Emmanuel Oswald Anganisye

Well Placement Optimization Subject to Realistic Field Development Constraints: A Case Study of Olympus Field

Master's thesis in Petroleum Engineering
Supervisor: Jon Kleppe
September 2019

Master's thesis

NTNU
Norwegian University of Science and Technology
Faculty of Engineering
Department of Geoscience and Petroleum

NTNU
Norwegian University of
Science and Technology

Emmanuel Oswald Anganisye

Well Placement Optimization Subject to Realistic Field Development Constraints: A Case Study of Olympus Field

Master's thesis in Petroleum Engineering
Supervisor: Jon Kleppe
September 2019

Norwegian University of Science and Technology
Faculty of Engineering
Department of Geoscience and Petroleum

NTNU
Norwegian University of
Science and Technology

Emmanuel Oswald Anganisye

Well Placement Optimization Subject To Realistic Field Development Constraints: Case Study Olympus Field

Dar Es Salaam, Tanzania

September 6^{th}, 2019

Supervisor: **Jon Kleppe**
Co-supervisor: **Richard Rwechungura**
Co-supervisor: **Mathias Bellout**

NTNU
Norwegian University of Science and Technology

Abstract

Well placement is the key in field development. Wells provide the means through which fluids of interest (oil) for this can can be extracted from the reservoir. Wells are so expensive to drill and thus proper engineering judgment of where and when to drill has to engage an intensive study to come up with optimal well locations.

Reservoir simulations have to be done to come up with scenarios from which optimal well locations are obtained. In this study manual well placement was done using Eclipse 100 reservoir simulator and excel as the basis of the optimization to come up with optimal well locations taking into considerations realistic field development constraints.

The objective of the study was to place wells optimally and thus improve oil production in Olympus field. In achieving this goal re-allocations of available producers and injectors was done taking into consideration field development constraints such as inter-well distance, well perforations and well controls. Where for the re-allocated injectors oil production improvement was achieved by adjusting to distance between the injectors and producers and engaging perforations in bottom layers to enhance pressure maintenance and sweeping of oil to the producers. This strategy was employed to available injector 2, Injector 3, Injector 4 , and Injector 5. Of all the injectors it was observed that **injector 3** in olympus field improved the most cumulative oil production by **3,505,102.29 bbl** which is equivalent to **9%** recovery increment as compared to the base case .

Focusing on the producers partial perforations in areas of high saturations and considerations on the producer relative distance from the influence of the injector was observed to be the guiding factors in re allocating the producers. This strategy was done to available producer 7, producer 9 and Producer 11. Of all these producers it was observed that reallocation of an available **producer 9** improved most cumulative production of by **3,628,527.233 bbl** which is equivalent to **9%** increment recovery when compared to the base case.

Placement of new producers and injectors was also done, and it was observed that placing vertical producers in areas with oil saturation above 80%, pressure above 200 bars, inter well distance relative to avoid stealing of oil from nearby wells also avoiding water influx to the producers. This was the frame of the guidance in placing the new producers. There were three new producer cases and two new injector cases which were presented in this study. There was new producer 1 , producer 2, producer 3. Of all these producers it was observed that **producer 2** gave the highest incremental cumulative production of **18,881,335.35 bbl** which is equivalent to **47%** increment recovery in production with NPV increment of **734 million** USD for the 20 years of oil production compared to the base case. Also for the new injector cases (Injector 1 and Injector 2) it was observed that **New injector 1** gave the highest incremental cumulative production of **2,206,703.10 bbl** which is equivalent to **5%** recovery increment in production with NPV increment of **145 million** USD for the 20 years of oil production compared to the base case.

Acknowledgment

I would like to present my sincere gratitude to Almighty God for the gift of life. He has assured good healthy throughout the entire time of my thesis and thus the progress of my work went as smooth as possible.

Also, I would like to present my gratitude to Equinor for an amazing ANTHEI project which provided a platform to pursue my masters at NTNU. It has been my deep desire to pursue Masters in Petroleum Engineering and Equinor have realized it.

Furthermore,I would like to appreciate my supervisors Prof. Jon Kleppe (NTNU), Prof. Richard Rwechungura (NTNU) and Prof Mathias Bellout (NTNU) for their sincere support through out this work. Without their dedication, enlightenment and close guidance this thesis could not be accomplished successfully.

Also, I would like to appreciate Dr.Itika (UDSM) for his daily guidance during studies and Mr. Anthony Maswi (UDSM) for his advice on report writing and simulations. Lastly but not least i would like to extend my gratitude to all who in one way or the other supported this work to its accomplishment, space may not be sufficient to mention all by names.

Contents

List of Tables

List of Figures

Nomenclature

PDO	Plan for Development and Operations
FPSO	Floating Production Storage and Offloading
NTNU	Norwegian University of Science and Technology
ANTHEI	Angola and Tanzania Higher Education Initiative
OIIP	Oil Initially In place
TVD	True Vertical Depth
UDSM	University Of Dar Es Salaam
FOPR	Feld Oil Production Rate
FOPT	Field Oil Production Total
FWCT	Field Water cut
FPR	Field Pressure
NPV	Net Present Value
FPR	Field Pressure.
GPS	General Purpose Search.
GA	Genetic Algorithms.
NTNU	Norwegian University of Science and Technology.
WOW	Wait on Weather.
BHA	Bottom Hole Assembly .
CAPEX	Capital Expenditure
DRILLEX	Drilling Expenditure

Chapter 1

Introduction

1.1 Demand for Hydrocarbons

According to the International Energy Outlook 2006, the coming decades there will be a significant growth in energy consumption as a result of robust economic see **figure 1.1**. While renewable energy sources become more economically competitive with fossil fuels (i.e. oil, natural gas, and coal), oil in particular will remain the dominant energy source until 2030. (Pérez-Lombard et al., 2008).

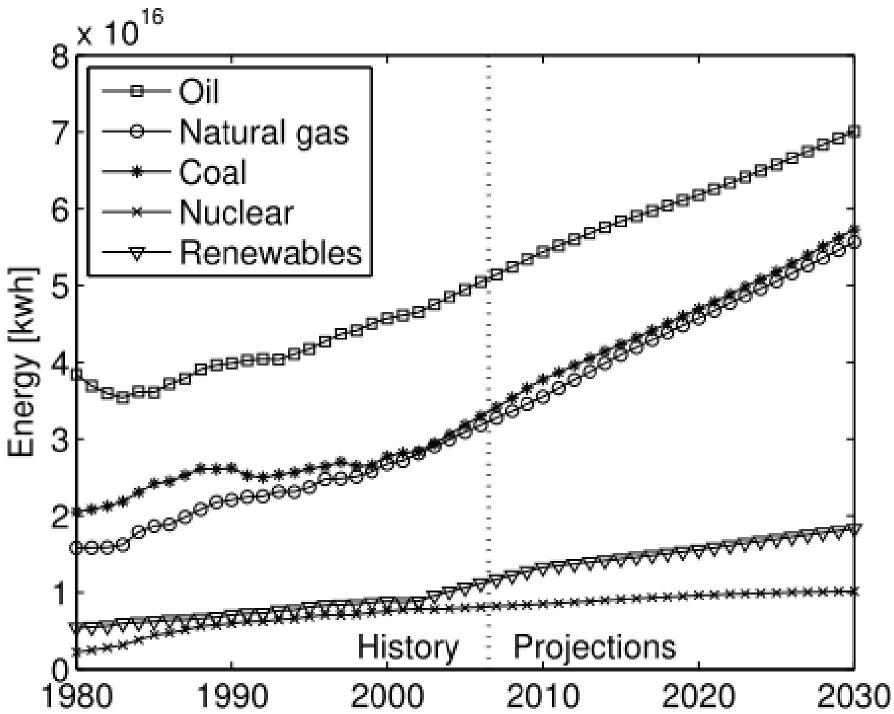

Figure 1.1: World marketed energy use by energy type, 1980-2030(Pérez-Lombard et al., 2008)

1.2 Stages in an Oil and Gas Field field

Origin of oil and gas

Oil and gas are trapped in the reservoir rocks buried underground on shore or offshore. Analysis of images of the earth's surface produced by seismic is done to determine allocation of the hydrocarbons accumulation. Then a geological model is created whereby potential prospects are identified as it can be observed in **figure 1.2.**

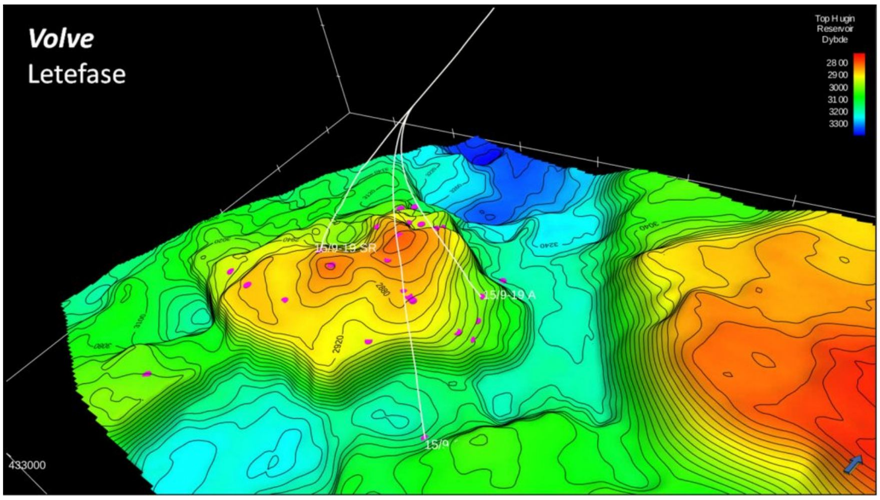

Figure 1.2: Volve field 3D geological model
(Equinor, 2018)

Exploration phase

Finding oil and gas reservoirs is a major challenge, since they can be located at great depths (e.g. several kilometers) and in very inaccessible areas (e.g. the Arc- tic). By sending sound waves through the ground and measuring how long they take to bounce back off the different layers of rock, geo-scientists create 3D maps of the subsurface (i.e. seismic imaging). Ultimately exploration wells are drilled to check if the identified prospects indeed contain hydrocarbons or not (Zandvliet, 2008).

Once the discovery is confirmed 3D numerical simulation models are built with the aim of estimating the initial volume of oil and gas in the reservoir and to simulate the reservoir fluid flow behaviour and optimize the field development scenario such as number, type and location of wells and level of field production. To acquire more information about the extent of the reservoir appraisal wells are drilled. After this an economic assessment is performed taking into account revenue according to production forecast and the estimated development costs. If the economic criteria set is achieved then the field is developed and produced.

Development phase

Next step is field development which establishes key issues such as the number of wells to be drilled to meet production targets, the recovery techniques to be employed to extract fluids from the reservoir, types and cost of installations such as platforms depending on the location of the project, separation systems of gas and fluids. Treatments systems needed to preserve the environment.

Production phase

Then after is field production. Normally field are produced in a duration between 15 to 30 years and may be extended up to 50 years or more for giant fields. During primary recovery only a small percentage of the initial hydrocarbons in place are usually produced. Referred to as the recovery factor, this is only around 10% for oil reservoirs. Because of production, however, the reservoir pressure declines and it may become necessary to inject fluids e.g water or gas through injection wells to 'flood' the reservoir by driving the hydrocarbons to the production wells. The life time of the reservoir comprise of a phase of production increase, a stabilization phase mainly called plateau, Injection phase with the aim of assisting the hydrocarbon recovery and thus maintain a satisfactory and projected volumes of hydrocarbons and finally is the depletion phase whereby the production decreases progressively. This can be clearly observed in **figure 1.3**. This study will focus on how to best select the optimum well location which is part of field development (Zandvliet, 2008).

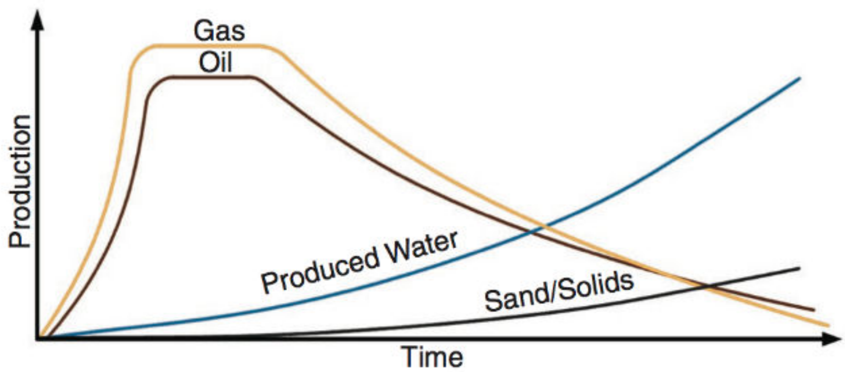

Figure 1.3: Common field production plan for reservoir fluids(Griffin & Teece, 2016)

Field development planning
When developing a field, the goal is often to maximize an economic criterion (e.g.oil and gas revenues minus field development costs).The choices that have to be made include the number, type, and location of wells, the type of surface facilities and the required infrastructure. These choices are referred to as inputs, and their effect can be measured through the produced volumetric flow rates of oil and gas and the pressures in wells, referred to as outputs. This is depicted as an open-loop process in **figure 1.4.**

Figure 1.4: Field development planning(Zandvliet, 2008)

Numerical reservoir simulation models, or reservoir models for short, often play an important role in field development planning. These models seek to describe the effect of decisions on hydrocarbon production and are often based on physical conservation laws. The time-varying (dynamic) properties in reservoir models are generally the fluid pressures and saturations, and are referred to as states. The remaining fluid properties (e.g. viscosity or density, which can be functions of the state) and geological properties (e.g. permeability or porosity) are generally considered to be time-invariant (static), and are referred to as parameters.

1.2.1 Problem Statement

Olympus field aim at improving its cumulative oil production. Methods such as pressure maintenance, placing new wells , rescheduling existing wells can be implemented. In the context of this study well placement will be implemented. Well placement is one of the key tasks in reservoir Engineering. Wells serves as flow paths of hydrocarbons and fluids from and to subsurface respectively. Optimization of well location is important in decision making and thus proper engineering judgment is required during the process. The challenge is that this puzzle incorporates aspects such as geology, flow complexities and reservoir heterogeneity in general. Thus optimum well placement subject to realistic field development constraints is a complex task and proper study of the model need to be done before implementing.

1.2.2 Objectives

Main Objective

The primary objective in well placement optimization basing on this study is to maximize cumulative Oil production.

Specific Tasks

In order to achieve the main objective the following specific tasks were done

(i) Re-allocations of producers and injectors to improve oil production.

(ii) New optimal wells Placement to improve Olympus Oil production.

1.2.3 Scope of the study

This study is based on simulations of well placements on Olympus field. Well location was simulated focusing on realistic field development such as well location, inter well distance, well depth and orientations with reference to base case model as observed on **figure 1.5**. Selection of the optimal well placement was based on improvement in cumulative Oil production.

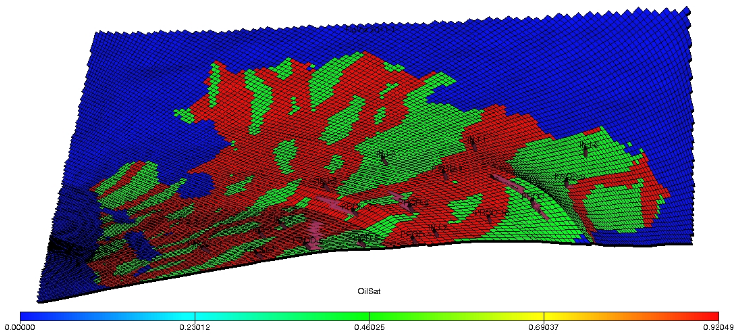

Figure 1.5: Olympus full field

Chapter 2

The Olympus field

2.1 Introduction

A synthetic reservoir model, OLYMPUS, inspired by a virgin oil field in the North Sea, was developed for the purpose of a benchmark study for field development optimization. The field is 9 km by 3 km and is bounded on one side by a boundary fault. The reservoir is 50m thick for which 16 layers have been modeled. In addition to the boundary fault 6 minor faults are present in the reservoir. The reservoir consists of two zones, separated by an impermeable shale layer. The top reservoir zone contains fluvial channel sands embedded in floodplain shales. The bottom reservoir zone consists of alternating layers of coarse, medium and fine sands with a predetermined dip similar to a clinoformal stratigraphic sequence. (Fonseca et al., 2017)

2.2 Model Dimensions

The model consists of grid cells of approximately 50 m x 50 m x 3 m each. No upscaling procedure has been performed; all the geological and petro-physical properties have been modeled on this same grid. The model has approximately 341,728 grid cells of which 192,750 are active. The inactive cells are mostly associated with the single-layer shale barrier in the model.

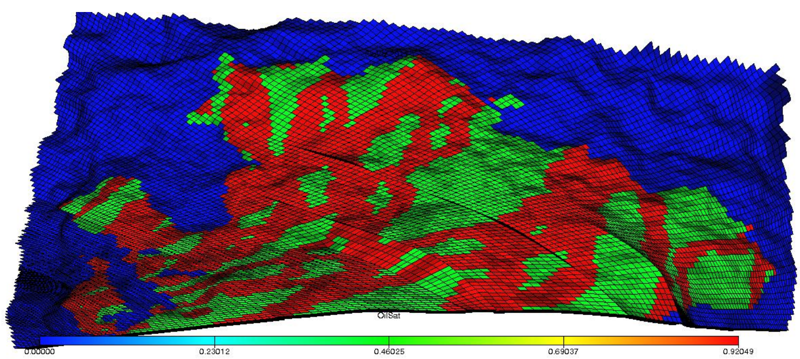

Figure 2.1: Olympus model

2.3 Facies and Property Modelling

4 different facies types were modeled in the different layers. An overview of the different facies types in the different zones is provided in **Table 2.1** Geological properties such as porosity, permeability and Net-To-Gross (NTG) were generated using standard geostatistical techniques for the different facies types. No porosity-permeability relationship was used, based on the assumption that insufficient data is available at the early stage of field development.

Table 2.1: Summary of facies properties.

Facies Type	Zones Presesnt	Porosity Ranges	Permiability Ranges	Net to gross
Channel Sand	top	0.2-0.35	400-1000 mD	0.1-1
Shale	Top and Barrier	0.03	1mD	0
Course sand	Bottom	0.2-0.3	150-400mD	0.7-0.9
Sand	Bottom	0.1-0.2	75-150mD	0.75-0.95
Fine Sand	Bottom	0.05-0.1	10-50mD	0.9-1

The permeability values in the X and Y directions are identical. The permeability in the Z direction is 10% of the permeability in the X direction.

From the available exploration well logs the depth of the Oil-Water Contact (OWC) was determined to be at 2090 m, with an in-situ hydrostatic pressure of 206 Bar. Each facies has its own relative permeability curve.

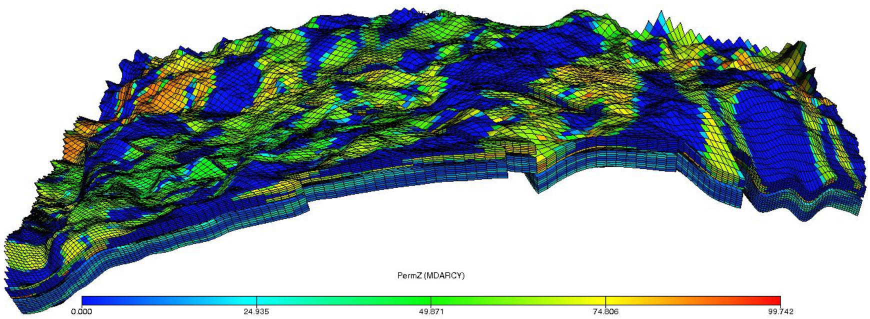

Figure 2.2: Olympus model showing layers

Chapter 3

Well Placement

3.1 Well

A well is a boring in the Earth that is designed to bring petroleum oil hydrocarbons to the surface or send gas or water to subsurface. During oil production usually some natural gas is released along with the oil.

There are a number of different types of wells that can be drilled, and these are described in this study. A particular well type may be best suited or most economic in the efforts to drain a specific configuration of hydrocarbons, **figure 3.1** shows an example of such wells. Various drilling strategies can be adopted to place wells in specific patterns with the aim of optimizing production from a field.

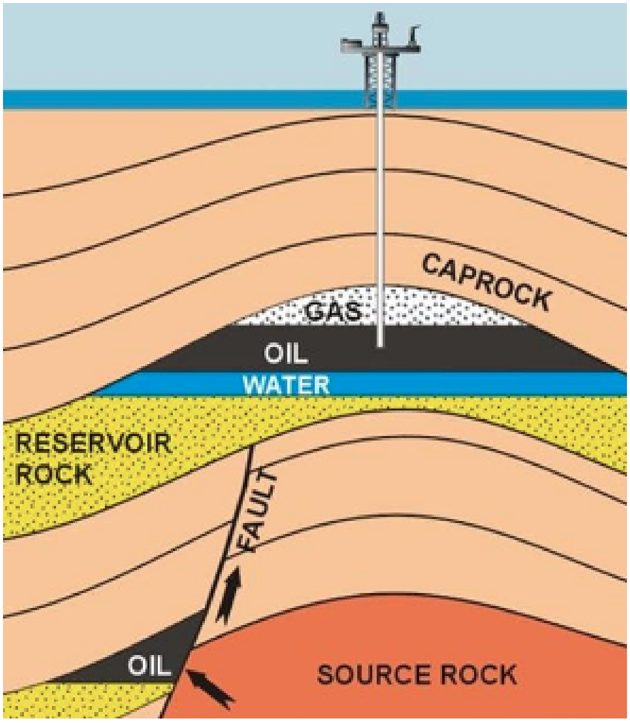

Figure 3.1: Vertical Well (Salami, 2014)

3.1.1 Conventional Wells

In the early days of the oil industry, drilling wells was a simple operation. A well location was picked at top reservoir, and the well was drilled directly down to the target as a vertical well,this can be observed on **figure 3.2**. These are what are termed as conventional wells.Then drilling became more sophisticated when the art of deviating wells was perfected. Here, the drill bit is deflected at an angle from the vertical toward a specific target. Deviated wells are commonly drilled from fixed drilling locations such as an offshore platform (Shepherd, 2009).

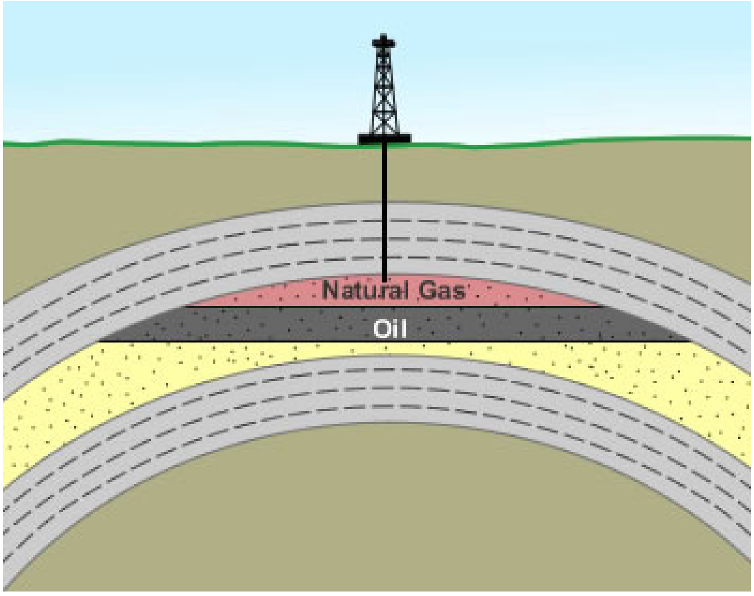

Figure 3.2: conventional well (2b1consulting, 2012)

3.1.2 Sidetrack Wells

This is where a well has already been drilled or partly drilled and there is a need to exit out of one side of the well to a different target. A sidetrack may be required if there is an object stuck in the original hole, which cannot be fished out. In producing fields, an existing well may be sidetracked if there is no further use for that well example when the oil well has watered out. A window will be cut in the casing of the original well by a special milling assembly, and drilling will then proceed out of the window toward a new target (Shepherd, 2009). A typical example of side tracked well is observed on **figure 3.3**

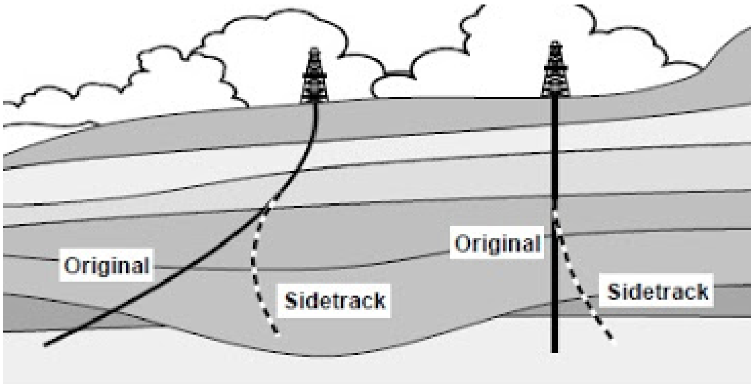

Figure 3.3: sidetrack well (Engineering, 2016)

3.1.3 Horizontal Wells

Horizontal wells are the ones where the reservoir section is drilled at a high angle, typically with a trajectory to keep the well within a specific reservoir interval or hydrocarbon zone. In a strict sense, these wells are rarely perfectly horizontal, but they tend to be near horizontal mostly, generally at an angle greater than 80 degrees from vertical (Shepherd, 2009).

Horizontal wells are drilled in a specific configuration. The tangent section of the well is drilled along a deviated well path to just above the reservoir section, to what is known as the kick off point. From the kick off point, the well is drilled at an increasingly higher angle, arcing around toward an angle close to horizontal. The point at which the well enters the reservoir is called the entry point. From there on, the well continues at a near-horizontal orientation with the intention of keeping it substantially within the reservoir target until the desired length of horizontal penetration is reached. A typical example of the horizontal well layout can be seen on **figure 3.4**. A horizontal well can be drilled geometrically where there is a reasonable confidence in the expected reservoir geometry. The targets are defined at the entry point and at total depth, and the well is drilled according to a set geometrical plan between them (Salami, 2014).

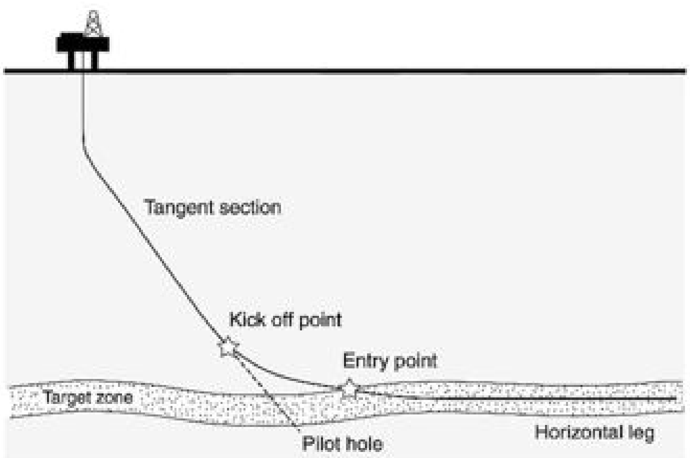

Figure 3.4: Horizontal well (Shepherd, 2009)

3.1.4 Multilateral Wells

Multilateral wells are the ones that have more than one branch radiating from the main borehole. Each branch can drain a separate part of the reservoir and produce into a common single well bore. The advantage of multilateral wells is that, for the same number of drainage points, they can be somewhat cheaper than developing new independent wells especially if separate wells had been drilled (Shepherd, 2009). **Figure 3.5** shows an example of multilateral well.

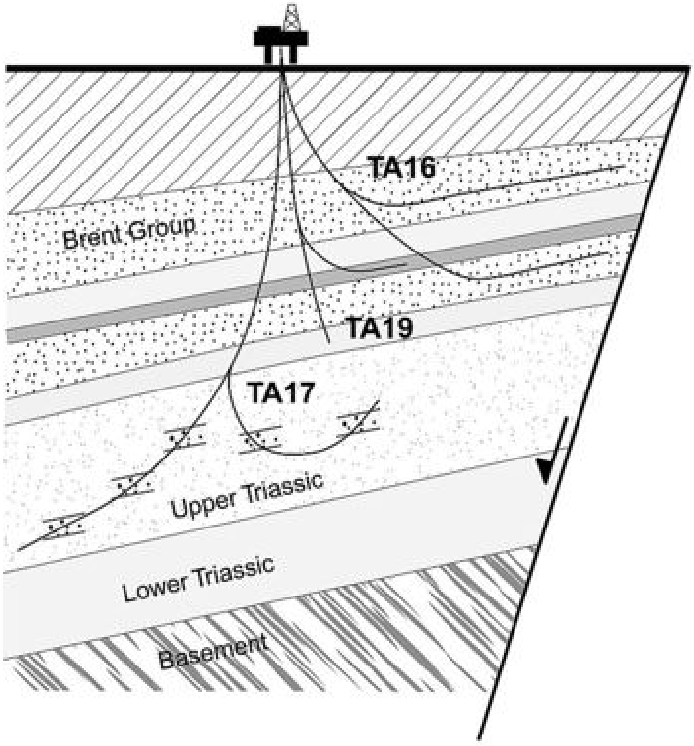

Figure 3.5: Multilateral well (Shepherd, 2009)

3.1.5 Well Placement

For decades, petroleum engineers have played a major role in oil and gas development activities. Their expert knowledge is considered indispensable when it comes to making the most important development decisions, which predetermine ultimate oil and gas recovery and thereby have a considerable economic impact. Among others well number and well placement are examples of such decisions. In the simplest cases, well placement patterns can be chosen quite intuitively. However, optimization of well placement turns into a non-trivial problem when it comes to reservoirs with complex geometry and heterogeneous property distribution (Zhang et al., 2010a). **Figure 3.6** indicates an example of several well placements which can be done on a particular model.

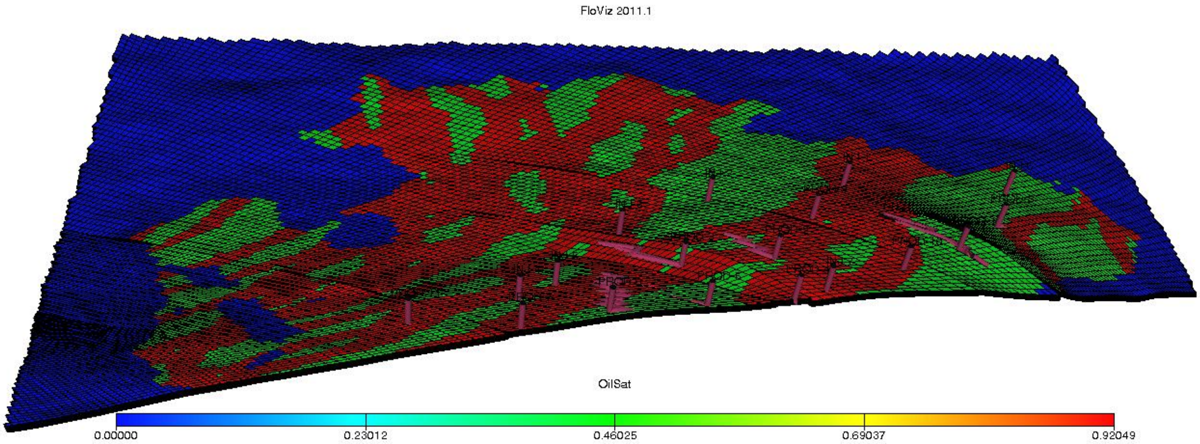

Figure 3.6: Optimal well placement locations sample olympus field

From a mathematical standpoint, well placement optimization is considered to be a challenging problem for at least three reasons.

Firstly, the reservoir system is not very well defined at the stage of field development planning. Indeed, the true, complete and deterministic information about the reservoir is never available in advance prior to massive development drilling. Therefore, this optimization problem is usually being solved using a reservoir model constructed with the limited amount of information available and based on one of many possible Geo-statistical realizations.

Secondly, reservoir heterogeneity along with the complexity of its geometry dramatically increase the number of optimization variables and complicate the search.

Thirdly, the objective function for such systems becomes non-smooth and multi-modal. Most known optimization methods would struggle to find the global optimum. For these reasons, the best solution to well optimization problem can be achieved when mathematical and reservoir engineering knowledge is combined together.

3.2 Well Placement Optimization Methods

There is a growing interest in application of optimization techniques to the well placement problem in recent years. These techniques are introduced into well placement optimization work in order to improve current engineering solutions and aid reservoir engineers in the decision-making process. There are different optimization algorithms. Each algorithm has unique properties and limitations, which make it useful for solving particular optimization tasks. Most of these optimization algorithms are classified as either gradient-based or derivative-free.

3.2.1 Gradient Based Optimization

Gradient-based optimization methods take advantage of gradient information of an objective function in order to determine the optimal search direction (steepest descent). Such methods are particularly efficient at finding local minima for high-dimensional convex problems. However, most gradient optimizers have problems dealing with noisy and discontinuous functions. Moreover, they are not designed to handle multi-modal or discrete problems, such as the case with the well placement problem (Zakharov, 2016).

Gradient-based methods are unlikely to find a global optimum of such a function, because they are not designed to handle multi-modal problems. Unlike derivative-free methods, gradient-based techniques have no way of escaping local optima as can be observed on **figure 3.7.** Besides, gradients for complex objective functions may not always be readily available and or may be difficult to compute. Gradients provide explicit information about the location of a local optimum, which is why it is considered good practice to utilize such information whenever possible(Zakharov, 2016).

Such explicit knowledge is the reason why gradient-based methods can outperform derivative-free methods in terms of computational efficiency. Clearly, gradient-based methods are not well suited for solving the well placement optimization problem. Firstly, the objective function for such problems is highly non-smooth and multi-modal. Secondly, well placement optimization is a discrete problem, which makes it impossible to compute gradients. Finally, a reservoir simulator is predominantly treated as a black box. Therefore, extraction of gradients is a simulator invasive process (Bellout et al., 2012).

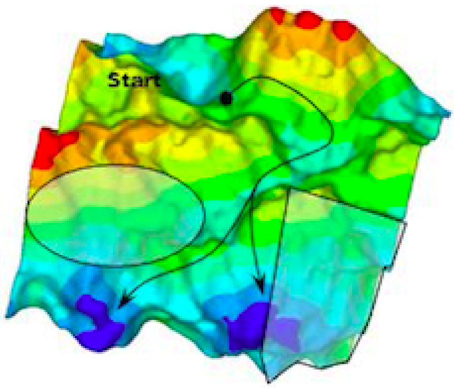

Figure 3.7: Gradient based optimization approach sample (Zakharov, 2016)

3.2.2 Derivative free methods

Derivative-free methods do not suffer from the same problems, which is why they are often preferred to gradient-based methods for solving the well placement optimization problem. Derivative-free (non-invasive black box) optimization has lately received considerable attention within the optimization community Unlike gradient-based methods, derivative-free techniques rely solely on the values of the objective function to guide the search. Derivative-free algorithms employ either a deterministic or a heuristic search strategy. In most cases, it means deploying a population of agents that sample the objective function at different locations. The agents share best-known objective function values amongst themselves through broadcasting. The **figure 3.8** indicates an example of the model whereby derivative free methods can optimize efficiently (Kramer et al., 2011).

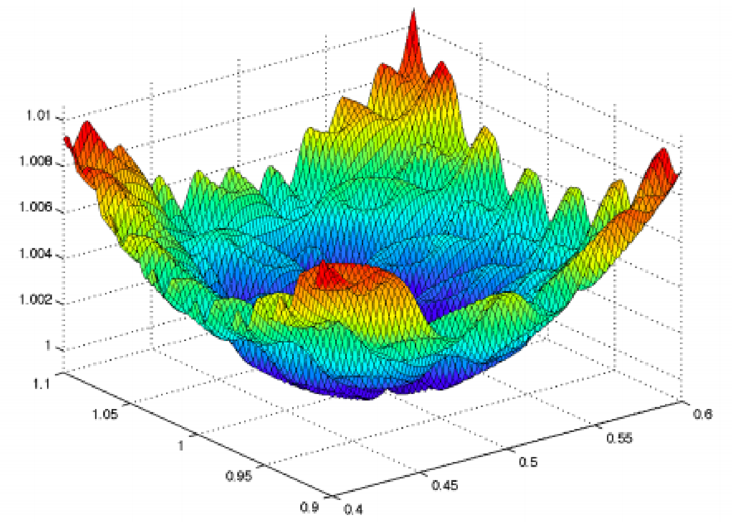

Figure 3.8: Derivative free model nature (Kramer et al., 2011)

Besides, the current numerical optimization methods can easily lead to overlooked opportunities and sub-optimal well placement which, in turn, can have a negative economic impact on a project in the long-term perspective. This means to come up with feasible results several simulations need to be conducted.

3.3 Research works relating to well placement optimization

(Bittencourt et al., 1997) developed a hybrid binary Genetic Algorithm (bGA), where they combined GAs with the polytope method to benefit from the best features of each method. The polytope method searches for the optimum solution by constructing a simplex with a number of vertices equal to one more than the dimensionality of the search space. Each of the vertices is evaluated and the method guides the search by reflecting the worst point around the centroid of the remaining nodes. This work tried to optimize the placement of vertical or horizontal wells in a real faulted reservoir. The algorithm sought to optimize three parameters for each well: well location, well type (vertical or horizontal), and horizontal well orientation. The study also integrated economic analysis and some practical design considerations in the optimization algorithm.

(Yildiz, 2013) optimized the placement of vertical wells using a GA without any hybridization. They tried to discern the effects of internal GA parameters, such as mutation probability, population size, initial seed, and the use of elitism. Their tests were applied on two synthetic rectangular models (a layer cake model and a highly heterogeneous one). For the tested cases, they found that the ideal mutation rate should be variable with generation. Using random seeds for their problem showed little sensitivity while the use of elitism showed significant improvement. The population size study they performed suggested that an appropriate size was equal to the number of the variables in the problem. When they used very big populations, solution convergence was deterred as more poor quality chromosomes had to be evaluated. They also drew attention to issues like absolute convergence and stability of the optimization algorithm.

(Zhang et al., 2010b) and (Yildiz, 2013) proposed different approaches for well placement optimization using gradient-based optimization techniques by representing the objective function in a functional form. They then calculated the gradient of this function and used a steepest ascent direction to guide the search. For the examples they considered, these methods seemed promising due to their efficiency in terms of number of simulation runs. The techniques were only applied to vertical wells and they expected more difficulty in applying them to problems with arbitrary well trajectories in complex model grids. Other issues they faced with these techniques include discontinuities in the objective function and convergence to local optima.

(Abukhamsin, 2009) compared the performance of several gradient-free methods like the Genetic Algorithm (GA), direct search methods, and combinations of the two (GAs). A subset of direct search methods, the hill climber. He used these algorithms to optimize control variables with multiple nonlinear constraints on a channelized synthetic 2D model. He also applied penalty functions to account for constraint violations. He concluded that, for problems considered, General Pattern Search (GPS) with penalty functions perform the best followed by the combined GA and GPS algorithm.

(Emerick et al., 2009) implemented an optimization tool based on GA to optimize the number, location, and trajectory of a number of deviated producer and injector wells.They proposed a method to handled unfeasible solutions by creating a reference population consisting only of fully feasible solutions. Any unfeasible solution encountered in the optimization was repaired by applying crossover between it and an individual from the reference population until a new feasible solution was obtained. They applied this technique in three full-field reservoir models based on real cases using two different strategies: the first one with the whole initial population defined randomly; and the second one by including an engineer's proposal in the initial population. Better results were observed in the second strategy and solutions were more intuitive for the tested case. They also suggested and tested an alternative optimization approach by only optimizing well type and number of an engineer's proposal. Although final results were not as good as the full optimization, they concluded that this approach can be used when there is time limitation to perform the full optimization in complex cases.

(Nogueira et al., 2009) proposed a methodology to optimize the number and placement of wells in a field through two optimization stages. The procedure started by creating reservoir sub-regions equal to the maximum number of wells. Then, a search for the optimum location of a single well was performed in each sector. The second stage aimed to optimize well quantity through sequential exclusion of wells obtained from the first stage. After a new optimum number of wells is reached, the first stage is performed again until no improvement in the objective function is observed. This strategy showed efficiency when tested on a heterogeneous synthetic model with light oil. They optimized both vertical and horizontal wells in separate studies. They also concluded that the proposed modularization of the problem speeds up the optimization process for their problem of consideration.

3.3.1 Conventional Well Placement Method

The conventional well placement method employs a manual trial and error process to find new well locations. This is done by identifying potential areas in the model by considering basic properties such as permeability, porosity, saturation, reservoir pressure and faults. Perforations is thus done into such zones to deplete hydrocarbons and improve production, similarly perforations are utilized for pressure maintenance when an injector is placed

When Using Eclipse 100 simulator, well name, position of the wellhead, its bottom hole reference depth and other specification data such as the group are set on the WELSPECS. Position and properties of one or more well completions such as well bore diameter, well status whether open or closed, perforation intervals are then Specified on COMPDAT section. Then well control data such as lower bottom hole pressure are specified on the WNCONPROD while injection types and rates are specified on the WNCONINJE. An include file containing prediction duration of the model is also modified in the given model.

In practice different simulation cases are developed. All developed cases are studied in comparison to the base case and the case giving optimal production is taken and presented for further economical studies and sensitivity analysis. Manual well placement is a time consuming process especially when the field is large. This is because several reservoir simulations are required to come up with the optimal placement.

3.4 Reservoir Simulation

Reservoir Simulation is the major part of a reservoir engineering tasks. Generally models of thousands of and sometimes hundreds of thousands grid blocks are created. Each grid block has its own properties such as pressure, porosities, permeabilities, faults and transmissibilities to mention a few. Utilizing these grid blocks numerical simulations are run.

Running simulations its a time consuming procedure depending on the size of the model in question. Generally initial models have quite considerable uncertainties and thus modification of the model properties are made to make the model reflect the reality behavior of the field.

Different types of reservoir simulators exists. Often the reservoir fluid are represented in simplified manner, by the black-oil model. Fluid phases are described in three phases, oil, water and gas. Fluid functions, depending on pressure and or saturation. Another fluid representation is compositional, where every component have its own set of properties. A set of analytical flow equations and definitions of the fluids are by discretization and approximations defined numerically.

In this study well placement procedure is utilized on ECLIPSE 100 simulator. ECLIPSE 100 is a black oil simulator, fully implicit, three phase and three dimensional. It is a black oil simulator because it assumes that oil and gas are two components only and that the compositions are constant with pressure and time. During simulation time variant and time invariant properties such as porosity ,permeability, oil saturation, faults were considered in the methodology of the study.

3.5 Black Oil Formulation

Petroleum reservoirs always contain both hydrocarbons and water. The former consists of many chemical components which, theoretically, should each be considered individually in the modeling process. Computationally, however, this is too demanding. Moreover, reservoir engineers are often mainly interested in predictions of future hydrocarbon production. Most reservoir models are therefore based on a so-called black oil formulation, which only considers three phases: oil, water and gas. (Zandvliet, 2008)

In this study simplifications are made by considering only oil and water and ignoring several important physical aspects such as gravity, capillary pressures and the presence of an aquifer.

3.6 Derivation of PDE's

The mass balance for oil (o) and water (w) are,

$$\frac{\partial}{\partial t}(\phi \rho_i S_i) = -\nabla.(\rho_i U_i) + q_i \qquad i \in (o, w) \tag{3.1}$$

where t is time, ∇ the divergence operator, ϕ the porosity, ρ i the density of the phase i, U_i the superficial velocity, and S_i the saturation. It is assumed that there is no flow across the boundaries of the reservoir geometry over which this equation is defined, other than through the source/sink terms q_o and q_w (i.e. so-called Neumann boundary conditions).

Conservation of momentum is governed by the Navier-Stokes equations, but is normally simplified for low velocity flow through porous media to be described by the semi-empirical Darcy's equation

$$U_i = -k\frac{k_{ri}}{\mu_i}\nabla P_i, \qquad i \in (o, w) \tag{3.2}$$

where p_i is the pressure of phase i, ∇ the gradient operator, k the permeability,k_{ri} the relative permeability, and μ_i the viscosity of phase i. The relative permeabilities are generally highly dependent on the water saturation S_w in that they can vary between 0 and a value smaller or equal to 1, and thus form a major source of nonlinearity.

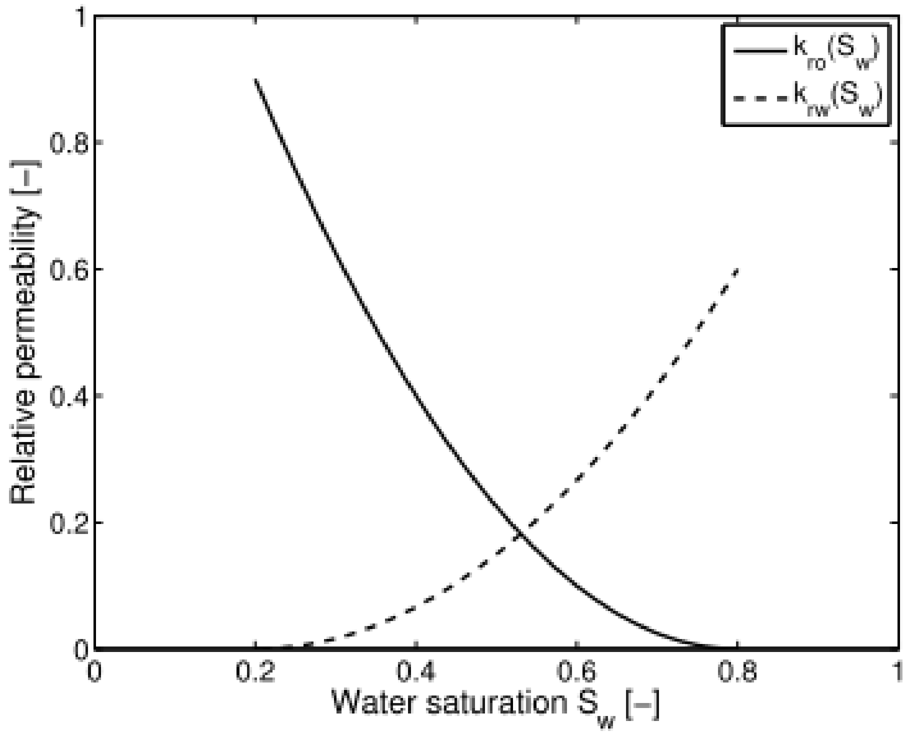

Figure 3.9: Relative Permeability curve

Substituting 3.2 into 3.1 leads to two flow equations with four dynamic unknowns: p_o , p_w , S_o and S_w . Two additional equations are required to complete the system description. The first is the closure equation requiring that the sum of the phase saturations equals one

$$S_o + S_w = 1 \tag{3.3}$$

Secondly, the difference between the individual phase pressures is given by the capillary pressure, which is assumed to be a function of water saturation. As mentioned earlier, however, we will ignore these capillary effects, and can there- fore write

$$P_w = P_o \tag{3.4}$$

Common practice in reservoir simulation is to substitute 3.3 and 3.4 into the flow equations by taking the oil pressure and water saturation (for notational convenience now symbolized by p and S as state variables, leading to the following partial differential equations (PDE's)

$$\frac{\partial}{\partial_t}(\phi\rho_{o(1-S)}) = \nabla.(k\frac{k_{ro}}{\mu_o}\rho_o\nabla_p) + q_o \tag{3.5}$$

$$\frac{\partial}{\partial_t}(\phi\rho_w S) = \nabla.(k\frac{k_{rw}}{\mu_w}\rho_w\nabla_p) + q_w \tag{3.6}$$

The variables ϕ, k, μ_i and ρ_i are, generally speaking, dependent on pressure. How- ever, for simplicity we assume the pressure dependency of ϕ, k and μ_i to be so small that it can be ignored.

3.7 Uncertanity in Reservoir Models

Model structure

Many simplifying assumptions have been made in deriving the model structure. The black oil formulation and semi-empirical Darcy's Law, for example, are only approximations of the true physics dictating multi-phase flow, as is the spatial discretization of the reservoir (for a large reservoir the grid block dimensions can be 100m $\times$ 100m $\times$ 10m). Fore the case of Olympus the dimensions are 50m x 50m x3m Furthermore, the reservoir geometry (e.g. the no-flow boundary) is also not exactly known.

Parameters

The fluid properties (e.g. relative permeability curves k_{rw} and k_{ro}) are determined by performing numerous tests on rock and fluids samples taken from wells. Even so, they are still only approximations as it is difficult to relate fluid properties on a micro-scale to properties on a grid-block size scale. The geological properties are also very uncertain due to the limited number of wells from which core samples can be taken, and the limited capacity of seismic experiments to distinguish between the different layers of the subsurface.

Initial Conditions

The initial conditions (e.g. the initial pressures and initial contact depths be- tween the different phases, which are translated into grid block saturations) are uncertain, again because of the limited number of wells from which measurements can be taken and because of capillary pressure effects. Note the contact depths are particular important, as these determine how much oil and gas is initially in place.

Disturbances
In some reservoirs there can be large disturbances affecting such as the presence of an active aquifer, that are only known to a limited extent. While the effect of these disturbances is not always undesirable (e.g. an active aquifer will slow down undesired pressure decline), they can have a significant impact on predictions.

3.8 Limitations in reservoir Models

Multiple models can be used to make predictions of future production, and the spread in these predictions together with their probabilities can be used to assess the impact of model uncertainty. Unfortunately, the spread can be very large, and this forms a major limitation in using reservoir models to make field development decisions. Furthermore, a large spread will obviously worry oil companies, as it can imply significant financial risk in developing a particular field.

Despite their limited reliability, reservoir models are a widely used tool for field development planning. Some of the simulators are commercially available (e.g. Schlumberger's Eclipse), and others proprietary (e.g. Shell's MoReS). The simulation results considered in this thesis have been obtained by using Schlumberger's Eclipse 100.

Chapter 4

Methodology

4.1 Model Initialization

To initialize a reservoir simulation model, the initial oil, gas and water pressure distribution and initial saturations must be defined in the reservoir model. The initialization of the reservoir simulation models is the process where the reservoir simulation model is reviewed to make sure that all input data and volumetrics are consistent. the current model is running from 2016 to 2036, with bottom hole pressure acting as the boundary condition.

It was observed that the field pressure dropped on the early days because a lot of all wells start producing at that time but pressure maintenance through injectors improves pressure through the injectors as can be observed on **figure 4.1**. Production rate in the field has demonstrated short duration of plateau as it can be observed on **figure 4.2**, with the producers and the injectors in question there has been an increase in cumulative oil production as it can be observed on **figure 4.3**. **Figure 4.4** shows oil in place draining due to oil production and finally since the producer drain fluids including water, it can be observed that cumulative oil production increases as it can be observed on **figure 4.5** .

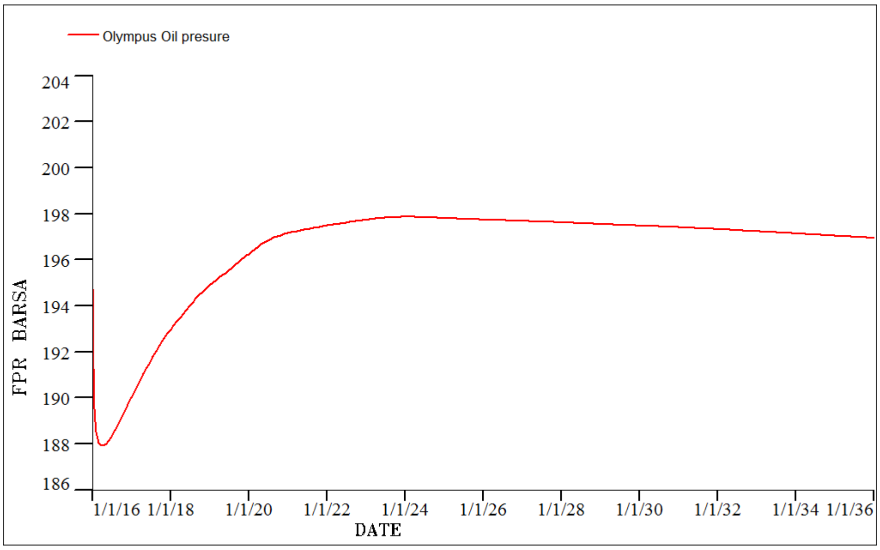

Figure 4.1: Olympus field pressure

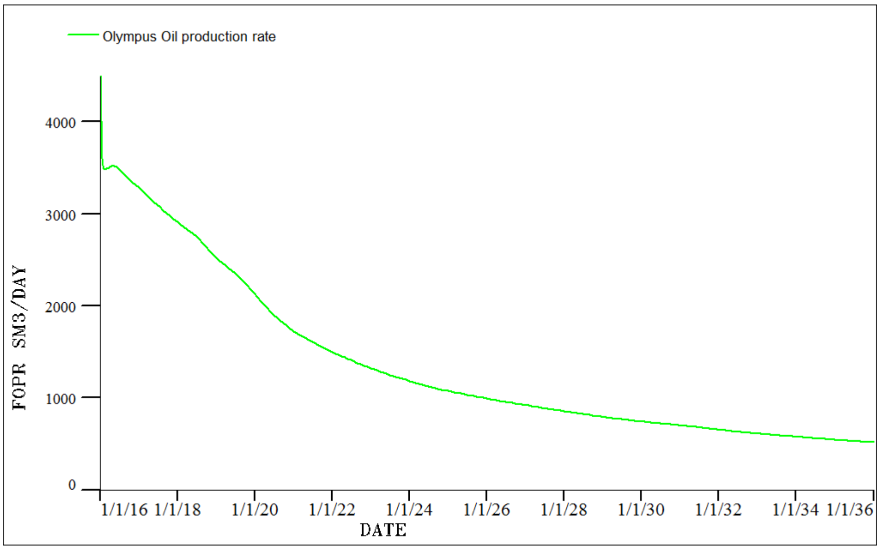

Figure 4.2: Oil Production rate

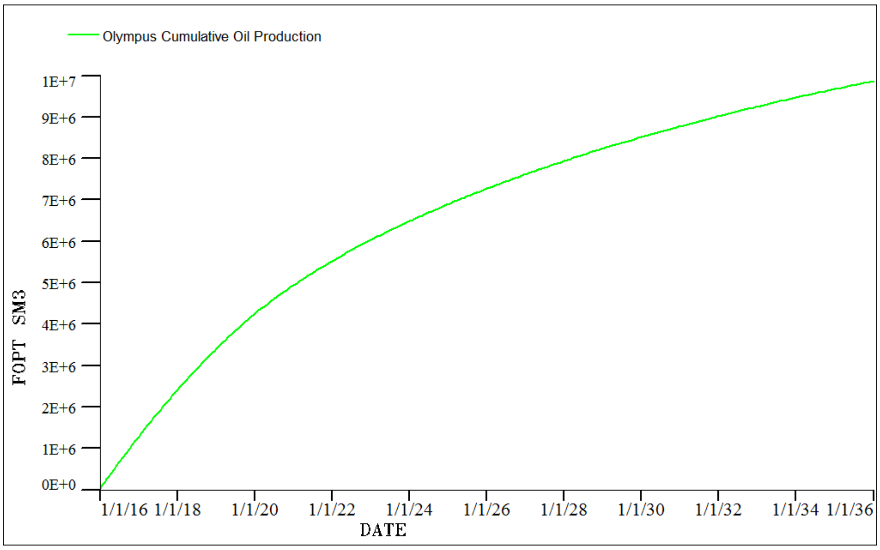

Figure 4.3: Cumulative Oil Production

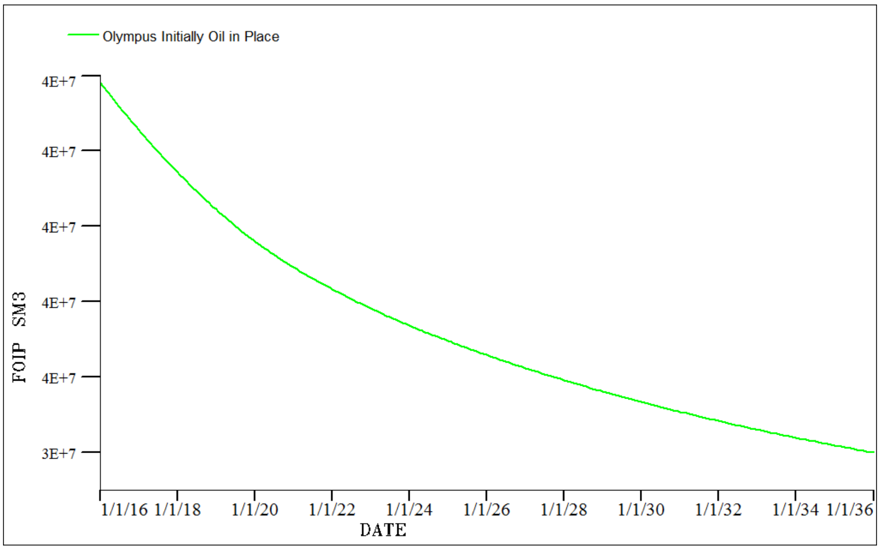

Figure 4.4: Field Oil in place

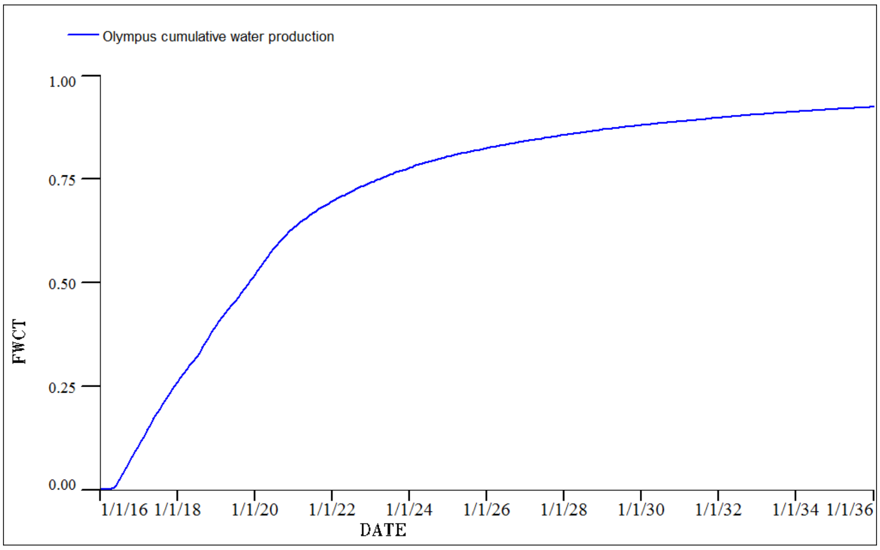

Figure 4.5: Field Cumulative Water Production

4.2 Identification of Potential Areas

During the process of optimizing production and future development of a field different strategies are considered. New wells can be drilled, existing wells can be re-completed and used as injectors or else side tracks can be made to target undrained areas. To find strategies to be employed a series of factors were considered on the given Olympus Eclipse 100 model. The following are the factors which were considered in selecting location as well as trajectories for well placement.

4.2.1 Reservoir pressure

The pressure of the fluids within the pores of a reservoir is fundamental in searching for the location of the well. Generally the source of this pressure is compaction of impermeable rocks such as shales forming sediments. The pore fluids cannot always escape and must then support the total overlying rock column, leading into high formation pressure. Study of pressure as can be observed on figure 4.6 indicates that there is an average pressure of about 200 Bars. This show for areas of potential saturation pressure maintenance will need to be considered. Reservoir pressure is important because fluids flows in the pores system of the reservoir by pressure difference.

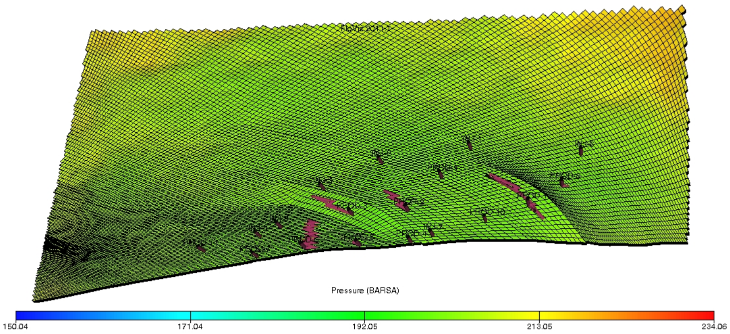

Figure 4.6: Olympus field pressure

4.2.2 Saturation

Saturation refers to relative amount of water, oil and gas in the pores of a rock, usually as a percentage of volume. In this reservoir model areas with potential oil saturation were obtained by running the base case to the end of prediction time. The aim is to study areas having potentials of oil up to the end of 10 years of the prediction time and thus provide key areas of interest to be considered for well placement. It can be observe on **figure 4.7** that the saturation in the middle of the model and most areas is above 50% and the rest part is occupied with water.

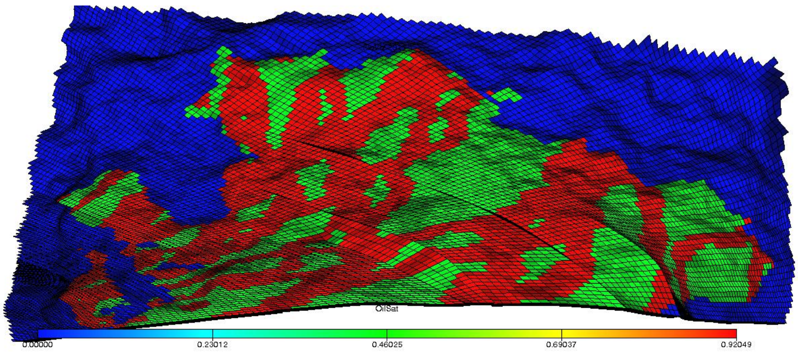

Figure 4.7: Olympus field Saturation profile

4.2.3 Fluid in Place

The oil in place gives the total quantity or content of hydrocarbons. Normally it is not measured but estimated from other parameters measured prior drilling or after production has begun.

Prior to oil production from a new reservoir, volumetric methods are used to estimate oil-in-place. The oil in place is calculated as the product of the volume of porous oil-bearing rock, the porosity of the rock, and its saturation. Correction factors have to be applied for the difference between the volume of the same mass of oil in the reservoir to its volume when brought to the surface, which is caused by the different physical conditions (temperature, pressure)(Wikipedia, 2018).
In this study each layer was studied to observe the fluids in place and it was observed layers 1-6 have potential of oil and however the subsequent layers have even more oil but there is more water too in nearby grids.

4.2.4 Permeability

Permeability is a measure of the ability of a porous material (often, a rock or an unconsolidated material) to allow fluids to pass through it. The permeability of a medium is related to the porosity, but also to the shapes of the pores in the medium and their level of connectedness (Wikipedia, 2017). From the study of the model in **figure 4.8 and 4.9** indicates there is low permeability in this field even lower in vertical permeability. However presence of non sealing faults allows fluids to flow

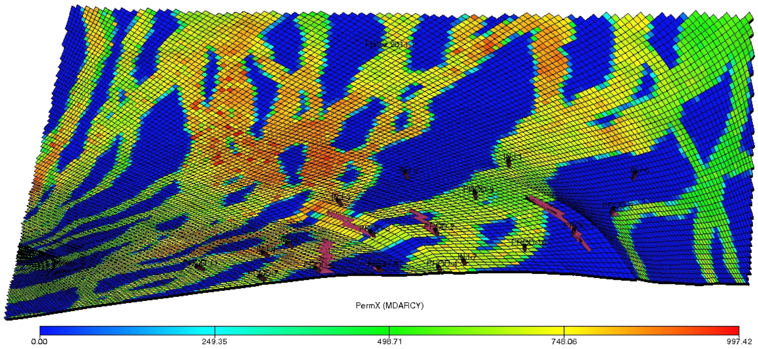

Figure 4.8: Olympus permeability along X and Y-direction

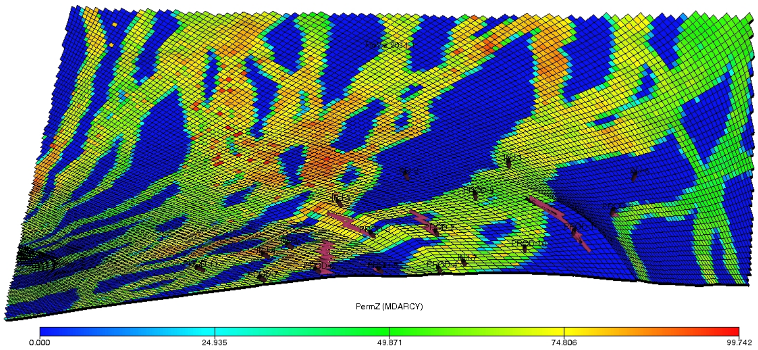

Figure 4.9: Olympus permeability along Z-direction

4.2.5 Fault Communication

Faults refers to break or planar surface in brittle rock across which there is observable displacement. Depending in the relative direction of displacement between the rocks, or faults blocks on either side of the faulty, its movement is described as normal, reverse or strike-slip (Schlumberger, 2018). The study on this model indicates that there is non sealing faults. This is because there is no sharp contrast in saturation observed across the fault. Some faults can be observed on **figure 4.10**

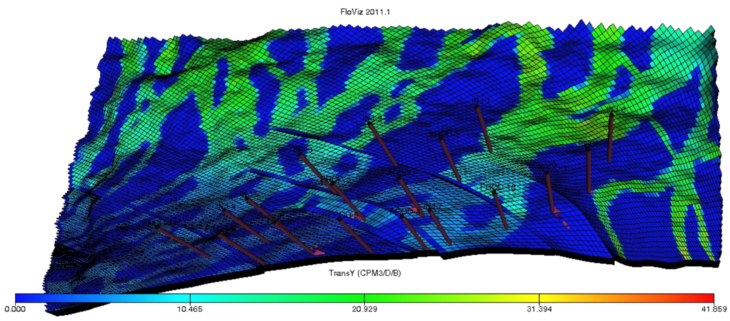

Figure 4.10: Olympus model faults

4.2.6 Well Performance and configuration

The behaviour of other wells in the model gives the trend of changes taking place in the field. Properties trend such as rapid pressure drop can be significant in deciding whether producer or injector wells are supposed to be drilled. Also status and behaviour of existing well were studied to develop interesting cases. Producers normally do not produce when pressure declines because it is the driving energy for production. Also depending on the location of the wells some consideration on which type of injection to be employed was done to count for the effect of water breakthrough.

Chapter 5

Results and Discussions

5.1 Well Placement Location

Study on the Olympus model basing on the procedures for observation of potential areas has subsequently resulted into identification of interesting well locations of which results into curiosity of focusing on well replacement. The identification observed in the model are such as Injector 4 is observed to be very close to the producers, injector 3 is observed to be very close to the fault, Injector 2 is observed to very close to the fault and perforates a very high oil saturation zone. further more injector 4 and 5 are very close to each other and perforates all layers, producer 7 is very close to the boundary and producer 9 is supposed to be at the centre of the segment.

5.1.1 Injector 5 re-allocation

Observation on the placement of injector 4 and 5 showed that, they are very close to each other and thus affect the way they all influence pressure maintenance and sweeping of fluids to the producer. Producer 5 is placed very close to the horizontal producer 6. Horizontal producer 6 occupies large drainage area for oil. To ensure proper maintenance of pressure then Injector 5 was placed within the radius of influence of producer 6 but much distant as compared to the base case. This can be observed on **figure 5.2 and figure 5.1.**

Placement of injectors such close to each other could result into loss of energy because they all perforates similar layers. Furthermore injector 5 is within the drainage zone of horizontal producer 6. This could disrupt the efficiency of pressure maintenance of the injector. Reallocation was done to this injector by placing it relatively away from the drainage zone of the producer and was made to perforate layers parallel to the direction of the horizontal producer and thus improve relatively the sweeping efficiency.

The suggested re-allocated resulted into an improve in field pressure as compared to the base case this can be observed on **figure 5.3**. Improvement in field pressure resulted into an increase in field production rate especially on the early days this can be observed on **figure 5.4**. An increase in field production rate results into increase in cumulative field production and this is observed on figure 5.5 where by an incremental production of **1,095,381.733 bbl** from the base case was observed. An advantage of this reallocation is that water cut is delayed as compared to the base case however cumulatively field water production is the same as can be observed on **figure 5.6.**

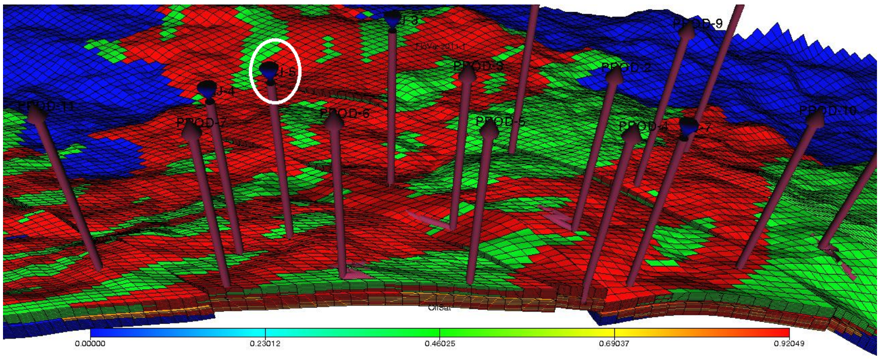

Figure 5.1: Olympus injector 5 Base case

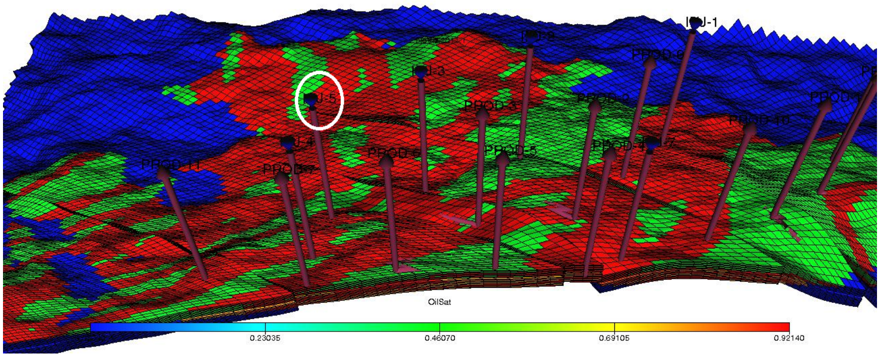

Figure 5.2: Olympus injector 5 re-allocated

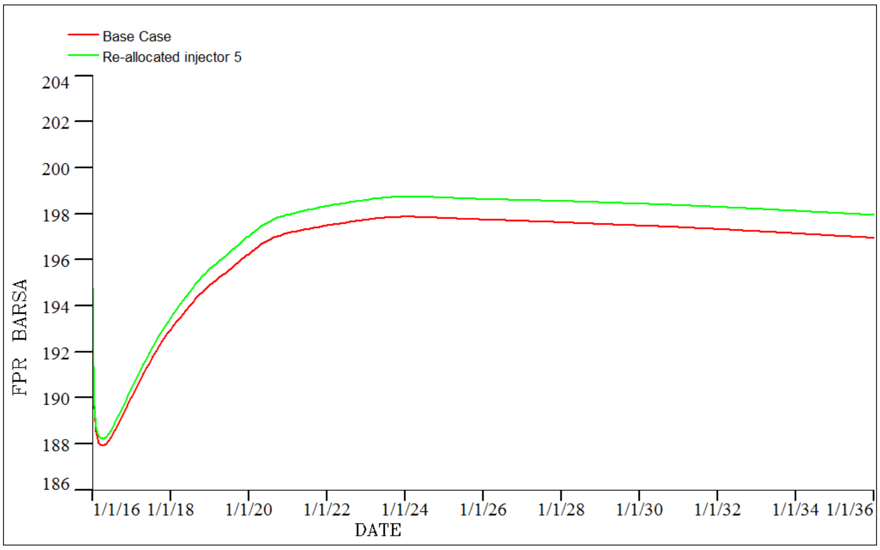

Figure 5.3: Olympus injector 5 re-allocated Oil Pressure

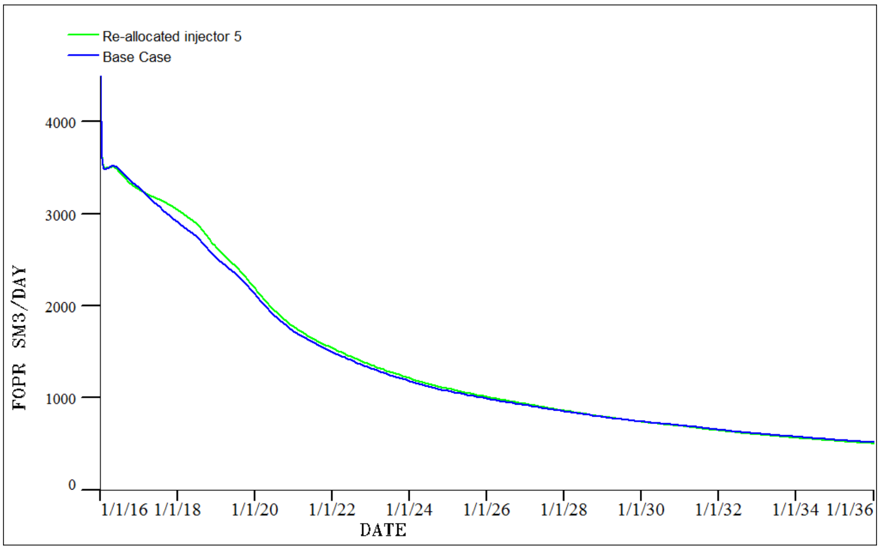

Figure 5.4: Olympus injector 5 re-allocated Oil production rate

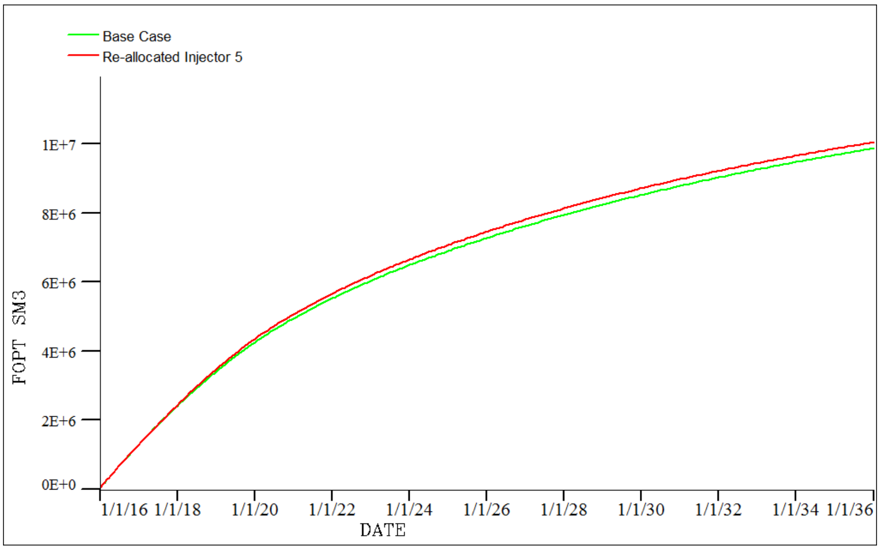

Figure 5.5: Olympus injector 5 re-allocated cumulative oil production

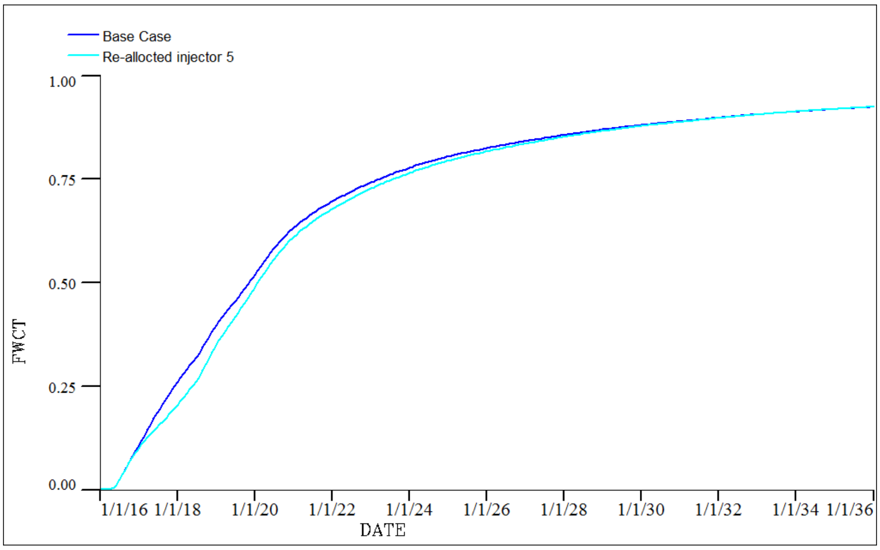

Figure 5.6: Olympus injector 5 re-allocated cumulation water production

5.1.2 Injector 3 re-allocation

Observation on the placement of injector 3 indicated that its is placed in a high oil saturation zone near the fault and relatively far from the influences of the nearby producers as observed on **figure 5.7**. This could result into loss of energy which could be useful to sweep fluids to the nearby producers. Considerations on the placement of this injector was done and the injector was on a region and where it could influence sweeping of fluids to the nearby producers and properly maintain pressure.

The region where the re-allocated well is placed can be observed on **figure 5.8**.Following this re-allocation pressure in the field was relatively improved as compared to the base case because injection fluid is not lost to the fault but rather used to maintain pressure in the field as it can be observed on **figure 5.9**.This increase in field pressure has resulted into an increase in field production rate because the energy to ensure fluids flows to the producer is available.

This increase in production rate is observed through out the production duration as it can be observed on **figure 5.10.** Availability of pressure and increase in production rate resulted into an improve in cumulative oil production as it can be observed on **figure 5.11** whereby this has resulted into a production incremental of **3,505,102.291 bbl** as compared to the base case. Proper perforations done on the reallocated injector results into lower water cut compared to the base case as it can be observed on **figure 5.12,** however cumulatively the re-allocated case has more less the same to the base case but just slightly below.

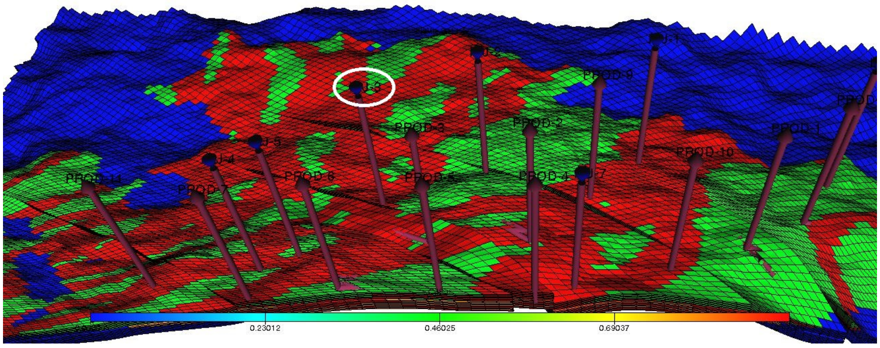

Figure 5.7: Olympus injector 3 Base case

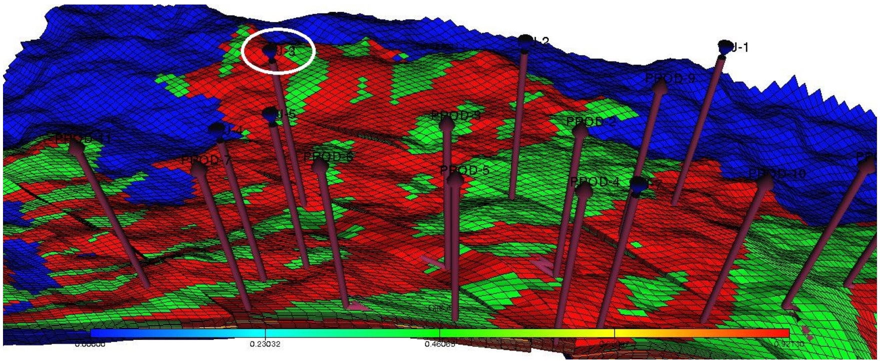

Figure 5.8: Olympus injector 3 re-allocated

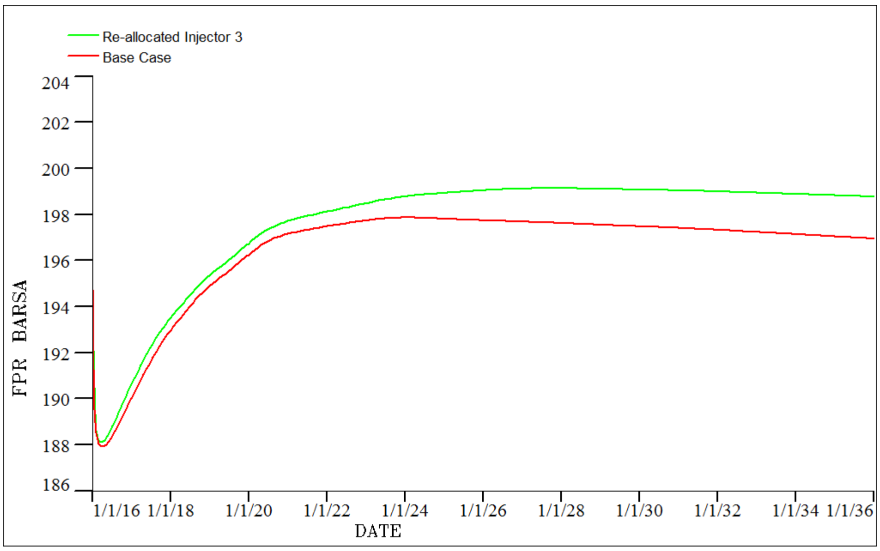

Figure 5.9: Olympus injector 3 re-allocated Oil Pressure

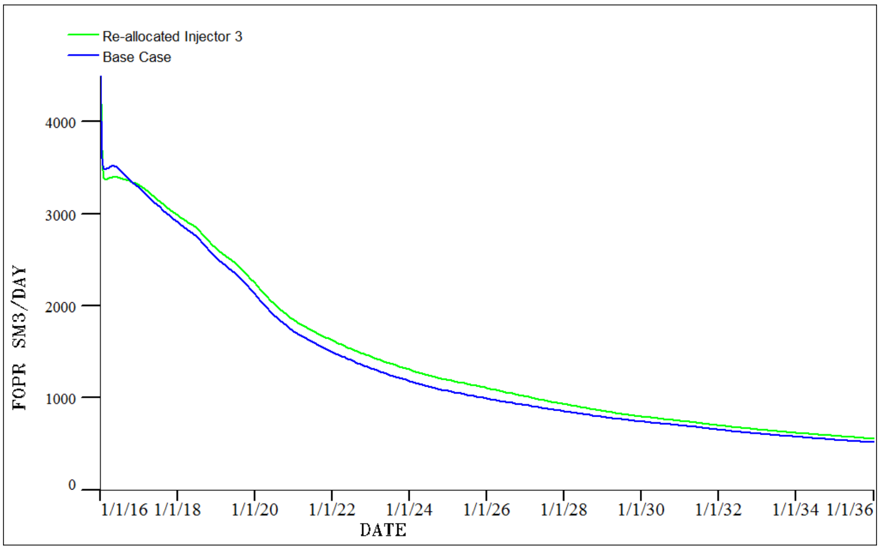

Figure 5.10: Olympus injector 3 re-allocated Oil production rate

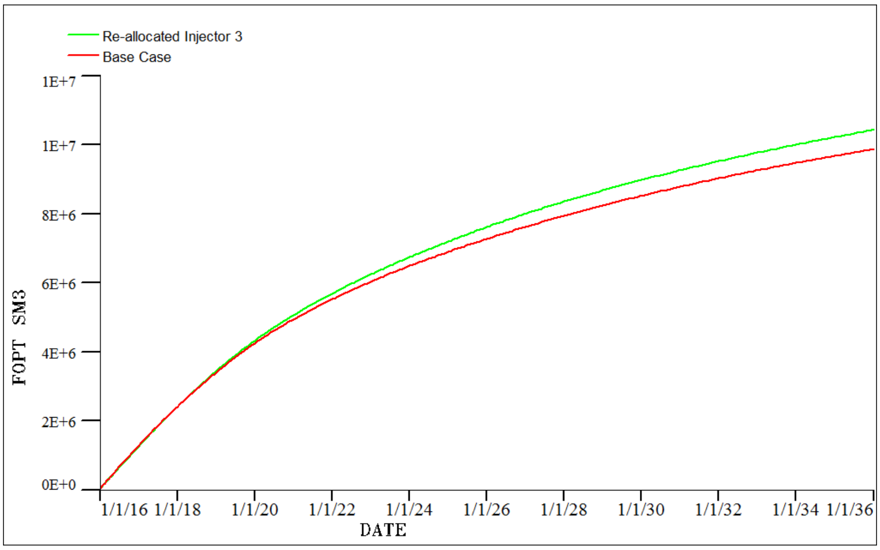

Figure 5.11: Olympus injector 3 re-allocated cumulative oil production

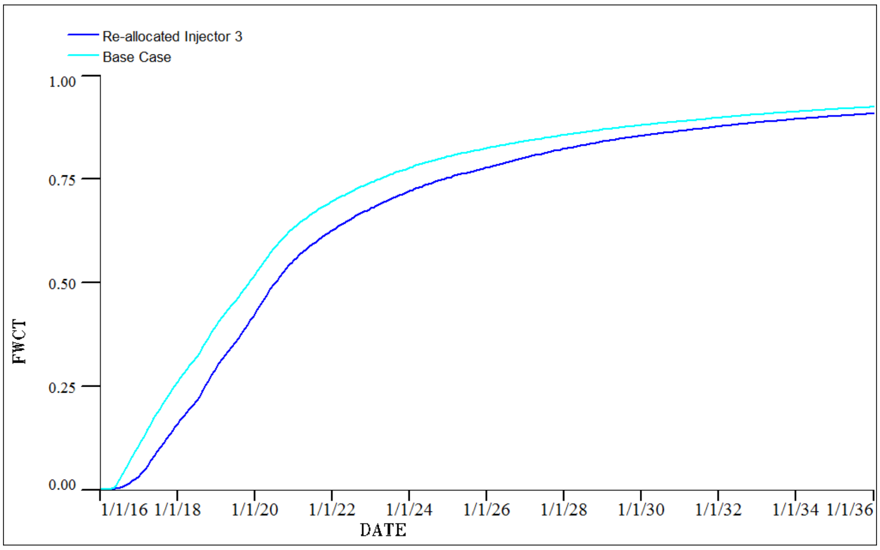

Figure 5.12: Olympus injector 3 re-allocated cumulation water production

5.1.3 Injector 4 re-allocation

Observation on injector 4 indicated that it perforates a high oil saturation zone. Presence of high saturation in this region has resulted into the distance between the injector and the producer to be very close as can be seen on **figure 5.13** which could result into early water break-through together with poor sweeping efficiency. According to **figure 5.14** injected 4 was placed in a relative low saturation region with selective perforations to ensure proper sweeping efficiency to the producer which has ultimately resulted into an increase in production rate in the field as can be observed on **figure 5.15** which will have an impact in production on cumulative production.

Reallocation of injector 4 has resulted in an incremental improve in production of **2,566,104.104 bbl**. This can be observed on **figure 5.16**, The increase in production means fluid are removed from the reservoir and thus pressure decreases as can be observed on **figure 5.17** which is way below the base case but relatively reasonable with the improve in production observed.

With partial perforations done on the re-allocated injector 4 there has been low cumulative water production because water hardly get chance to commingle into the producer which are by now relatively distant from the reallocated injector. This is observed by less cumulative water as compared to the base case which can be observed on **figure 5.18**

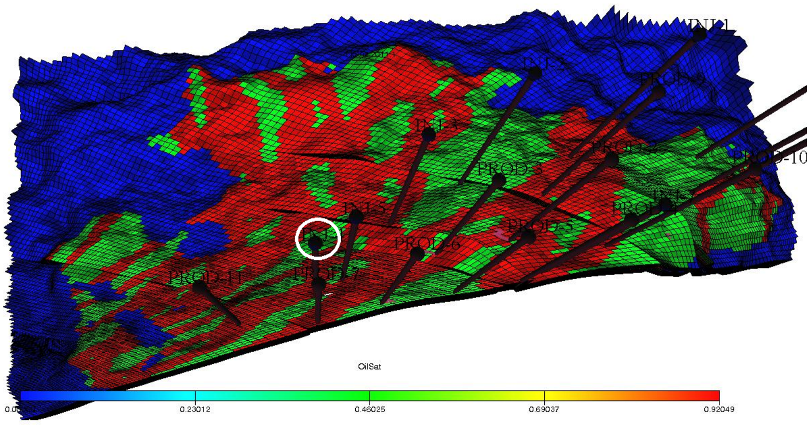

Figure 5.13: Olympus injector 4 Base case

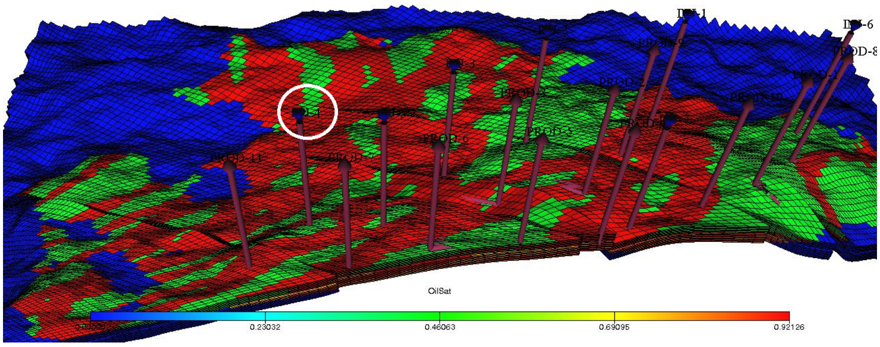

Figure 5.14: Olympus injector 4 re-allocated

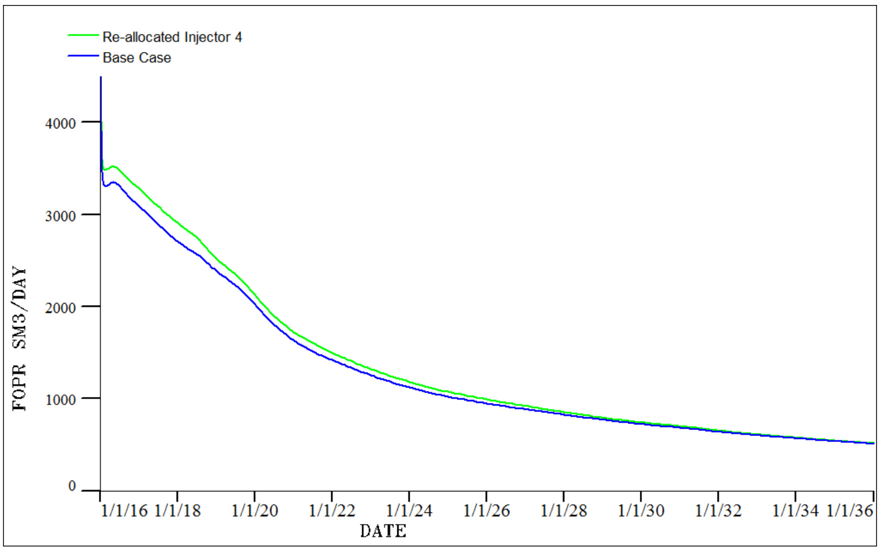

Figure 5.15: Olympus injector 4 re-allocated Oil production rate

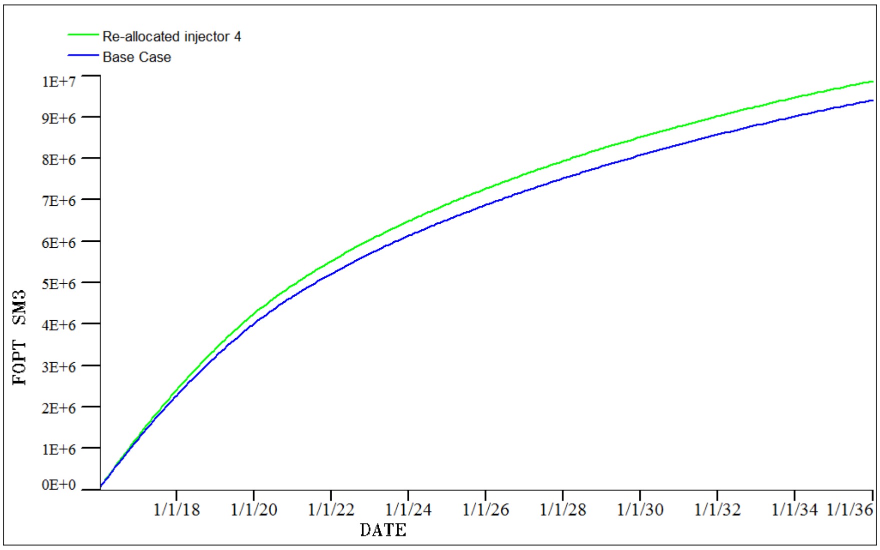

Figure 5.16: Olympus injector 4 re-allocated cumulative oil production

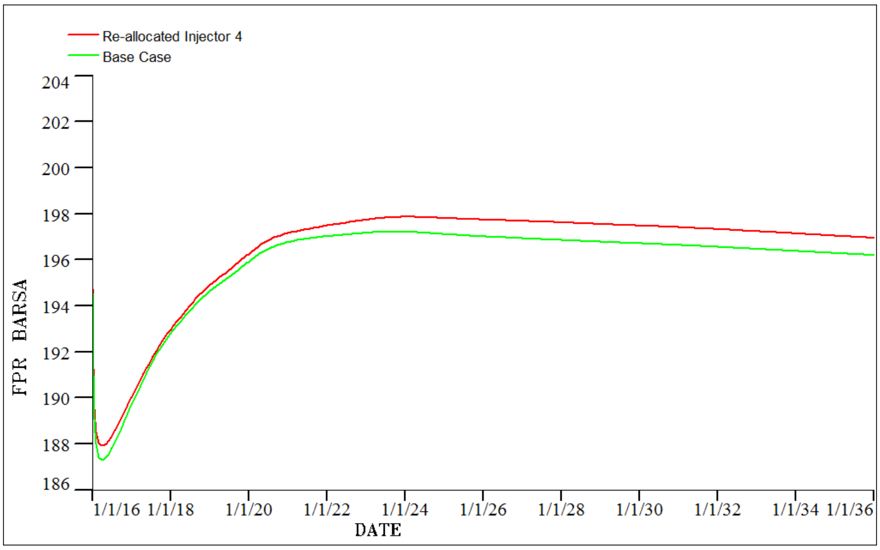

Figure 5.17: Olympus injector 4 re-allocated Oil Pressure

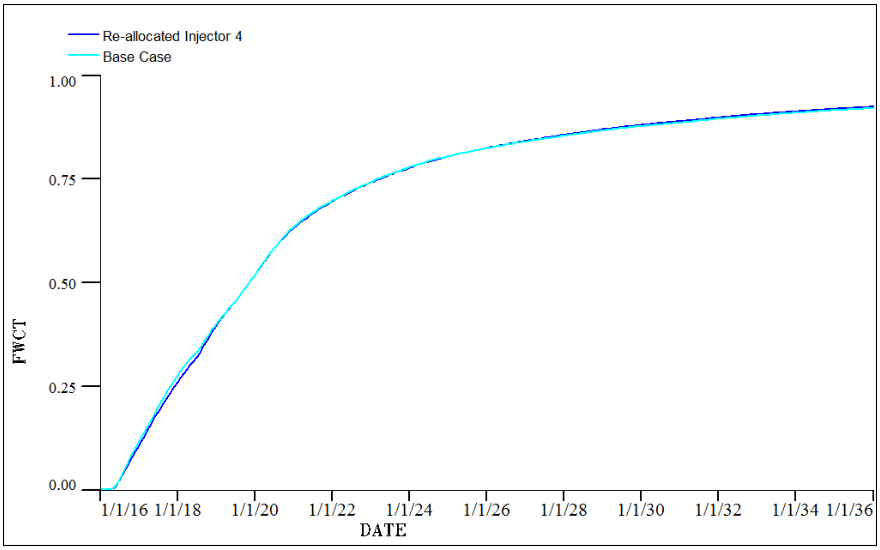

Figure 5.18: Olympus injector 4 re-allocated cumulation water production

5.1.4 Injector 2 re-allocation

Observations on the placement of injector 2 shows that the injector is placed right on the fault this could result int loss of energy and poor sweeping efficiency of the fluids as it can be observed on **figure 5.19** and thus placement of the injector into a place where it could maintain field pressure more efficiently than in the current location. The consideration here was to make sure that it assists other injectors to maintain pressure and improve production at nutshell and that was the drive to replace it as it can be observed on **figure 5.20**. Pressure maintenance was improved because the potential for energy loss to the fault is minimized this can be observed on **figure 5.21**.

However this improve in pressure has very slightly improved the production rate , this is because the injector has more less not assisted the sweeping process of the fluids to the producers due to its relative distance from the same. This is clearly observed on **figure 5.22**. This small increase in production rate has ultimately resulted into a slight improve in field cumulative oil production as it can be observed on figure 5.23 whereby there was an incremental increase in production by **908,335.3634 bbl** from the base case. This slight improve in production was attributed with a slight increase in water cut due to relatively high pressure in the field due to reallocated injector but the difference was insignificant as it can be observed on **figure 5.24**

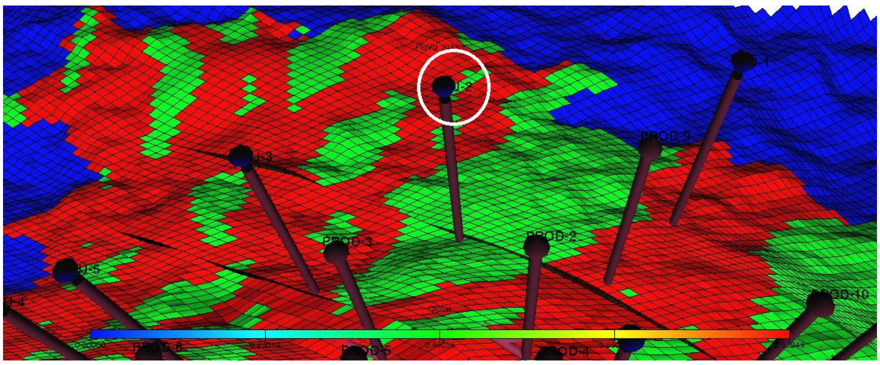

Figure 5.19: Olympus injector 2 Base case

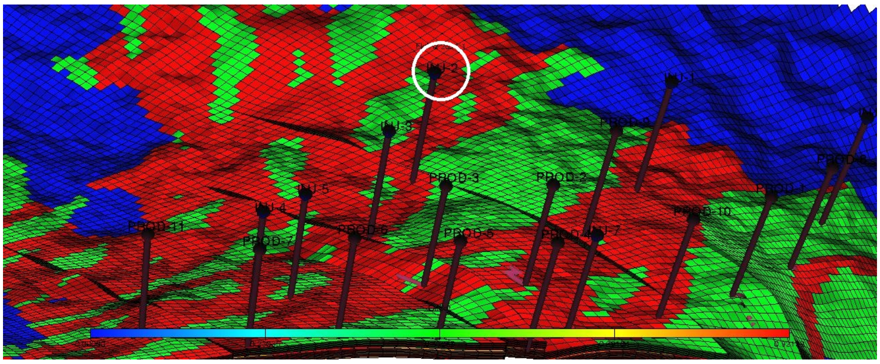

Figure 5.20: Olympus injector 2 re-allocated

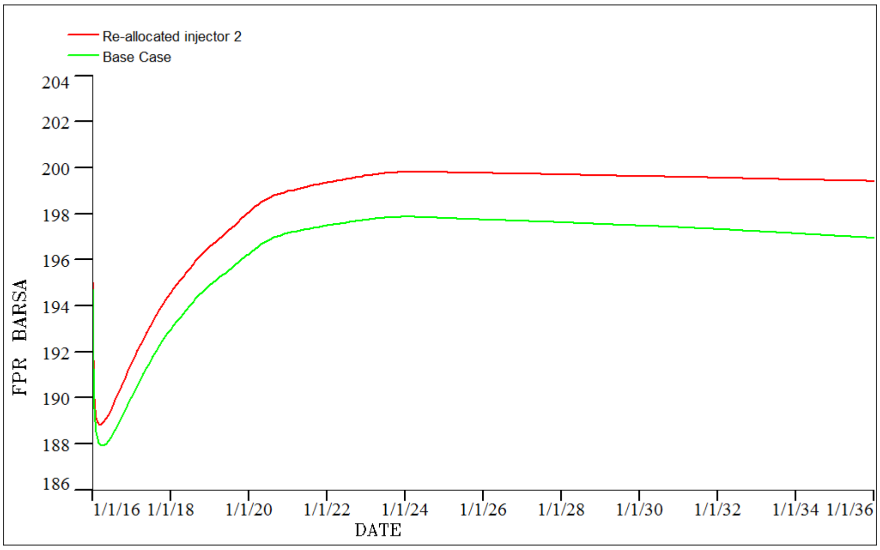

Figure 5.21: Olympus injector 2 re-allocated Oil Pressure

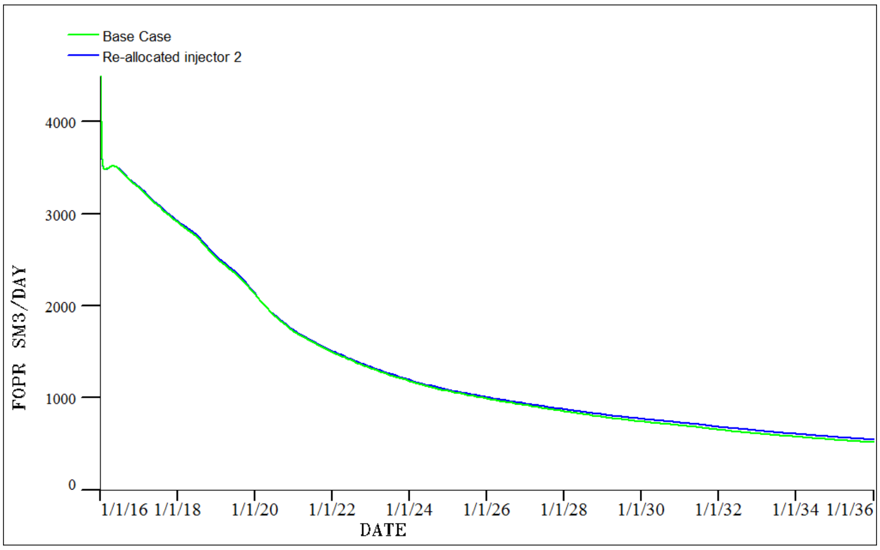

Figure 5.22: Olympus injector 2 re-allocated Oil production rate

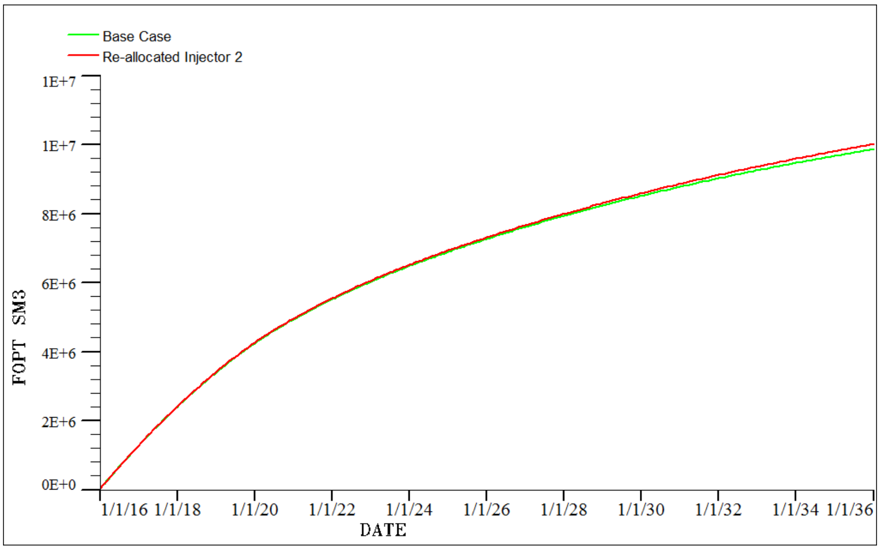

Figure 5.23: Olympus injector 2 re-allocated cumulative oil production

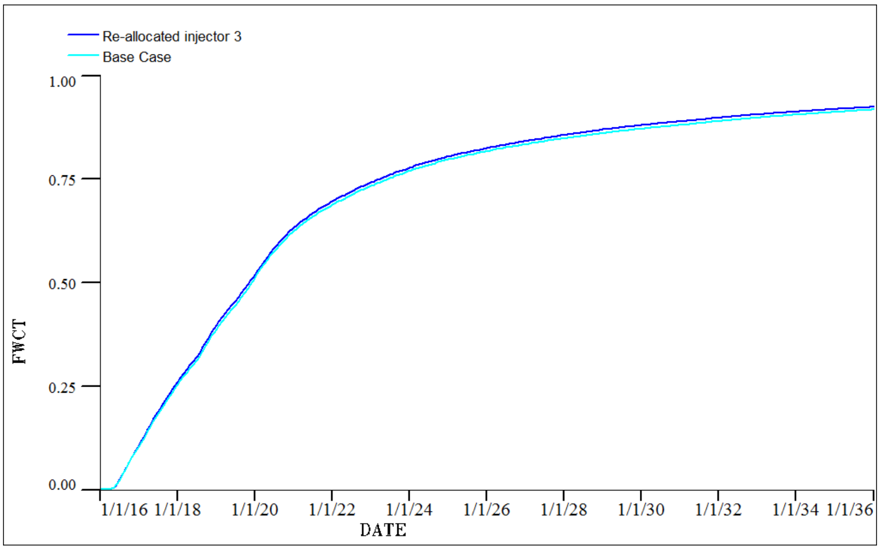

Figure 5.24: Olympus injector 2 re-allocated cumulation water production

5.2 Producer Re-allocations

Observations on the producers locations basing on realistic field development constraints was done and it was observed that there are producers which are misplaced on the faults, on the zones where there is no pressure maintenance strategies also with perforations on layers which have no promising saturations of oil. The producers of interest in this case was producer 7, producer 9 and producer 11 as they can be observed on **figure 5.25**.To begin with producer 7 was studied and it was found that it is placed on the fault boundary which could affect the drainage of fluids because it drains fluids from limited directions. Thats why producer 7 had to be re allocated in the the influence of injector 4 and 5 as it can be observed on **figure 5.26**.

Together with the re-allocation partial perforations on potential layers was done and this resulted into an improvement in field Oil production as can be observed on **figure 5.27**, whereby there was an incremental improve in field cumulative oil production of **1,613,970.278 bbl** as compared to the base case. This increment was a result of improvement in production rate due to perforations on potential areas and sweeping of the nearby injectors. This slight improve in production rate is as can be observed on **figure 5.28**. Since the producer is now placed near the injectors and its perforates up to near water zones then there is a relative increase in water cut as it can be observed on **figure 5.30**.

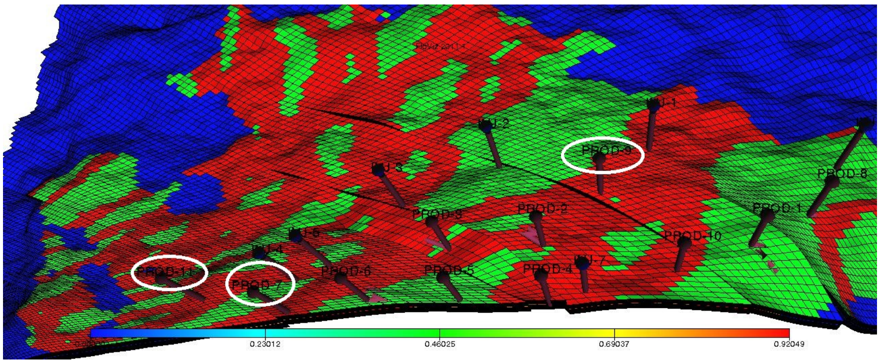

Figure 5.25: Olympus producer 7 re-allocated

5.2.1 Producer 7 Re-allocations

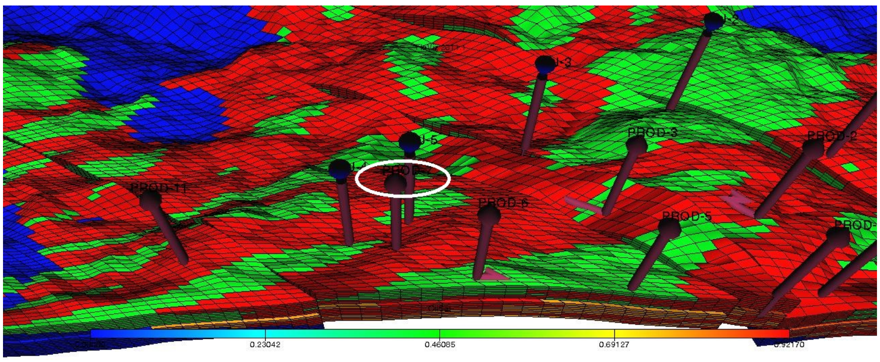

Figure 5.26: Olympus producer 7 re-allocated

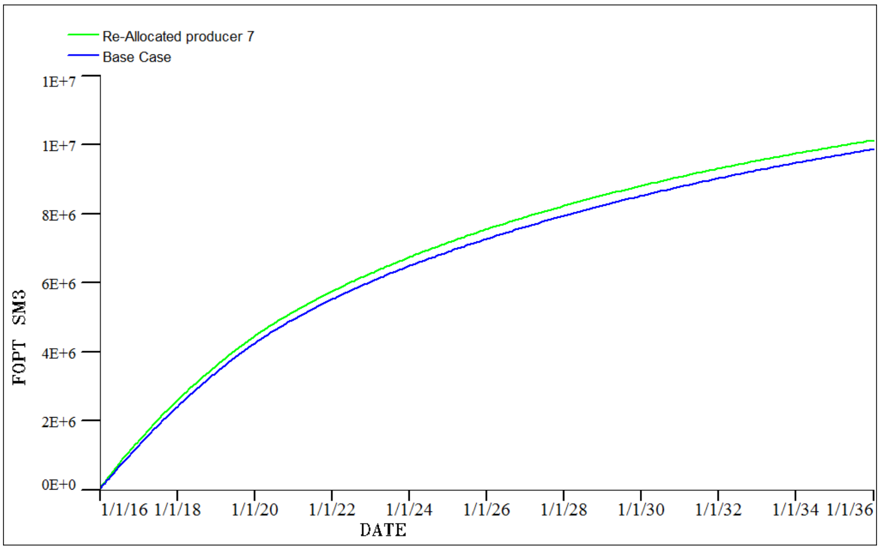

Figure 5.27: Olympus producer 7 re-allocated

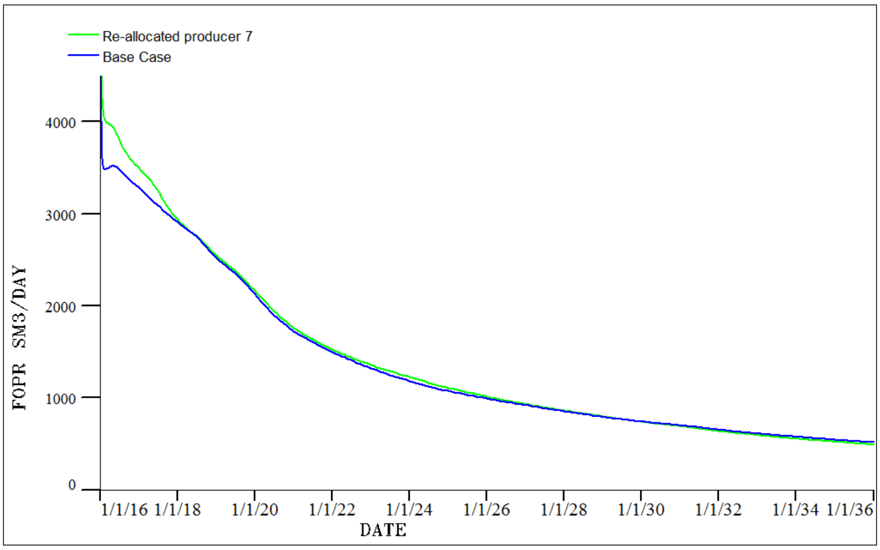

Figure 5.28: Olympus producer 7 re-allocated

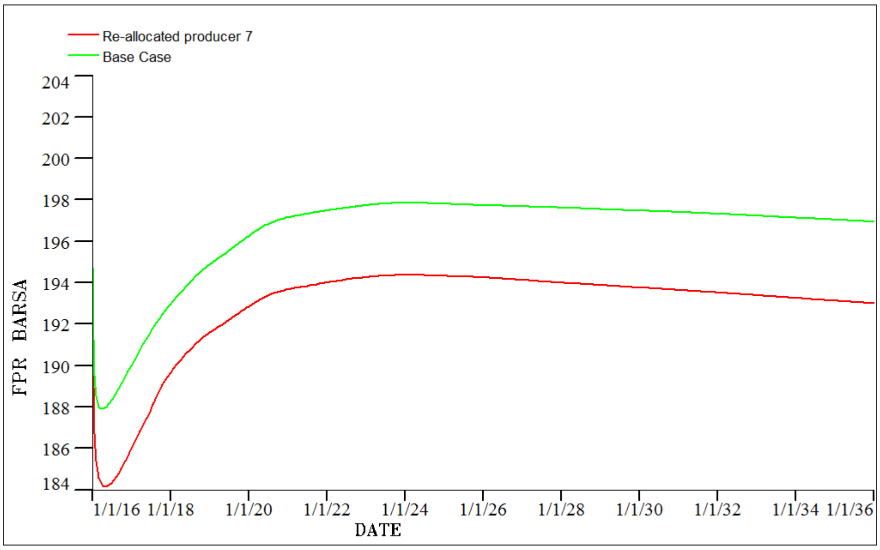

Figure 5.29: Olympus producer 7 re-allocated

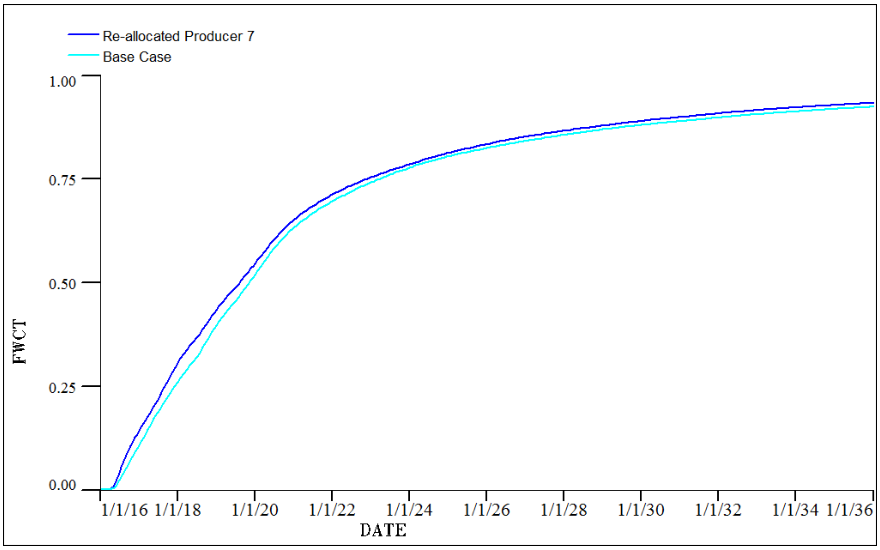

Figure 5.30: Olympus producer 7 re-allocated

5.2.2 Producer 9 Re-allocation

Observation on producer 9 showed that it is placed relatively very close to the fault and distant from the influence of injectors because of the low permeability observed in the layers which are found below.Thus it was inevitable for this producer to be reallocated to improve production. Producer 9 was placed and perforated high saturation layers, good permeability area and better drainage area as it can be observed on **figure 5.31.** Producer 9 resulted into an improve in cumulative oil production as it can be observed on **figure 5.32**, this has resulted into an incremental cumulative oil production of **3,628,527.233 bbl** as compared to the base case.

This was vivid because placement of the producer in this region increased the production rates because more fluid were drained to the producer than the base case this is pointed on **figure 5.33** where by the reallocated case has higher rates at early times and more less the same rates at later times. This reasonable increase in production observed resulted into a decrease in field pressure as compared to the base case because more fluids are drained out. This is pointed too by observing cumulative water production on **figure 5.35** where more water cut is achieved with the new case resulting producing more water at early times but with similarities when focusing on cumulatively water produced.

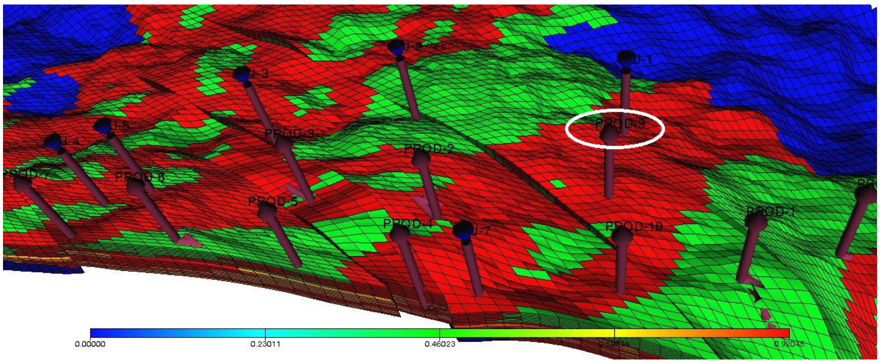

Figure 5.31: Olympus producer 9 re-allocated

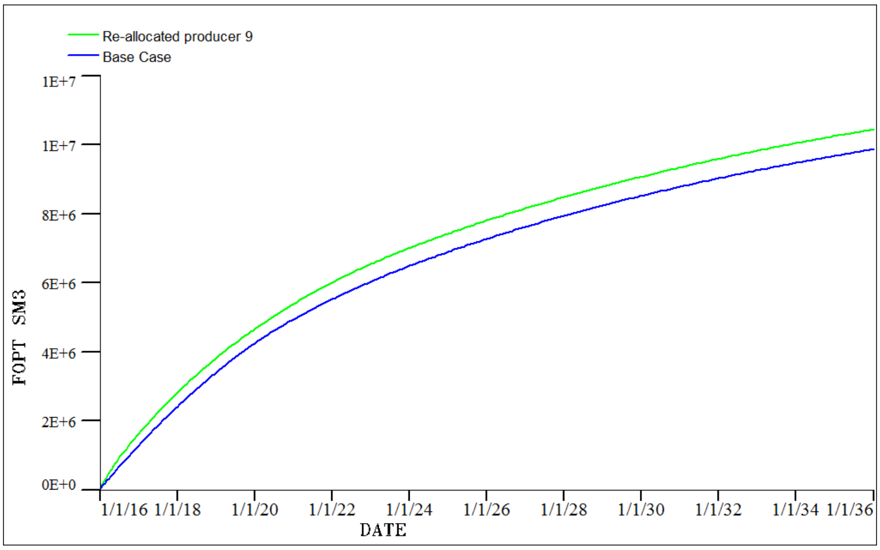

Figure 5.32: Olympus producer 9 re-allocated

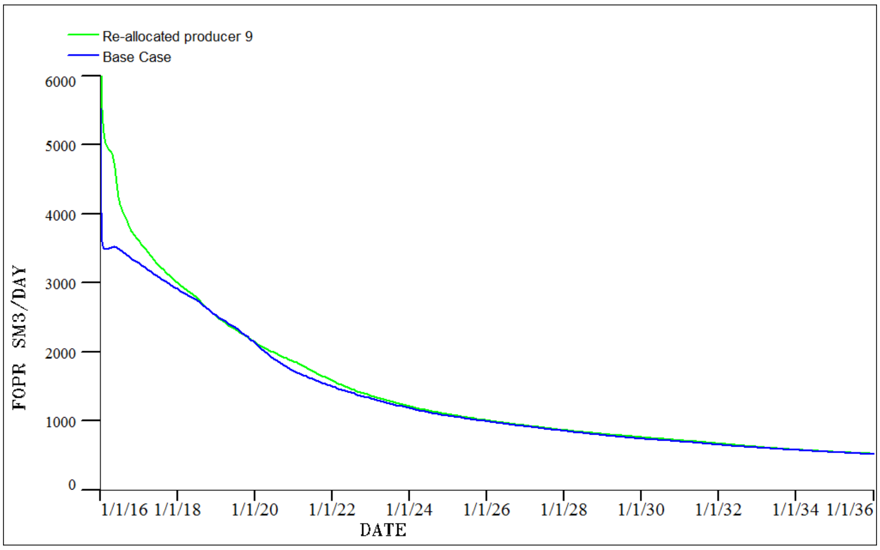

Figure 5.33: Olympus producer 9 re-allocated

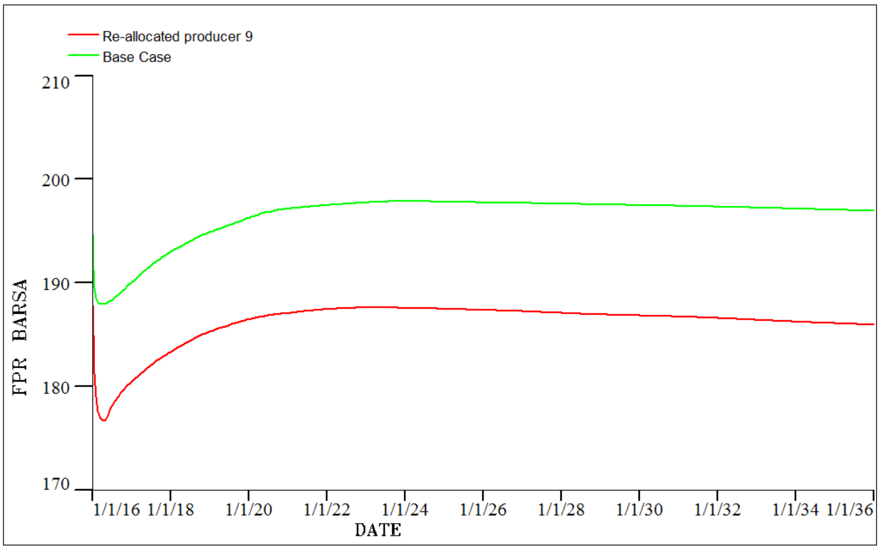

Figure 5.34: Olympus producer 9 re-allocated

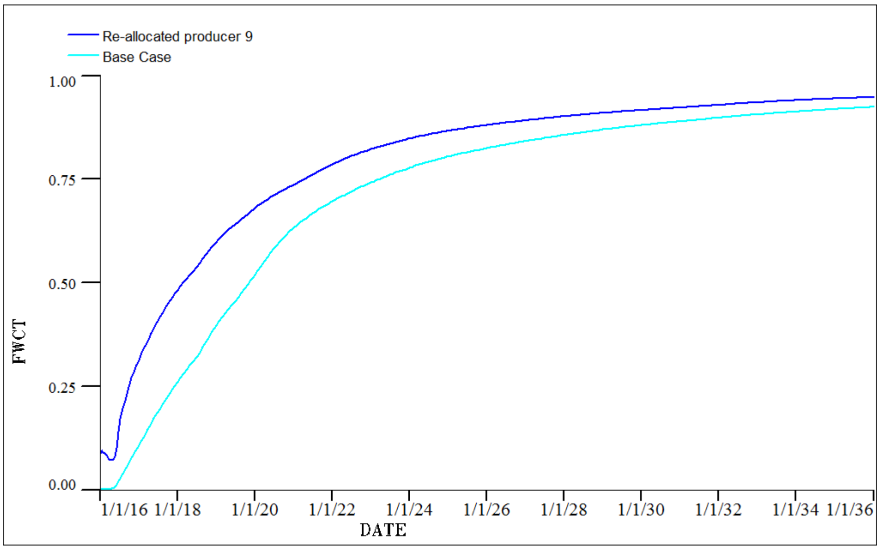

Figure 5.35: Olympus producer 9 re-allocated

5.2.3 Producer 11 Re-allocation

Observations on producer 11 indicated that it perforates low saturation layers and it placed relatively far from the influence of injectors and thus little influence of the same when considering sweeping from the injectors. Efforts were made to reallocate relatively close to the influence of the injectors and perforate higher saturation and permeability layers in question as can be observed on **figure 5.36**. Higher permeability in this area and availability of water in adjacent zones resulted into influx of water into the producer with lower oil production **figure 5.37**, lower oil production rate **figure 5.38**, sudden decrease in pressure **figure 5.39** and rapid increase in water cut **figure 5.40**. this is shows it was not optimal to reallocate the well in this zone.

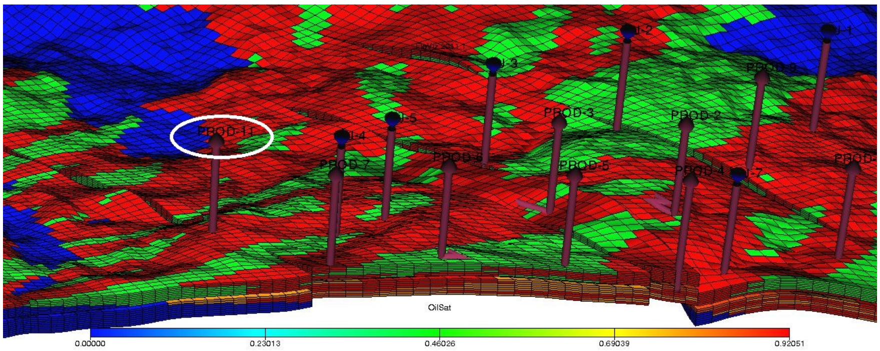

Figure 5.36: Olympus producer 11 re-allocated

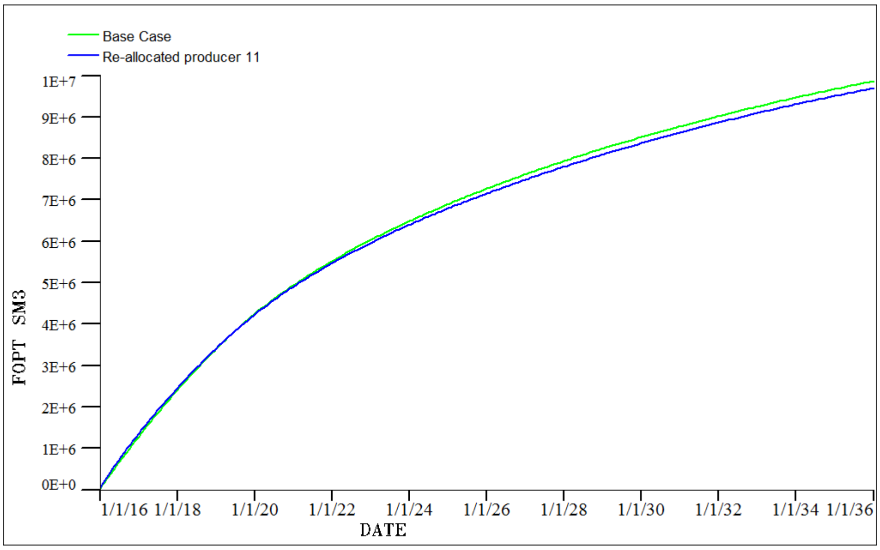

Figure 5.37: Olympus producer 11 re-allocated

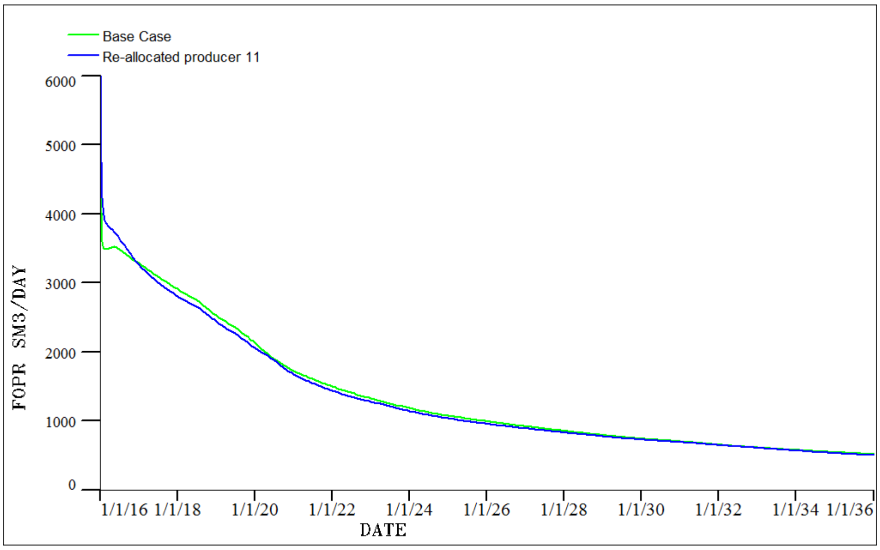

Figure 5.38: Olympus producer 11 re-allocated

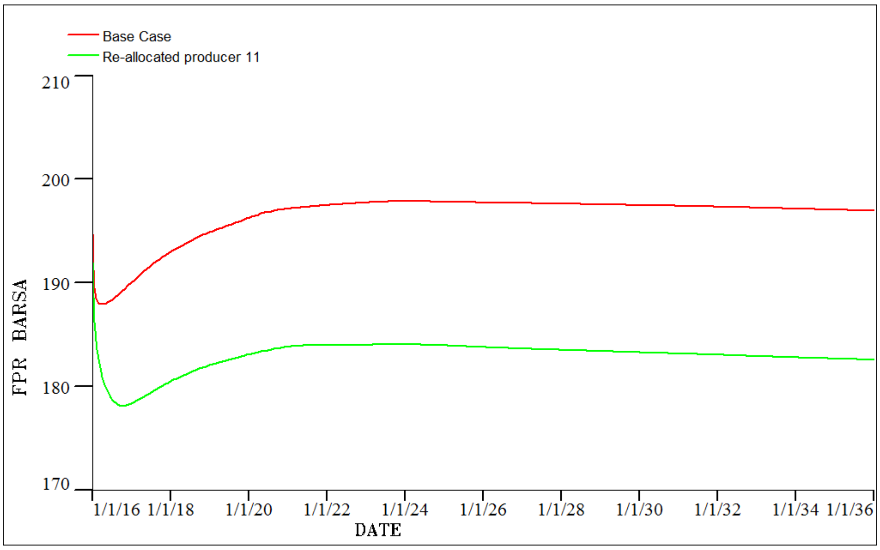

Figure 5.39: Olympus producer 11 re-allocated

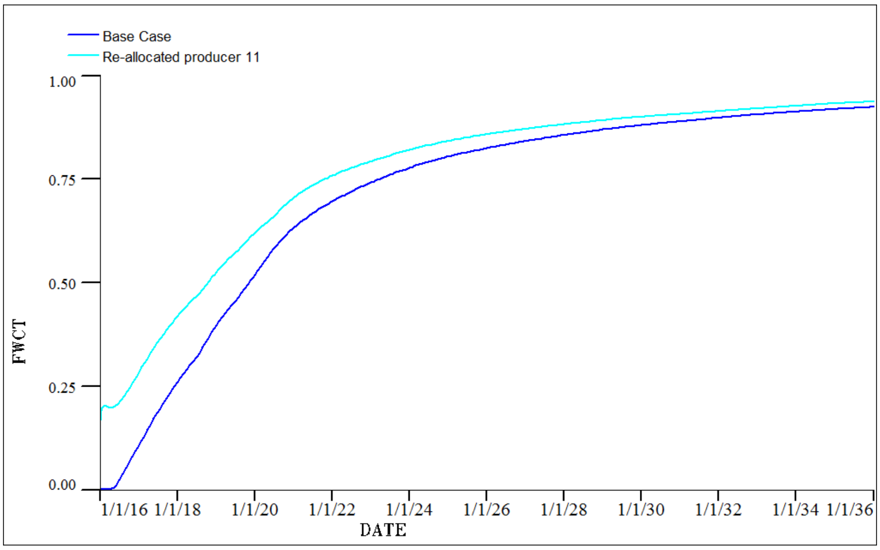

Figure 5.40: Olympus producer 11 re-allocated

5.3 New Well Placement Location

Placement of New wells was inevitable by the fact that perspective is trivial that will improve production. However detailed study has to be done to insure that the well so drilled is optimal and will result into profit from the revenue generated.The given Olympus model has wells in it but now a study of where to place new wells was done and the decision was made to concentrate on the region where there are fewer are placed to avoid associated complications. The area of interest can be shown exclusively and inclusively as on **figure 5.41** and **figure 5.42** where areas of interest are highlighted as can be observed on the zoomed part **figure 5.43**

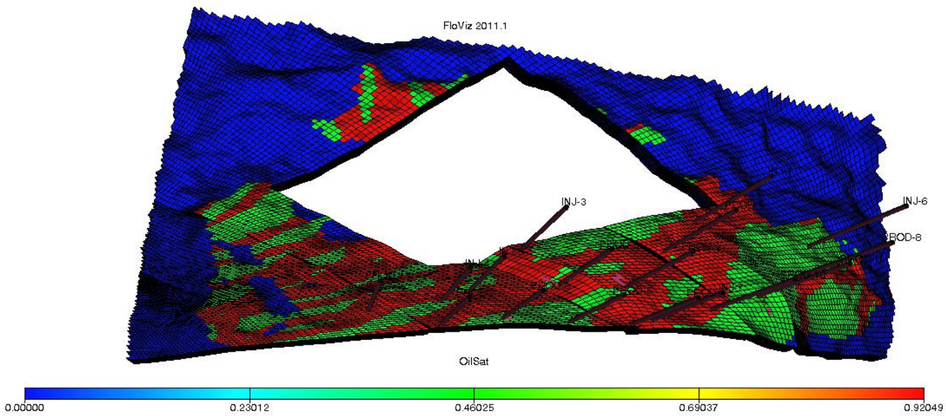

Figure 5.41: Olympus exlusive model;the white part indicating the area of concentration for producer placement

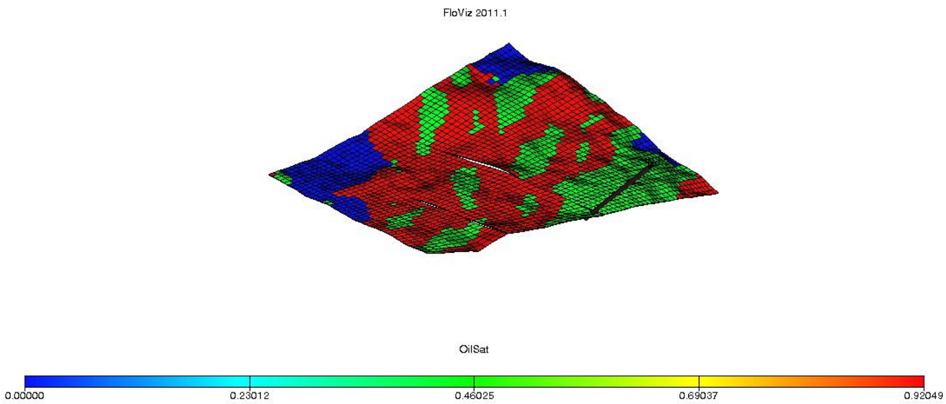

Figure 5.42: Olympus inclusive model indicating the concentration area for well placement.

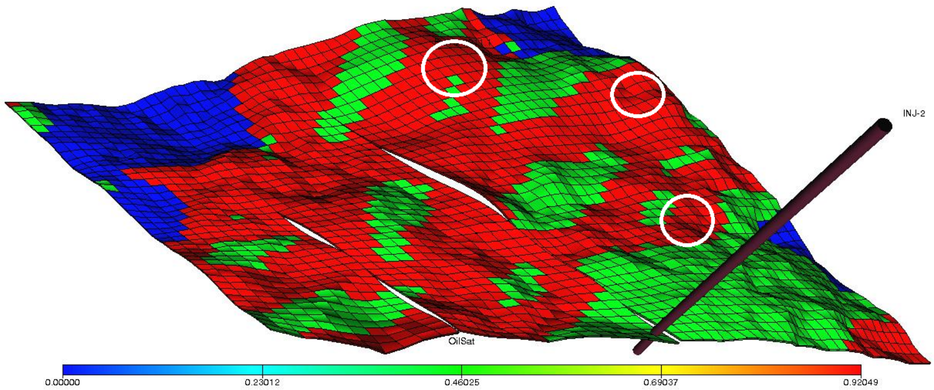

Figure 5.43: Olympus inclusive model

5.4 New Producer wells Cases

Several Simulations were run and few cases were selected to be presented here. Producers in this case were placed on 1 Jan 2019 and have different perforations basing on the saturations, permeability and pressure in the area of interest, the minimum Bottom hole pressure was fixed to be 150 bars and it served as the boundary condition as well. In this study three producer cases are discussed and their placements observed on **figure 5.44** for producer 1,**figure 5.45** for producer 2 and **figure 5.46** for producer 3 .Their results were plotted with reference from the base case.

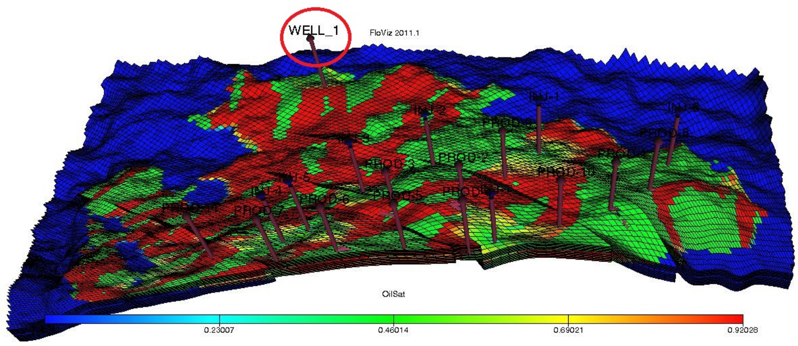

Figure 5.44: Producer Case 1

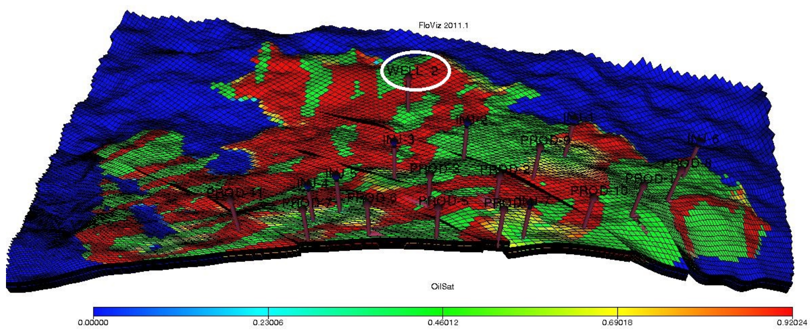

Figure 5.45: Producer Case 2

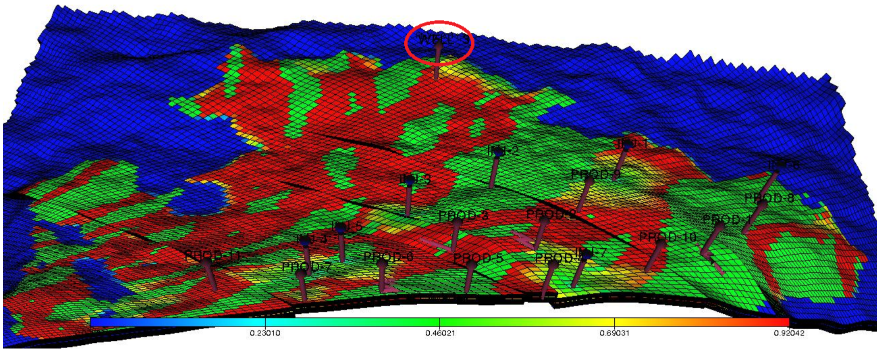

Figure 5.46: Producer Case 3

5.5 New Producer Results

The placed producers improved the production from the base case as observed on **figure 5.47** whereby **producer 2** resulted into higher improvement in production , followed by **producer 3** then **producer 1**. **Producer 2** was placed on a higher saturation zone ,relatively higher permeability and high pressure. **Producer 3** perforated higher permeable area with good oil saturation but there was potential for water influx because it was on a ridge near water. **Producer 1** perforated layers with high oil saturation and high permeability but nearby there was potential for water intervention to the producers. Observation on the placed producers shows that **producer 2** produced an incremental of **18,881,335.35 bbl** as compared to the base case while **producer 3** produced an increment of **14,414,846.92 bbl** as compared to the base case and finally **producer 1** produced an increment of **10,856,349.18 bbl** as compared to the base case.

The improve in production as explained is reflected with what is observed on the production rates whereby **producer 2** has the highest rate because its penetration to higher saturation layers drains more fluids to the producer, followed by **producer 3** then **producer 1** as it can be observed on **figure 5.48**. Drainage of oil by the producer results into a decrease in pressure in the field. In this case there was a rapid decrease in pressure for all developed cases as it can be observed on **figure 5.49** this is because large quantity of fluids were removed from the reservoir. According to the available cases **producer 2** produced less water followed by **producer 3** then **producer 1**. All these have less water produced as compared to the base case.

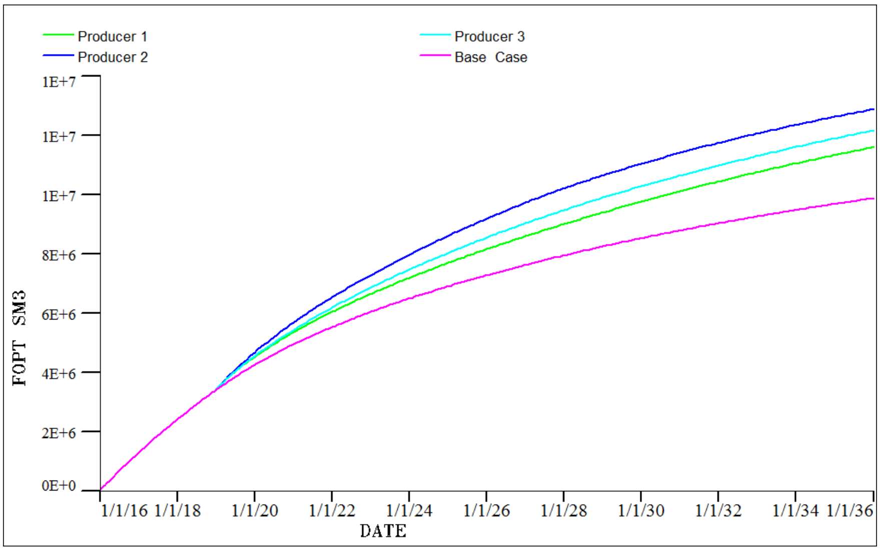

Figure 5.47: cumulative Oil production

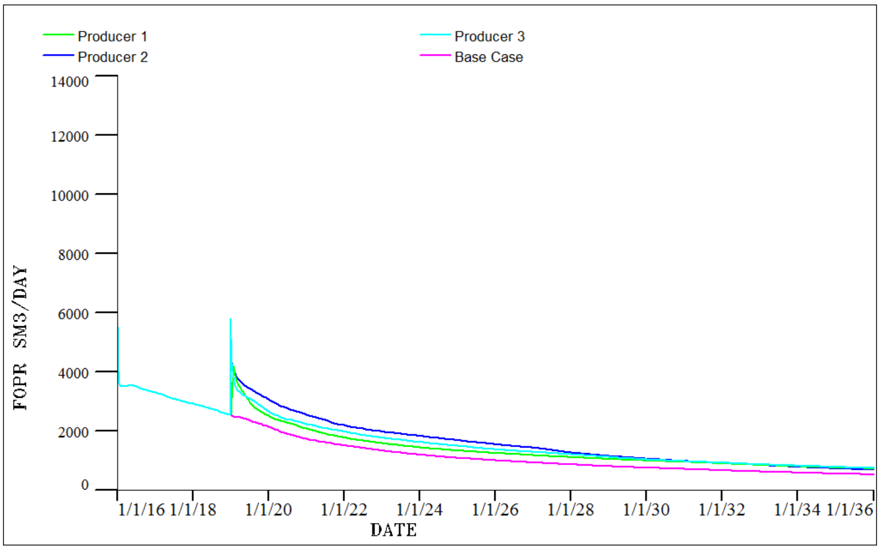

Figure 5.48: Oil production rate

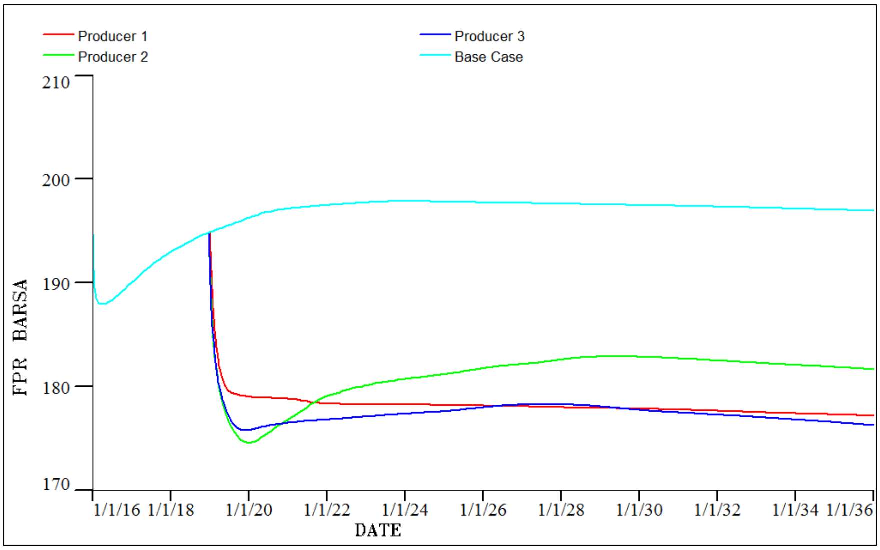

Figure 5.49: Oil production rate

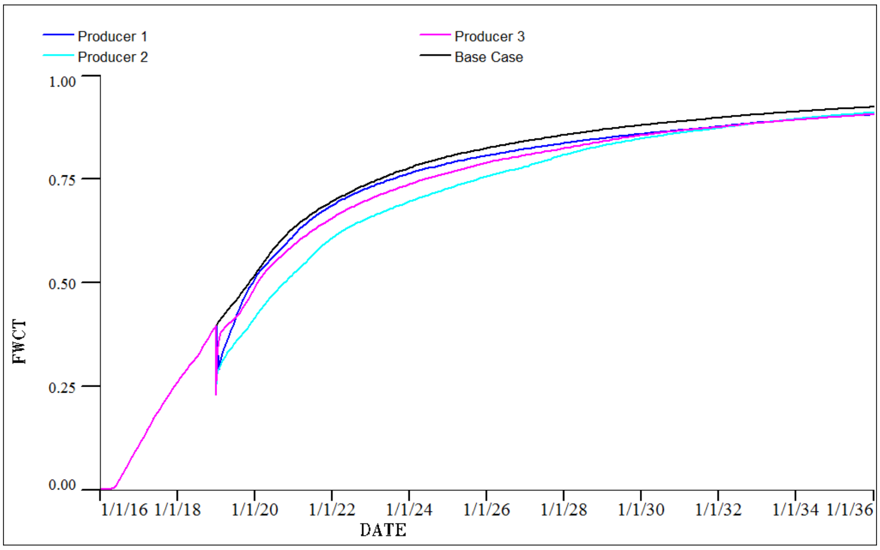

Figure 5.50: Oil production rate

5.6 New Injector wells Cases

There was a need for consideration for placement of injectors to improve field pressure and improve the sweeping efficiency of the producers. Several cases were simulated but only two are presented here.Because they were considered to be more promising than the rest cases in question. The placements to be discussed are as shown on **figure 5.51** for New injector 1 and **figure 5.56** for New injector 2.

5.6.1 New Injector 1

New injector 1 was placed to improve pressure maintenance for producer 9 and 10 which are vertical producers . The available injectors in this place were mainly supporting the horizontal producers such as producer 2 this was because the perforations were mainly around the horizontal producer and thus influence sweeping in the drainage area of the horizontal producers. Thus placing this new injector in this place could influence production in the intended producer and the field in general. Observation on **figure 5.52** the the cumulative production curve below shows there was an incremental production of **2,206,703.10 bbl** from the base case . This is influenced by the production rate increased because the placed injector has increased the influx of fluids to the producers as it can be observed on **figure 5.53**. All these improvements were a result of pressure improvement in the field imposed by the new injector placed this is observed by higher pressure profile on **figure 5.53**. With all these improvements there was relatively low associated water cut as it can be observed on **figure 5.55** all these were the drive for discussing this case here.

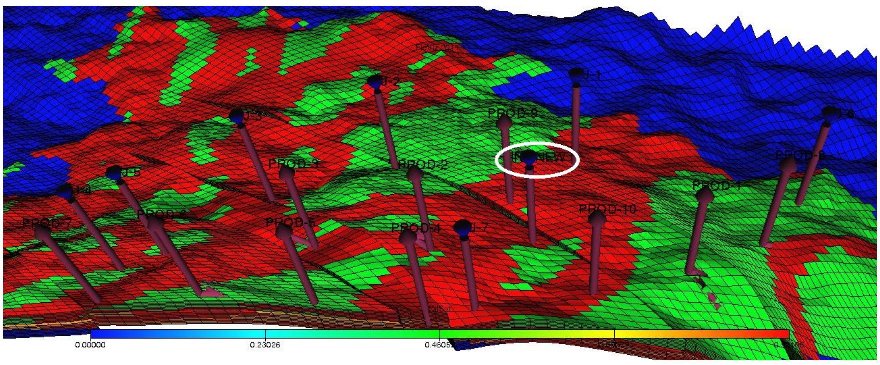

Figure 5.51: Olympus New Injector-1

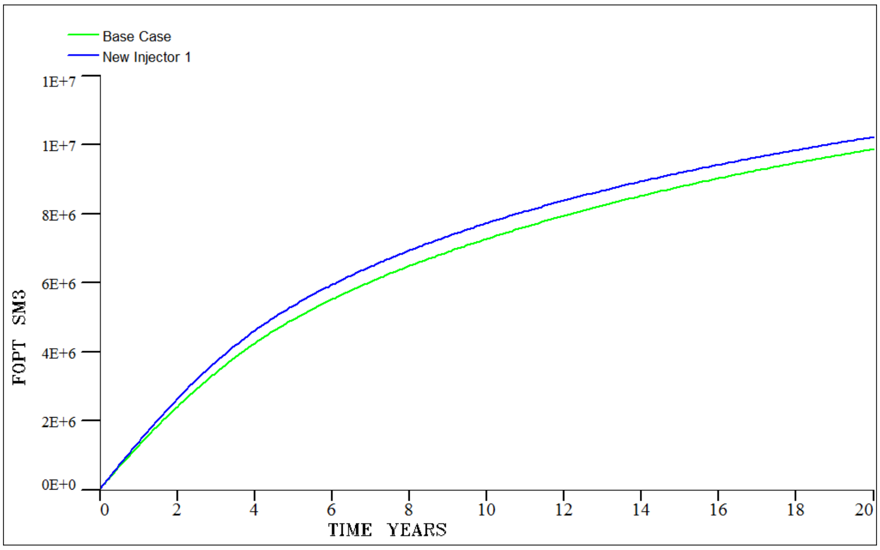

Figure 5.52: Olympus New Injector-1

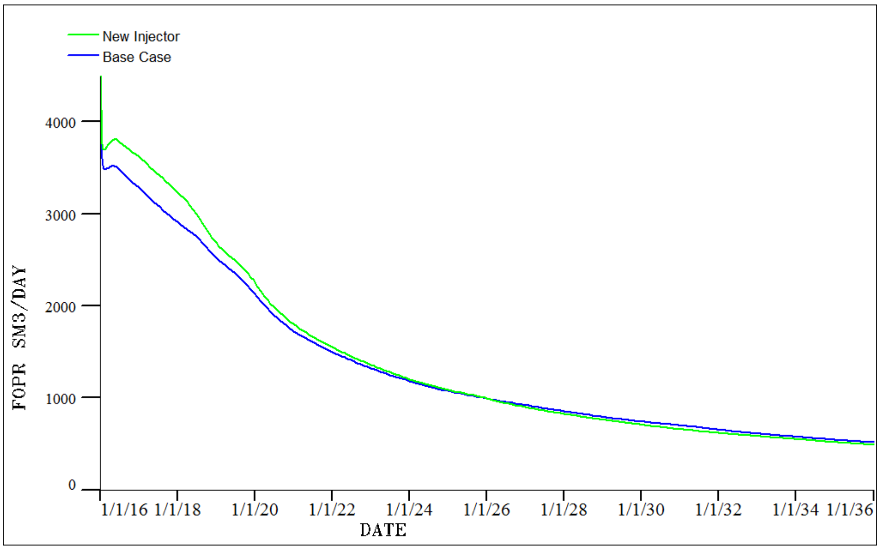

Figure 5.53: Olympus New Injector-1

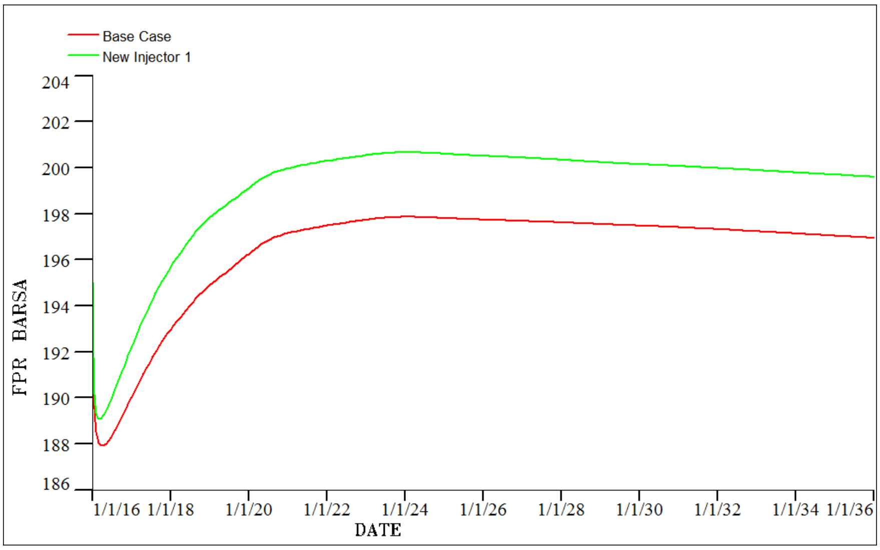

Figure 5.54: Olympus New Injector-1

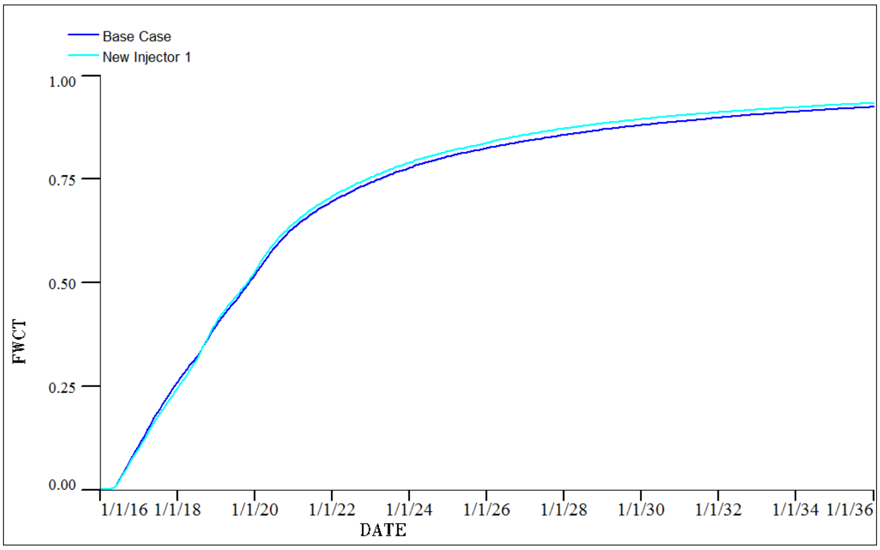

Figure 5.55: Olympus New Injector-1

5.6.2 New Injector 2

New injector 2 was also placed to improve pressure maintenance for horizontal producer 1. The available injector in this place were mainly supporting producer 2 this was because the perforations were parallel to vertical producer 8. Thus placing this new injector in this place could influence production in the intended producer and the field in general. Observation on **figure 5.57** the the cumulative production curve below shows there was an incremental production of **943,262.68 bbl** from the base case .

This is influenced by the production rate increased because the placed injector has increased the influx of fluids to the producers as it can be observed on **figure 5.58**. All these improvements were a result of pressure improvement in the field imposed by the new injector placed this is observed by higher pressure profile on **figure 5.58**. With all these improvements there was relatively low associated water cut higher at early times as it can be observed on **figure 5.60**

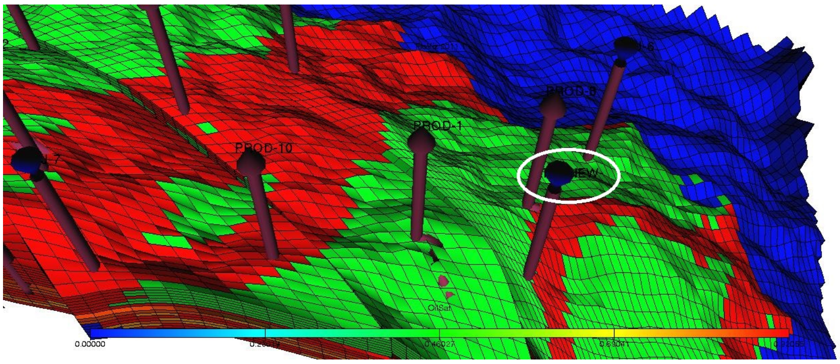

Figure 5.56: Olympus New Injector-2

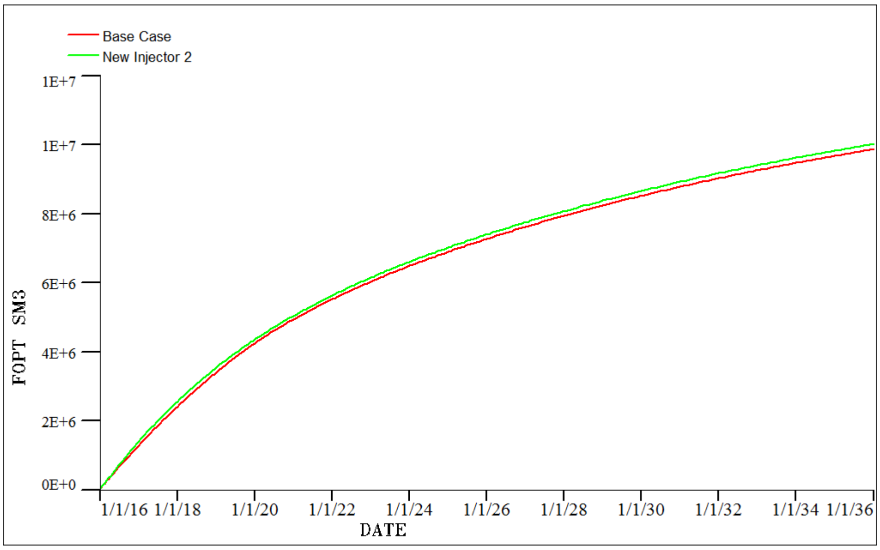

Figure 5.57: Olympus New Injector-2

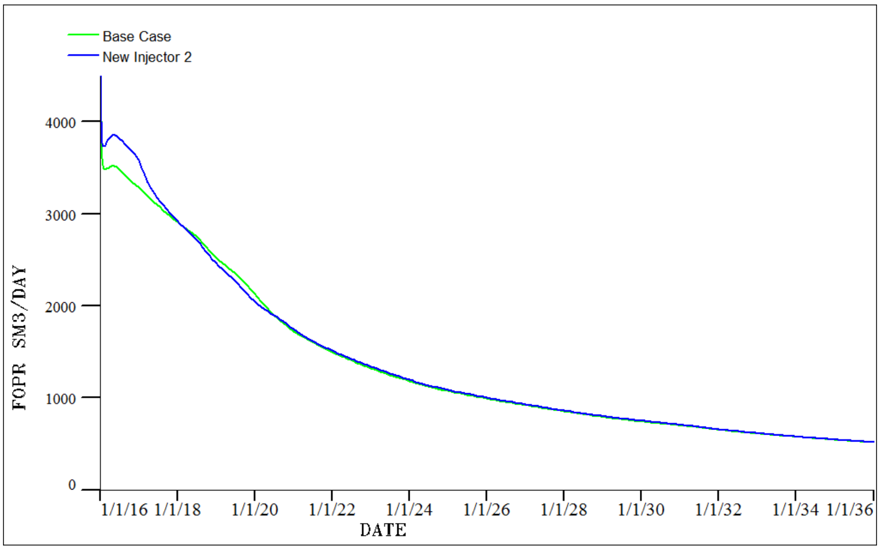

Figure 5.58: Olympus producer New injector -2

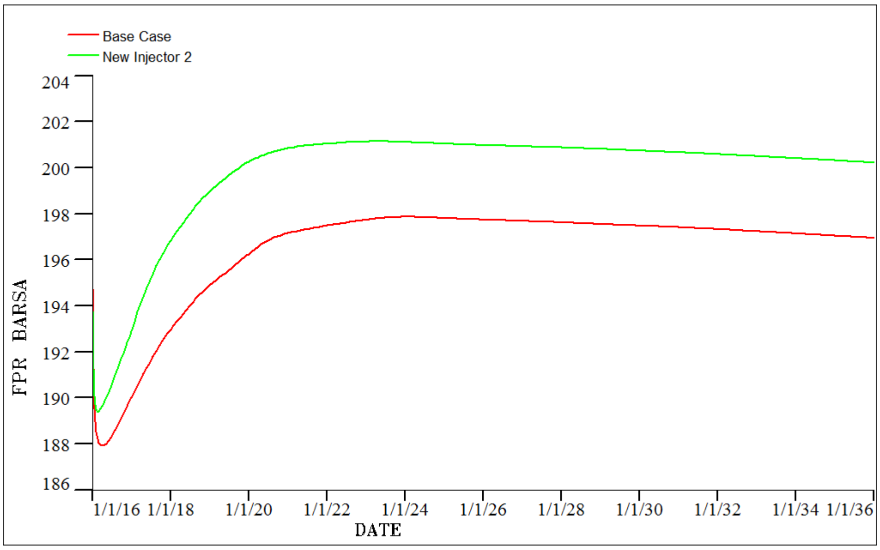

Figure 5.59: Olympus producer new injector-2

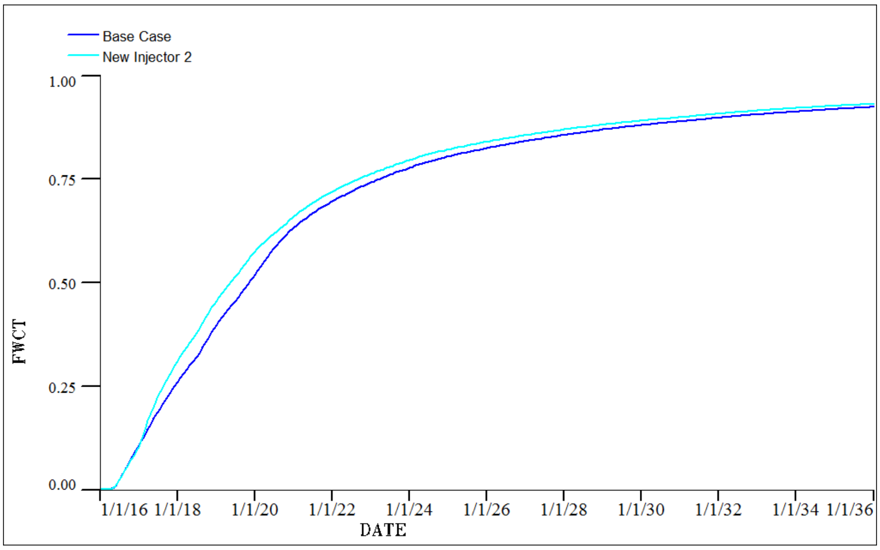

Figure 5.60: Olympus new injector-2

Chapter 6

Economic Analysis

Net Present Value (NPV) is the value of all future cash flows (positive and negative) over the entire life of an investment discounted to the present. This is an important indicator of how the field generate or use money on the entire life time of the project.NPV is calculated using the formulation provided in **(Onwunalu & Durlofsky, 2010)**, reproduced here for convenience.

$$NPV = \sum_{t=1}^{T} \frac{CF_t}{(1+r)^t} \tag{6.1}$$

Where r is the rate of return, T is the set of time intervals,CF_t is the cash flow in the time period t and the capital expenditure, C^{capex} is the cost of any development work and is defined as

$$C^{capex} = \sum_{w=1}^{N_{well}} C^{surface} + C^{drill} L^{shaft} \tag{6.2}$$

where N_well refers to the number of wells to drilled, C is the cost of the superscript and L is the well depth in feet. The cash flow term is revenue minus expenses.

$$CF_t = p^o \mathrm{Q}_t^O + p^g \mathrm{Q}_t^g - C^{wp} Q \mathrm{Q}^w p_t - C^{wi} \mathrm{Q}^w i_t \tag{6.3}$$

where p is the price of oil ,C is the cost of water production or water injection and Q denotes the production or injection rates of each fluid during the denoted time intervals. For simplicity many financial considerations are omitted in this study because the focus is to observe if the the developed cases have comparatively improved production optimally basing on the developed assumptions and controls.

The following were the assumptions put in place in performing economic analysis. The up time for production in a year was 95%, The CAPEX was assumed to be 434 Million USD, the OPEX 50 Million USD excluding inflations and DRILLEX was set to be 120 Million USD including perforation completing and well equipment, Discount rate was set to be 10% , Oil price was set to be 65 USD and assumed to be constant as they can be observed on **table 6.1**.

All these figures were set taking a reference to various field in Norway this because the model used in this study is a mimic of a field in North sea. The assumption was that in the same year the well was drilled and commenced production.

	Production	
Uptime	95	%
Prod days/yr	346.75	days/year
Wells	11	
CAPEX - TOTAL	4.34E+08	USD
OPEX	1.00E+08	USD
DRILLEX	1.20E+08	USD /well
Discount rate	0.10	fraction
Oil price	65	[USD/stb]

	Time end of year	Oil production in year [stb]	Revenue USD	DRILLEX USD	CAPEX USD	OPEX USD	Total Cost USD	Cash Flow USD	discount factor	Discounted Cash Flow: PV(i) USD
2016	0	8.09E+06	5.26E+08			5.00E+07	5.00E+07	4.76E+08	1.00	4.76E+08
2017	1	7.06E+06	4.59E+08			5.00E+07	5.00E+07	4.09E+08	0.91	3.72E+08
2018	2	6.24E+06	4.05E+08			5.00E+07	5.00E+07	3.55E+08	0.83	2.94E+08
2019	3	7.97E+06	5.18E+08	1.20E+08	4.34E+08	5.00E+07	6.04E+08	-8.61E+07	0.75	-6.47E+07
2020	4	6.33E+06	4.11E+08			5.00E+07	5.00E+07	3.61E+08	0.68	2.47E+08
2021	5	5.37E+06	3.49E+08			5.00E+07	5.00E+07	2.99E+08	0.62	1.86E+08
2022	6	4.72E+06	3.07E+08			5.00E+07	5.00E+07	2.57E+08	0.56	1.45E+08
2023	7	4.32E+06	2.81E+08			5.00E+07	5.00E+07	2.31E+08	0.51	1.19E+08
2024	8	4.00E+06	2.60E+08			5.00E+07	5.00E+07	2.10E+08	0.47	9.78E+07
2025	9	3.66E+06	2.38E+08			5.00E+07	5.00E+07	1.88E+08	0.42	7.97E+07
2026	10	3.37E+06	2.19E+08			5.00E+07	5.00E+07	1.69E+08	0.39	6.53E+07
2027	11	3.06E+06	1.99E+08			5.00E+07	5.00E+07	1.49E+08	0.35	5.22E+07
2028	12	2.73E+06	1.78E+08			5.00E+07	5.00E+07	1.28E+08	0.32	4.07E+07
2029	13	2.49E+06	1.62E+08			5.00E+07	5.00E+07	1.12E+08	0.29	3.24E+07
2030	14	2.30E+06	1.49E+08			5.00E+07	5.00E+07	9.93E+07	0.26	2.62E+07
2031	15	2.14E+06	1.39E+08			5.00E+07	5.00E+07	8.89E+07	0.24	2.13E+07
2032	16	1.98E+06	1.29E+08			5.00E+07	5.00E+07	7.86E+07	0.22	1.71E+07
2033	17	1.83E+06	1.19E+08			5.00E+07	5.00E+07	6.89E+07	0.20	1.36E+07
2034	18	1.70E+06	1.10E+08			5.00E+07	5.00E+07	6.04E+07	0.18	1.09E+07
2035	19	1.59E+06	1.03E+08			5.00E+07	5.00E+07	5.33E+07	0.16	8.72E+06
									NPV [USD]	2.24E+09

Table 6.1: Olympus cash flow example

Cash flow analysis as observed on table 6.1 was done for all new well cases developed and comparison was made on the incremental production and the incremental NPV generated. According to the economic analysis it can be observed that Producer 2 resulted into the highest Incremental production of all the developed cases when compared to the base case. As it can be observed on **figure 6.1** producer 2 has the incremental cumulative production of approximately **20 million barrels** from the base case followed by producer 3 about **14 million barrels**, then producer 1,about **12 million barrels** Injector 1 about **3 million barrels** and finally injector **1 million barrels**.

Similarly an observation on the NPV generated from the cases as shown on **figure 6.2** it can be observed that Producer 2 had the highest Incremental NPV by about 38% which is an increase of about 734 Million USD when compared to the base case followed by producer 3 an increment of about 29% which is 563 million USD and producer 1 23% which is 451 million USD, injector 1 7% which is 145 million USD and injector 2 3% which is 53 Million USD.

Finally a plot of Discounted cash flow with time was drawn as it can be seen on **figure 6.3** and it was observed that in the beginning there was cash more cash outflow than inflows because more money is injected to ensure drilling of the new wells. There after there has been more cash inflows as observed by a sharp increase in Cash flow this is because no more wells are drilled in this time but rather more of revenues are generated from the production utilizing the available drilled wells at early times. and the gradually the cash flows decreases because production decreases too

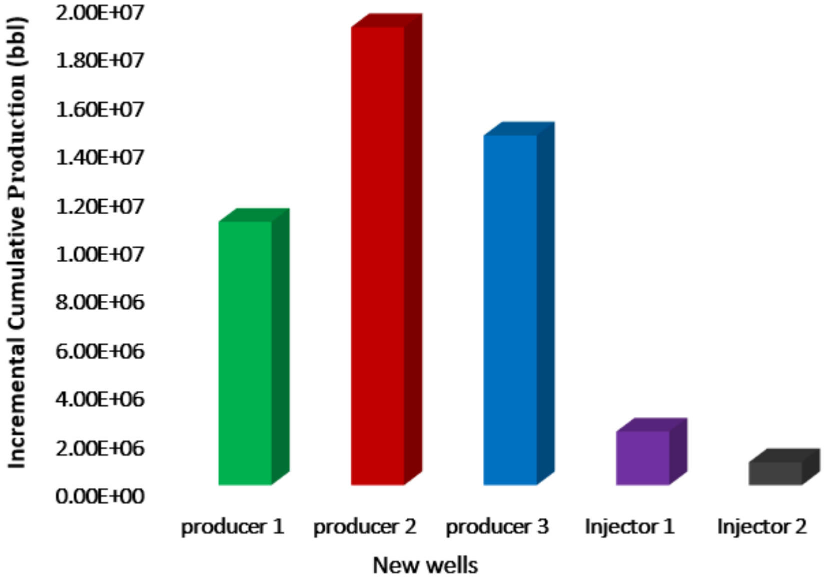

Figure 6.1: Olympus incremental Production

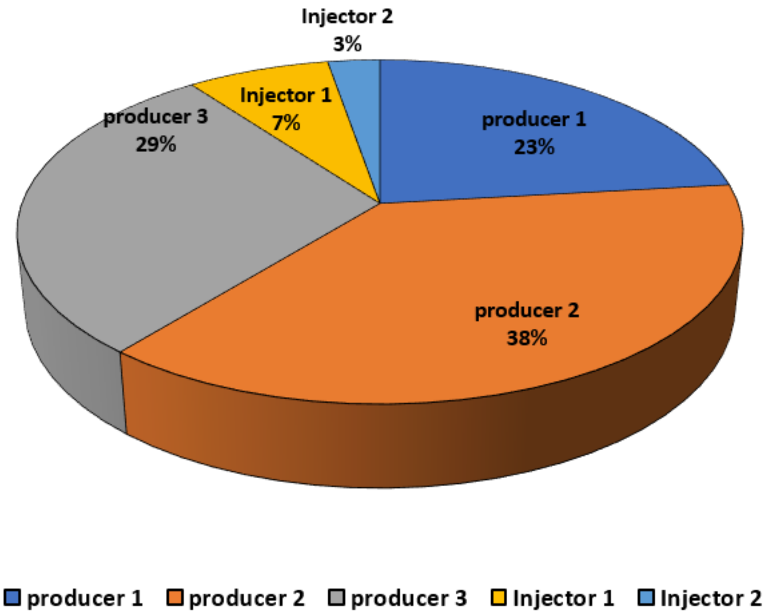

Figure 6.2: Olympus incremental NPV from base case

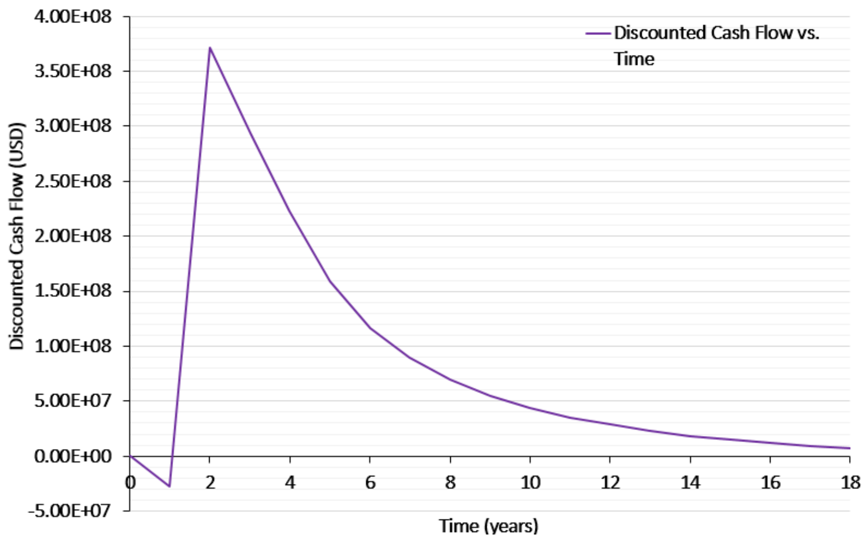

Figure 6.3: Olympus Cash flow trend for the best case

Chapter 7

Sensitivity Analysis

Mathematical models are utilized to approximate various highly complex engineering, physical, environmental, social, and economic phenomena. Model development consists of several logical steps, one of which is the determination of parameters which are most influential on model results. A **'sensitivity analysis'** of these parameters is not only critical to model validation but also serves to guide future research efforts (Iman & Helton, 1988). Modelers may conduct sensitivity analyses for a number of reasons including the need to determine: **(1)** which parameters require additional research for strengthening the knowledge base, thereby reducing output uncertainty; **(2)** which parameters are insignificant and can be eliminated from the final model; **(3)** which inputs contribute most to output variability; **(4)** which parameters are most highly correlated with the output; and **(5)** once the model is in production use, what consequence results from changing a given input parameter. (Iman & Helton, 1988).

There are many different ways of conducting sensitivity analyses; however, in answering these questions the various analyses may not produce identical results . Generally, sensitivity analyses are conducted by: **(a)** defining the model and its independent and dependent variables **(b)** assigning probability density functions to each input parameter, **(c)** generating an input matrix through an appropriate random sampling method, calculating an output vector.

7.1 Sensitivity Analysis Methods

Many authors, when referring to the degree to which an input parameter affects the model output, use the terms 'sensitive', 'important', 'most influential', 'major contributor', 'effective interchangeably (Iman & Helton, 1988). (Hamby, 1994) have made a distinction by referring to 'important' parameters as those whose uncertainty contributes substantially to the uncertainty in assessment results, and 'sensitive' parameters as those which have a significant influence on assessment results. The consensus among authors is that models are indeed sensitive to input parameters in two distinct ways: (1) the variability, or uncertainty, associated with a sensitive input parameter is propagated through the model resulting in a large contribution to the overall output variability, and (2) model results can be highly correlated with an input parameter so that small changes in the input value result in significant changes in the output. The necessary distinction between important and sensitive parameters is in the type of analysis being conducted: uncertainty analysis (parameter importance) or sensitivity analysis (parameter sensitivity). An important parameter is always sensitive because parameter variability will not appear in the output unless the model is sensitive to the input. A sensitive parameter, however, is not necessarily important because it may be known precisely, thereby having little variability to add to the output. The following are the common sensitivity methods.

7.1.1 Differential Sensitivity Analysis

Differential analysis, also referred to as the direct method, is discussed first since it is the backbone of nearly all other sensitivity analysis techniques. Methods in the literature range from solving simple partial derivatives to spatial and temporal sensitivity analyses (Morisawa & Inoue, 1974), (Iman & Helton, 1988). A sensitivity coefficient is basically the ratio of the change in output to the change in input while all other parameters remain constant . The model result while all parameters are held constant is defined as the 'base case'. Differential techniques are structured on the behavior of the model given a specific set of parameter values, e.g. assuming the base-case scenario is with all parameter values set to their mean. (Morisawa & Inoue, 1974). use the differential method as a means of selecting desirable conditions for underground waste disposal sites in Japan. They note, however, that, with the direct method, the magnitude of variable sensitivity is dependent on the base-case scenario. A major drawback is that this localized behavior may not be applicable for realms far from the base case.

7.1.2 One-at-a-time Sensitivity Measure

Conceptually, the simplest method to sensitivity analysis is to repeatedly vary one parameter at a time while holding the others fixed (Breshears, 1987). A sensitivity ranking can be obtained quickly by increasing each parameter by a given percentage while leaving all others constant, and quantifying the change in model output. This type of analysis has been referred to as a 'local' sensitivity. This helps determine how different values of an independent variable impact a particular dependent variable under a given set of assumptions. And this is the method which was employed in this study. In this case the dependent variable was NPV and the independent variables were Oil price, Capital Expenditure (CAPEX), drilling expenditure (DRILLEX) and drilling delay.

Observation on the developed tornado chart as observed on **figure 7.1** which shows the influence of the inputs to the output of the model on the best case so far (infill drilling of producer of vertical producer 2) which is observed on the results discussions together with the economic analysis done on the prior chapters.

It was observed that Oil price was very uncertain, from the tornado chart it can be observed that the oil price variation has the largest impact on the NPV obtained. However if the oil price varies by -30% still the NPV is above zero indicating that the drilled well will still be feasible to be drilled and give NPV of **1.30 Billion USD** which is below the Base case which is **2.24 Billion USD** for 20 years of oil production but positive meaning well placement in this location proves to be optimal

Increase in oil price by $+30\%$ would result into an NPV of 3.18 Billion which is way higher than the base case which is 2.24 Billion as mentioned in previous paragraphs.

Also CAPEX was assumed to vary by 30%accounting for factors such as wrong assumptions in assigning the cost figures in question. This variation in CAPEX indicated that that infill drilling will still be feasible and profitable to run because increase in CAPEX by +30% still gives **2.14 Billion USD** NPV which is adjusted by −30% it the Base case having no well but positive. Similarly when the cost is

Another factor was DRILLEX which was uncertain because of estimated drilling meters and the cost can used which can vary if the more days are used by the rig during drilling to the desired reservoir depth. The variation of +30%indicated that it has little effect on the NPV because increase in DRILLEX by +30% still resulted into **2.21 Billion USD** which is similarly below the reference case but above zero which is shows it is still profitable to drill this well.

Another factor was Delay in drilling this is because it was observed that there is a degree of communication between layers thus delay would have impact in the total production from the reservoir. Delay had little impact in NPV calculation this is because fluids do not migrate and thus it just have impacts in forecasting income. From this discussion it can be observed that oil price was the most sensitive parameter to be monitored. This can also be observed on the spider chart **figure 7.2** which shows oil price is the economic input having the largest influence to the NPV because of the largest deviation from the base case. And before execution of this strategy oil price need to be a priority sensitive input variable to be considered .

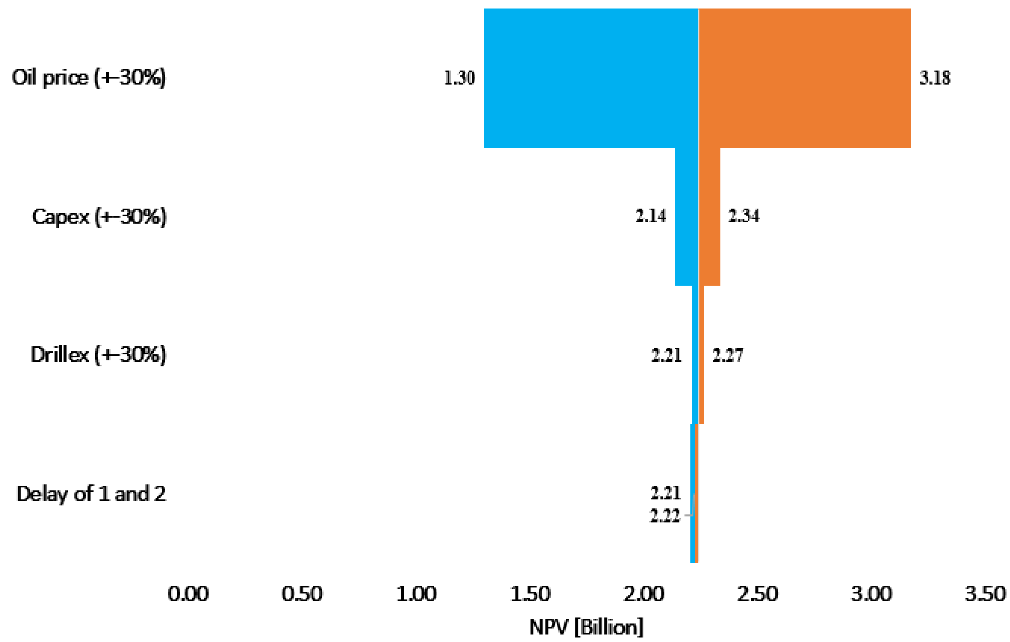

Figure 7.1: Olympus NPV sensitivity Tonardo chart

7.1.3 Limitation of Tonardo chart

As observed on figure **figure 7.1**. Tornado chart has helped to determine how the NPV outputs are influenced by each input, how ever the caveats of this method is that only one variable was changed at a time independently of the other and thus it can not account for multiple impacts of variables.

Also the results are highly dependent on the base case used for a variable and thus when generating the base case several simulations are supposed to be done.

Focusing on the **Spider Plot** which is plotted with the varying property on Y axis NPV for this case and the uncertain input on X axis (Oil price, Drillex, Capex, Opex), the wider the space from the base case the larger are the impacts of the variables for the NPV. According to the **figure 7.2** Oil price again deviates more from the base and thus much concern need to be put on the Oil price than the rest of the variables considered when focusing on placing a new well.

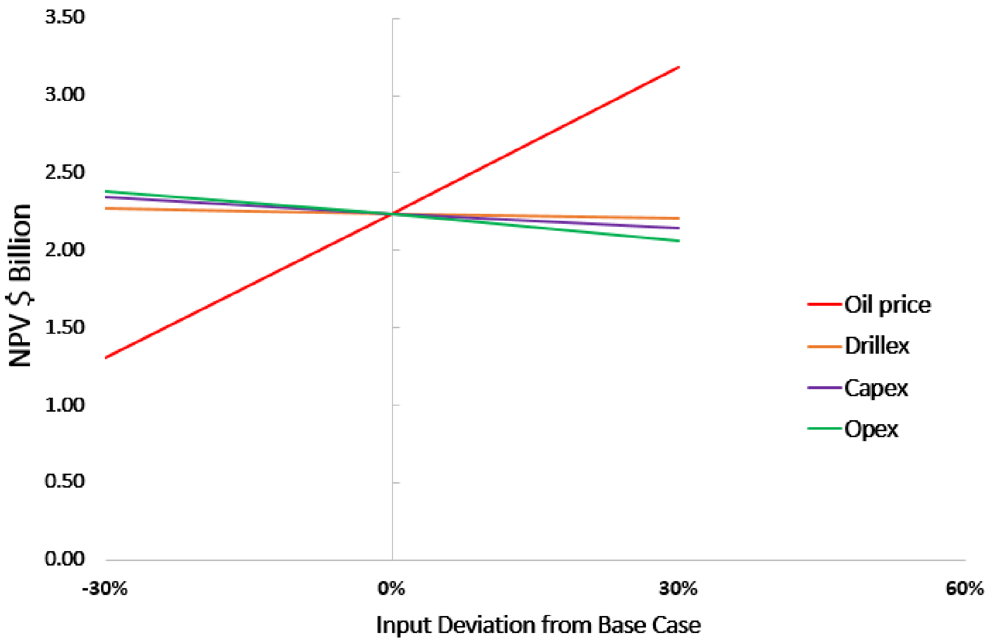

Figure 7.2: Olympus NPV sensitivity spider chart

Chapter 8

Risk Assessment

Well placement projects are always developed in order to extract resources and utilize the available opportunities, which is often associated with uncertainties, challenges and risks. Risks are always inevitable, even when it comes to small scale projects execution. Hence, risk assessment and its subsequent management becomes the key to a project's success. When new wells are to be placed in an oil or gas field, potential risks have to be assessed and managed to avoid setbacks and failures in the project in question.

Some risks associated with well placement are discussed below:

8.1 Financial Risks:

Price volatility is a major risk for the Petroleum sector. Increasing costs of extraction and global political dynamics have a serious affect oil prices. In order to mitigate the impacts of financial risks it is significantly important to forecast future petroleum demand and use discounted cash flows during the investment period.

8.2 Strategic Risks:

We live in an ever-changing world marked by technological advancements. The energy industry is no exception to that with recent attempts to develop bio-fuels. Although the competition offered by these advancements is very small, it cannot be neglected. But still oil continue to be the dominant energy source over the coming years.

8.3 Operational Risks:

Planning of well locations are done on reservoir models as observed. Models are representative of reality , Thus when executing the plan, care and engineering judgments need to be put in place to achieve the goal of drilling the new well to meet the improvement in production. If no care is taken unnecessary expenses becomes inevitable and thus operations becomes difficult.

8.4 Compliance Issues:

Regulatory compliances have increased operational and financial challenges in the oil industry. Governments and regulatory authorities normally set safety regulations and environmental guidelines. The environment is always a serious concern as it poses a direct threat to marine and human life. Therefore, such risks need to be accounted for to avoid costs which can make well placement uneconomic for executions purposes.

8.5 Drilling Risks:

- **Wait on Weather (WOW)**: This is one of the most common problem encountered during drilling operations. It can cause potential operational delays especially in the North Sea area. Based on industrial experience, an extra duration of about 10-15 % of the total drilling time is considered in the planning to cater for WOW issue (Kullawan, 2012). It is important to incorporate this risk in planning to avoid financial setbacks because Olympus Model mimics the real field in North Sea.
- **Kick:** They vary considerably in their probability of occurrence, depending upon activity level and the geological condition (Kullawan, 2012). In drilling new wells the probability of experiencing a kick is high if pressure is not properly controlled and experience shows if kicks are not well handled results into blowout.
- **Bottom Hole Assembly (BHA) Failure:** In the event of a BHA failure, the extra duration required depends significantly on the depth of failure (Kullawan, 2012). Hence, each hole section would have different range of extra duration. This should be a consideration while planning the drilling operation and the extra duration caused by such events should be estimated based on previous experience.
- **Stuck Pipe Events:** Statistical studies carried out by (Howard & Glover, 1994) for stuck pipe events show that one of every three wells drilled in the Gulf of Mexico and the North Sea has experienced stuck pipe problems. Thus, the probability of occurrence is intermediate. However, time lost is translated into financial loss and must be considered in the planning phase.

Risk analysis resulted in the risk matrix shown in **table 8.1**. The important outcome of this analysis is a structured basis for identifying mitigation to reduce risk and its consequences. The allocations in the matrix are explained with associated mitigations in **table 8.2.** No substantial risks were identified to terminate execution of well placements. Mitigations must be implemented to avoid more specific delay of drilling as it will increase cost rapidly due to the rig rate and cost of equipment.

	CONSEQUENCE				
LIKELIHOOD	Insignificant (1)	Minor (2)	Moderate (3)	Major (4)	Extreme (5)
Rare (1)					
Unlikely (2)			Compliance Risks	Stuck pipe	
Possible (3)			Operational Risks		
Likely (4)	Strategic Risks		BHA Failure	Wait on Weather	kick
Almost certain (5)					Oil price

Very High	High	Medium	Low

Table 8.1: Risk matrix.

Risk	Category	Explanation	Mitigation
Strategic Risk	low	Technological changes and development	Allowing dynamics to give room for new technology.
Compliance Risk	low	Change of policies and guidelines	Observation to regulations put in place
Operational Risk	medium	Change of operational controls and targets	Following proper drilling practises to avoid unnecessary costs
Stuck Pipe	Medium	Can result into closure of a well	Selection of mud system resulting to smooth mud cake
BHA failure	Medium	Very expensive may result into well trajectory change	Proper drilling practises by reducing weight on bit.
Wait On Weather	Medium	It's common to most North Sea fields	Proper scheduling of drilling practises (summer time in North Sea)
Kick	High	Can lead into a potential of blowout	Proper controlled drilling
Oil Price	Very High	Oil prices varies considerably	Precise estimations of future fuels demands and market fluctuations

Table 8.2: Summary of the risk assessment

Chapter 9

Conclusion and Future work

Observation on the developed cases indicates that well placement need to consider field development constraints such as pressure, faults, saturation, inter well distance and production controls. From this study it was found that re-placement of the producer and the injectors on the base case considering the mention parameters gave promising improve which shows there were some mis-locations of the wells on the base case. This is why the reallocations have to large extent improved the oil production in the olympus field.

Reallocations of injectors it was observed that inter well distance and perforation on the correct places for drainage of the fluids by enhancing draw down was the key. For example on the base model an injector 5 was on the drainage area of horizontal producer 6. After re-allocation relatively distant from the producer more of water could not reach the producer shortly and better pressure maintenance was achieved giving an improvement of **1,095,381.733 bbl** which is equivalent to about **3%** increment of oil production as compared to the base case, similarly injector 3 produced an improvement of **3,505,102.291 bbl** which is equivalent to about **9%** increment, injector 4 an improvement of **2,566,104.104 bbl** which is equivalent to about **6%** increment Injector 2 gave an improvement of **908,335.3634 bbl** which is equivalent to about **2%** increment. Furthermore sweeping of fluids to the producer was more efficient.Thus when placing injectors it is important to consider inter-well distance, horizontal permeability to avoid early water breakthrough but also considering improving sweeping efficiency.

On re-placement of the producers on the base case it was observed there was a challenge on selection of the perforations layers also some producer were located relatively far from the influence of injectors for pressure maintenance and improving sweeping of fluids and improve oil production. Thus producers are supposed to be placed on a high saturation and with considerations on pressure maintenance. For example **producer 9** was not efficiently influenced its production by injector 1 because it was misplaced But proper placement has resulted into an increment of **3,628,527.233 bbl** in production which is equivalent to about **9%** recovery increment. similarly **producer 7** resulted into an improvement of **1,613,970.278 bbl** which is equivalent to about **4%** recovery increment of oil from the base case.

Placement of new wells was more promising and thus it proved that placing new wells gives more improvements in production with the economic constraints be taken into consideration. And it was found that producer 2 which is a vertical producer an incremental production of about **18,881,335.35 bbl** which is as incremental recovery improve of **47%** compared to the base case with the incremental NPV of about **734 Million USD**,and producer 3 giving oil production increment of **14,414,846.92 bbl** which is about **36%** recovery improve compared to the base case with NPV increment of 563 Million USD, Producer 1 giving oil production increment of **10,856,349.18 bbl** which is an increment of about **27%** in oil recovery with NPV increment of 451 Million USD. This shows vertical wells perforating high saturation, away from the influence of other wells, relatively high pressure area improves cumulative oil production of the field and becomes for drilling purposes in a realistic field. Relative improvements in cumulative oil production is observed when an injector is placed as well this is because pressure is maintained properly and sweeping efficiency of oil to the producers is improved when permeability is good, this is observed by an improvement in oil production of **2,206,703.10 bbl** which is about **5%** Oil recovery increment from the base case and NPV increment of **145 Million USD** when injector 1 is placed.

Also there was **943,262.68 bbl** cumulative oil production increment which is equivalent to **2%** oil recovery increment from base case and an increment of **53.0 Million USD** in NPV when injector 2 is placed all these comparison being done with reference to the base case.

9.1 Future work

This study focused on Manual well placement subject to realistic field development constraints which involved mainly trial and errors well placements to improve cumulative oil production optimally. Thus recommendation is that automatic well placements need to be done by using heuristic methods and reconcile with the manual placements and see which of the two approaches give a more promising improvement in oil production while taking into considerations involvement of petroleum expertise in the process.

And it is supposed to be done on a real field model so that the obtained results can be of use in field development of the same. Incorporating real field data will enrich the study and thus involve more controls. Here optimizers will be involved to ensure proper constraints such as well location, inter well distance, well trajectories are all taken into considerations in achieving the desired optimal well location.

Intensive Economic analysis is supposed to be done with actual inputs from the real field in operation as actual values in practice, this will enrich the optimization process and reduce the assumptions on most of the costs and other cash flow inputs. This will incorporate uncertainty analysis as well to ensure the chosen case is truly optimal for field development purposes engaging randomness of the variables.

Sensitivity analysis is supposed to be done including multiple variables to represent the real influence of the inputs to the outputs of the model of interest. This will remove bias in observing the effect of the variation in the variables with respect to the overall field output.

References

2b1consulting. (2012). *Conventional Oil and Gas.* Retrieved from https://www.2b1stconsulting.com/conventional-oil-and-gas20-03-2019

Abukhamsin, A. Y. (2009). Optimization of well design and location in a real field. *Unpublished MS thesis, Stanford University, CA.*

Bellout, M. C., Ciaurri, D. E., Durlofsky, L. J., Foss, B., & Kleppe, J. (2012). Joint optimization of oil well placement and controls. *Computational Geosciences*, *16*(4), 1061–1079.

Bittencourt, A. C., Horne, R. N., et al. (1997). Reservoir development and design optimization. In *Spe annual technical conference and exhibition.*

Breshears, D. D. (1987). *Uncertainty and sensitivity analyses of simulated concentrations of radionuclides in milk* (Tech. Rep.). Colorado State Univ., Fort Collins (USA). Dept. of Radiology and Radiation ....

Emerick, A. A., Silva, E., Messer, B., Almeida, L. F., Szwarcman, D., Pacheco, M. A. C., ... others (2009). Well placement optimization using a genetic algorithm with nonlinear constraints. In *Spe reservoir simulation symposium.*

Engineering, P. . G. (2016). *Sidetracking.* Retrieved from http://petroleumandgasengineering.blogspot.com/2016/02/sidetracking.html

Equinor. (2018). Disclosing all volve data. Retrieved from https://www.equinor.com/en/news/14jun2018-disclosing-volve-data.html

Fonseca, R., Geel, C., & Leeuwenburgh, O. (2017). Description of olympus reservoir model for optimization challenge. *Integrated Systems Approach to Petroleum Production*.

Griffin, J. M., & Teece, D. J. (2016). Opec behaviour and world oil prices.

Hamby, D. (1994). A review of techniques for parameter sensitivity analysis of environmental models. *Environmental monitoring and assessment*, *32*(2), 135–154.

Howard, J., & Glover, S. (1994). Tracking stuck pipe probability while drilling. In *Spe/iadc drilling conference.* Society of Petroleum Engineers. Retrieved from https://doi.org/10.2118/27528-MS

Iman, R. L., & Helton, J. C. (1988). An investigation of uncertainty and sensitivity analysis techniques for computer models. *Risk analysis*, *8*(1), 71–90.

Kramer, O., Ciaurri, D. E., & Koziel, S. (2011). Derivative-free optimization. In *Computational optimization, methods and algorithms* (pp. 61–83). Springer.

Kullawan, K. (2012). *Risk based cost and duration estimation of well operations.*

Morisawa, S., & Inoue, Y. (1974). On the selection of a ground disposal site by sensitivity analysis. *Health physics*, *26*(3), 251–261.

Nogueira, P. D. B., Schiozer, D. J., et al. (2009). An efficient methodology of production strategy optimization based on genetic algorithms. In *Latin american and caribbean petroleum engineering conference.*

Onwunalu, J. E., & Durlofsky, L. J. (2010). Application of a particle swarm optimization algorithm for determining optimum well location and type. *Computational Geosciences*, *14*(1), 183–198.

Pérez-Lombard, L., Ortiz, J., & Pout, C. (2008). A review on buildings energy consumption information. *Energy and buildings*, *40*(3), 394–398.

Salami, O. T. (2014). *Synthesis and working mechanism of humic acid graft copolymer fluid loss additives suitable for cementing high pressure/high temperature oil and gas wells* (Unpublished doctoral dissertation). Technische Universität München.

Schlumberger. (2018). *Glossary.* Retrieved from `https://www.glossary.oilfield.slb.com/en/Terms/f/fault.aspx13.02.2019`

Shepherd, M. (2009). *Oil field production geology: Aapg memoir 91* (Vol. 91). AAPG.

Wikipedia. (2017). Permeability. Retrieved from `https://en.wikipedia.org/wiki/Permeability_(earth_sciences)30.01.2019`

Wikipedia. (2018). Determination of originally oil in place. Retrieved from `https://en.wikipedia.org/wiki/Oil_in_place24.01.2019`

Yildiz, A. R. (2013). Comparison of evolutionary-based optimization algorithms for structural design optimization. *Engineering applications of artificial intelligence*, *26*(1), 327–333.

Zakharov, A. (2016). *On the importance of expert knowledge in well placement optimisation* (Unpublished master's thesis). NTNU.

Zandvliet, M. J. (2008). Model-based lifecycle optimization of well locations and production settings in petroleum reservoirs.

Zhang, K., Li, G., Reynolds, A. C., Yao, J., & Zhang, L. (2010a). Optimal well placement using an adjoint gradient. *Journal of Petroleum Science and Engineering*, *73*(3-4), 200–226.

Zhang, K., Li, G., Reynolds, A. C., Yao, J., & Zhang, L. (2010b). Optimal well placement using an adjoint gradient. *Journal of Petroleum Science and Engineering*, *73*(3-4), 220–226.

Appendices

	Production	
Uptime	95	%
No of prod days/yr	346.75	days/year
Wells	21	
CAPEX - TOTAL	4.34E+08	USD
OPEX	1.00E+08	USD
DRILLEX	1.20E+08	USD /well
Discount rate	0.10	fraction
Oil price	65	[USD/stb]

FORMULA USED FOR CALCULATING THE NPV

$$NPV = \sum_{i=0}^{N} \frac{\text{Oil Price(i)} \times \text{Production rate(i)-CAPEX(i)-DRILLEX(i)-OPEX(i)}}{(1+r)^{i}}$$

	Time end of year	Oil production in year [stb]	Revenue USD	DRILLEX USD	CAPEX USD	OPEX USD	Total Cost USD	Cash Flow USD	discount factor	Discounted Cash Flow: PV(i) USD
2016	0	8.09E+06	5.26E+08	1.20E+08	4.34E+08	5.00E+07	6.04E+08	-7.78E+07	1.00	-7.78E+07
2017	1	7.06E+06	4.59E+08			5.00E+07	5.00E+07	4.09E+08	0.91	3.72E+08
2018	2	6.24E+06	4.05E+08			5.00E+07	5.00E+07	3.55E+08	0.83	2.94E+08
2019	3	5.33E+06	3.47E+08			5.00E+07	5.00E+07	2.97E+08	0.75	2.23E+08
2020	4	4.35E+06	2.83E+08			5.00E+07	5.00E+07	2.33E+08	0.68	1.59E+08
2021	5	3.66E+06	2.38E+08			5.00E+07	5.00E+07	1.88E+08	0.62	1.17E+08
2022	6	3.21E+06	2.09E+08			5.00E+07	5.00E+07	1.59E+08	0.56	8.97E+07
2023	7	2.85E+06	1.86E+08			5.00E+07	5.00E+07	1.36E+08	0.51	6.96E+07
2024	8	2.58E+06	1.67E+08			5.00E+07	5.00E+07	1.17E+08	0.47	5.48E+07
2025	9	2.36E+06	1.53E+08			5.00E+07	5.00E+07	1.03E+08	0.42	4.38E+07
2026	10	2.18E+06	1.42E+08			5.00E+07	5.00E+07	9.19E+07	0.39	3.54E+07
2027	11	2.02E+06	1.32E+08			5.00E+07	5.00E+07	8.16E+07	0.35	2.86E+07
2028	12	1.88E+06	1.22E+08			5.00E+07	5.00E+07	7.24E+07	0.32	2.31E+07
2029	13	1.75E+06	1.14E+08			5.00E+07	5.00E+07	6.38E+07	0.29	1.85E+07
2030	14	1.65E+06	1.07E+08			5.00E+07	5.00E+07	5.70E+07	0.26	1.50E+07
2031	15	1.55E+06	1.00E+08			5.00E+07	5.00E+07	5.05E+07	0.24	1.21E+07
2032	16	1.45E+06	9.40E+07			5.00E+07	5.00E+07	4.40E+07	0.22	9.58E+06
2033	17	1.36E+06	8.82E+07			5.00E+07	5.00E+07	3.82E+07	0.20	7.55E+06
2034	18	1.28E+06	8.30E+07			5.00E+07	5.00E+07	3.30E+07	0.18	5.94E+06
2035	19	1.21E+06	7.85E+07			5.00E+07	5.00E+07	2.85E+07	0.16	4.66E+06
									NPV [USD]	1.50E+09

Table 1: Olympus cash flow base case

Production		
Uptime	95	%
No of prod days/yr	346.75	days/year
Wells	11	
CAPEX - TOTAL	4.34E+08	USD
OPEX	1.00E+08	USD
DRILLEX	1.20E+08	USD /well
Discount rate	0.10	fraction
Oil price	65	[USD/stb]

	Time	il production in ye	Revenue	DRILLEX	CAPEX	OPEX	otal Co	ash Flo	discount	ounted Cash Flow: PV(i)
	end of year	[stb]	USD	USD	USD	USD	USD	USD	factor	USD
2016	0	8.09E+06	5.26E+08			5.00E+07	5.00E+07	4.76E+08	1.00	4.76E+08
2017	1	7.06E+06	4.59E+08			5.00E+07	5.00E+07	4.09E+08	0.91	3.72E+08
2018	2	6.24E+06	4.05E+08			5.00E+07	5.00E+07	3.55E+08	0.83	2.94E+08
2019	3	7.07E+06	4.59E+08	1.20E+08	4.34E+08	5.00E+07	6.04E+08	-1.45E+08	0.75	-1.09E+08
2020	4	5.18E+06	3.37E+08			5.00E+07	5.00E+07	2.87E+08	0.68	1.96E+08
2021	5	4.34E+06	2.82E+08			5.00E+07	5.00E+07	2.32E+08	0.62	1.44E+08
2022	6	3.79E+06	2.47E+08			5.00E+07	5.00E+07	1.97E+08	0.56	1.11E+08
2023	7	3.43E+06	2.23E+08			5.00E+07	5.00E+07	1.73E+08	0.51	8.86E+07
2024	8	3.15E+06	2.05E+08			5.00E+07	5.00E+07	1.55E+08	0.47	7.23E+07
2025	9	2.93E+06	1.90E+08			5.00E+07	5.00E+07	1.40E+08	0.42	5.95E+07
2026	10	2.75E+06	1.79E+08			5.00E+07	5.00E+07	1.29E+08	0.39	4.96E+07
2027	11	2.59E+06	1.68E+08			5.00E+07	5.00E+07	1.18E+08	0.35	4.14E+07
2028	12	2.45E+06	1.59E+08			5.00E+07	5.00E+07	1.09E+08	0.32	3.47E+07
2029	13	2.31E+06	1.50E+08			5.00E+07	5.00E+07	1.00E+08	0.29	2.90E+07
2030	14	2.20E+06	1.43E+08			5.00E+07	5.00E+07	9.27E+07	0.26	2.44E+07
2031	15	2.09E+06	1.36E+08			5.00E+07	5.00E+07	8.58E+07	0.24	2.05E+07
2032	16	1.97E+06	1.28E+08			5.00E+07	5.00E+07	7.81E+07	0.22	1.70E+07
2033	17	1.85E+06	1.21E+08			5.00E+07	5.00E+07	7.06E+07	0.20	1.40E+07
2034	18	1.76E+06	1.15E+08			5.00E+07	5.00E+07	6.45E+07	0.18	1.16E+07
2035	19	1.68E+06	1.09E+08			5.00E+07	5.00E+07	5.92E+07	0.16	9.67E+06
									NPV [USD]	1.96E+09

Table 2: Olympus cash flow for new producer 1 case

Production		
Uptime	95	%
No of prod days/y	346.75	days/year
Wells	11	
CAPEX - TOTAL	4.34E+08	USD
OPEX	1.00E+08	USD
DRILLEX	1.20E+08	USD /well
Discount rate	0.10	fraction
Oil price	65	[USD/stb]

	Time	Oil production in year	Revenue	DRILLEX	CAPEX	OPEX	Total Cost	Cash Flow	discount	Discounted Cash Flow: PV(i)
	end of year	[stb]	USD	USD	USD	USD	USD	USD	factor	USD
2016	0	8.09E+06	5.26E+08			5.00E+07	5.00E+07	4.76E+08	1.00	4.76E+08
2017	1	7.06E+06	4.59E+08			5.00E+07	5.00E+07	4.09E+08	0.91	3.72E+08
2018	2	6.24E+06	4.05E+08			5.00E+07	5.00E+07	3.55E+08	0.83	2.94E+08
2019	3	7.21E+06	4.69E+08	1.20E+08	4.34E+08	5.00E+07	6.04E+08	-1.35E+08	0.75	-1.02E+08
2020	4	5.50E+06	3.57E+08			5.00E+07	5.00E+07	3.07E+08	0.68	2.10E+08
2021	5	4.77E+06	3.10E+08			5.00E+07	5.00E+07	2.60E+08	0.62	1.61E+08
2022	6	4.24E+06	2.76E+08			5.00E+07	5.00E+07	2.26E+08	0.56	1.27E+08
2023	7	3.85E+06	2.50E+08			5.00E+07	5.00E+07	2.00E+08	0.51	1.03E+08
2024	8	3.54E+06	2.30E+08			5.00E+07	5.00E+07	1.80E+08	0.47	8.40E+07
2025	9	3.25E+06	2.11E+08			5.00E+07	5.00E+07	1.61E+08	0.42	6.83E+07
2026	10	3.02E+06	1.96E+08			5.00E+07	5.00E+07	1.46E+08	0.39	5.63E+07
2027	11	2.83E+06	1.84E+08			5.00E+07	5.00E+07	1.34E+08	0.35	4.69E+07
2028	12	2.63E+06	1.71E+08			5.00E+07	5.00E+07	1.21E+08	0.32	3.86E+07
2029	13	2.42E+06	1.58E+08			5.00E+07	5.00E+07	1.08E+08	0.29	3.11E+07
2030	14	2.26E+06	1.47E+08			5.00E+07	5.00E+07	9.70E+07	0.26	2.55E+07
2031	15	2.14E+06	1.39E+08			5.00E+07	5.00E+07	8.92E+07	0.24	2.13E+07
2032	16	2.02E+06	1.31E+08			5.00E+07	5.00E+07	8.15E+07	0.22	1.77E+07
2033	17	1.90E+06	1.24E+08			5.00E+07	5.00E+07	7.37E+07	0.20	1.46E+07
2034	18	1.80E+06	1.17E+08			5.00E+07	5.00E+07	6.72E+07	0.18	1.21E+07
2035	19	1.71E+06	1.11E+08			5.00E+07	5.00E+07	6.10E+07	0.16	9.97E+06
									NPV [USD]	2.07E+09

Table 3: Olympus cash flow for producer 3

Production		
Uptime	95	%
Nuo of prod dys/ ye	346.75	days/year
Wells	18	
CAPEX - TOTAL	4.34E+08	USD
OPEX	1.00E+08	USD
DRILLEX	1.20E+08	USD /well
Discount rate	0.10	fraction
Oil price	65	[USD/stb]

	Time	Oil production in year	Revenue	DRILLEX	CAPEX	OPEX	Total Cost	Cash Flow	discount	Discounted Cash Flow: PV(i)
	end of year	[stb]	USD	USD	USD	USD	USD	USD	factor	USD
2016	0	8.75E+06	5.69E+08	1.20E+08	4.34E+08	5.00E+07	6.04E+08	-3.52E+07	1.00	-3.52E+07
2017	1	7.84E+06	5.09E+08			5.00E+07	5.00E+07	4.59E+08	0.91	4.18E+08
2018	2	6.79E+06	4.41E+08			5.00E+07	5.00E+07	3.91E+08	0.83	3.23E+08
2019	3	5.65E+06	3.68E+08			5.00E+07	5.00E+07	3.18E+08	0.75	2.39E+08
2020	4	4.56E+06	2.96E+08			5.00E+07	5.00E+07	2.46E+08	0.68	1.68E+08
2021	5	3.80E+06	2.47E+08			5.00E+07	5.00E+07	1.97E+08	0.62	1.22E+08
2022	6	3.31E+06	2.15E+08			5.00E+07	5.00E+07	1.65E+08	0.56	9.33E+07
2023	7	2.92E+06	1.90E+08			5.00E+07	5.00E+07	1.40E+08	0.51	7.17E+07
2024	8	2.61E+06	1.70E+08			5.00E+07	5.00E+07	1.20E+08	0.47	5.58E+07
2025	9	2.38E+06	1.55E+08			5.00E+07	5.00E+07	1.05E+08	0.42	4.44E+07
2026	10	2.15E+06	1.40E+08			5.00E+07	5.00E+07	8.98E+07	0.39	3.46E+07
2027	11	1.97E+06	1.28E+08			5.00E+07	5.00E+07	7.77E+07	0.35	2.72E+07
2028	12	1.81E+06	1.18E+08			5.00E+07	5.00E+07	6.79E+07	0.32	2.16E+07
2029	13	1.68E+06	1.09E+08			5.00E+07	5.00E+07	5.90E+07	0.29	1.71E+07
2030	14	1.56E+06	1.01E+08			5.00E+07	5.00E+07	5.13E+07	0.26	1.35E+07
2031	15	1.46E+06	9.47E+07			5.00E+07	5.00E+07	4.47E+07	0.24	1.07E+07
2032	16	1.37E+06	8.93E+07			5.00E+07	5.00E+07	3.93E+07	0.22	8.56E+06
2033	17	1.29E+06	8.41E+07			5.00E+07	5.00E+07	3.41E+07	0.20	6.75E+06
2034	18	1.22E+06	7.92E+07			5.00E+07	5.00E+07	2.92E+07	0.18	5.25E+06
2035	19	1.15E+06	7.48E+07			5.00E+07	5.00E+07	2.48E+07	0.16	4.05E+06
									NPV [USD]	1.65E+09

Table 4: Olympus cash flow for new injector 1

Production		
Uptime	95	%
No of prod dys/yr	346.75	days/year
Wells	11	
CAPEX - TOTAL	4.34E+08	USD
OPEX	1.00E+08	USD
DRILLEX	1.20E+08	USD /well
Discount rate	0.10	fraction
Oil price	65	[USD/stb]

	Time	Oil production in year	Revenue	DRILLEX	CAPEX	OPEX	Total Cost	Cash Flow	discount	Discounted Cash Flow: PV(i)
	end of year	[stb]	USD	USD	USD	USD	USD	USD	factor	USD
2016	0	8.81E+06	5.73E+08	1.20E+08	4.34E+08	5.00E+07	6.04E+08	-3.14E+07	1.00	-3.14E+07
2017	1	7.27E+06	4.73E+08			5.00E+07	5.00E+07	4.23E+08	0.91	3.84E+08
2018	2	6.16E+06	4.01E+08			5.00E+07	5.00E+07	3.51E+08	0.83	2.90E+08
2019	3	5.15E+06	3.35E+08			5.00E+07	5.00E+07	2.85E+08	0.75	2.14E+08
2020	4	4.33E+06	2.81E+08			5.00E+07	5.00E+07	2.31E+08	0.68	1.58E+08
2021	5	3.70E+06	2.40E+08			5.00E+07	5.00E+07	1.90E+08	0.62	1.18E+08
2022	6	3.25E+06	2.11E+08			5.00E+07	5.00E+07	1.61E+08	0.56	9.10E+07
2023	7	2.90E+06	1.88E+08			5.00E+07	5.00E+07	1.38E+08	0.51	7.09E+07
2024	8	2.60E+06	1.69E+08			5.00E+07	5.00E+07	1.19E+08	0.47	5.57E+07
2025	9	2.38E+06	1.55E+08			5.00E+07	5.00E+07	1.05E+08	0.42	4.45E+07
2026	10	2.20E+06	1.43E+08			5.00E+07	5.00E+07	9.32E+07	0.39	3.59E+07
2027	11	2.04E+06	1.33E+08			5.00E+07	5.00E+07	8.27E+07	0.35	2.90E+07
2028	12	1.90E+06	1.24E+08			5.00E+07	5.00E+07	7.35E+07	0.32	2.34E+07
2029	13	1.77E+06	1.15E+08			5.00E+07	5.00E+07	6.51E+07	0.29	1.89E+07
2030	14	1.67E+06	1.08E+08			5.00E+07	5.00E+07	5.83E+07	0.26	1.53E+07
2031	15	1.56E+06	1.01E+08			5.00E+07	5.00E+07	5.12E+07	0.24	1.23E+07
2032	16	1.46E+06	9.46E+07			5.00E+07	5.00E+07	4.46E+07	0.22	9.72E+06
2033	17	1.36E+06	8.85E+07			5.00E+07	5.00E+07	3.85E+07	0.20	7.62E+06
2034	18	1.28E+06	8.34E+07			5.00E+07	5.00E+07	3.34E+07	0.18	6.00E+06
2035	19	1.21E+06	7.90E+07			5.00E+07	5.00E+07	2.90E+07	0.16	4.74E+06
									NPV [USD]	1.56E+09

Table 5: Olympus cash flow for new injector 2

SENSITIVITY ANALYSIS				
	NPV min [USD]	NPV max [USD]	NPV min [billion USD]	NPV max [billion USD]
Oil price (+-40%)	1.30E+09	3.18E+09	1.30	3.18
Drillex (+-30%)	2.21E+09	2.27E+09	2.21	2.27
Capex (+-30%)	2.14E+09	2.34E+09	2.14	2.34
Opex (+-30%)	2.06E+09	2.38E+09	2.06	2.38
Delay of 1 and 2	2.21E+09	2.22E+09	2.21	2.22

DATA FOR TORNADO CHART				
	Delay of 1 and	Drillex (+-30%)	Capex (+-30%)	Oil price (+-30%)
NPV min [USD]	2.21	2.21	2.14	1.30
NPV base [USD]	2.24	2.24	2.24	2.24
NPV max [USD]	2.22	2.27	2.34	3.18

Table 6: Olympus economic analysis sensitivity data

					Convert	6.28981
NPV				incremental		
Base Case	1.50E+09					
producer 1	1.96E+09		producer 1	4.51E+08		
producer 2	2.24E+09		producer 2	7.34E+08		
producer 3	2.07E+09		producer 3	5.63E+08		
Injector 1	1.65E+09		Injector 1	1.45E+08		
Injector 2	1.56E+09		Injector 2	5.30E+07		
Production	Cumulative (sm3)	Cumulative (bbl)	Incremental (bbl)	Recovery Factor		
Base Case	9867886.20	62067129.30		0.25		
producer 1	11593908.00	72923478.48	10856349.18	0.29	0.2714087	27.1409
producer 2	12869779.00	80948464.65	18881335.35	0.32	0.4720334	47.2033
producer 3	12159664.00	76481976.22	14414846.92	0.30	0.3603712	36.0371
Injector 1	10218724.00	64273832.40	2206703.10	0.26	0.0551676	5.51676
Injector 2	10017853.00	63010391.98	943262.68	0.25	0.0235816	2.35816
Production	Incremental (bbl)					
producer 1	1.09E+07					
producer 2	1.89E+07					
producer 3	1.44E+07					
Injector 1	2.21E+06					
Injector 2	9.43E+05					

Table 7: Olympus economic analysis calculations data

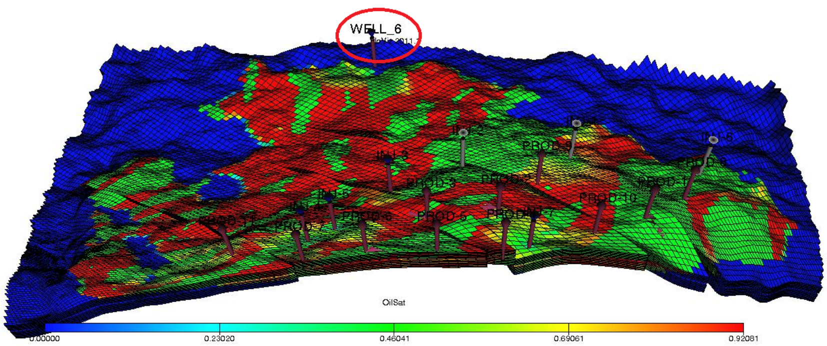

Figure 1: Olympus new injector placement which was not improving oil production due to low permeability

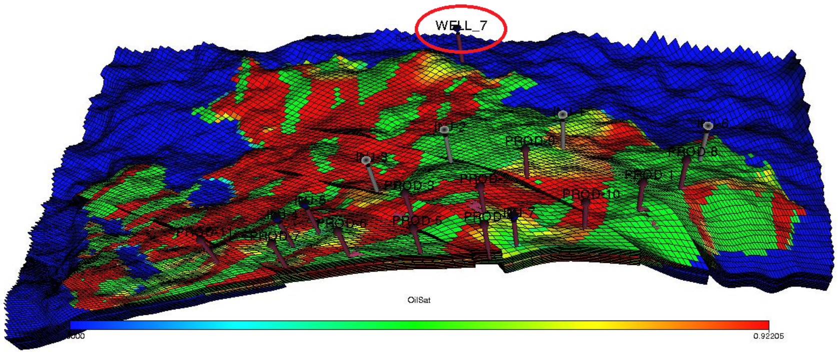

Figure 2: Olympus another new injector placement which was not promising due to low horizontal permeability

NTNU
Norwegian University of
Science and Technology