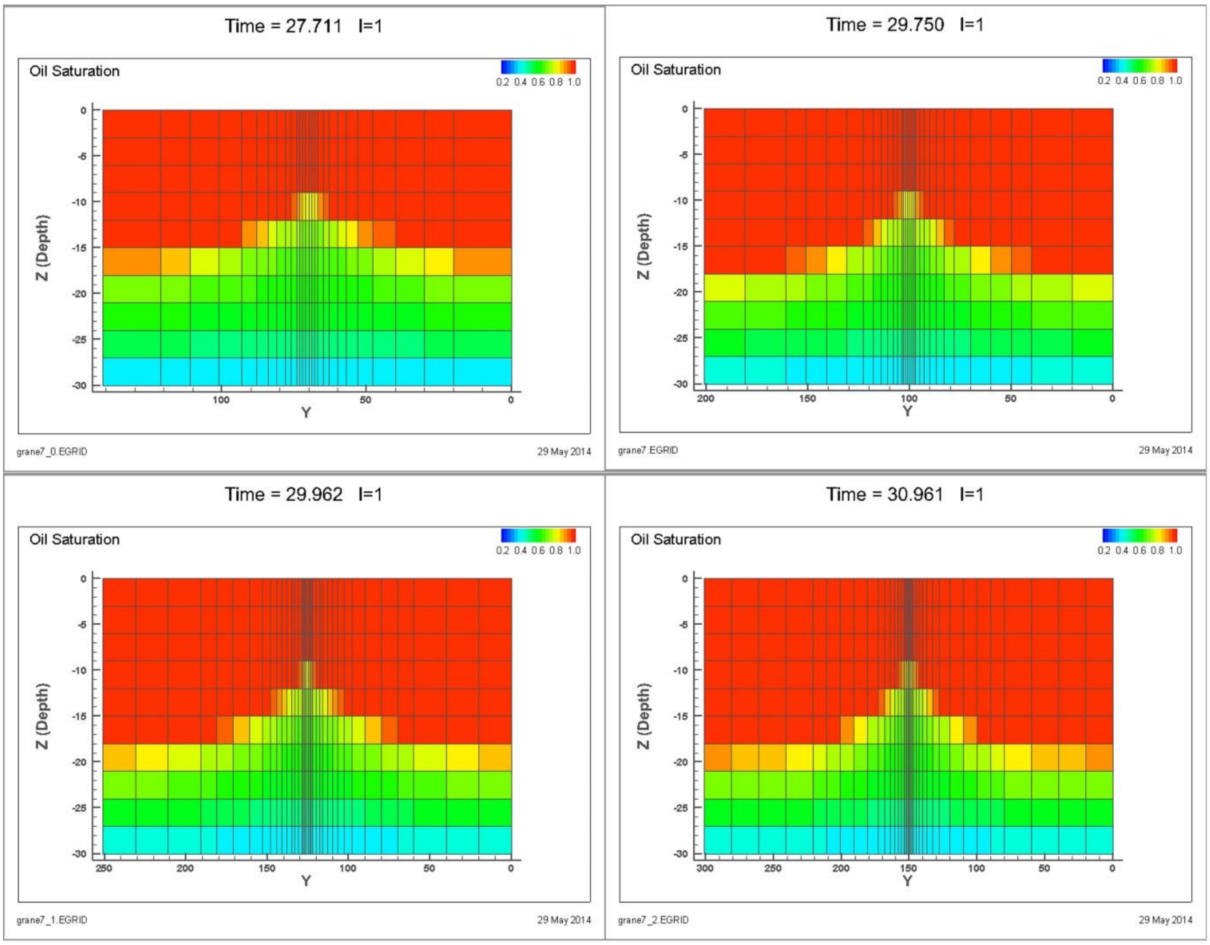

Figure 4-7: Saturation profile on the reservoir volume closer to the breakthrough i) left top: case 01 ii) right top: case 02 iii) left bottom: case 03 iv) right bottom: case 04

4.3 Effect of relative permeability

Modelling and simulations are performed to observe the influence of the relative permeability mainly upon flow rates, the water breakthrough and the oil extraction efficiency. The Figure 4-8 shows the relative permeability data found in literature. The graphs are drawn in Excel package with polynomial trends. Three different cases are developed for the comparison where the residual water and the residual oil values are different from each other. At the beginning of the simulation, the well surrounding is filled with 100% saturated oil. During the simulation oil saturation throughout the reservoir is reduced gradually, at the same time water saturation starts to increase initially from zero. However, water is not entered the wellbore until the water saturation near the well exceeds its own residual amount. The oil extraction can be continued till the oil saturation falls down to its residual amount. Residually saturated oil over the reservoir remains in the abandoned oil field after the well-life.

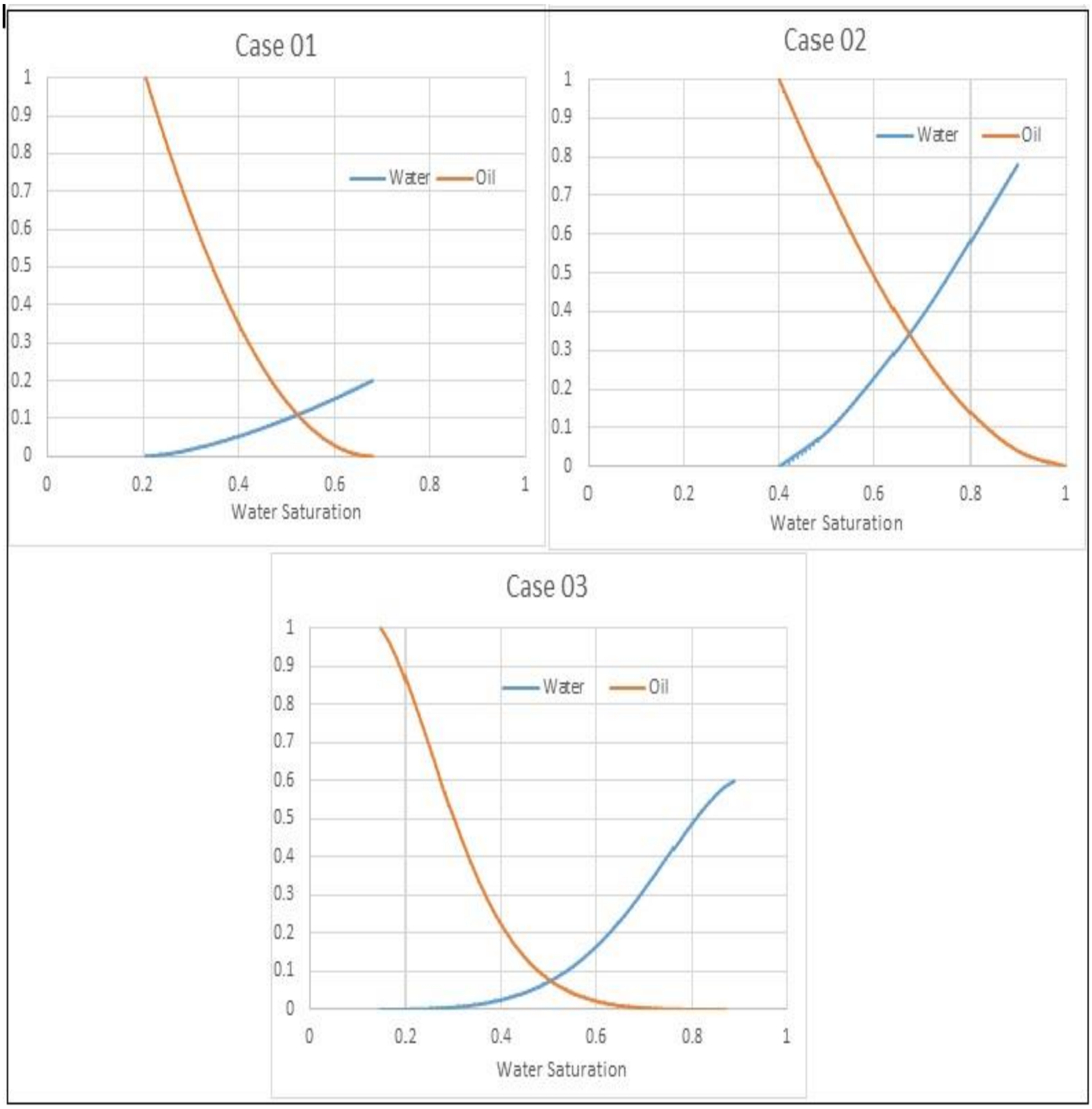

Figure 4-8: Relative permeability values

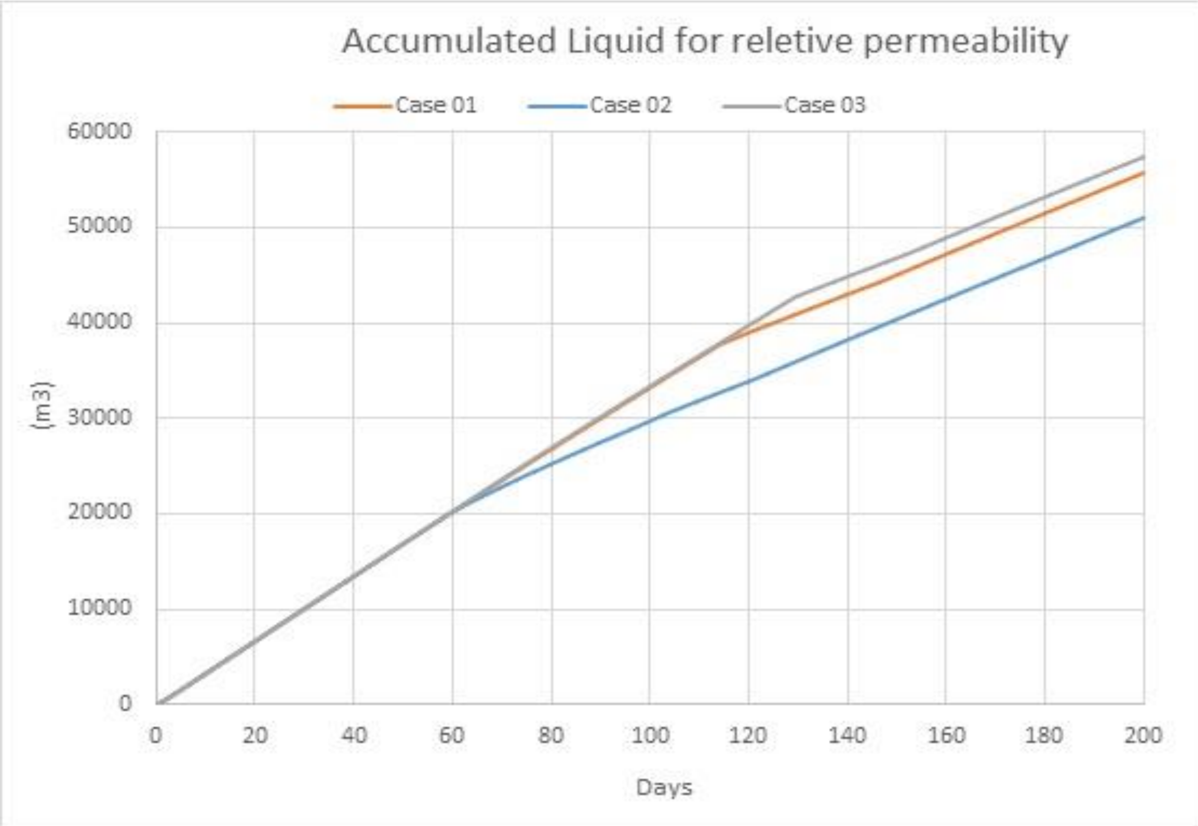

Figure 4-9: Accumulated Liquid profiles vs life time

Oil flow rates in every cases until the water breakthrough lies around the same value at $337 m^3/_{Day}$. After the breakthrough, water enters into the wellbore and then inflow behavior turns into multiphase. Therefore, the sum of two relative permeability values is lower than absolute permeability according to the equation (2-4). The phase flow of the individual component depends on the corresponding relative permeability and the viscosity. Total flow rate is then the sum of all the phase flow rates in the multiphase flow. Total flows of discussed cases in the report are two phase flows --- water and oil --- which equal to the sum of water flow and oil flow. Furthermore, the total flow rate depends on all the relative permeabilities and viscosities of the components. Even though the equation (2-4) is applied in multiphase flows, the total flow rate is not necessarily to be below than the flow rate before the water breakthrough. Viscosity values would compensate the effect of relative permeabilities as shown in equation (2-3) and lead to a high flow rate. The Figure 4-9 shows the accumulated total liquid volumes with respect to time. Upon on the simulation result the total flow rates of all the cases are decreased after the breakthrough. It seems that the relative permeability values of the multiphase flow influence to the flow rate reductions. The liquid flow rate is continuously changed after the breakthrough since the water saturation near the well is changed and then the relative permeability varies accordingly. Hence, the flow rate change after the break through can be summed up with the dynamic variation of the relative permeability along the reservoir.

Table 4-5: Breakthrough data with different relative permeability

Case	Water Breakthroug h	Liquid Volume at breakthrough (m3)	Water saturation at well Grid	Volume at 100 days (m3)	
				Liquid	Oil
Case 01	53.8996	18193	0.292087	33219	28672
Case 02	55.3902	18688.5	0.444542	29717	25980
Case 03	68.2161	23025.4	0.265484	33367	30973

The Table 4-5 shows the information near the water breakthrough. Accumulated oil volumes have the similar characteristics at the breakthrough since oil is the only flow before the multiphase condition is achieved. The water breakthrough time is varied for the different cases which behavior is mainly discussed here. The water saturation of the reservoir is an important parameter to understand the differences of the breakthrough time. Even though the multiphase condition is not achieved in inflow before the breakthrough, the condition is reached with in the reservoir. The Table 4-5 shows the saturation at the grid (1, 16, 4) where well is located is equal to the residual water saturation in all the cases. These saturation values can be obtained from the Tecplot data.

If water drive with same speed within the reservoir, the cone must have the same saturation profile. Then the breakthrough time delayed according to the residual saturation so that longest breakthrough time should occur at the highest residual water saturation case, in case 02. However, with the simulation results latest breakthrough happen in case 03 which has the lowest residual value. This phenomena can be explained with the relative permeability graphs in Figure 4-8. Even though the water breakthrough happen at the residual saturation of water at the well-grid, water dispersion throughout the reservoir is not happen in same speed due to the multiphase flow within the reservoir. When it is closer to oil residual level, relative permeability of water increased exponentially, see Figure 4-8. Below the residual oil point the relative permeability of water stabilized at absolute permeability and water start to act as a single phase flow. This characteristic of water leads to early break through, once water saturation exceed the oil residual amount water phase is highly activated. Water relative permeability curves are active in the case 01, 02 and 03 consequently. The permeability curves of water are fully explained the water break through time together with the multiphase flow behavior within the reservoir before the breakthrough.

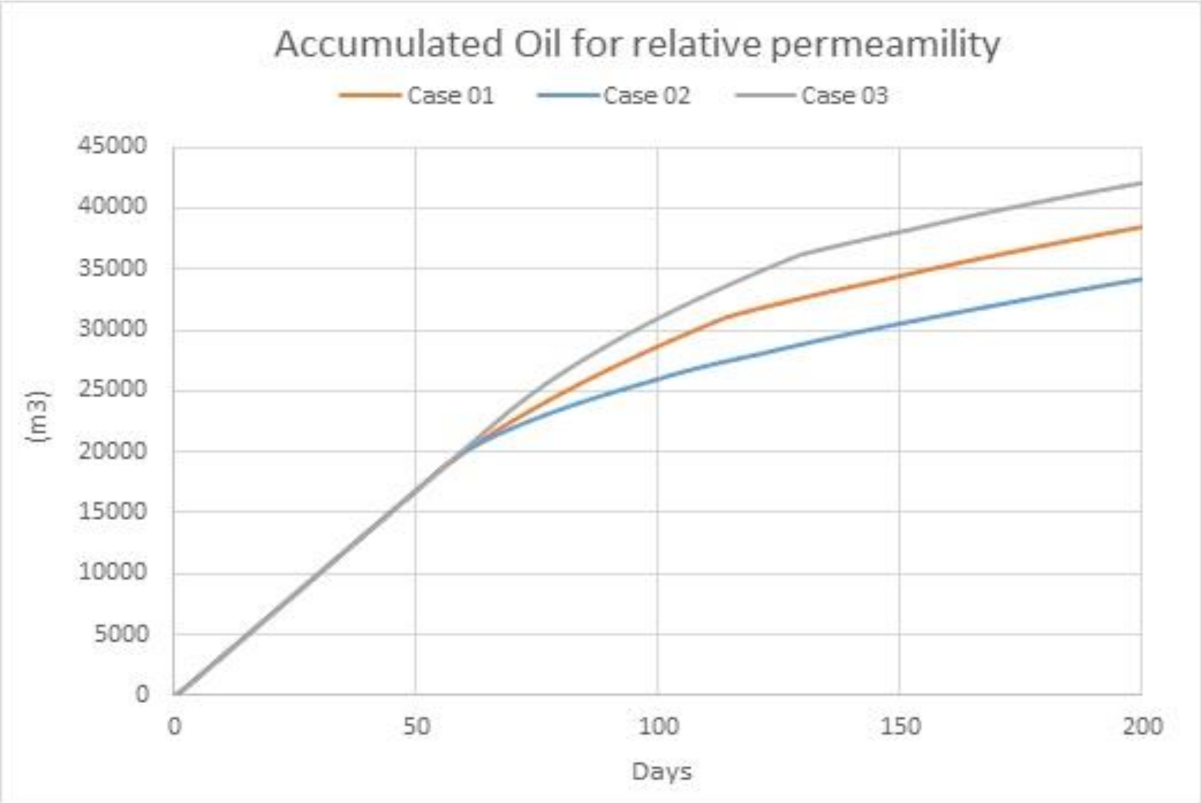

Figure 4-10: Accumulated Oil profile vs life time

Oil flow rates of all the cases are gradually decreased after the water breakthrough. The decreasing rate is diverse from each other and the reduction of the decreasing rate over the time can be introduced as a common observation for every cases. At the same time the total flow rate is also reduced as previously discussed, so oil flow comparison with each cases is not easy. By the way, case 01 and 03 have approximately similar dynamic behavior on the total flow rate. Therefore, it is simple to observe the oil flow behavior after breakthrough with these two cases.

The gradients of the accumulated oil curves have almost a similar variation in these two cases after the breakthrough which denotes oil flow rate behaviors. Accumulated amount seems to converged to a certain value as shown in the Figure 4-10 and this corresponding value is higher in the case 03. Therefore, case 01 produces less oil with the same reservoir size than the case 03. Moreover, it can be concluded that the delayed water breakthrough case has a higher recovery factor and this characteristic can be used to increase the oil recovery with further studies.

Even though the case 02 residual oil saturation is zero, it produces the lowest amount. This feature reveals lower oil residual reservoirs are not always produced higher oil volumes and the influence of the relative permeability is stronger than oil residual amount in some fields. The Figure 4-11 shows the oil saturation profile at the breakthrough of discussed cases. Inspection of simulation results of the oil reservoir saturation profile shows that narrow water cone is occupied by the earliest breakthrough case at same well-time.

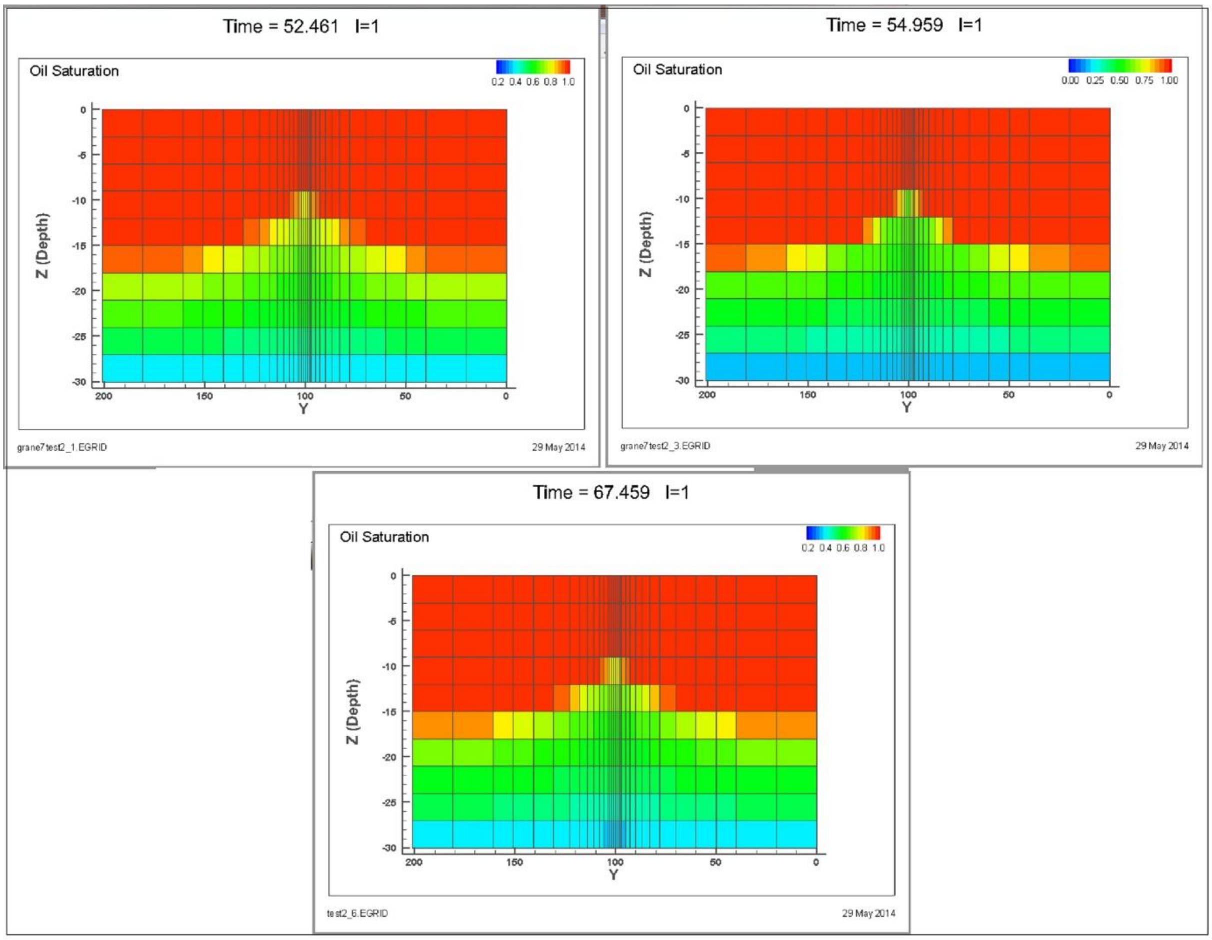

Figure 4-11: Oil saturation profile closer to breakthrough i)case 01 ii)case 02 iii)case 03

4.4 Water flow controlling

This subchapter is discussed the usage of controlling mechanisms built in OLGA module for a better control solution. There are different kind of controllers are built in OLGA, by the way only the PID controller is used under the discussion. The objective of this modelling and simulation trials is to control water flow after the breakthrough. In real world operation, offshore process capacity might not enough to handle multiphase flow beyond a specific water percentage or volume flow. Therefore, it is important to control the inflow within the capable limitations of the process. Controlling of inflow is useful in two different aspects as it keeps the flow volume within the process limitations of the plant and increase the oil recovery factor. If the inflow is higher than the critical flow rate, reduction of inflow rate is always lead to reduce water coning effect. Therefore, overall idea of water flow controlling is to reduce water coning impact and extract more oil. Three main developed models are discussed in order to control the inflows with PID controllers. Anyhow, only one ICD is used to simplify the simulation and to reduce the running time before go for a complex model. Selected control variables are mentioned below in three cases accordingly.

- Case 01 – Total flow rate $\left[{m^3}/{Day}\right]$
- Case 02 – Water flow rate $\left[{m^3}/{Day}\right]$
- Case 03 – Water cut [%]

All the cases are simulated without the controller at first to observe the behavior before the controller is installed. Simulated models with the PIDs are named with "Cntrl" prefix in every cases to identify easily. The comparisons are done at last of the discussion with each other models to find the optimum solution between three.

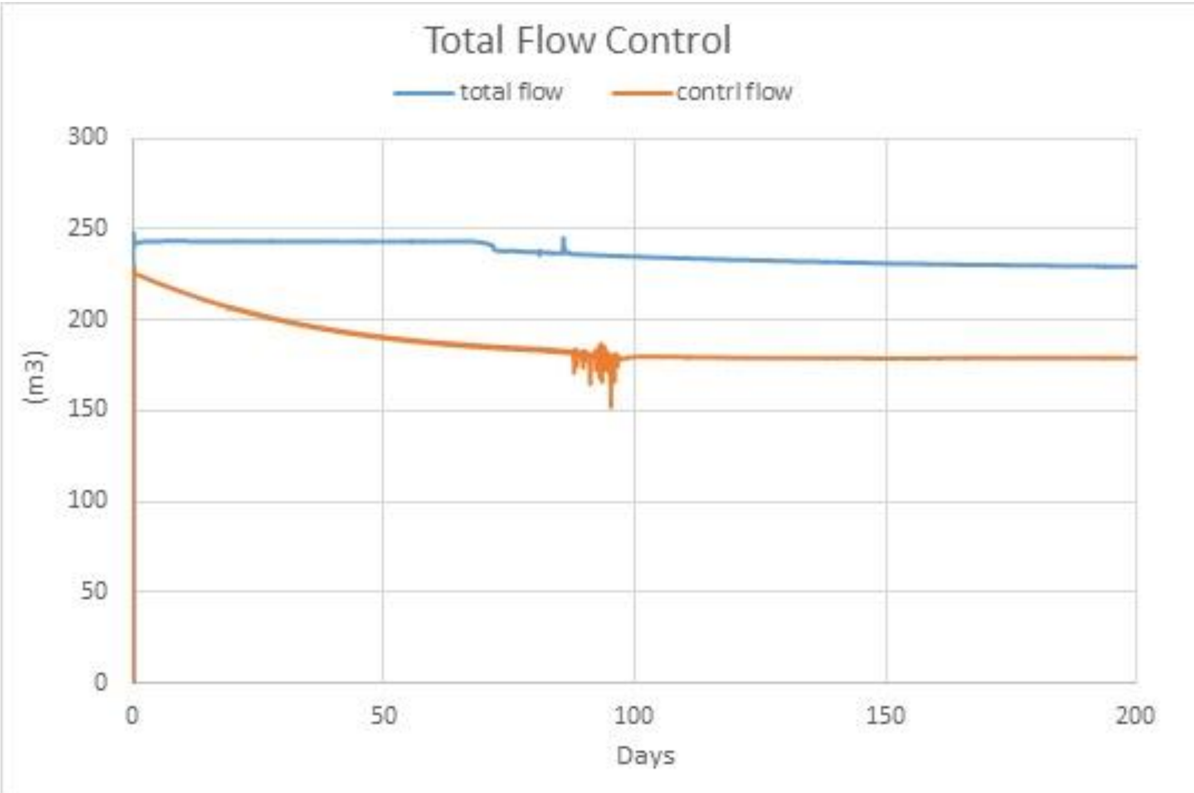

Figure 4-12: Measured controller variable of total flow control

General PID controller has three constants namely proportional, integral and differential. The differential constant is adjusted to zero in all controlled models used in the report such that it acts as a PI controller. Tuning of the controller is also an important factor when introducing the controller system for the process. The trial and error method is used to find the robust constants for the case. Without proper constants, controlling within the desired limitation is impossible. Inappropriate constants might lead the system to instability or stablize at another state which doesn't fulfill the needy of the process. Controlling signal is given by the PID to the control valve then the valve area is changed according to the received signal.

Table 4-6: used PID controller constants

Case	Proportional Constant	Integral constant (S)	Set Point
Cntrl Case 01	-0.003	1000000	180
Cntrl Case 02	-0.003	100000	100
Cntrl Case 03	-0.01	1000000	15

Figure 4-12 shows the control variable behavior of two corresponding cases where the total flow rate is selected as the control variable. In the original case, total liquid flow rate lies around $240 m^3/_{Day}$ over the well life. PID is set to control the total flow rate at $180 m^3/_{Day}$ and controlling is achieved by the reducing of the valve area. The pressure difference between the reservoir and the wellbore can be reduced by decreasing the valve area, since the pressure drop is inversely proportional to the valve area. The Figure 4-12 shows that the system takes around 85 days to reach its set value, even though valve area tends to reduce from the beginning. This is a negative sign of this model since it takes long time to stabilize at the set point. Finer tuning of PID may overcome this problem. Breakthrough information is available in the Table 4-7: Comparative data in controlling and it can be seen that breakthrough time is extended in the controlled case than the original. The expansion of the breakthrough time has not been given any improvement on oil recovery such that the accumulated oil volume is approximately the same in both cases. Same oil amount is extracted within 155 days in original case where the controlled model spends 200 days. It has not given any significant difference of water volume reduction when extracting the same oil volume after 200 days. After all, water break through delayed around 15 days and the same oil amount is extracted after 45 days in the controlled model. Yielding the oil at the maximum possible flow rate before the break through is the most economical way of production, if there is enough handling capacity in the operation. However, after the breakthrough there are several factors influence on the optimal flow rate such as handling capacity and the water cut. Therefore, this method has not given any attractive solution for the controlling.

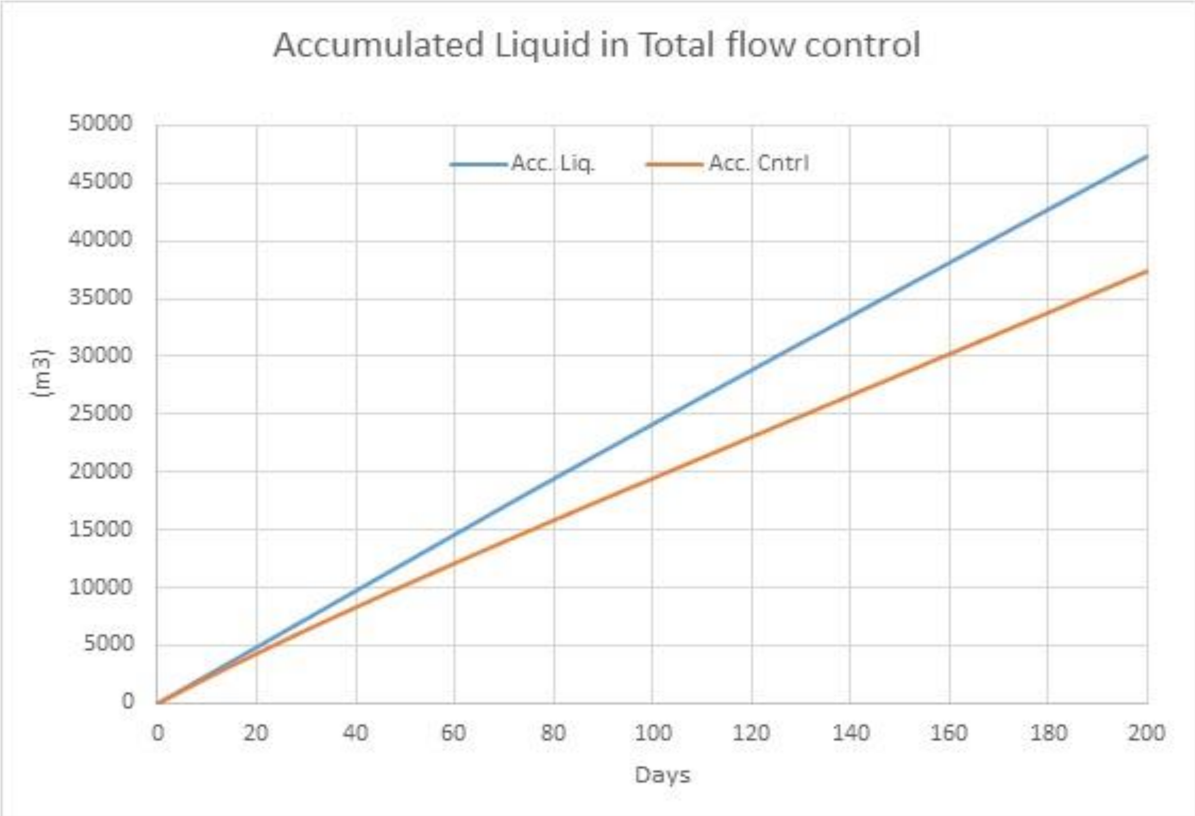

Figure 4-13: Accumulated liquid volume of Total flow control

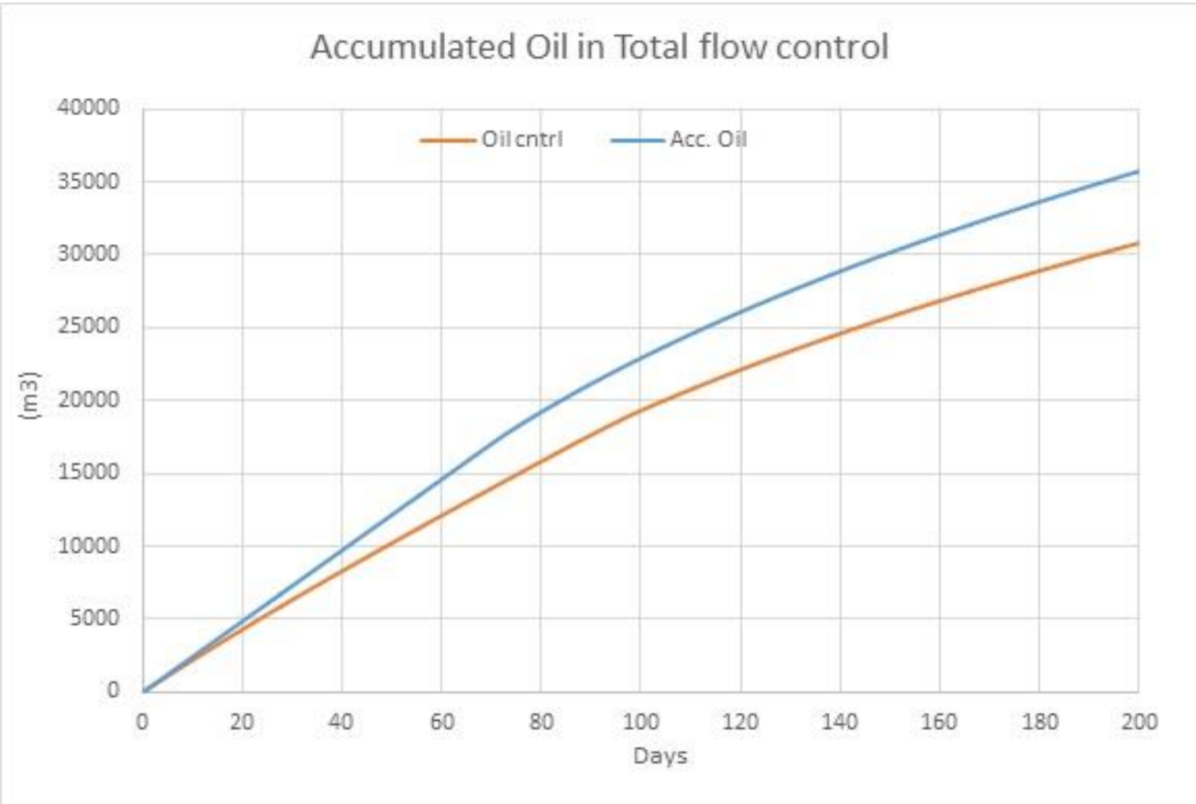

Figure 4-14: Accumulated Oil volume of total flow control

Case 02 is built up to monitor the influence of water flow rate controlling over the oil production. In this case, water flow rate is selected as the controlling variable and transmitter installed in the model measures the water flow rate. Measured value of the variable send to the PID where the value is executed and then a signal is forwarded to the control valve. The control valve starts to operate once the measured variable reaches the set point. If the water flow rate tends to deviate from the set point valve opening is adjusted to regulate the measured variable. Originally, total flow rate is somewhere around $240 m^3/_{Day}$ and set point is held at $100 m^3/_{Day}$ which is similar to 41.6% of water cut. The PID is not activated until the water flow rate reach its set point and it overcomes the drawback noticed in case 01 where the total rate is disturbed before the water breakthrough. The water breakthrough occurs in both original and controlled cases are at the same time, if the water flow rate is selected as the controlled variable. The Figure 4-15 shows both original and measured variables in the same graph. Same oil amount in controlled case after 200days, is extracted 4 days before without the controller originally and the little reduction in water volume also can be detected. This behavior is becoming handy for a longer simulation results such that water volume is reduced more and more for the same accumulated oil volume in two cases. The water cut reduction for the same amount of oil can be observed in Figure 4-16 and Figure 4-17. Water cuts stand around 62% and 57% in original and controlled cases respectively.

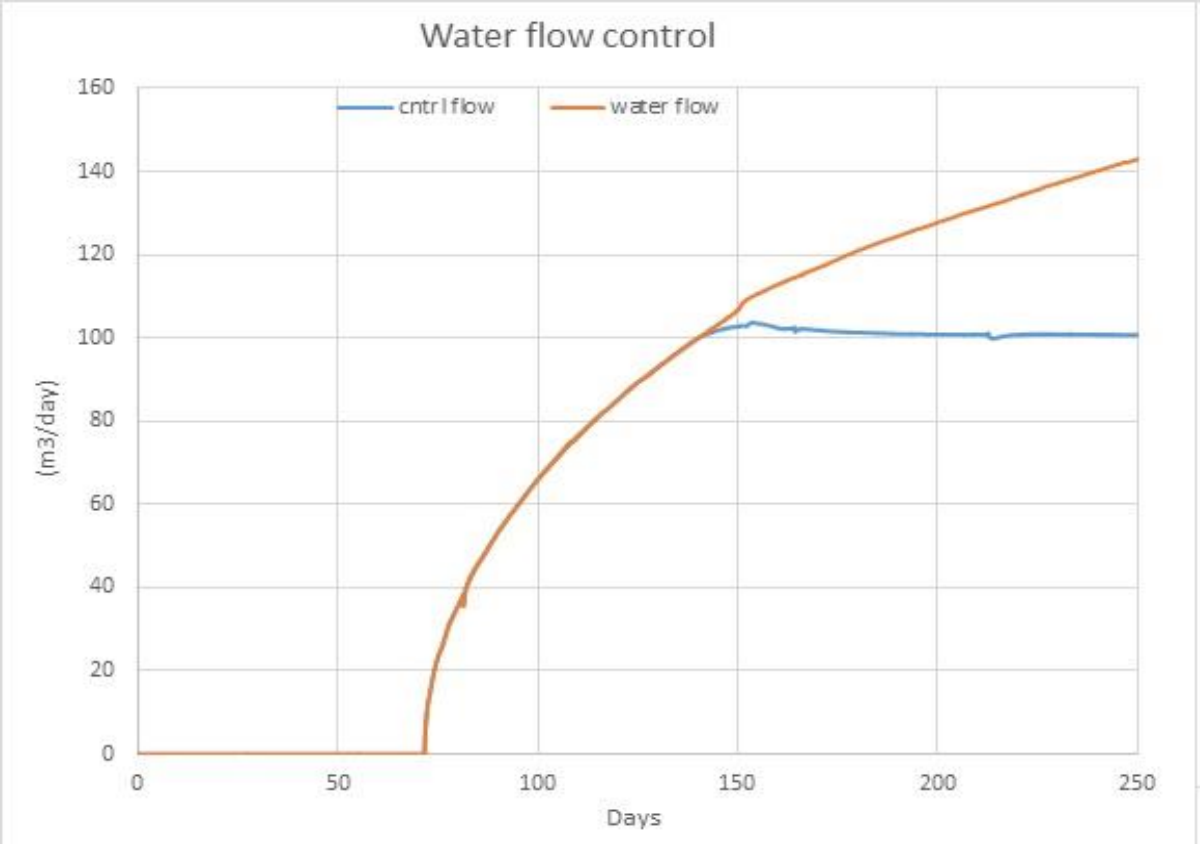

Figure 4-15: : Measured controller variable of water flow control

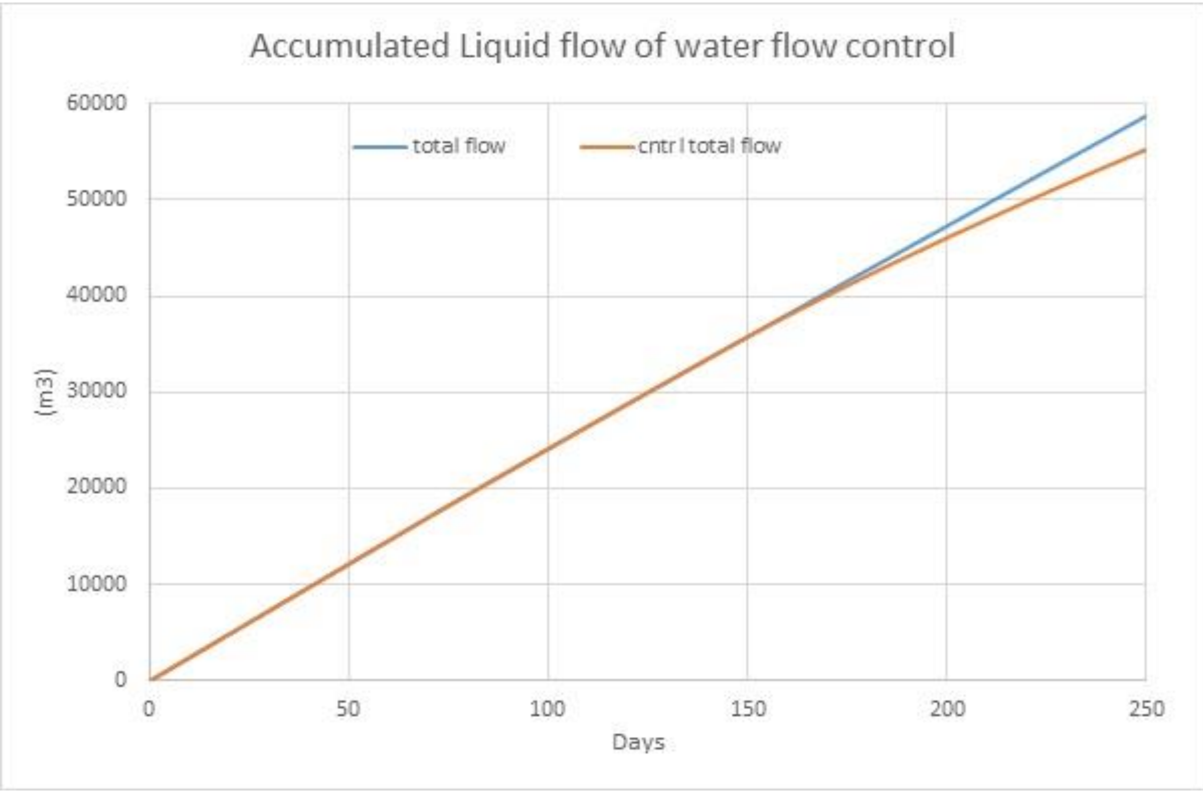

Figure 4-16: Accumulated liquid volume of water flow control

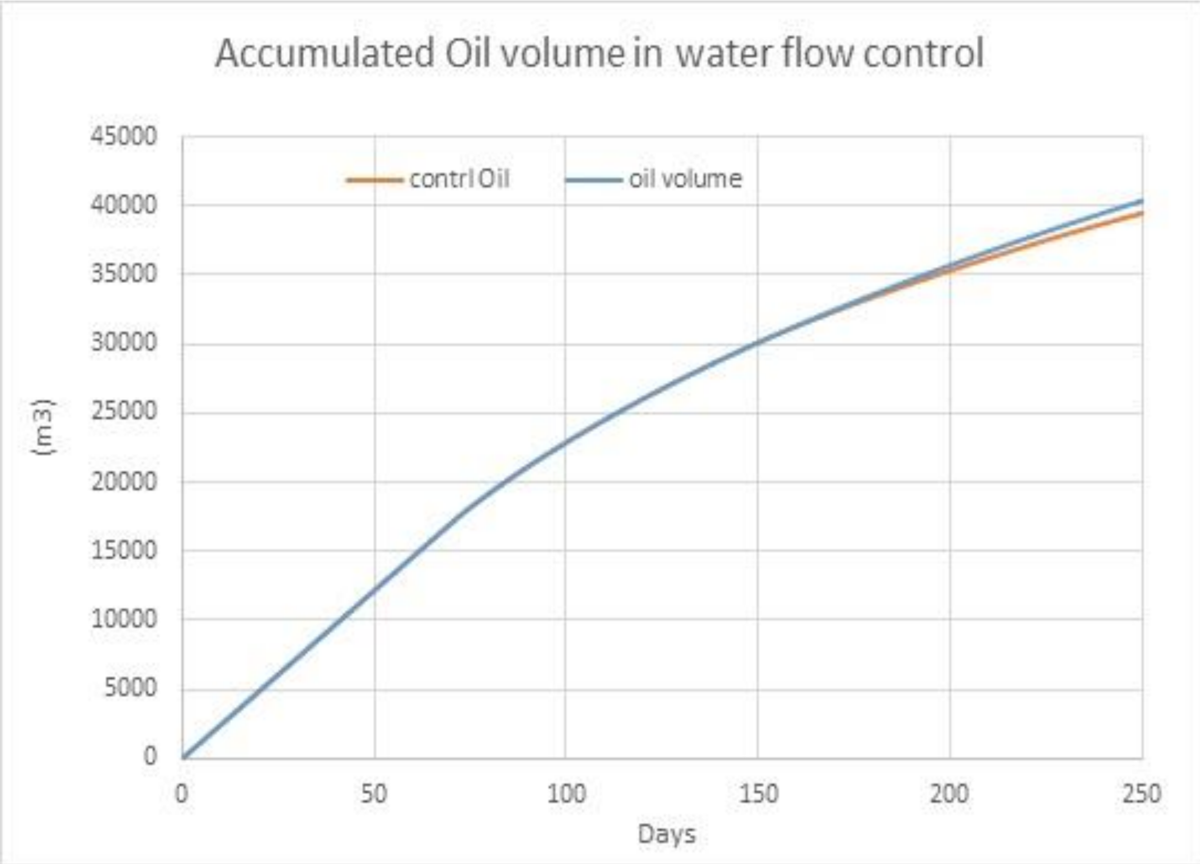

Figure 4-17: Accumulated oil volume of water flow control

Third attempt is made to inspect the multiphase flow behavior with the water cut controlled model. Transmitter measured variable is water cut and unit is selected as percentage. Tuning of the PID was harder than two previous cases. Both controlled and non-controlled cases are run for 200 days with selection of trend data and profile data. The Figure 4-18 shows the measured variables over the time in both cases. Controller measured signal consumes long time to reach the set point as shown in the graph. However, the used controller constants are not far from previously discussed strategies, furthermore the proportional constant is higher than both other cases. If the set point is kept in a higher value around 50%, the system is unstable. Therefore, trails are done with a lower set point as 15% water cut which is well below than the real operation.

Accumulated liquid volume is significantly decreased in these trials as shown in the Figure 4-19 due to the low set point used in the controlled model simulation. Time for the breakthrough has the same value in both cases since the PID is not activated within breakthrough time. After 200 days, controlled case produces 32270$m^3/_{Day}$ oil volume and without the controller same amount is produced within 168 days. Nevertheless liquid volume for the same amount of oil, is significantly declined with the controller. The Table 4-7 gives the water volume reduction and the reduction is comparatively higher than two other strategies.

Table 4-7: Comparative data in controlling

Case	Breakthrough		After 200 days		Similar Oil volume	
	Days	Volume (m3)	Liquid	Oil	Liquid	days
Case 01	71.6844	17444.3			37052	155.407
Cntrl Case 01	87.6953	17244..3	37387.7	30816.2		
Case 02	71.6478	17418.6			46448.9	196.287
Cntrl Case 02	71.6877	17428.2	46065.1	35325.7		
Case 03	71.6782	17427			39973	168.14
Cntrl Case 03	71.689	17429	36368	32270		

Figure 4-18: Measured controller variable of water cut control

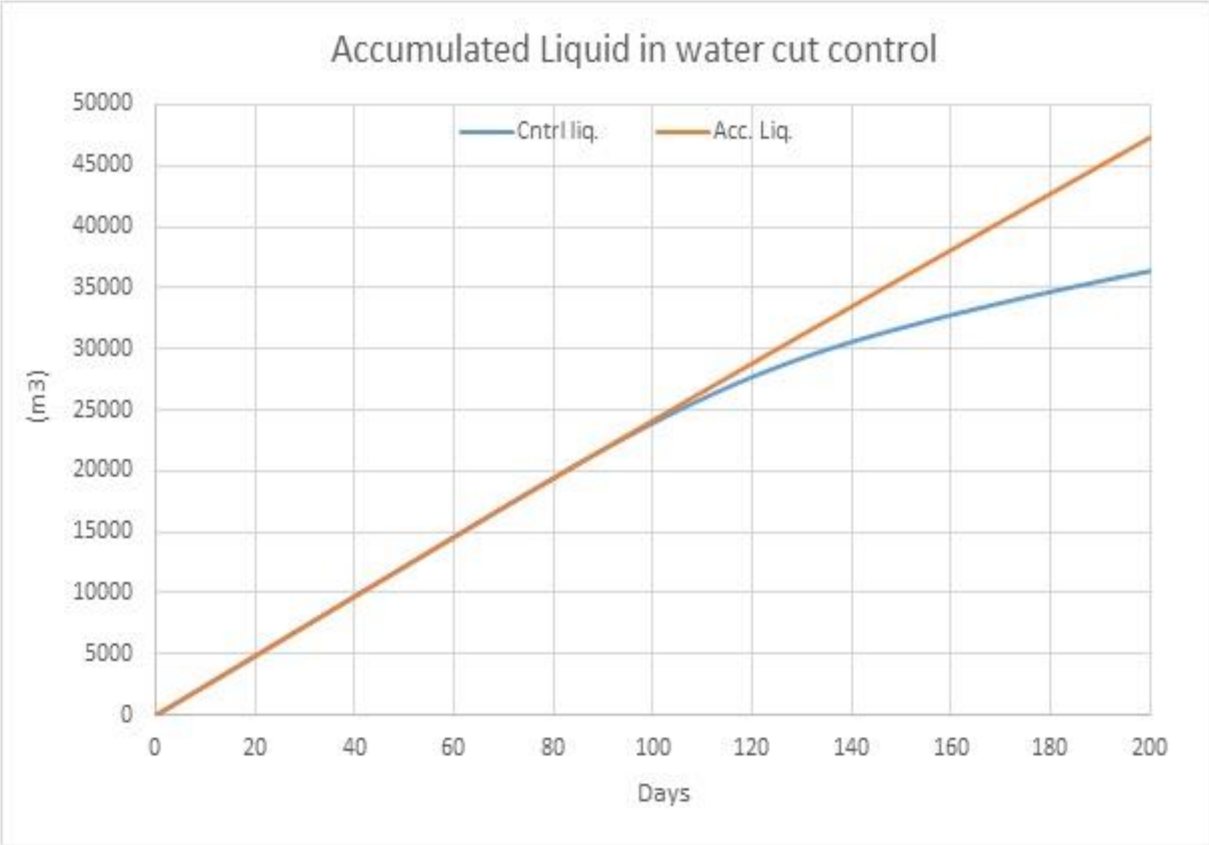

Figure 4-19: Accumulated liquid volume of water flow control

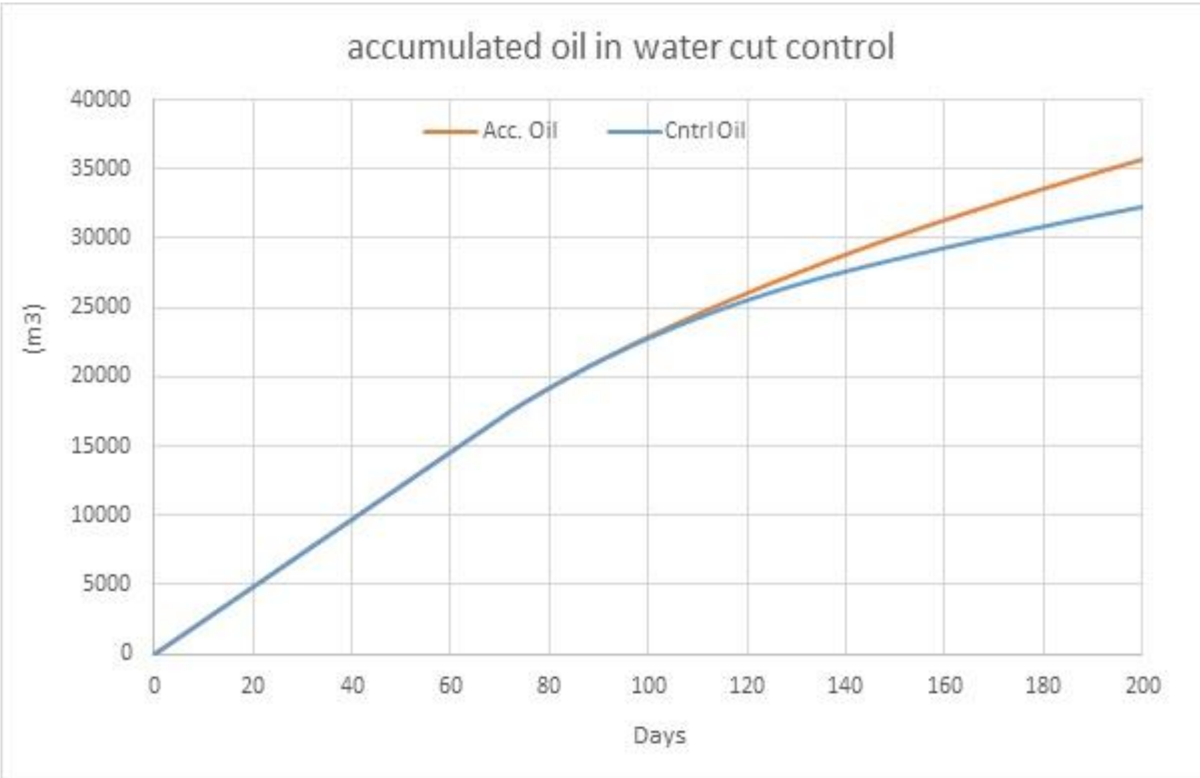

Figure 4-20: Accumulated oil volume of water flow control

Among three controlled cases only the 1st case has the expanded water breakthrough period which is a disadvantage in real operation. The other two cases have the same water breakthrough time so that 2nd and 3rd cases are better in water break through period. Water volume reduction is increased in case 01, 02 and 03 respectively where case 03 has the best reduction for the same oil production. Case 02 gives the fastest oil production rate after 200 days which has the highest accumulated oil amount and case 01 has the lowest. However, the case 03 has some interesting features on water volume controlling even though the tuning is not easy with the PID. Controller measured variable gives smooth curve in case 02. Finally, within the obtained results from three cases discussed under this chapter, the best controlling solution is given by the case 02. The water flow rate is selected as the controller variable in the next complex simulation with a PID controller and having several ICDs.

4.4.1 Controlled model with several ICDs

Two models are created with five ICDs to investigate the controlling features with water flow. This models consume long time for the simulation compared to the previous controlled model since it has more data to execute. Results from the one ICD controlled case were helpful for the PID tuning. However, the same parameters don't give fairly tuned condition as obtained in one ICD case. The Figure 4-21 shows the controlled variables behavior with respect to time in both cases. In this case set point is set $600^{m^3}/_{Day}$. The controlled variable in the figure is not fully stable. Therefore, much more trials should be carried out to achieve the stability of the system. Time limitation of the project is restricted to obtain the robust constant for the model. Some results are given below with table and graphs obtained from the simulations. The water saturation of the reservoir closer to all the ICDs are lies in the same profile which is a one important observation from this simulation.

Table 4-8: Flow results with five ICDs

Case	After 200 days (m3)		Same oil amount	
	Oil	Liquid	liquid (m3)	Days
Non-controlled			278793	188
Controlled	196445	275601		

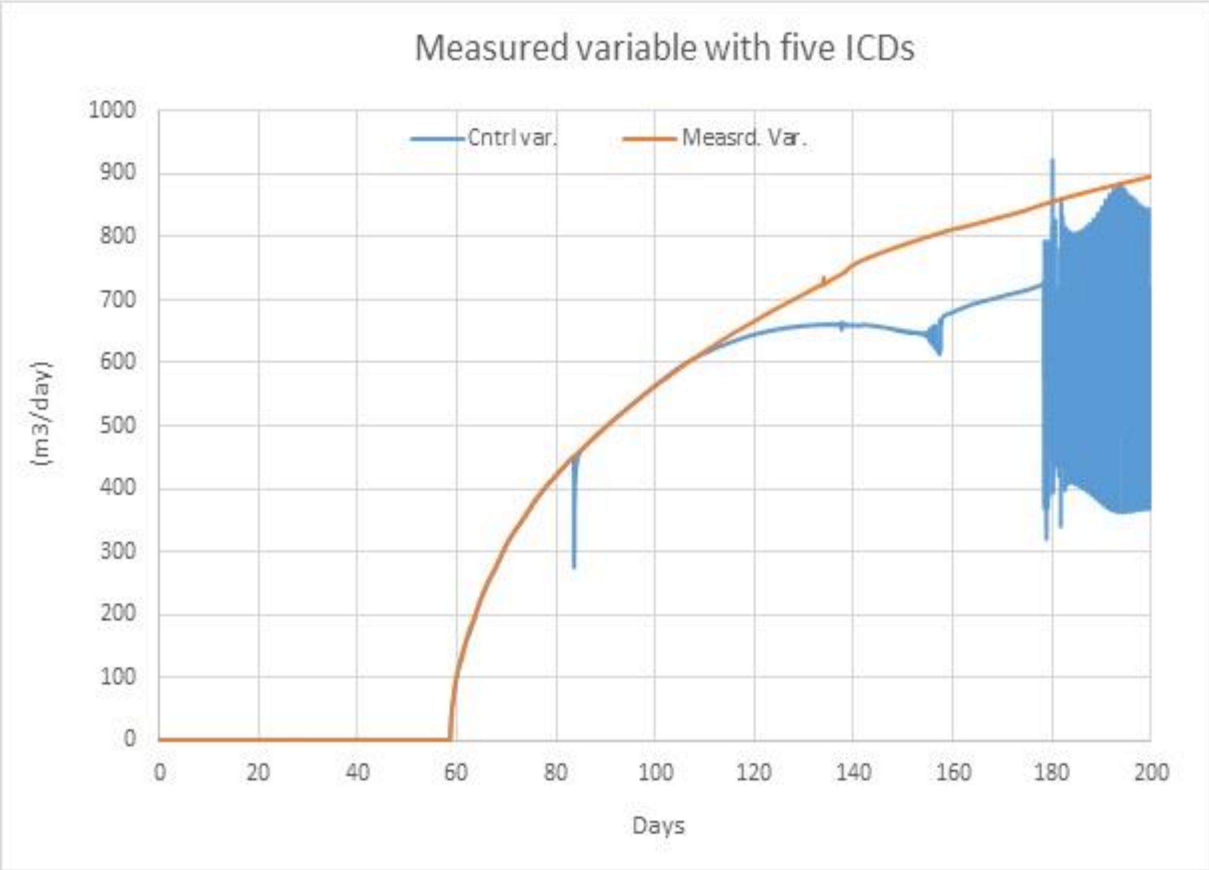

Figure 4-21: Controlled variable with 5 ICDs

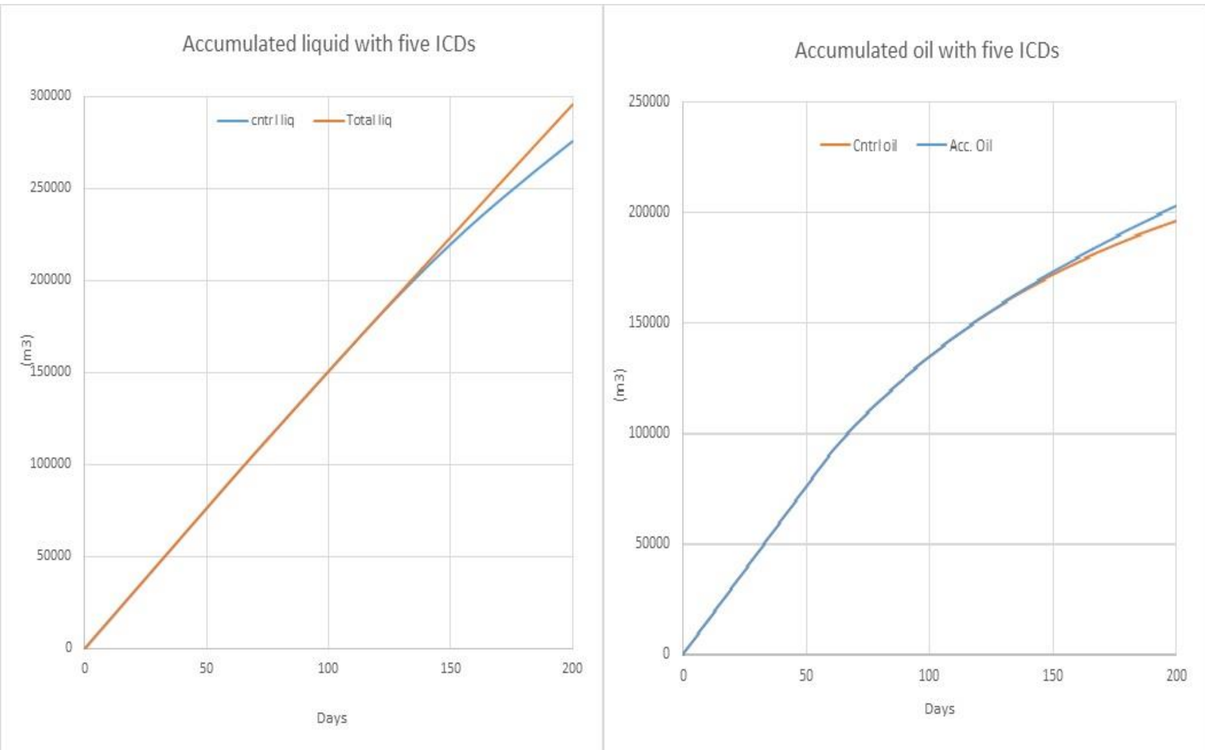

Figure 4-22: Accumulated flow volumes with five ICDs

5 Discussion and the Conclusion

This project was carried out to gain a better understanding about the oil recovery in heavy oil reservoirs. A major challenge in oil fields is that decreasing of oil production rate and the remaining amount of oil after the well shutdown. There are so many factors affect such drawbacks. Developing technologies have given positive results on oil recovery factor. Oil recovery technology is continuously introducing new mechanisms aiming optimized economic recovery before shutting down. Water flooding and enhance oil recovery methods are used successfully to increase the recovery factor. A better understanding is always needed to develop and introduce new techniques to improve the recovery.

Water breakthrough can be identified as a strong challenge faced in heavy oil production and it causes in increasing the water cut during the operation. Multiphase flow after breakthrough on the other hand demands additional methods to oil separation and the maintenance which adds high maintenance and operational cost. The coning effect is the reason to early breakthrough during the production. The water coning is a function of several factors such as production rate and reservoir properties. Therefore, understanding over reservoir properties is necessary to study about the oil recovery. This report consists descriptions about some reservoir properties which strongly affect on water coning and commonly used oil recovery methods.

Inflow Control Device (ICD) techniques are also well-developed methods to increase the recovery factor. ICDs have several attractive features to decrease the water coning effect and to control the production. The report mainly discussed the behaviors of the process with several reservoir properties and ICDs. Inflow simulations are used to observe the behaviors which is common practiced in the industry. The OLGA-Rocx module and Tecplot AS were used throughout the project for simulations and observations with interested properties. The Grane oil field was used as the reference heavy oil reservoir. Modelling and simulation with OLGA-Rocx was briefly discussed before observing the simulation results. At the beginning, the selection of reservoir grid size in Rocx, in order to minimize the simulation time, is discussed with several models. With this simulations, it was noticed that the near-well grid size influence on the recovery. The number of grids can be reduced by partitioning the reservoir geometry such that the finer grids near the well and coarser grids away from the well. Other than the grid size, the simulation step size and the plotting variable selection also influence the simulation time significantly.

Secondly, the dependence of the reservoir size was investigated. Models were developed with different dimensions of reservoir. The biggest reservoir is twice larger as the smallest reservoir and other cases were selected between them. The simulation results showed the extracted amount of oil has a converging pattern with respect to the reservoir size. The water cone seems flat for bigger reservoirs while narrow coning is noticed for smaller cases. Therefore, the number of wells and the distance between wells are also critical factors in oil recovery. Cost estimation for well installation and the operation also needed to be given a complete solution for suggesting the number of wells for a specific reservoir.

The influence of the relative permeability is also observed with different permeability curves found in the literature. The simulations showed variations of in water breakthrough time, accumulated total liquid, accumulated oil and the possible extracted amount of oil. Most of the observed behaviors can be explained with the multiphase flow. The multiphase flow strongly depends on relative permeablities even for similar water cuts. The variation in water breakthrough times is a result of multiphase flow rate within the reservoir before the breakthrough. The flow rate variations in inflow can be described by multiphase flow behaviors in both the reservoir and the horizontal well. The results were shown that the minimum oil residual case always does not give the maximum recovery due to the flow characteristics inside the reservoir. Multiphase flow can turn into a single water phase flow after the oil residual limit specially near to the aquifer so that the water mobility is highly activated. The activated water can enter to the wellbore even though there is a large amount of oil remain in the reservoir.

Finally, simulations are carried out to investigate the behaviors over several controlling mechanisms. PID controller were used in every case while changing the control variables. The total flow rate, the water flow rate and the water cut were selected as control variables. Tuning PID controller is common in every case and a trial and error method was used for tuning. The total flow rate control action did not give any attractive features on recovery and also it causes to reduce oil flow rate even before the breakthrough. PID tuning becomes complex in water cut controlling and it takes a longer period to reach the set point. However, it gave better results when reducing the water cut in inflow. Altogether, water flow controlled method gave attractive solutions for most of the desired characteristics. Therefore, the water flow controlling technique was continued with the complex models.

5.1 Future works

Most of the simulations were carried out with the same ICD diameter. If the flow rate across the ICD lies in bottle neck range, the observed variations may not be accurate. Therefore, a study should be performed to eliminate the critical conditions of the operation. In all the cases, horizontal well is installed at the same elevation. The elevation changing could be done with simulations to extract more oil than the observed amounts. Furthermore, several wells can be installed along the Y-direction to observe saturation profile, if there are two pressure drops applying for a same point. During the reservoir size simulations, only the trends are discussed. Moreover using obtained trends, optimal number of wells for a specific reservoir volume can be found with more simulations. A deeper observation into the reservoir saturation profile is needed to explain the behavior of the multiphase flow within the reservoir. The influence of the relative permeability can be completely explained with the multiphase flow behavior. Most of the cases, it is observed that accumulated oil amount converge for a specific volume in each case. By simulating longer period recoverable amount of oil is also able to estimate. PID tuning is very important in controlling, more and more trial and error methods are needed to find robust parameters. The controllers other than PID could give better controlling solution for the process. Finally, the simulations throughout the report are performed for homogeneous reservoirs. However, complete homogeneous reservoirs are not available in practical world. Therefore, more realistic parameters should be used to obtain better validated results.

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Appendix 1: Project description

Telemark University College

Faculty of Technology

FMH606 Master's Thesis

Title: Near well simulations of heavy oil reservoir with water drive

TUC supervisor: Prof. Britt Halvorsen

External partner: InflowControl AS, Vidar Mathiesen (co-supervisor)

Task background:
A major challenge at the Norwegian Continental Shelf (NCS) and other oil fields in the world is the declining oil production and the relatively low recovery rate. Estimates show that although the oil is localized and mobile, about half of the oil is remaining in the reservoir after shut down. Heavy oil represents a massive world resource more than twice the size of global reserves of light or conventional oil, and it is focused a lot on developing technology to increase the oil recovery from heavy oil reservoirs. Water flooding and different types of enhanced oil recovery (EOR) methods are used for this purpose. A better understanding of the multiphase reservoir condition and the reservoir properties are therefore required.

Task description:

The project will focus on:

1. Literature study. Getting a fundamental understanding of the reservoir conditions when water flooding or different types of EOR are used.
2. Computational study of heavy oil production using water drive. Rocx in combination with OLGA will be used as Software.

Practical arrangements:
Necessary software will be provided by TUC.

Signatures:

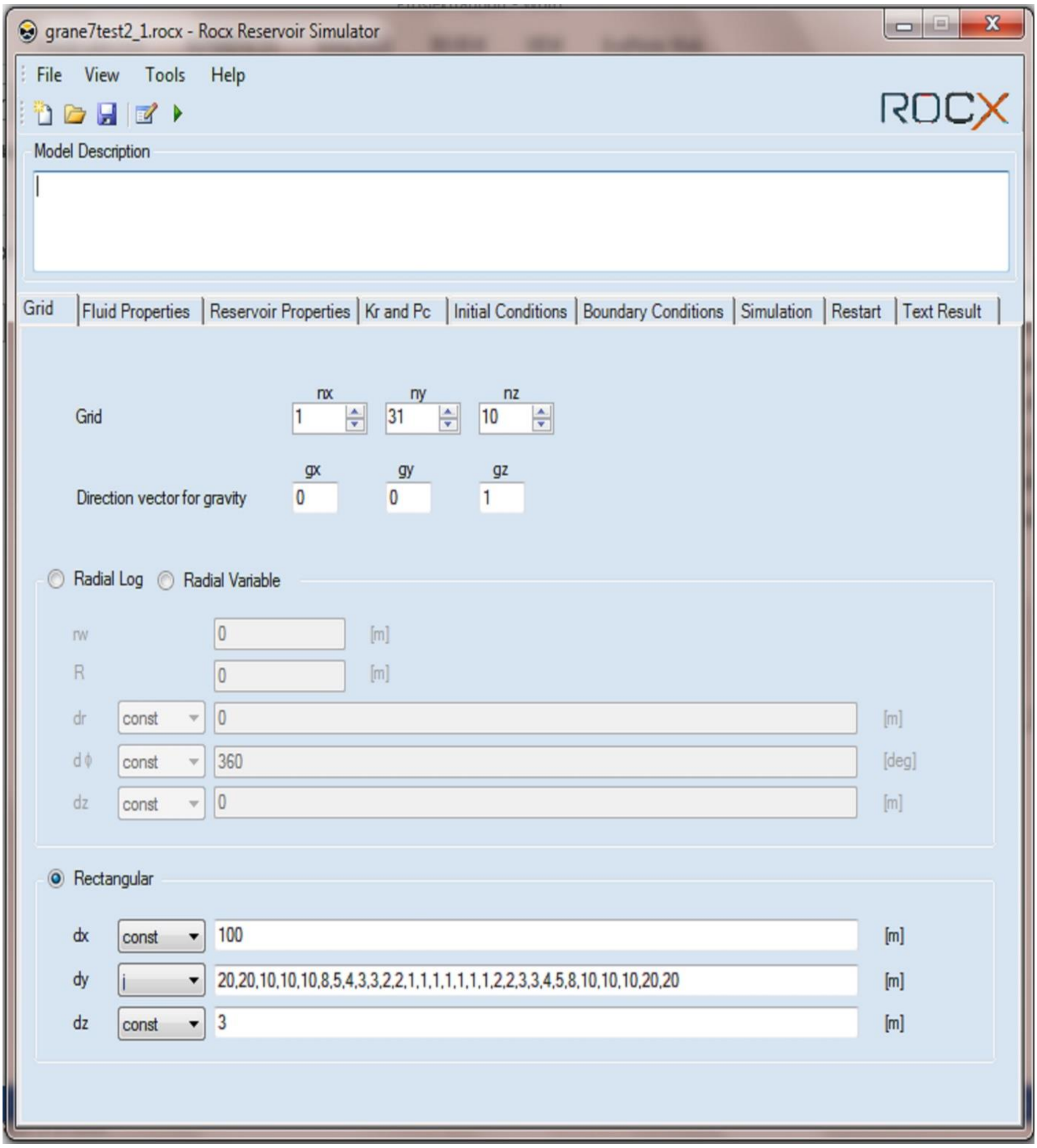
Student (date and signature):

Britt Halvorsen

Supervisor (date and signature):

Address: Kjølnes ring 56, NO-3918 Porsgrunn, Norway. **Phone:** 35 57 50 00. **Fax:** 35 55 75 47.

Appendix 2: Rocx interface



Appendix 3: Components and Model browser in OLGA