COMMINGLED PRODUCTION FROM STACKED RESERVOIR; ACCOUNTING FOR ZONAL CONTRIBUTIONS

A thesis presented to the Department of Petroleum

Engineering African University of Science and

Technology, Abuja

In partial fulfilment of the requirements for the degree of

MASTER OF SCIENCE

By

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June 2019

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ABSTRACT

In recent time, one of the ways of optimizing hydrocarbon production is commingling production from stacked reservoirs. Commingled production refers to the production of hydrocarbon from two or more separate zones through a single tubing string (Ferrer, 1998). This work aims to account for zonal contribution in a two-layered reservoir undergoing commingled production at the wellbore and to investigate the effect of rock and fluid properties on cumulative flow rate. For the actualization of this work, the following objectives were achieved: extensive literature search, investigation of the reservoir and fluid parameters that will affect contributions and the effect of their relative sizes and development of a model for flow into the wellbore.

A lot of simulations were done using a cylindrical model. The static and dynamic simulation was done with CMG Builder and IMEX. Pressure and other parameters like permeability, viscosity and thickness of each zones were investigated and results were collated to develop a flow model into the wellbore.

Based on obtained results, it can be concluded that reservoir simulation can be appropriately used to allocate commingled production from stacked reservoirs, pressure drop and reservoir rock and fluid properties affect commingled production from a layered reservoir and can be used for production allocation, Darcy's flow equation is valid for the radial flow system considering the pressure drop and the rock and fluid properties as parameters, flow rate is constant and higher for layer with better rock and fluid properties when cross flow occurs than when there is no crossflow and for a single layer reservoir, formation pressure contribute the most to flowrate.

Keywords: Commingled Production, Layered Reservoir, Wellbore, Flowrate, Crossflow, Reservoir Simulation, Zonal Contributions.

ACKNOWLEDGEMENT

I wish to express my profound gratitude to Prof. Michael Onyekonwu for his guidance, advice, motivation and direction he gave me during this work. I also want to appreciate him for the opportunity he gave me to intern at Laser Engineering and Resources Consultants Limited, Port-Harcourt. Your time in reading and correcting this report is equally appreciated.

I thank Dr Igbokoyi for the measures he put in place as the Head of Department to keep me on my toes, as well as your questions and suggestions during this study.

I wish to acknowledge and appreciate the staff of Laser Engineering and Resources Consultants Limited, Port-Harcourt particularly those in the Reservoir Management Department (RM) for their contributions during the course of this study, thank you.

My appreciation also goes to the Faculty and Staff of the African University of Science and Technology (AUST) for providing me with the enabling environment to study.

I also want to appreciate all my friends and classmates that made my stay in AUST worth it, God bless you.

Lastly, a deep appreciation and immense gratitude to my family for their support, inspiration, and encouragement.

DEDICATION

This work is dedicated to God Almighty for granting me the knowledge and wisdom to carry out this research and to my father Engr. M.S. Otitolaiye for always being there for me.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

CHAPTER 1

INTRODUCTION

1.1 BACKGROUND OF STUDY

With the World energy demand increasing by the day as a result of population growth and industrialization, there is a need to optimize hydrocarbon production. One of such ways of optimizing hydrocarbon production is commingling production from stacked reservoirs. Commingled production refers to the production of hydrocarbon from two or more separate zones through a single tubing string (Ferrer, 1998; Villanueva-Triana and Civan, 2013). Commingled production from two or more zones is the ideal method to accelerate production from a single well. Also, marginal reservoirs, which are uneconomical to produce from each layer separately, could become feasible for production.

Commingled reservoirs are defined as reservoirs which are only connected through the wellbore. The main concept is that these reservoirs do not have any communication across reservoir boundaries (Salam, 2018). One of the parameters that have to be known is the contribution from each commingled reservoir to the total production from the well. The application of intelligent completions for commingled wells improves not only the production and recovery optimization for each individual reservoir but also maximizes the value of the well. Any optimization technique has to base its calculations on the contribution and tries to improve the objective function. This function may be to maximize oil recovery, for instance.

Proper reservoir management demands that individual production zone in a commingled production is known, to the total production stream. Commingled layered reservoirs are those which communicate only in the wellbore. A complete permeability barrier exists between the various layers, hence there is no crossflow. Even though, if the total production of gas, oil, and water from a field is correct and the allocation of the production from each well is accurate, the Reservoir engineer still has a difficult task in allocating production from a well to the individual reservoirs if production is commingled. In the U.S., commingling production from two or more separate reservoirs in a common tubing string is carefully controlled. In most producing states, commingling production is permitted only when it is necessary from an economic point of view. However, in non-U.S. areas, it is common practice to produce as many as four or five separate reservoirs through one tubing string, so little is known about how much of the oil comes from each reservoir (Slider, 1983)

When two zones are commingled without control, the zones are most likely to produce in a suboptimum manner due to the differences in pressure, productivity index, gas-oil-ratio (GOR), and water production. One zone may crossflow into another, and breakthrough of water in one zone may mitigate the hydrocarbon production in the other zone, reducing ultimate recoveries. Commingled production from stacked reservoirs in the same field, or a single reservoir with multiple pay intervals, has many benefits during the development of a field – higher production rates per well, cost savings from reduction in the total number of development wells, flexibility in locating surface facilities as a result of minimal footprint, etc. (Ansah et al., 2009)

1.2 STATEMENT OF THE PROBLEM

Having recognized the need and relevance of commingled production, this study will investigate the possibility of using rock and fluid properties to account for zonal contribution in a two-layered reservoir undergoing commingled production at the wellbore and also investigate the effect of rock and fluid properties on cumulative flow rate.

1.3 OBJECTIVES OF THE STUDY

For the actualization of this work, the following objectives will be achieved:

- Extensive literature search
- Investigate the reservoir and fluid parameters that will affect contributions and the effect of their relative sizes.
- Develop a model for flow into the wellbore.

1.4 SCOPE OF THE STUDY

The scope of this study is to use simulation modelling to allocate contribution from each reservoir layer in commingled production. Although extensive literature search will be done for both oil and gas reservoirs, the main interest of the study is on oil reservoirs. Also, the simulation will be restricted to two layers in which cross flow and no cross flow scenarios will be investigated. Commingling from more than two producing zones gets complicated if cross flow occurs between layers.

1.5 ORGANIZATION OF THESIS

This thesis is divided into five chapters. Chapter one presents an overview of the problem of this study, the objectives of the study and the scope of the study. Chapter two discusses the literature review of studies and techniques to allocate production in wells that are in

commingled production. Chapter three discusses the methodology, which describes how the simulation will be carried out. Chapter four focuses on the results and discussion of the results of the study. And lastly, chapter five covers the conclusion and recommendations.

CHAPTER 2

LITERATURE REVIEW

2.1 COMMINGLED PRODUCTION

Commingled production of hydrocarbon from stacked reservoir in vertical wells is common these days. Many oil and gas reservoirs are stratified to different extents resulting from sedimentation process over long geological periods. Layered reservoir comprises two or more layers that may have different formation and fluid characteristics. The conventional means is to produce from each layer of the reservoir separately and monitor the layers independently by using the appropriate well completion techniques. The other method is to produce from multiple reservoirs simultaneously through a single tubing string. Stacked reservoirs are classified basically into two, namely: stacked reservoir with crossflow and stacked reservoir without crossflow. In the reservoir with crossflow, the layers hydrodynamically communicate while there is a separation by flow barrier, for instance, shale, when there is no crossflow. The drawbacks of the conventional technique of production are that it could take some time to drain all the reservoirs, and production frequently prevents the use of secondary and/or enhanced recovery techniques that have the possibility to increase ultimate recovery of hydrocarbon.

The disadvantage of the second technique is that production from each zone and from the well can be limited because the tubing size is limited by the casing size. Although casing size can be increased to accommodate the larger tubing for maximum production, this is, however, a steeply-priced option. When two zones are commingled without appropriate control, the layers are most likely to produce in a suboptimum manner due to the differences in pressure, gas-oil-ratio (GOR), productivity index, and water production. One zone may crossflow into another, and gas or water breakthrough in one zone may limit the oil production in the other, lowering final recoveries. The introduction of intelligent well systems (IWS) allows the independent monitoring and controlling production from each zone to optimize a well's flowing parameters. Several studies have been published to demonstrate the importance of the application and benefits of intelligent well completion (IWC), particularly for stacked reservoirs where commingled production is done (Jalali et al., 1998; Lucas et al., 2001).

Konopczynski et al. (2003) and Han (2003) showed that commingling production from multiple reservoir layers increases recovery over time. The conventional approach to allocation from the different zones use techniques such as mechanical gauging, production logging or

tracer surveys; whilst these are essential techniques, they are very expensive (Kaufman et al., 1987)

Ferrer (1998) discussed the applications, advantages, limitation of commingling and the effect of commingling on IPR curves by designing a five-well pilot test program for a period of six months. He concluded that commingling production can increase reserves by extending the well's economic life and help to reduce conning, cusping, sand production, fine migration and other types of production problems by increasing the bottom-hole pressure without significantly decreasing production rate.

Oil and gas reserves arising from multilayered reservoirs are large. These reservoirs are mostly heterogeneous and most of the time comprise of formation where layers may have separate values of porosity, thickness, permeability and skin factor. Description of a particular layer is important from reservoir evaluation and management point of view since layering influences primary and secondary oil recovery. Stacked reservoirs present some special problems; for instance, variations in the permeabilities of the layers can cause uneven depletion and poor hydrocarbon recovery. Water flooding projects in a layered reservoir can result in poor sweep efficiency because the oil that is unswept is mostly bypassed in the lower permeability zones. For reservoirs that are producing commingling, differences in well performance and production could result from huge variations in the skin or permeability-thickness product.

Effective management of reservoirs producing from commingled zones, thus, stipulates that one know the contribution of individual production streams to total production.

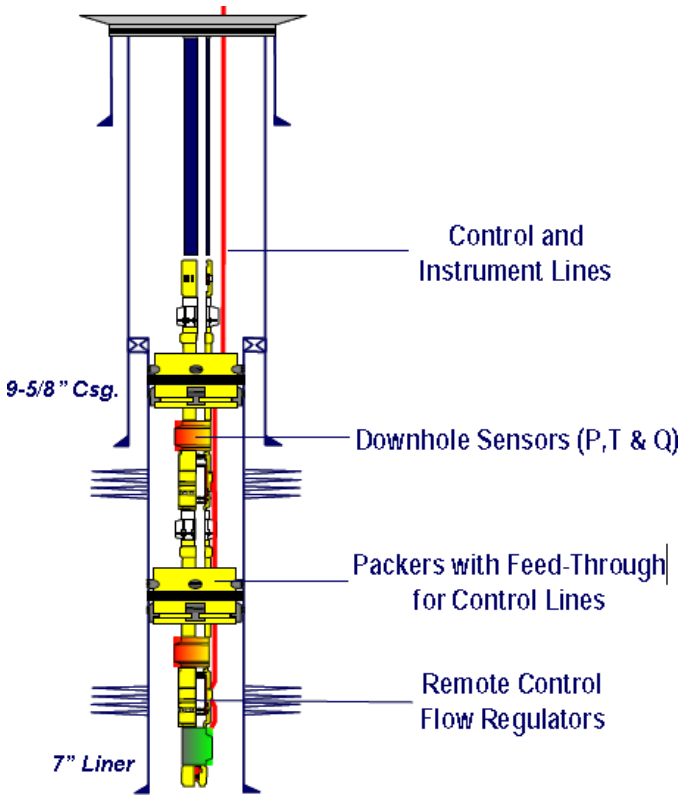

Figure 2. 1: Schematics of IWC (adapted from Sakowski, 2005)

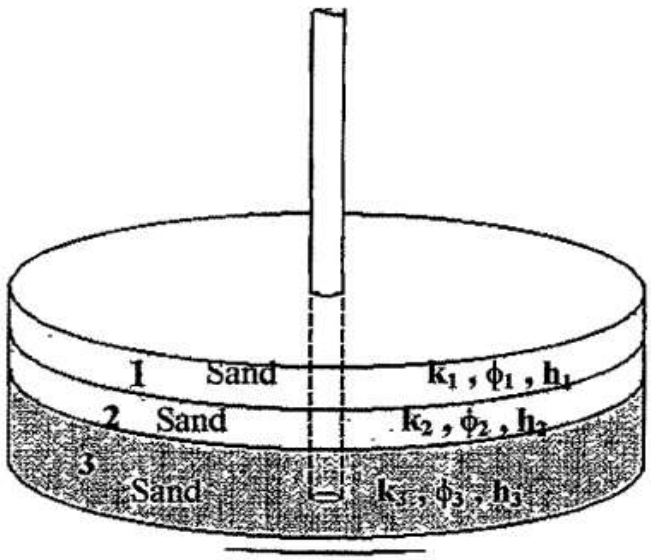

Figure 2. 2: Three-layer reservoir with crossflow

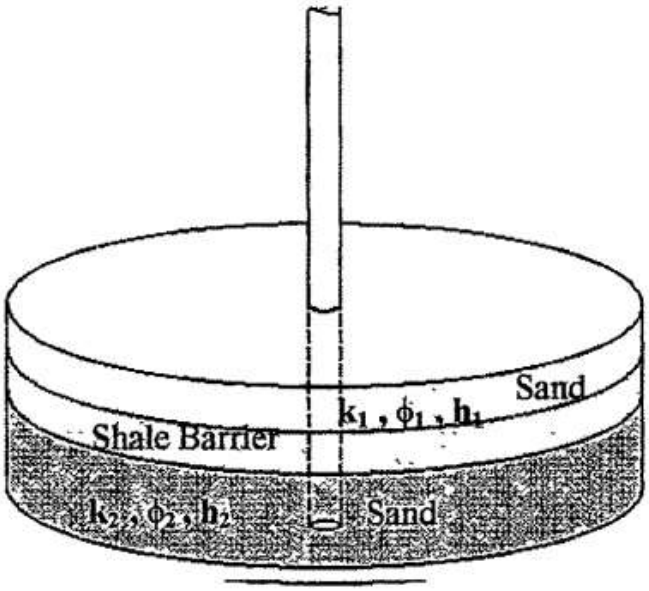

Figure 2. 3: Two-layer reservoir without crossflow

2.2 DETECTION OF INTERLAYER CROSSFLOW

According to Russell and Prats (1962), there are four general methods that can be used to detect interlayer crossflow. These methods are formation testing, petrophysical analysis, flow tests on a sample core rock, and pressure and production analyses behaviour. The degree of crossflow before the well is completed can be determined using petrophysical analysis, flow tests and possibly formation testing. Layer rock properties such as permeability and porosity distribution can be obtained from petrophysical information, but then, it is expensive to core all layers' thickness, therefore, enough petrophysical data are not available and it is difficult to prove if crossflow occurs or not in a contiguous layer. As a result, pressure and production analyses approach is conducted at the early production stage to detect if interlayer crossflow occurs between layers.

If the well is producing, pressure drawdown or pressure buildup test can be used to detect the presence of cross-flow. If the pressure drawdown test is used, the plot of flowing bottom-hole pressure vs time should be linear after reaching the pseudo-steady state. If the drawdown test does not give a linear result and the same slope after pseudo-steady state, then crossflow does not occur. In the case of the buildup test, Fetkovich et al. (1990), showed the behaviours of

layered reservoir without crossflow. According to them, if crossflow exists, the plot of rate (b/d) against time (days) on a semi-log graph is linear, otherwise no crossflow.

2.2.1 The Economic Effect of Crossflow on Production

From the performance point of view, the advantages of interlayer crossflow are two (Fetkovich et al. 1990). The first advantage is that it takes a short period of time to reach economic production rate compared to the rate of production from a formation without crossflow. The second benefit is a higher oil recovery since tight layers are depleted effectively. From these benefit, it is obvious that formation crossflow has an intense effect on the economics of draining a reservoir. Other advantages of formation crossflow are: (1) It reduces the cost of perforation and completion since high permeable zone is perforated and tight zone will be drained by crossflow. (2) It makes interpretation of routine tests easier e.g. pressure build-up test and reservoir limit tests must be undertaken with longer time duration in a reservoir without crossflow to obtain complete data than reservoirs with crossflow where such tests are less expensive and generally requires less time to carry out.

2.3 REVIEW OF RESERVOIR PROPERTIES AFFECTING FLOWRATE

Darcy's law, which was initially developed for water flow is used to describe the flow of hydrocarbon reservoir fluids. If a horizontal linear flow of an incompressible fluid is established through a core sample of a cross-section of area A and length L, then the governing fluid flow equation is defined thus:

$$v = \frac{-kdp}{\mu dL} \quad \text{.....Eq. 2.1}$$

Where: ν = apparent fluid flowing velocity, cm/sec

k = proportionality constant, or permeability, Darcy's

μ = viscosity of the flowing fluid, cp

dp/dL = pressure drop per unit length, atm/cm

It should be noted that the velocity, v in Equation 2.1 is not the actual velocity of the flowing fluid but is the apparent velocity obtained by dividing the flow rate by the cross-sectional area across which fluid is flowing. Substituting the relationship, q/A, in place of ν in Equation 2.1 and solving for q results in

$$q = \frac{-kAdp}{\mu dL} \quad \text{.....Eq. 2.2}$$

Where q = flow rate through the porous medium, cm^3/sec

A = cross-sectional area across which flow occurs, cm^2

k has been arbitrarily assigned a unit called Darcy in honour of the man responsible for the development of the theory of flow through porous media.

Thus, when all other parts of Equation 2.2 have values of unity, k has a value of one Darcy. One Darcy is a fairly high permeability as the permeabilities of most reservoir rocks are less than one Darcy. In order to avoid the use of fractions in describing permeabilities, the term millidarcy is used. As the term indicates, one millidarcy, i.e., 1 mD, is equal to one-thousandth of one Darcy. The negative sign in Equation 2.2 is necessary as the pressure increases in one direction while the length increases in the opposite direction.

For a radial steady-state flow, Darcy's equation in a differential form can be written as:

$$q = \frac{2\pi kh(p_e - p_{wf})}{\mu In({}^{r_e}/_{r_w})} \text{.....Eq. 2.3}$$

Where:

q = flow rate, reservoir cm^3/sec; k = absolute permeability, Darcy; h = thickness, cm; r_e = drainage radius, cm, r_w = wellbore radius, cm; pe = pressure at drainage radius, atm; p_{wf} = bottom-hole flowing pressure and μ = viscosity, cp. Equation 2.3 in field unit can be expressed as

$$q = \frac{7.08\times10^{-3} kh(p_e - p_{wf})}{B_o \mu_o In({}^{r_e}/_{r_w})} \text{.....Eq. 2.4}$$

2.3.1 Weighted-Average Permeability

This averaging method is used to determine the average permeability of layered-parallel beds with different permeabilities. Consider the case where the flow system is comprised of three parallel layers that are separated from one another by thin impermeable barriers, i.e., no cross flow as shown in Figure 2.4. The total flow rate q_t into the wellbore is equal to the sum of the flow rates through each layer or:

$$q_t = q_1 + q_2 + q_3 \text{.....Eq. 2.5}$$

And the average permeability is given as:

$$k_{avg} = \frac{k_1h_1 + k_2h_2 + k_3h_3}{h_t} \text{.....Eq. 2.6}$$

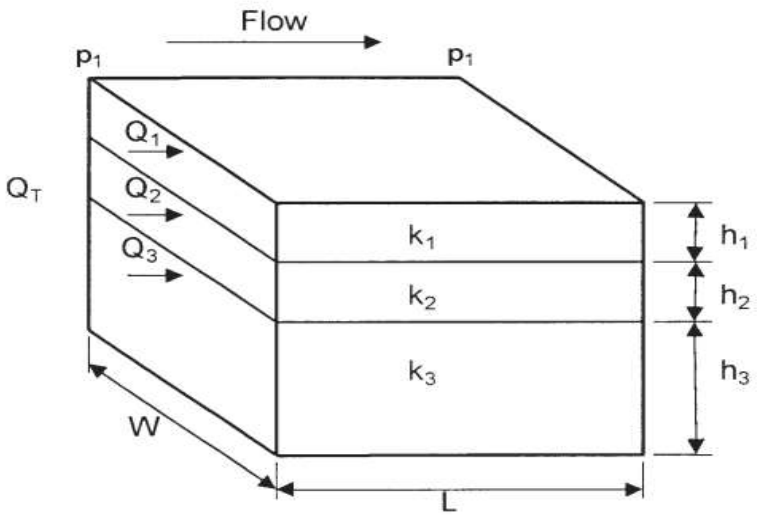

Figure 2. 4: Linear flow through layered beds

2.3.2 Harmonic Average Permeability

Permeability variations can occur laterally in a reservoir as well as in the vicinity of a wellbore. Consider Figure 2.5, which shows an illustration of fluid flow through a series combination of beds with different permeabilities.

For a steady-state flow, the flow rate is constant and the total pressure drop Δp is equal to the sum of the pressure drops across each bed, or

$\Delta p = \Delta p_1 + \Delta p_2 + \Delta p_3$

Substituting for the pressure drop by applying Darcy's equation, i.e.

Equation 2.20, gives:

$$k_{avg} = \frac{L}{(L/K)_1 + (L/K)_2 + (L/K)_3} \text{.....Eq. 2.7}$$

In the radial system shown in Figure 2.60, the averaging methodology can be applied to produce the generalized expression as:

$$k_{avg} = \frac{ln\left(r_e/r_w\right)}{\sum_{j=1}^{n}\left(\frac{ln\, r_j/r_{j-1}}{k_j}\right)} \text{.....Eq. 2.8}$$

From Equation 2.3, for a reservoir with two layers, the ratio of the flow rate of the layers can be expressed as:

$$\frac{q_1}{q_2} = \frac{2\pi k_1 h_1 \Delta p_1}{\mu ln\left({}^{r_e}/_{r_w}\right)} \times \frac{\mu ln\left({}^{r_e}/_{r_w}\right)}{2\pi k_2 h_2 \Delta p_2} \quad \text{Eq. 2.9}$$

If the layers have the same pressure drop (ΔP), Equation 2.9 reduces to:

$$\frac{q_1}{q_2} = \frac{k_1 h_1}{k_2 h_2} \quad \text{Eq. 2.10}$$

It is expected that if the thickness (h) and the permeability (k) of the layers are the same, then $q_1 = q_2$ i.e. the contribution from the layers will be the same. This equal contribution from the layers when the pressure drop and the rock and fluid properties are the same will be validated in Chapter 4 of this work.

It can also be seen from Equation 2.3 that aside from the pressure drop, fluid viscosity, pay thickness and permeability affects zonal contribution. It will also be investigated in Chapter 4 to see if rock and fluid properties can be used to allocate production from a layered-reservoir.

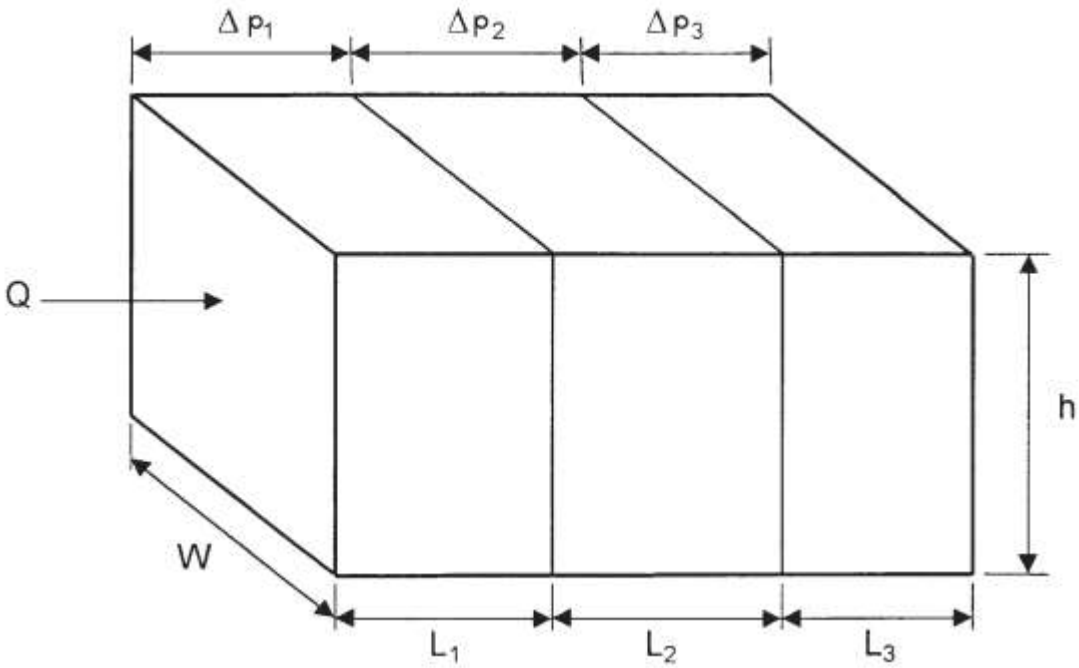

Figure 2. 5: Linear flow through series beds (Cartesian)

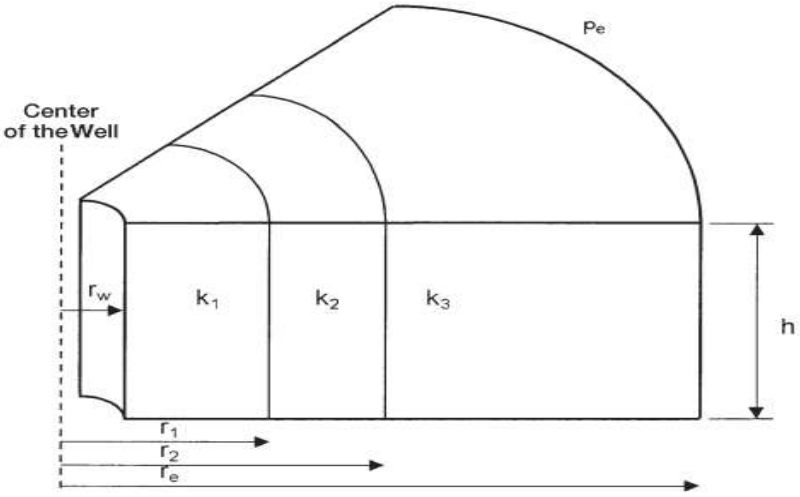

Figure 2. 6: Flow-through series beds (Radial)

2.4 METHODS FOR ACCOUNTING FOR ZONAL CONTRIBUTIONS

2.4.1 Production Logging

Production logs are mainly utilized to allocate production on a zone by zone basis and also to detect production problems such as leaks. Production logging involves several measurements used to determine fluid and flow properties. Examples of fluid flow meters are turbine (spinner) flowmeters, markers (tracers) and heated anemometry. Commonly, the fluid velocity is measured with a spinner flowmeter comprising of a rotating blade that turns when fluid moves past it. The velocity obtained from the spinner is calibrated to account for friction in spinner bearings and fluid viscosity effect. After making the necessary correction to the spinner velocity, it is converted to average fluid velocity using computer modelling techniques, resulting in the fluid velocity profile across the diameter of the pipe. A detailed review of the use of a production logging tool for reservoir diagnosis can be found in McKinley (1982).

Figure 2. 7: Schematics of production logging tool (adapted from Parijat Mukerji, 2013)

2.4.2 Geochemistry

Application of reservoir geochemistry for production allocation in commingled production from stacked reservoirs are detailed in the work of Kaufman et al. (1987), McCaffrey et al. (1996) and Nicolle et al. (1997). Also, reviews of reservoir geochemistry are given by e.g. Larter and Aplin (1995) and Larter et al. (1997).

Kaufman et al. (1987) described the use of gas chromatographic production allocation method and demonstrated its use with two field examples in Indonesia. The chromatogram obtained represents unique oil fingerprints, which were used for correlation. Their data acquisition and post-run processing were done using a desktop computer. They developed and optimize the software for processing the chromatographic data, oil correlation and oil mixture percentage and assumed linear mixing behaviour for oil. They compared chromatogram of different oil visually and identified regions where adjacent peaks vary in relative heights. They then used the ratio of peak heights to represent those regions and graphically displayed the peak height ratio data by making a star plot using polar coordinate. Each axis of the plot represents data for a specific ratio. With the plot, they successfully allocated production from different zones. Also, according to Kaufman et al. (1987), chromatographic analysis method has several advantages over production logging. It is an inexpensive and simple analysis, the analysis can be set up in a field laboratory, turnaround times are short and the technique can be used where conventional production logging techniques are inadequate.

McCaffrey et al. (1996) introduced the use of biomarker indicators in biodegradable oil to predict variation in oil viscosity and gravity. These variations were then utilized to optimize well completions such as placement of new wells and completion intervals and assessment of relative production from discrete zones using data from 80 sidewall cores and 17 oil in the Cymric field, California. Unlike Kaufman et al. (1987) approach, McCaffrey et al. (1996)

proposed another method that was based on GC peak heights and not GC peak height ratios. The advantage of this approach is that it doesn't require analysis of an artificial mixture of end-member oils (since peak heights always mix linearly) and it is also applicable to any number of mixed zones.

Nicolle et al. (1997) stated the drawbacks of Production Logging Tool (PLT) and the advantages of geochemistry over PLT. Based on their work, they successfully applied geochemistry to allocate production for two and three reservoir zones respectively using high capillary gas chromatography. It is known for e.g. Kaufman et al. (1987) that oil from the same reservoir display identical chromatogram whereas oil from separate reservoir exhibits quantifiable chromatographic difference. They made detailed oil chromatogram comparison using a software program (PFR) developed by Chevron. Peak heights were measured against baseline and the subsequent peak ratios were calculated for closely spaced or adjacent peaks to normalize the chromatographic data. They defined the working space of their statistical comparison from n-C_9 to n-C_{22} alkanes but can be extended if the need arises. As a result of evaporation problems during sampling and succeeding storage, light ends (< C_9) were generally not considered. They compared the result of production allocation from the zones via geochemistry and PLT and obtained a close match.

McCaffrey et al. (2011) made an improvement to McCaffrey et al. (1996) approach. They improved their previous work by identifying several sources of error and accounted for those errors in their new model. They applied their approach to oil and gas reservoir. They also gave a detailed discussion on the benefits of using geochemical allocation method compared to production logging tool. They presented four cases studies in their work. In the first two case studies, geochemical allocation method was approved by the regulatory body after several months' trial studies of monitory allocation by both geochemical method and production logging to account for zonal contributions. The results obtained from both approaches were very close and subsequently, the geochemical allocation method was used. The two remaining case studies demonstrated the application of geochemical allocation method to monitor change in production resulting from (1) water injection and (2) opening and closing of perforation within a well.

Huseby et al. (2005), introduced a technique for incorporating geochemical data in reservoir simulation to improve reservoir model. In their method, they used the routine measurement of natural inorganic ion concentration in hydrocarbon production wells and applied the ions as

non-partitioning water tracers. According to them, their method can be used to allocate produced water to a particular water producing zone in commingled production. They demonstrated the method in a field in the North Sea and established that incorporation of geochemical data into reservoir simulation procedure can improve reservoir simulation model significantly.

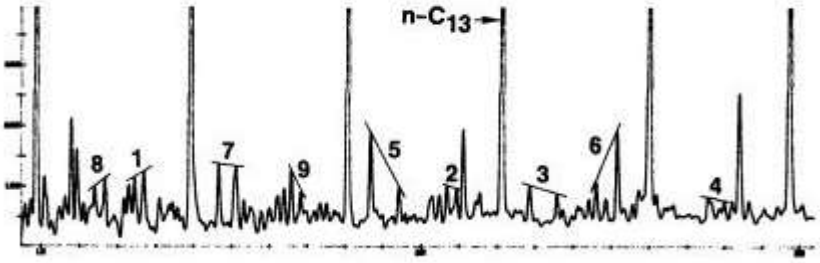

Figure 2. 8: Visual analysis of chromatogram

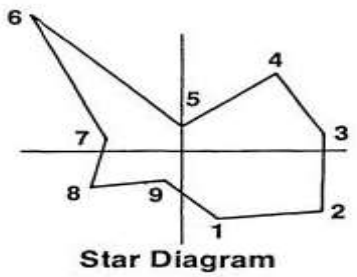

Figure 2. 9: Graphical display of selected peak ratios (Star Diagram)

2.4.3 Modelling Approach.

Several attempts have been made to model stacked reservoir commingling production for oil and gas.

In the work of Fetkovich et al. (1990), they investigated the main factors affecting multi-layered reservoir performance with no cross-flow. They revealed that a production decline exponent of a layered reservoir is always larger than that of a single-layer reservoir and established that decline exponent value between 0.5 and 1 signifies a layered reservoir. They also showed that a material-balance equation and a stabilized backpressure curve method gives the same results for production forecasts of layered systems as those obtained from a radial model.

Also, Juell et al. (2011) used a backpressure equation (BPE) for wells producing from layered gas reservoirs to estimate the gas properties including wellbore crossflow. They assumed a constant bottom-hole pressure for the flowing well. They liken the reservoir backpressure calculation and the outcomes from the numerical simulator and concluded that the backpressure equation can be used to predict depletion performance of layered reservoirs whilst coupled with the material balance equation of the layers in no crossflow gas reservoirs.

Kuppe et al. (2000) used p/z-plot method for a two-layered reservoir to develop a spreadsheet program that evaluates Original Gas in Place (OGIP), layer productivity, and recoverable reserves for tight gas commingled reservoirs without crossflow. They categorized multi-layered reservoirs into two categories by way of grouping the high permeability layers into one composite layer and the low permeability layers into another. Their findings indicated that the material balance (p/z) approach is limited and may be effectively used only under constrained conditions, such as for non-communicating layers related to no cross-flow and no high permeability contrasting between various layers.

El-Banbi and Wattenbarger (1996) developed a method to match the production data for commingled gas reservoirs. They used the idea that if the OGIP and flow coefficients of each layer are known, production from each layer can be calculated. To utilize their model, they assumed non-Darcy flow coefficient, pseudo-steady production across every layer and a constant bottom-hole flowing pressure. Their model, however, has limited usage and fails to accurately match the production history for reservoirs produced predominantly under transient-state conditions. They overcame this limitation by modifying the initial stabilized flow model (El-Banbi and Wattenbarger, 1997) to allow for transient state condition.

In the work of Russell and Prats (1962), the overall performance of a two-layered reservoir containing single-phase compressible fluid with crossflow was investigated. The work was carried out under a constant terminal pressure for various flow regimes and a constant terminal rate for pseudo-steady state condition. They considered a cylindrical tank-shape and closed boundary reservoirs with homogeneous and isotropic properties and assumed that viscosity and wellbore pressure were constant. They applied a finite Hankel transforms to solve the diffusivity equation and revealed that, while crossflow happens between two layers, the oil recovery will be higher and the depletion will take a longer time.

Woods (1970) developed a simple model to predict the flow rate of fluid in a two-layer system. In his work, he assumed identical wellbore pressure for all layers, constant transmissibility and

skin factor for all layers, no cross flow and ignored gravity effect. Woods model for flow rate in a particular layer is simply a factor multiplied to the total flow rate of the two layers.

Bourdet (1985) explained the pressure behaviour for a two-layered reservoir with cross-flow. He took into consideration wellbore storage and skin and showed that his solution could be represented by the general form of many other reservoir model solution. He demonstrated that his solution was similar to the solutions obtained from other problems when some reservoir parameters took limiting values.

Kucuk, et al. (1984) proposed a new testing technique for a two-layered commingled reservoir. Their approach involves the use of nonlinear parameter estimation by coupling wellbore pressure with sand face production rate of each layer. The coupling of the sand face production rate of the layer is very important for multilayered reservoirs because rate transient of each layer shows information about the layer, and the pressure of the wellbore is obtained via averaging reservoir parameters

Villanueva-Triana and Civan (2013) developed an improved model for commingled oil reservoirs containing three layers with a formation cross flow and external boundary effect. Their method involved coupling reservoir hydraulic with wellbore in multilayer reservoirs, which was solved by a Newton-Raphson finite difference iterative method. The wellbore was modelled based on the Cullender and Smith (1956) model while the reservoir was modelled based on the Darcy and continuity equation and solved using the iterative finite-difference numerical solution. In their work, they considered the reservoir properties such as initial reservoir pressure, skin factor, effective permeability and thickness to be different for each layer and slightly compressible oil was considered.

Onwunyili and Onyekonwu (2013) developed a robust simulator that allows the calculation of fluid flow and pressure profile along different zones of the reservoir with different rock properties and the wellbore. The simulator couples the wellbore model and reservoir model into a single model that simulates the pressure and production performance from multi-layer reservoir in commingled production and successfully allocated production from two reservoir layers. Their work was however limited to no crossflow situation in a reservoir at pseudo-steady and steady-state flow only. Unlike Villanueva-Triana and Civan (2013), Onwunyili and Onyekonwu (2013) incorporated additional wellbore and reservoir model in their work. They also gave a detailed modelling procedure used in their work and the algorithm used by their simulator to allocate production

Ilozobhie and Egu (2013) used MBAL to predict layers of the reservoir where crossflow occurred in a well in Niger Delta, Nigeria and predicted the individual contribution of each layer to the total production. The outcome obtained from their modelling was based on the variation of permeability at constant porosity, water break saturation, and thickness. They used the inbuilt multi-layer Buckley Leverett and multi-layer Stiles model to obtain contribution from each zone. They supplied reservoir parameters such as pressure, temperature, dip angle, reservoir width, water/gas injection rate, and connate water saturation into the multilayer tool component of MBAL to generate pseudo relative permeability curves for the Buckley Leverett and Stiles models. Their model assumes the same pressure difference across the length of all layers.

2.5 RESERVOIR MANAGEMENT

In order to enhance recovery from the reservoir around the world, proper reservoir management practice is required. Previously, non-integrated reservoir management was done only if major spending is planned but for the past 20 years, integrated reservoir management has been much emphasized and practice. Integrated reservoir management involves the coordination of petroleum engineers, geologist and geophysicists to advance exploration, development and production of oil and gas (Satter et al., 1994)

Many papers have defined reservoir management, Satter et al., 1994 defined reservoir management as the usage of existing human, technological and financial resources to get the most out of a reservoir by optimizing recovery while minimizing capital and operating expenditure. The primary aim of reservoir management is to control operations for the purpose of maximizing possible economic recovery from a reservoir based on the information available about the reservoir (Thakur, 1995). A team approach comprising of engineering personnel, technology, data and geoscientists are essential for effective reservoir management (Satter et al., 1994). Practices in reservoir management include setting goals, planning, implementing, evaluating, monitory and revising original plans all through the reservoir's life from exploration to abandonment (Fowler et al., 1996).

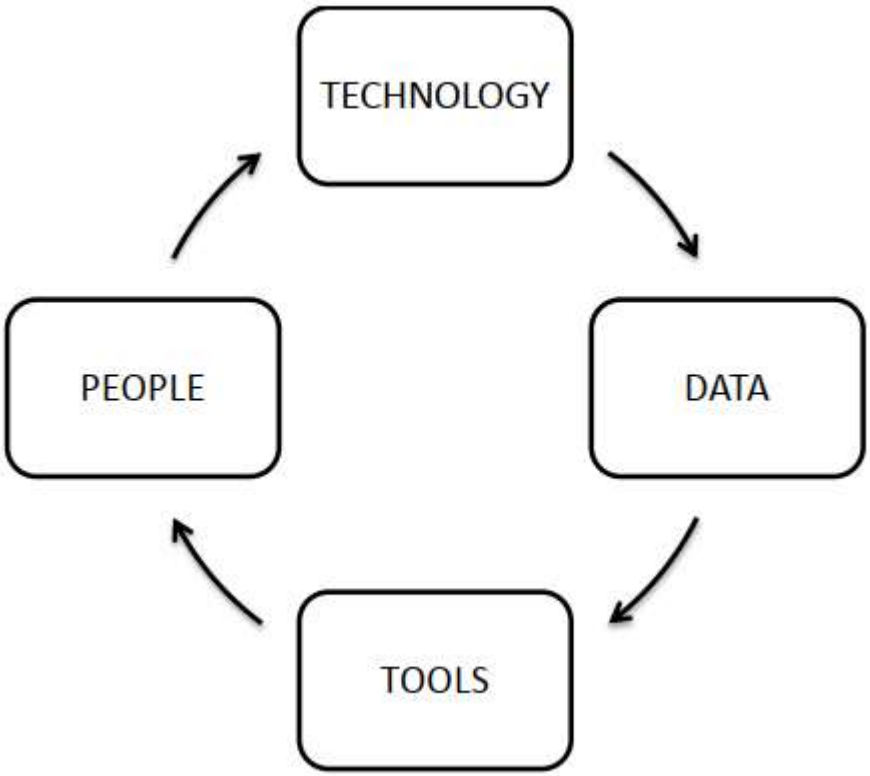

Figure 2. 10: Reservoir management (adapted from Satter et al., 1994)

It should be noted that reservoir management does not mean using a high-tech methodology to improve production in large reservoir and reservoir management is necessary because all reservoirs need to be managed. Intelligent well completion used in commingling production forms a part of reservoir management. Reservoir management utilizing intelligent completions enables a good understanding of the reservoir, leading to a higher recovery of hydrocarbon. According to Lau, 2008, the implementation of intelligent wells in projects requires the joint effort of several disciplines, a combined workflow that systematically integrates the influence of different disciplines all through the life cycle of a project and this is paramount to success. For effective reservoir management in commingling production, it is, therefore, necessary to account for zonal contributions.

CHAPTER 3

METHODOLOGY

This chapter describes the methodology used in this work. It includes input data into the simulator such as PVT, relative perm and initial reservoir conditions etc. A lot of simulations were done using a cylindrical model. Since the study is a single well, it is imperative to use a cylindrical model to describe the reservoir properly. The static and dynamic simulation was done with CMG Builder and IMEX respectively. Pressure and other parameters like permeability, viscosity and thickness of each zones were investigated. Results were collated to develop a flow model into the wellbore as will be discussed in chapter 4.

3.1 DATA FOR SIMULATION

3.1.1 Geometry

Radial Extent, ft	2000
Wellbore Radius, ft	0.25
Angular theta division	3
Number of radial blocks	10
Grid block width in I direction, ft	0.364114, 0.89443, 2.19713, 5.39715, 13.2579, 32.5673, 80.0003, 196.517, 482.736, 1185.82
Grid block width in J direction, ft	3*120
Dip angle, degrees	0
Depth to top of the formation, ft	9500
Number of vertical layers	2
Sweep (Max 360°)	360

3.1.2 Rock and Fluid Data

Rock compressibility, psi-1	0.000004
Reference pressure for calculating the effect of rock compressibility	4000 psi
Water Compressibility, psi-1	0.000003
Oil Compressibility for under saturated oil, psi-1	0.00001

Oil viscosity compressibility for under saturated oil, psi-1 0

PVT Region 1 correlation parameters:

- Reservoir temperature ,°F 150
- Stock-tank oil density, API 35 (53.0013 lb/ft^3)
- Gas specific gravity 0.7

Stock-tank water density, Ibm/cu ft 63.02

PVT Region 2 correlation parameters:

- Reservoir temperature ,°F 150
- Stock-tank oil density, API 25 (56.388 lb/ft^3)
- Gas specific gravity 0.65
- Stock-tank water density, Ibm/cu ft 63.02

3.1.3 Initial Condition

Calculation Method: User specified pressure and saturation for each grid block (User Input) (Pressure and Saturation at each grid block must be specified by the user under the PRES, SW and SO keywords)

3.1.4 Well Data

Skin 0

Produced well completed in blocks 1,1,1 and 1,1,2

Well Constraint:

- Max surface oil rate = 4000bbl/day
- Min bottom hole pressure = 500 psi
- Max surface water rate = 500 bbl/day

3.1.5 PVT Data Obtained Using Correlations

Table 3. 1: PVT Region 1

P (psi)	Rs (ft3/bbl)	Bo	Eg (ft3/bbl)	viso (cp)	visg (cp)	co (1/psi)
14.696	4.18871	1.04155	4.81098	2.66967	0.012086	3.00E-05
280.383	48.3282	1.05838	95.0486	2.05078	0.01237	3.00E-05
546.07	102.646	1.07989	191.687	1.62441	0.012802	3.00E-05
811.757	162.59	1.10453	294.808	1.34011	0.013357	3.00E-05
1077.44	226.625	1.13174	403.983	1.14127	0.014038	3.00E-05

1343.13	293.928	1.16123	518.033	0.995572	0.014847	3.00E-05
1608.82	363.977	1.19277	634.92	0.884594	0.015783	2.69E-05
1874.5	436.407	1.22622	751.928	0.797372	0.016832	2.20E-05
2140.19	510.948	1.26143	866.194	0.72705	0.017972	1.86E-05
2405.88	587.39	1.29831	975.301	0.66915	0.019177	1.59E-05
2671.57	665.565	1.33677	1077.63	0.620636	0.020418	1.39E-05
2937.25	745.336	1.37673	1172.4	0.579382	0.02167	1.23E-05
3202.94	826.588	1.41813	1259.47	0.543855	0.022916	1.10E-05
3468.63	909.222	1.46091	1339.11	0.512926	0.02414	9.92E-06
3734.31	993.154	1.50501	1411.84	0.485744	0.025335	9.02E-06
4000	1078.31	1.55039	1478.27	0.461657	0.026493	8.25E-06
4160	1130.16	1.57832	1515.51	0.448426	0.027172	7.84E-06
4320	1182.41	1.60668	1550.84	0.436039	0.027837	7.47E-06

Table 3. 2: PVT Region 2

P (psi)	Rs (ft3/bbl)	Bo	Eg (ft3/bbl)	viso (cp)	visg (cp)	co (1/psi)
14.696	2.7359	1.04197	4.79401	9.11474	0.0123805	3.00E-05
280.383	31.5661	1.05217	94.2399	7.07287	0.0126361	3.00E-05
546.07	67.0444	1.06504	189.002	5.53179	0.0130209	3.00E-05
811.757	106.198	1.07962	288.948	4.45672	0.0135077	3.00E-05
1077.44	148.023	1.09557	393.554	3.69236	0.0140936	3.00E-05
1343.13	191.982	1.11273	501.792	3.13182	0.0147779	2.63E-05
1608.82	237.735	1.13098	612.104	2.70818	0.0155568	2.08E-05
1874.5	285.044	1.15023	722.536	2.37933	0.0164215	1.70E-05
2140.19	333.731	1.17043	831.028	2.11809	0.0173578	1.43E-05
2405.88	383.66	1.1915	935.745	1.9064	0.018348	1.23E-05
2671.57	434.721	1.21342	1035.32	1.7319	0.0193737	1.07E-05
2937.25	486.824	1.23613	1128.94	1.58591	0.0204178	9.50E-06
3202.94	539.895	1.25962	1216.25	1.46219	0.021466	8.49E-06
3468.63	593.868	1.28384	1297.25	1.35615	0.0225071	7.66E-06

3734.31	648.69	1.30876	1372.2	1.26435	0.0235327	6.96E-06
4000	704.311	1.33438	1441.46	1.18418	0.0245369	6.37E-06
4160	738.174	1.35013	1480.61	1.14064	0.0251298	6.05E-06
4320	772.304	1.36611	1517.96	1.10021	0.0257129	5.76E-06
4480	806.693	1.38233	1553.61	1.06258	0.026286	5.50E-06
4640	841.332	1.39877	1587.66	1.02747	0.0268488	5.25E-06
4800	876.216	1.41544	1620.2	0.994639	0.0274013	5.03E-06

3.1.6 Relative Permeability Data from Correlations

Table 3. 3: Oil-Water Relative Permeability Table

Sw	Krw	Krow
0.2	0	0.8
0.246875	1.83E-05	0.638248
0.29375	0.000207	0.501324
0.340625	0.000856	0.386787
0.3875	0.002344	0.292284
0.434375	0.005118	0.215548
0.48125	0.009688	0.154408
0.528125	0.016617	0.106787
0.575	0.026517	0.070711
0.621875	0.040045	0.044311
0.66875	0.057903	0.025835
0.715625	0.080831	0.013648
0.7625	0.109606	0.00625
0.809375	0.145045	0.002283
0.85625	0.187996	0.000552
0.903125	0.239343	4.88E-05
0.95	0.3	0

Table 3. 4: Liquid Gas Relative Permeability Table

SI	krg	krog
0.4	0.3	0
0.45	0.187996	0
0.5	0.109606	0
0.51875	0.087445	4.88E-05
0.5375	0.068685	0.000552
0.55625	0.052993	0.002283
0.575	0.040045	0.00625
0.59375	0.029532	0.013648
0.6125	0.021155	0.025835
0.63125	0.014631	0.044311
0.65	0.009688	0.070711
0.66875	0.006071	0.106787
0.6875	0.00354	0.154408
0.70625	0.00187	0.215548
0.725	0.000856	0.292284
0.74375	0.000313	0.386787
0.7625	7.57E-05	0.501324

3.1.7 Array Properties

Table 3. 5: Reservoir Rock and Fluid Properties Investigated

Scenarios	Simulation run	Layers	Res. Pres. (Psia)	K (mD)	ϕ	h (ft)	μ (cP)	Comment
1	1	Upper	4000	800	0.25	100	0.46	Pressure Investigation
		Lower	4000	800	0.25	100	0.46	
	2	Upper	4000	800	0.25	100	0.46	
		Lower	3800	800	0.25	100	0.46	
2	1	Upper	4000	800	0.25	100	0.46	Permeability Investigation
		Lower	4000	700	0.25	100	0.46	
	2	Upper	4000	800	0.25	100	0.46	

		Lower	4000	400	0.25	100	0.46	
3	1	Upper	4000	800	0.25	100	0.46	Thickness Investigation
		Lower	4000	800	0.25	80	0.46	
	2	Upper	4000	800	0.25	100	0.46	
		Lower	4000	800	0.25	40	0.46	
4	1	Upper	4000	800	0.25	100	0.46	Viscosity Investigation
		Lower	4000	800	0.25	100	1.21	
	2	Upper	4000	800	0.25	100	1.21	
		Lower	4000	800	0.25	100	0.46	

3.2 DESIGN OF EXPERIMENTS

Four factors, two levels full factorial design was carried out using Minitab to investigate the factors that affect cumulative flow rate into the wellbore for a single-layered reservoir.

Table 3. 6: Factorial design Table to investigate the effect of rock and fluid properties on a single-layered reservoir

Factors	Minimum Value	Maximum Value
Pressure (psi)	3300	3700
Permeability (mD)	400	800
Thickness (ft)	40	100
Viscosity (cP)	0.46	1.21

The values of reservoir rock and fluid properties presented in Table 3.5 were assumed and used to investigate how they impact on cumulative flow rate.

CHAPTER 4

RESULTS AND DISCUSSIONS

4.1 STATIC MODELLING AND DYNAMIC SIMULATION

A 3D radial model was built using CMG Builder. Input parameters presented in Chapter 3 (see Table 3.5) were used to build the static model. The results are presented in Figure 4.1, Figure 4.2 and Figure 4.3 respectively.

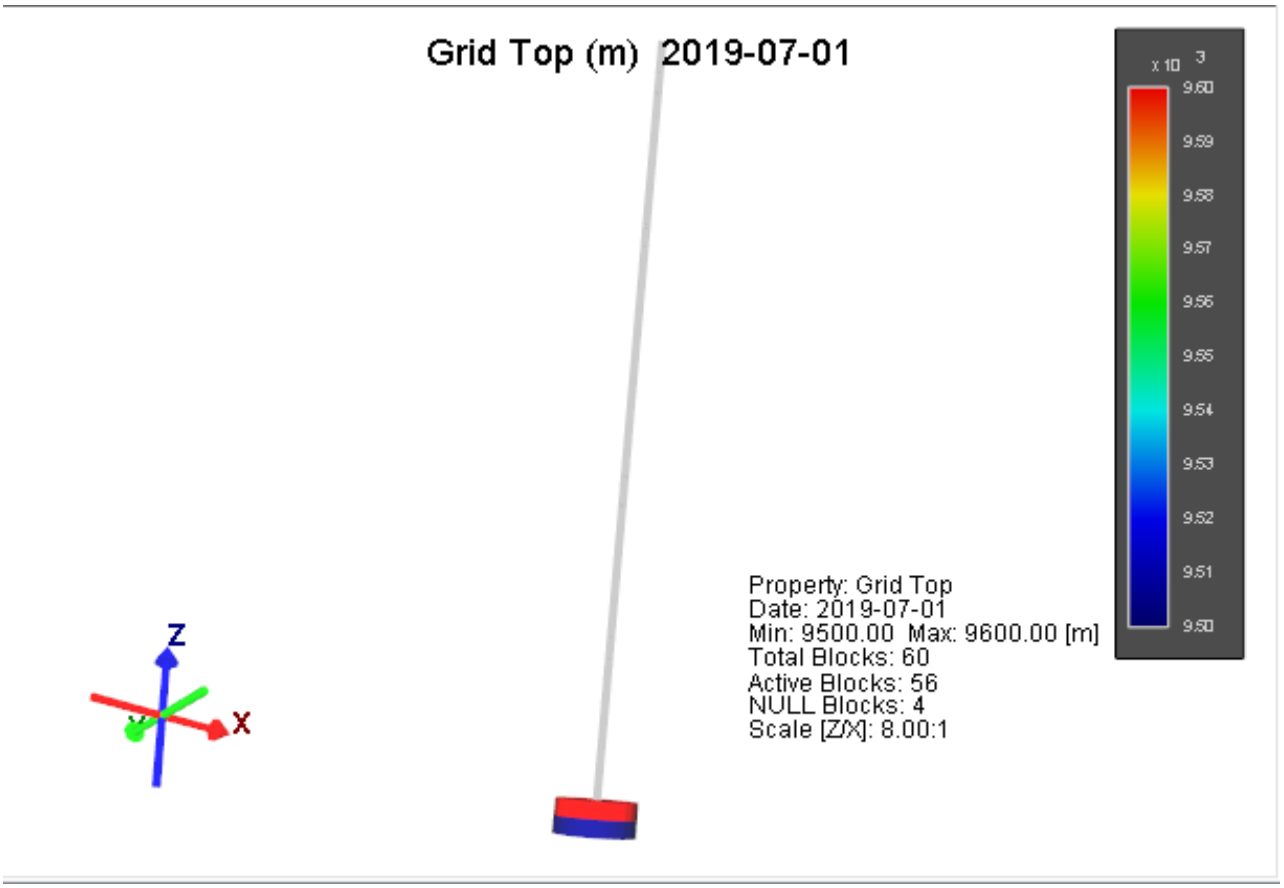

Figure 4. 1: 3D view of the reservoir and well

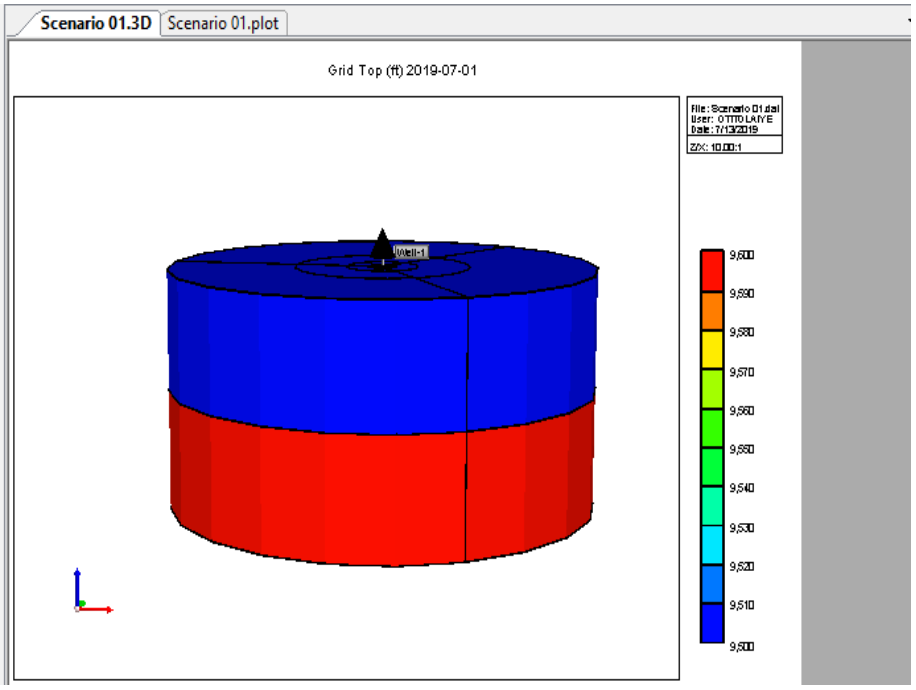

Figure 4. 2: 3D view of the reservoir

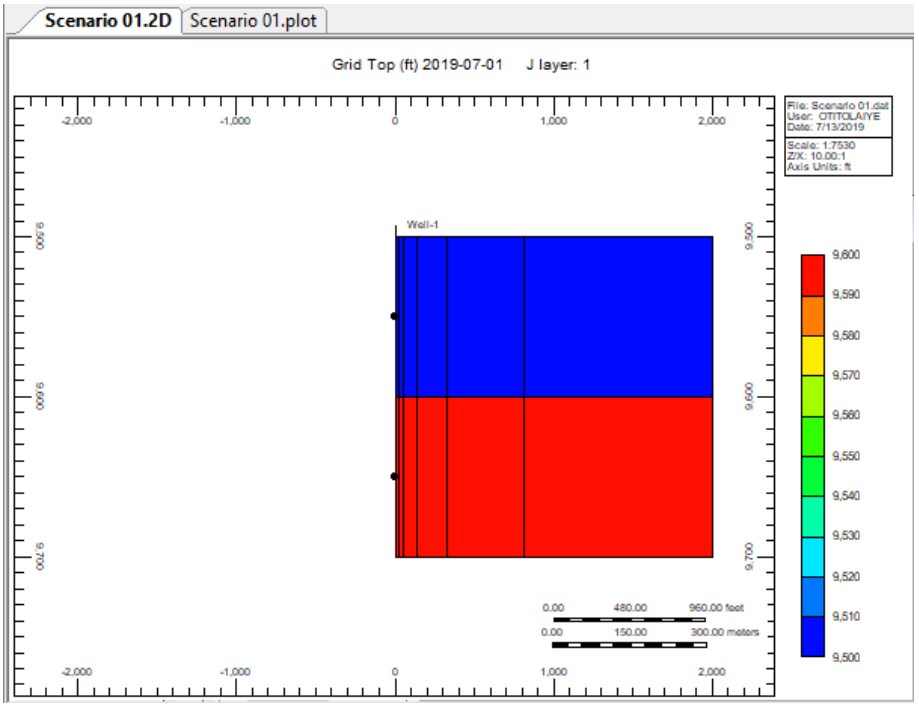

Figure 4. 3: Well completions (Perforations)

4.2 CASE STUDIES

4.2.1 Scenario 1a: Pressure Investigation (No Cross-Flow Situation)

In this case, rock and fluid properties of the two layers were the same and the simulation was carried out to investigate pressure effect on flowrate. In the first simulation, the original formation pressure in each layer was 4000psi and the original formation pressure is in the ratio 1.0. As the simulation progresses, the pressure kept falling, and the corresponding simulation time was 2984 days when the abandonment pressure was reached.

In the second simulation, the original formation pressure of the upper and lower layers were 4000psi and 3800psi respectively and the simulation formation pressure ratio is 1.053. When the original formation pressure ratio was 1.0, the average oil flow rate of the upper and lower producing layers was 2003.29 STB/day and 1996.71 STB/day respectively and the cumulative flow rates were 5.978 MMSTB and 5.958 MMSTB respectively. Since all reservoir parameters are the same, it is expected that the oil contribution from layer 1 (upper layer) and layer 2 (lower layer) be equal. The slightly higher contribution from the upper layer as seen from Figure 4.4 possibly results from a lower Pwf, causing a higher pressure drop and subsequently a higher production.

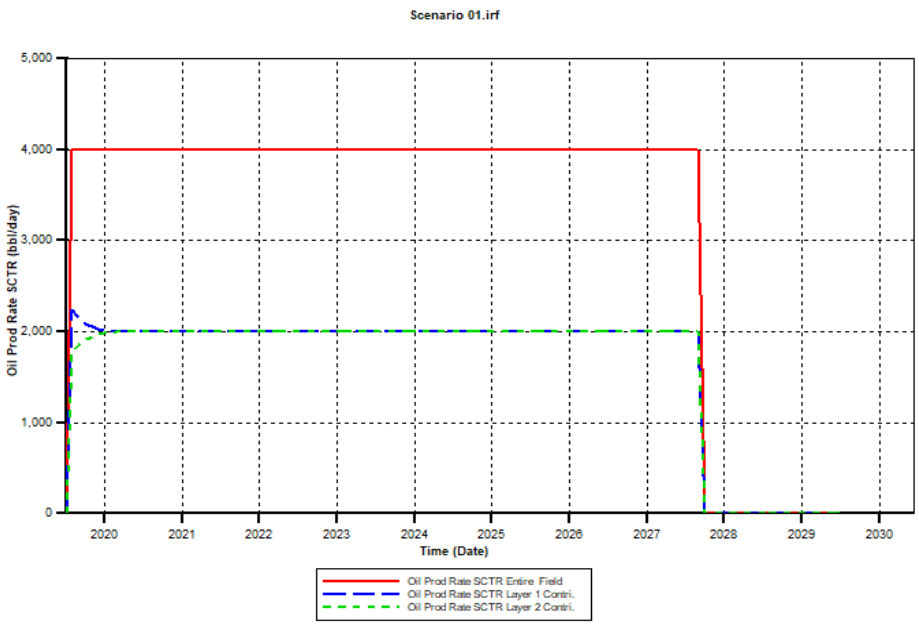

Figure 4. 4: Oil production rate when formation pressures were equal

Figure 4.4 also validates Darcy's law for radial flow. As discussed in the literature review (see section 2.3), the permeability-thickness ratio for the two layers is directly proportional to the

ratio of their respective flow rate, therefore, it is expected that contributions from both layers be equal.

In the second simulated situation where the original formation pressure ratio was 1.053, the average oil flow rate of the upper and lower producing layers were 2036.75 STB/day and 1963.25 STB/day respectively and the cumulative flow rates were 5.890 MMSTB and 5.678 MMSTB respectively. It was also observed that the well reached the abandonment pressure in 2892 days which is earlier than the first scenario depicted, this must-have resulted from the lower pressure in the lower layer.

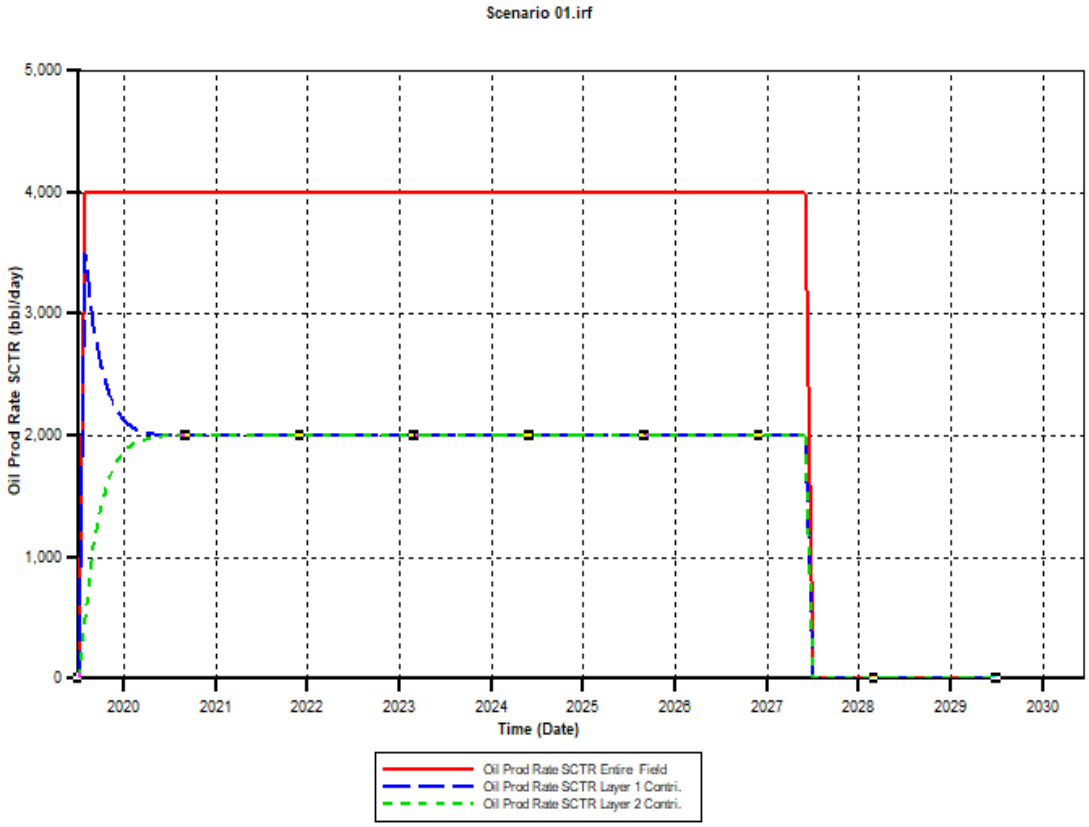

Figure 4. 5: Oil production rate when formation pressures were different.

4.2.2 Scenario 1b: Pressure Investigation (Crossflow Situation)

In this scenario, the same simulations carried out in scenario 1a were repeated but crossflow was allowed between the reservoir layers. In the first simulation, all properties were the same and the original formation pressure for each layer was equal.

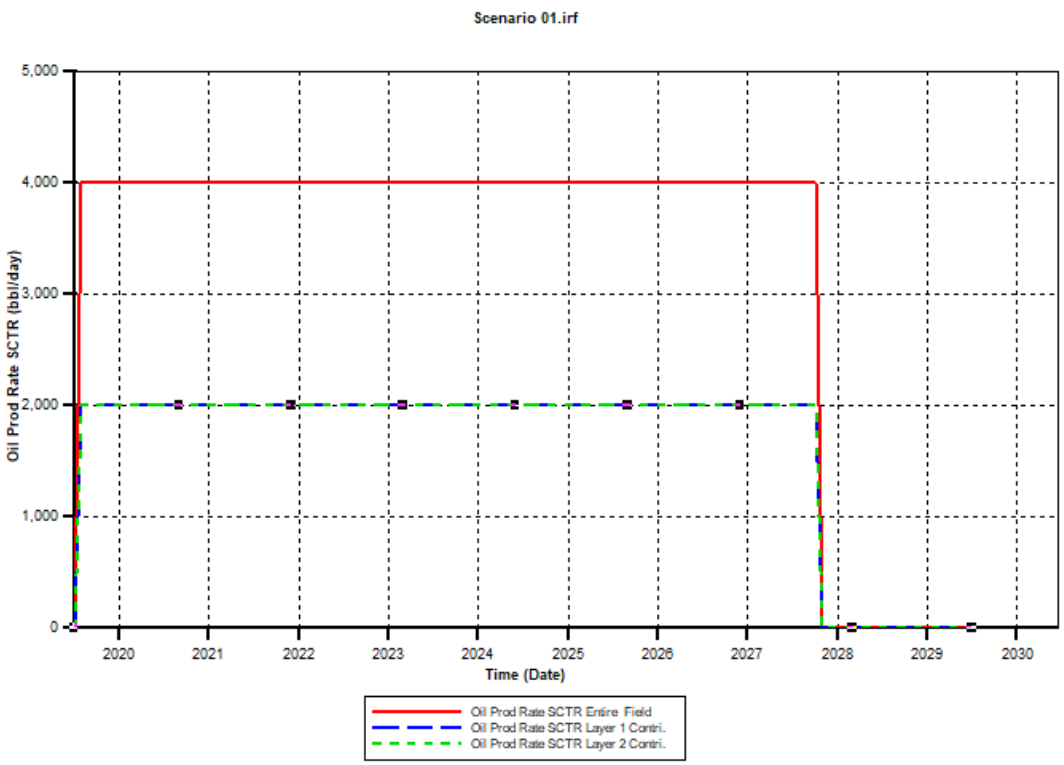

Figure 4. 6: Oil production rate when formation pressures were equal (Crossflow situation)

From the result presented in Figure 4.6, it is seen that the contribution from each layer is the same when the original formation pressure for each layer was equal. Also when the pressure in the upper layer was 4000 psi and that of the lower layer was 3800psi as shown in Figure 4.7, the contribution from both the upper and lower layer is also the same, unlike in no cross-flow situation where the higher pressured layer depleted very fast initially as shown in Figure 4.5.

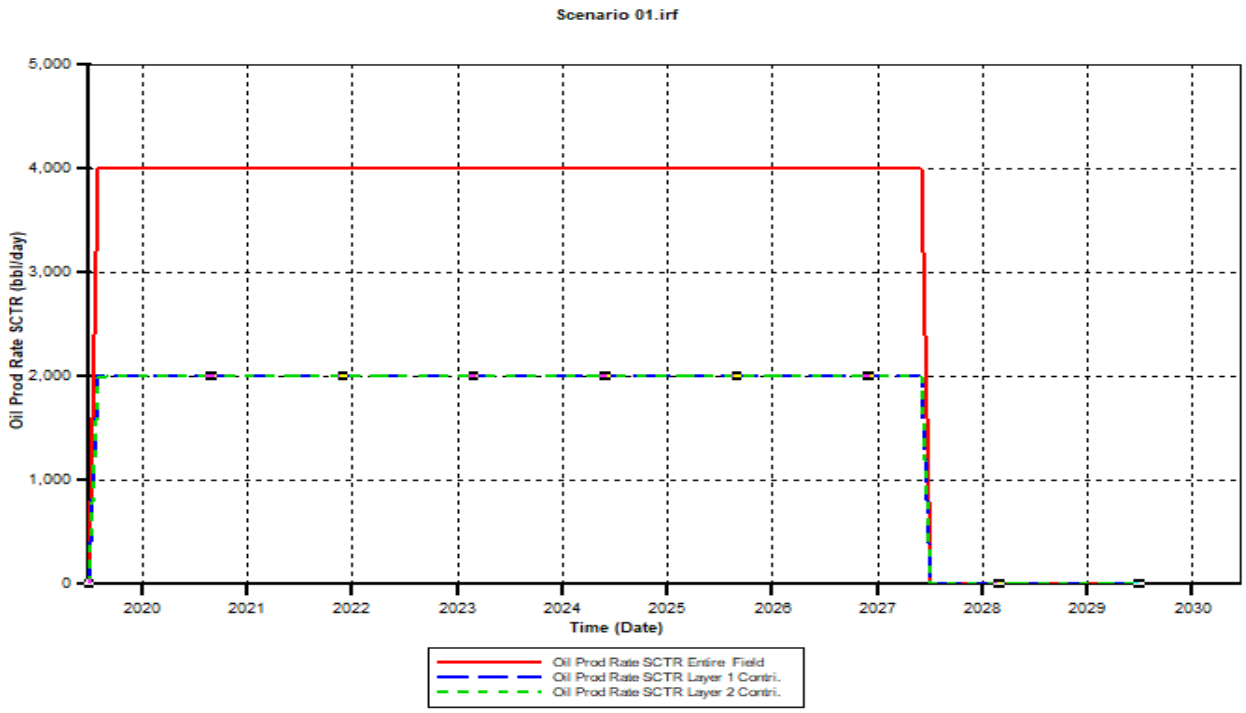

Figure 4. 7: Oil production rate when formation pressures were different (Crossflow situation)

4.2.3 Scenario 2a: Permeability Investigation (No Cross-Flow Situation)

In the first simulation, similar permeability for the upper and lower layer was investigated. The permeability for the upper layer was 800mD while that of the lower layer was 700 mD and the permeability ratio was 1.14 with same original formation pressure. In the second simulation, the permeability of the upper layer was 800mD and that of the lower layer was 400mD and the permeability ratio was 2.0.

When the permeability ratio was 1.14, the average oil flow rate for the upper and lower layer was 2066.98 STB/day and 1933.02 STB/day respectively as shown in Figure 4.8 and the cumulative flow rate was 6.168 MMSTB and 5.768 MMSTB respectively. Since the permeability of the upper layer was higher, it is seen that the output contribution of the upper producing layer is higher than that of the lower producing layer.

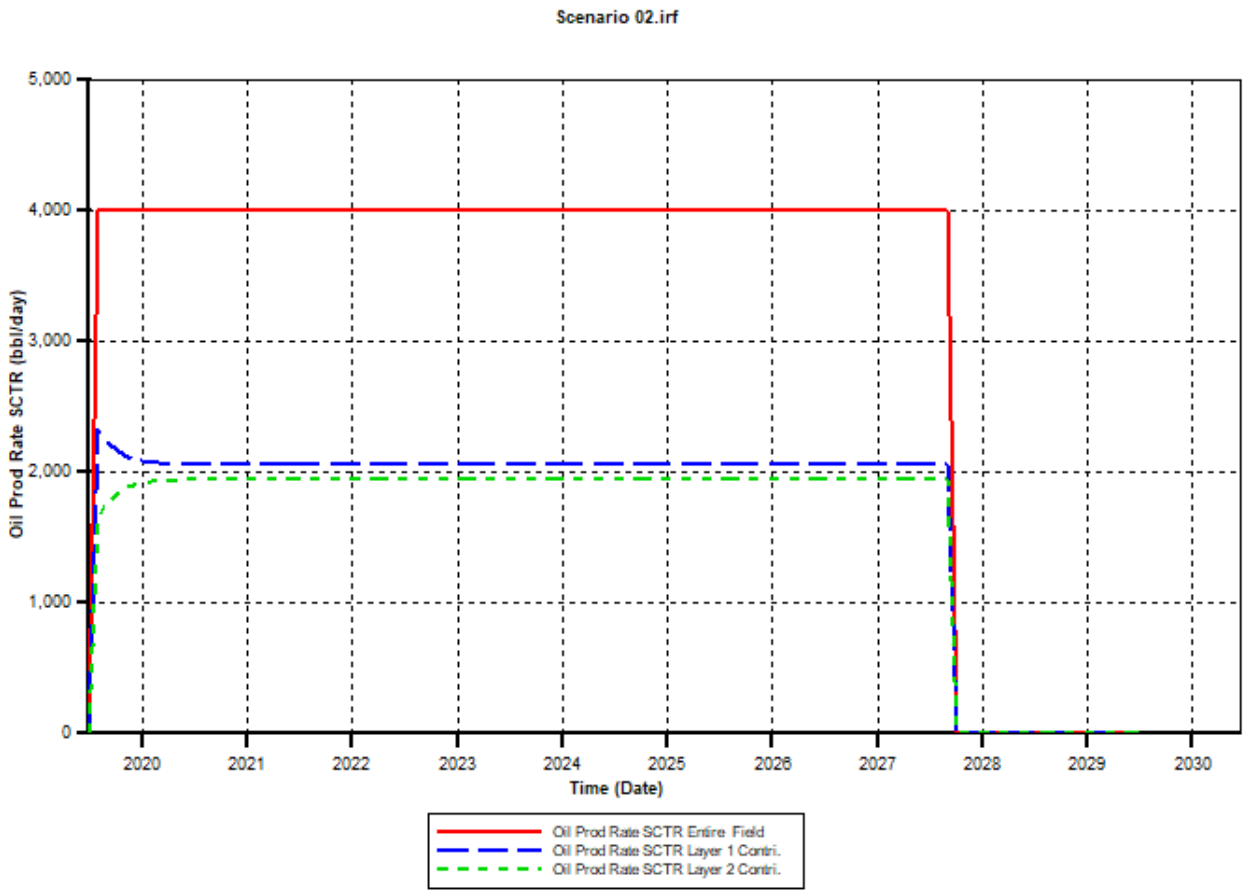

Figure 4. 8: Oil production rate when the permeability of the upper layer was 800mD and that of the lower layer was 700mD

Similarly, when the permeability ratio was 2.0, the upper layer has higher permeability and the flow rate and cumulative production from the upper layer is higher. Compared with the permeability ratio of 1.14, when the permeability ratio was 2.0, the contribution from the higher permeability layer was higher and the contribution from the lower permeability layer was lower.

Figure 4.8 shows the simulation result when the permeability in the upper layer was 800mD and that of the lower layer was 700mD and Figure 4.9 shows the simulation result when the permeability in the upper layer was 800mD and that of the lower layer was 400mD. It is obvious from Figure 4.8 and Figure 4.9 that when the original formation pressures are the same for each layer, permeability affects contribution from each layer and the more the differences in the permeability ratio of the layers, the higher the contribution from the layer with better permeability.

Also, using the resistances in parallel concept, we can evaluate the average permeability that can be used to quantify the total flow rate into the wellbore. In this situation, the average permeability can be computed as discussed in section 2.3 as 750mD and 600mD for the first and second simulation run respectively.

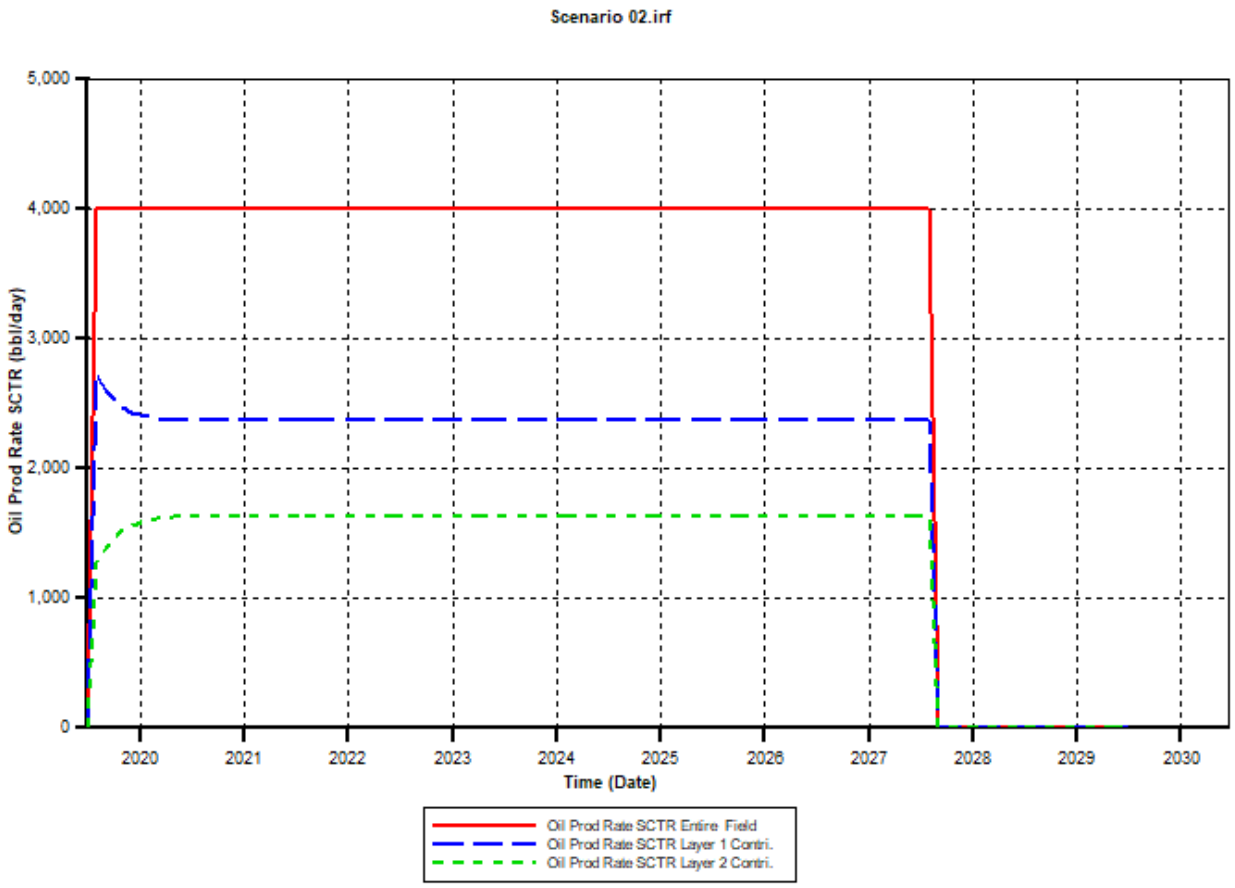

Figure 4. 9: Oil production rate when the permeability of the upper layer was 800mD and that of the lower layer was 400mD

4.2.4 Scenario 2b: Permeability Investigation (Crossflow Situation)

Figure 4.10 shows the oil production rate when the permeability of the upper layer was 800mD and that of the lower layer was 700mD and Figure 4.11 shows the oil production rate when the permeability of the upper layer was 800mD and that of the lower layer was 400mD when crossflow is allowed between the reservoir layers. Using the same properties as Scenario 2a but this time, cross-flow is allowed between the layers. It is seen that the average flow rate for the upper and lower producing layer was 2127.52 and 1872.48 STB/day respectively and cumulative flow rate of 6.349 MMSTB and 5.587 MMSTB respectively

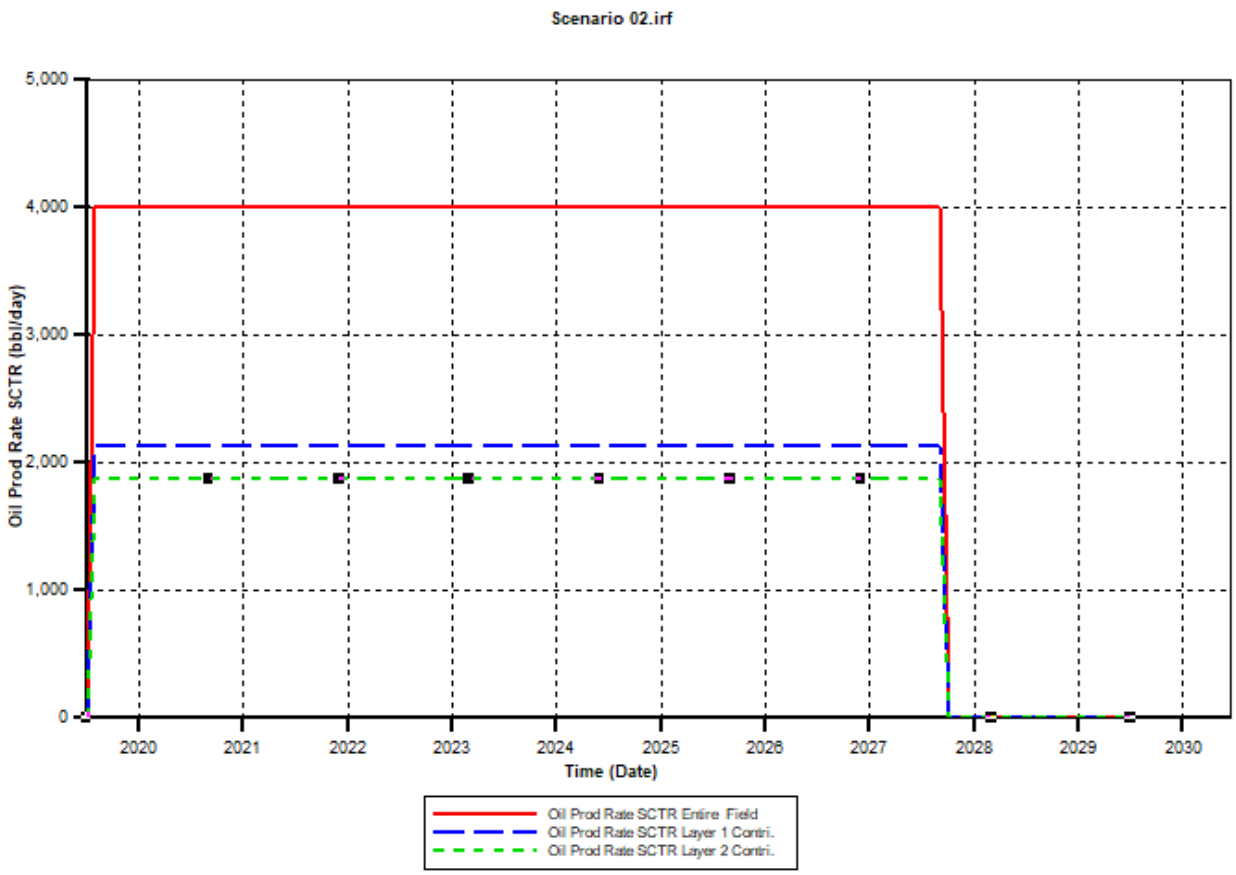

Figure 4. 10: Oil production rate when the permeability of the upper layer was 800mD and that of the lower layer was 700mD and cross-flow was allowed between layers.

When the permeability ratio was 2.0, the average flow rate of the upper and lower producing layers were 2652.91 and 1347.09 STB/day respectively and cumulative flow rate of 7.916 MMSTB and 4.020 MMSTB respectively

Compared with the no cross-flow between layers situation, it is seen that, for the reservoir layer with higher permeability, production is higher in a cross-flow situation than in a no cross-flow situation. This is an indication that cross-flow increases contribution from higher permeability layer and decreases the contribution from a layer with a lower permeability.

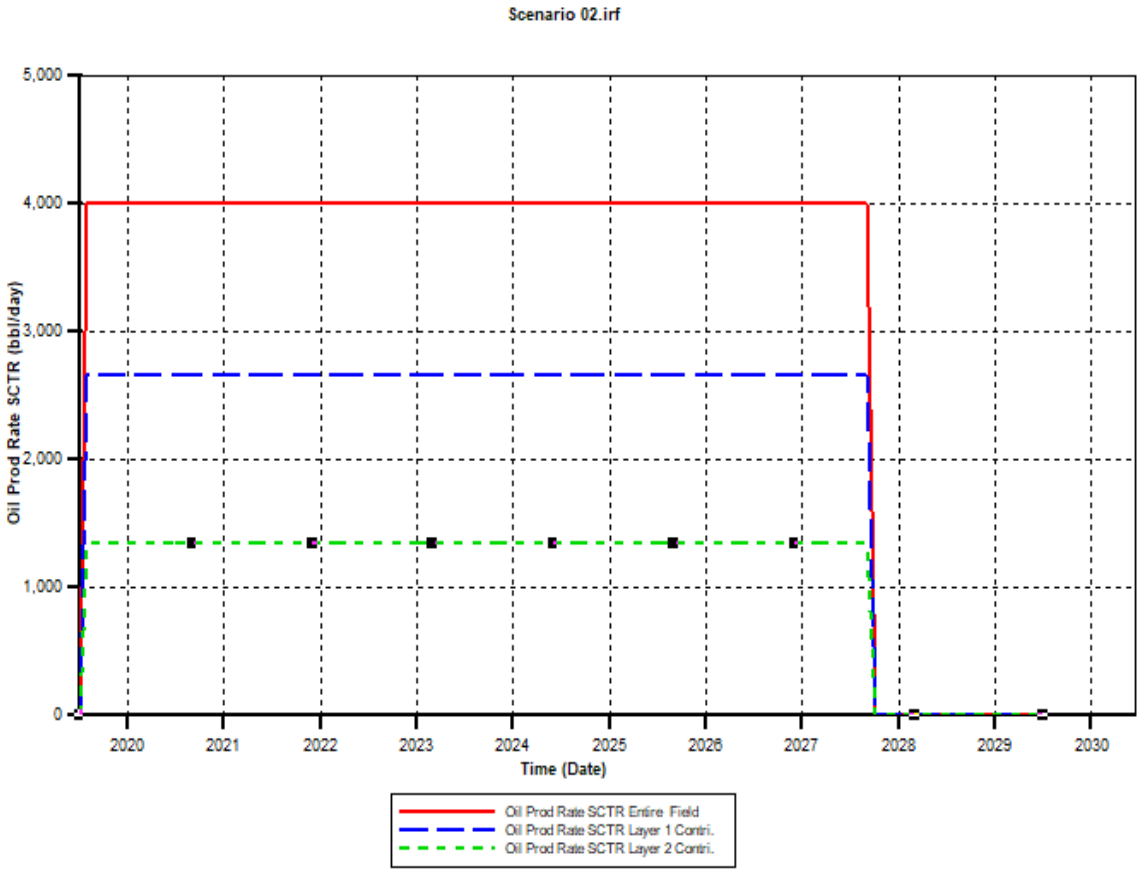

Figure 4. 11: Oil production rate when the permeability of the upper layer was 800mD and that of the lower layer was 400mD and cross-flow occurred between layers.

4.2.5 Scenario 3a: Thickness Investigation (No Cross-Flow Situation)

Figure 4.12 shows the oil production rate when the upper and lower layer thickness was 100ft and 80ft respectively. The average flow rate was 2219.81 STB/day and 1780.19 STB/day respectively and cumulative production rate of 5.949 MMSTB and 4.771 MMSTB respectively. From Figure 4.12, it is seen that the layer with higher pay thickness has a higher contribution to the total flow rate in the wellbore. Since the thickness in the two layers is close, it is seen that the contributions from the two layers are equally close. It can also be seen that at early production time, production from the upper layer declined slowly and became steady over the years. On the other hand, production from the lower layer increased slightly at an early time and became steady over the years.

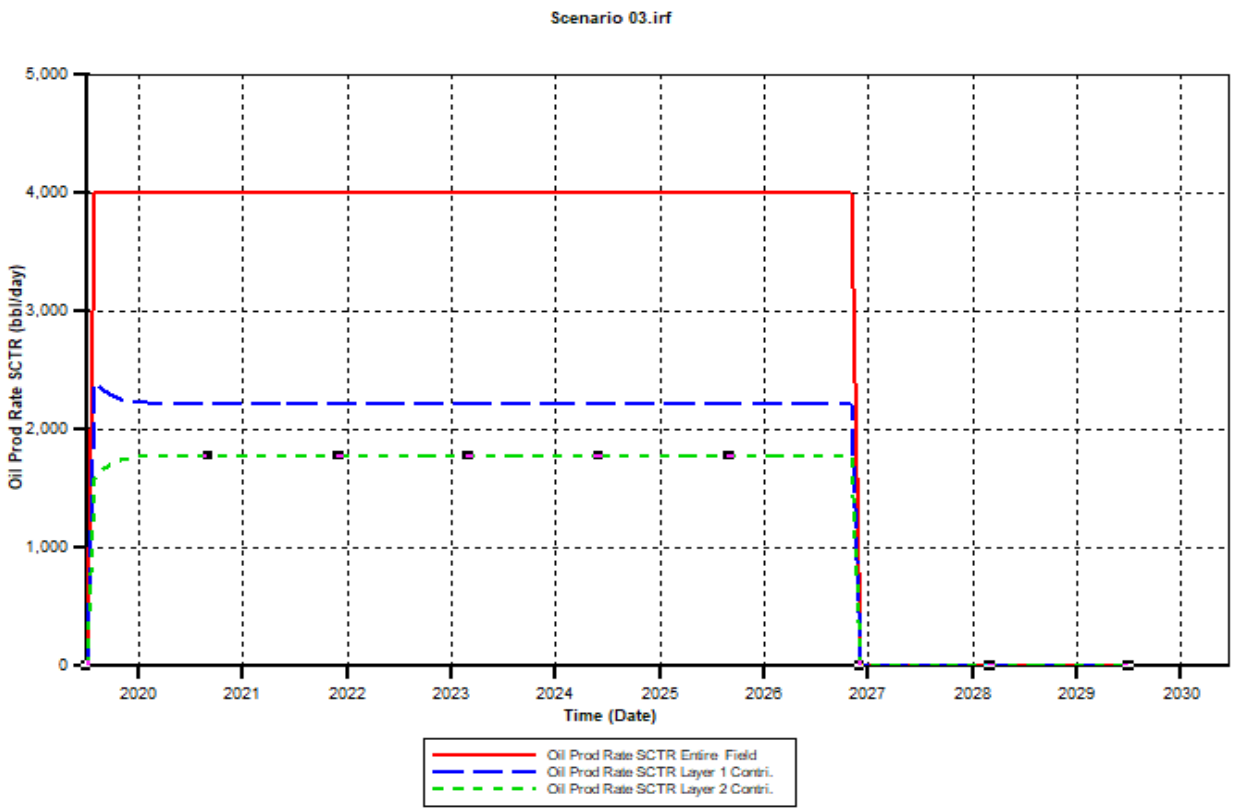

Figure 4. 12: Oil production rate when the thickness of the upper layer was 100ft and that of the lower layer was 80ft

Figure 4.13 shows oil production rate when the thickness of the upper layer was 100ft and that of the lower layer was 40ft and the corresponding thickness ratio was 2.5. The average flow rate for the upper and lower reservoir layer was 2857.46 STB/day and 1142.54 STB/day and the cumulative production rate of 5.915 MMSTB and 2.365 MMSTB respectively. The abandonment pressure was reached after 2070 days, which is earlier than the first simulation run. This must-have resulted from the upper layer depleting very fast causing the pressure to drop rapidly

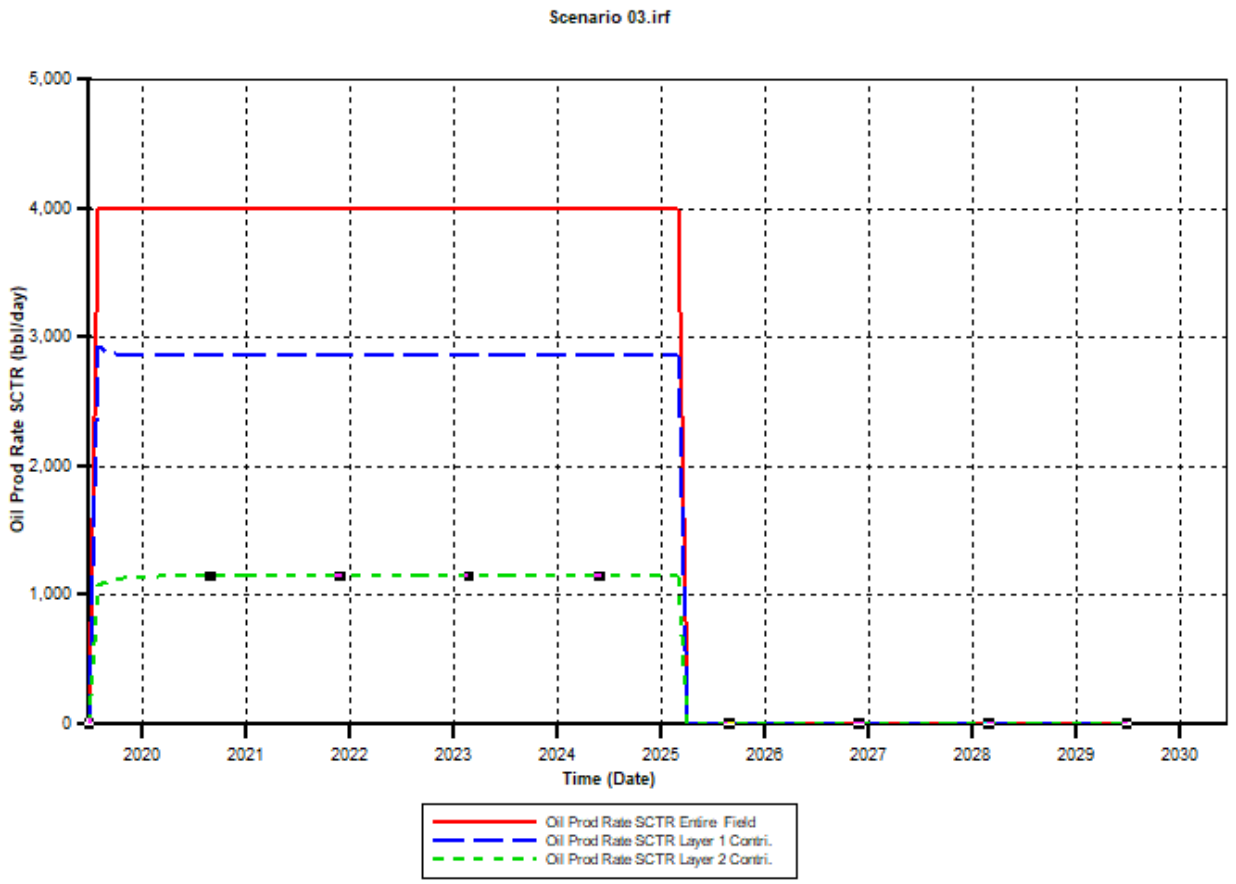

Figure 4. 13: Oil production rate when the thickness of the upper layer was 100ft and that of the lower layer was 40ft

4.2.6 Scenario 3b: Thickness Investigation (Crossflow Situation)

Figure 4.14 shows the oil production rate when the thickness of the upper layer was 100ft and that of the lower layer was 80ft. Crossflow between the reservoir layers was allowed. The average flow rate for the upper and lower layer was 2224.53 STB/day and 1775.47 STB/day respectively with a cumulative production rate of 5.96 MSTB and 4.76 MMSTB respectively. The abandonment pressure was reached after 2680 days.

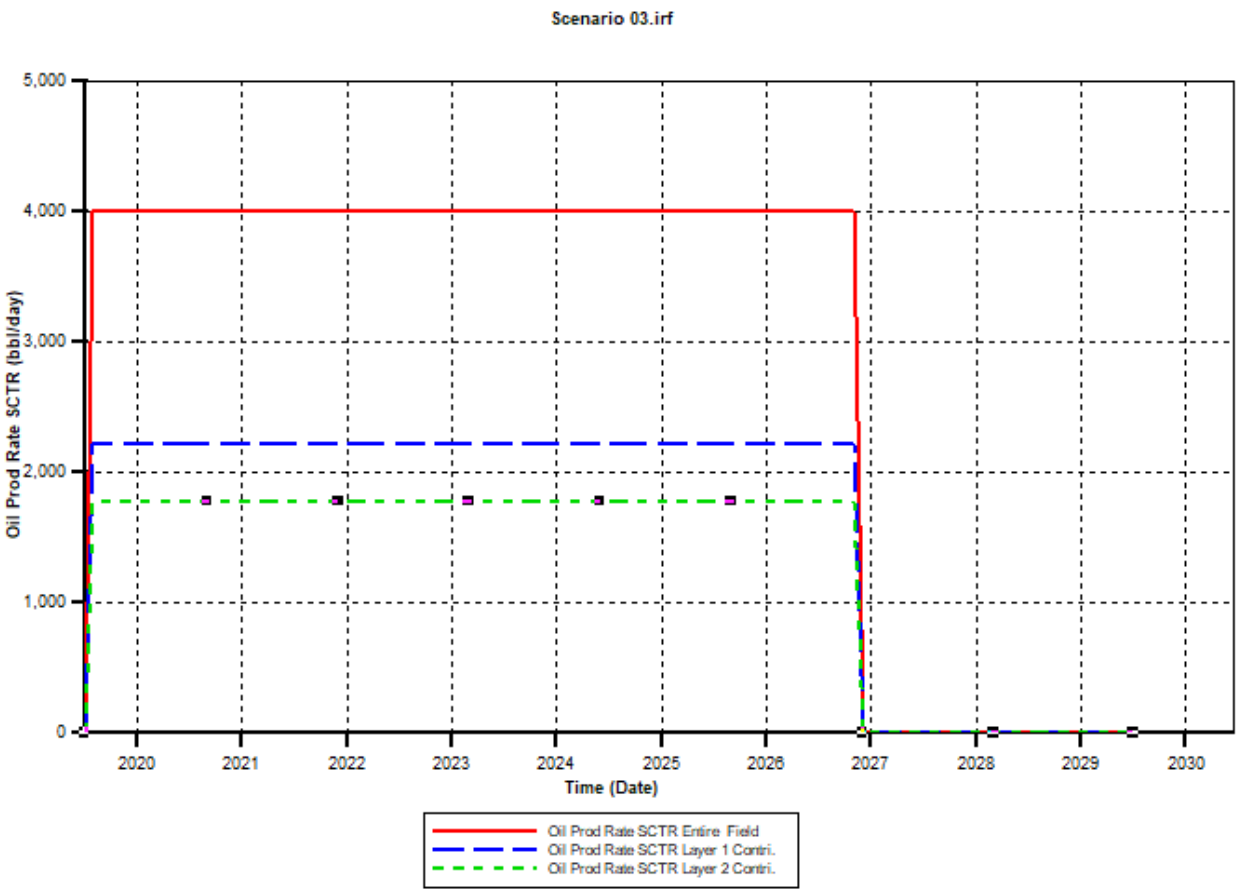

Figure 4. 14: Oil production rate when the thickness of the upper layer was 100ft and that of the lower layer was 80ft and cross-flow occurred between layers.

Figure 4.15 shows the oil production rate when the thickness of the upper layer was 100ft and that of the lower layer was 40ft and cross-flow between the layers occurred. The average production flow rate for the upper and lower layers was 2855.60 STB/day and 1144.40 STB/day respectively and cumulative production rate of 5.911 MMSTB and 2.369 MMSTB respectively. The abandonment pressure was reached after 2070 days, a time earlier than the scenario where the permeability ratio of the layers was smaller.

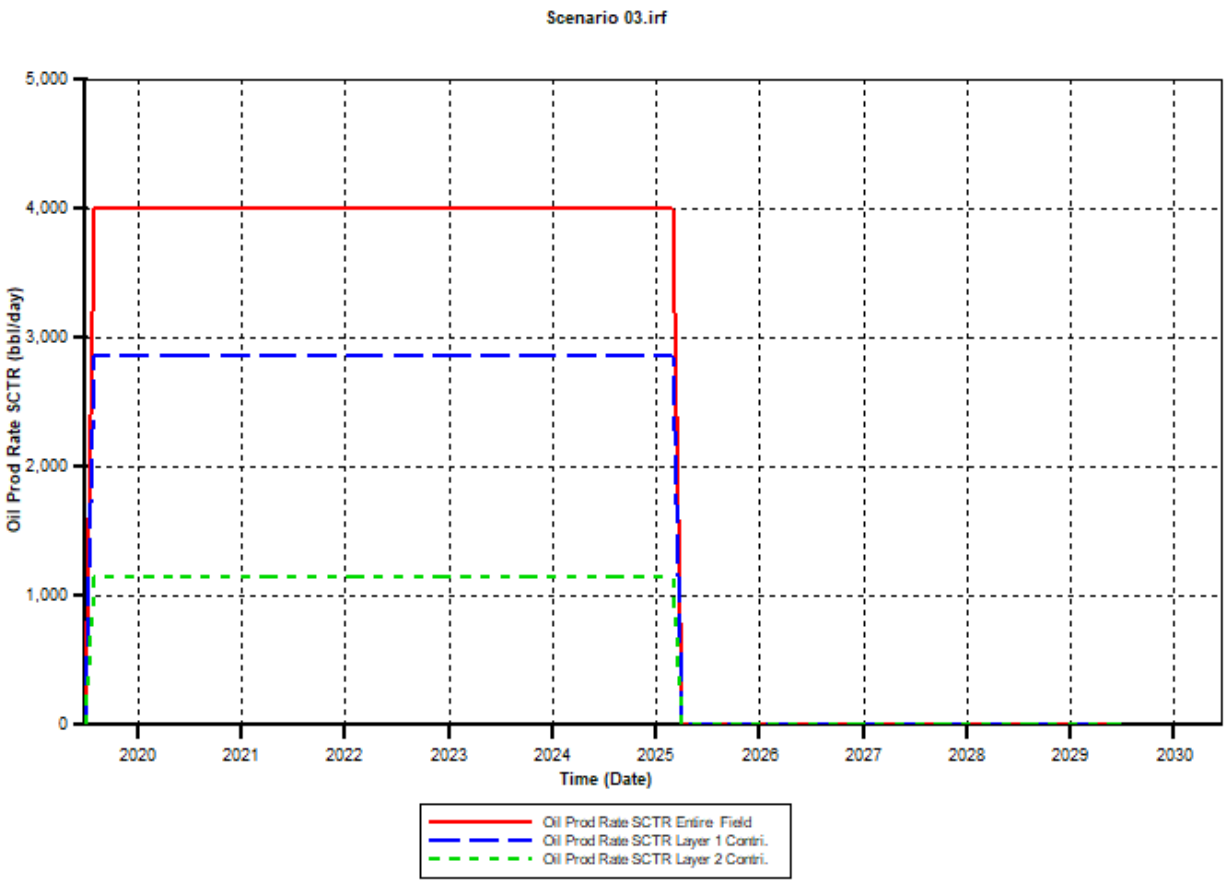

Figure 4. 15: Oil production rate when the thickness of the upper layer was 100ft and that of the lower layer was 40ft and cross-flow occurred between layers.

4.2.7 Scenario 4a: Viscosity Investigation (No Cross-Flow Situation)

In the first simulation run, the viscosity of the upper reservoir layer was 0.46cp and that of the lower layer was 1.21cp. The average oil flow rate of the upper reservoir layer with smaller viscosity was 2416.41 STB/day and the oil flow rate for the lower layer with a higher viscosity was 1583.59 STB/day and the cumulative production rate of the upper and lower layers was 7.061 MMSTB and 4.627 MMSTB respectively. The abandonment pressure was reached after 2922 days. From the data presented, it is seen that oil flow rate and viscosity are inversely proportional as we expect. Figure 4.15 shows the contribution from the upper and the lower layer when crossflow did not occur between the layers.

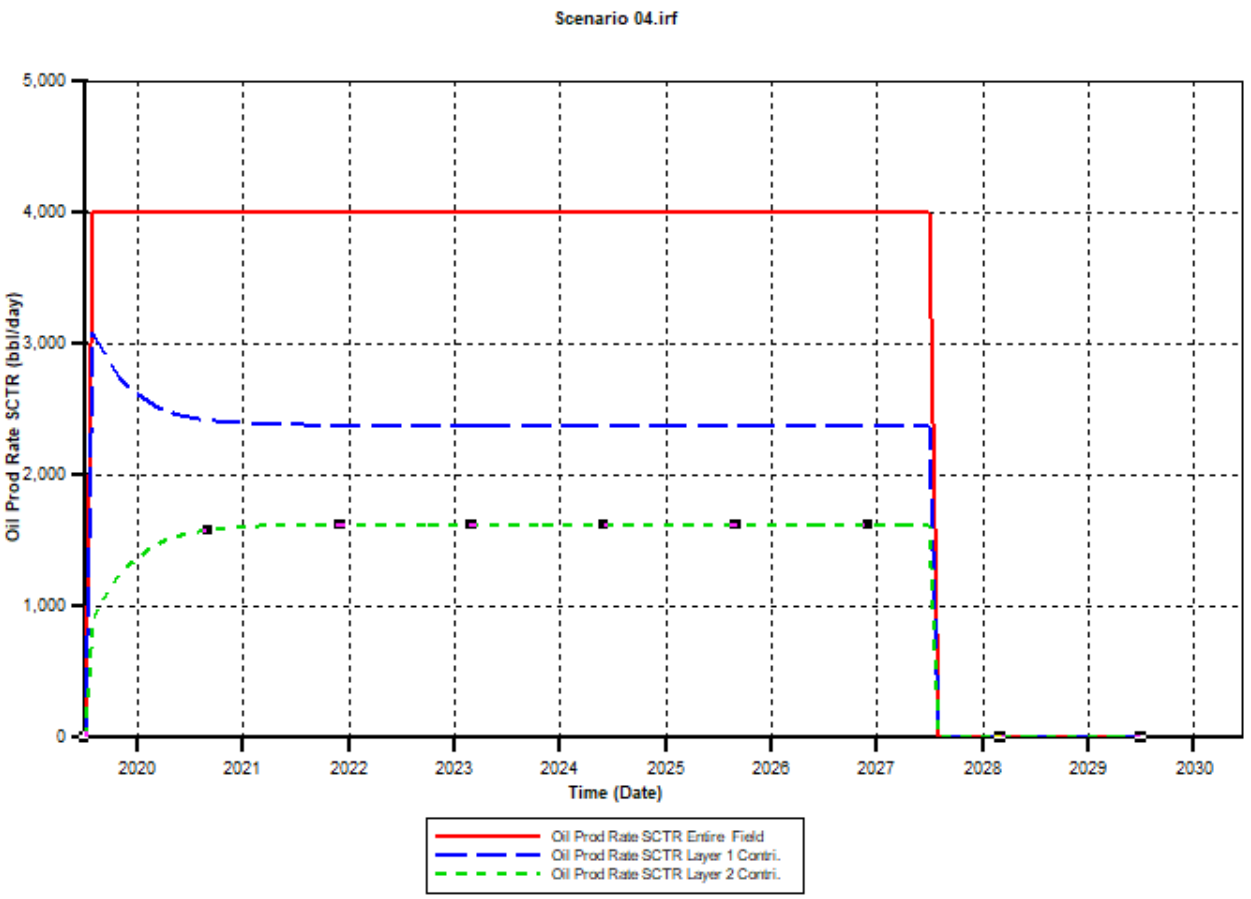

Figure 4. 16: Oil production rate when the viscosity of the upper layer was 0.46cp and the viscosity of the lower layer was 1.21cp.

In the second simulation run, the average oil production rate when the viscosity of the upper layer was 1.21cp and the viscosity of the lower layer was 0.46cp was 1594.12 STB/day and 2405.88 STB/day respectively and cumulative production rate of 4.658 MMSTB and 7.030 MMSTB for the upper and lower reservoir layer respectively. The abandonment pressure was reached after 2922 days. As seen from Figure 4.17, the upper layer has a more viscous fluid and the contribution from the upper layer was smaller. In the same manner, the lower layer has a less viscous fluid and the contribution was higher than that of the lower layer. This confirms that flow rate and viscosity are inversely related

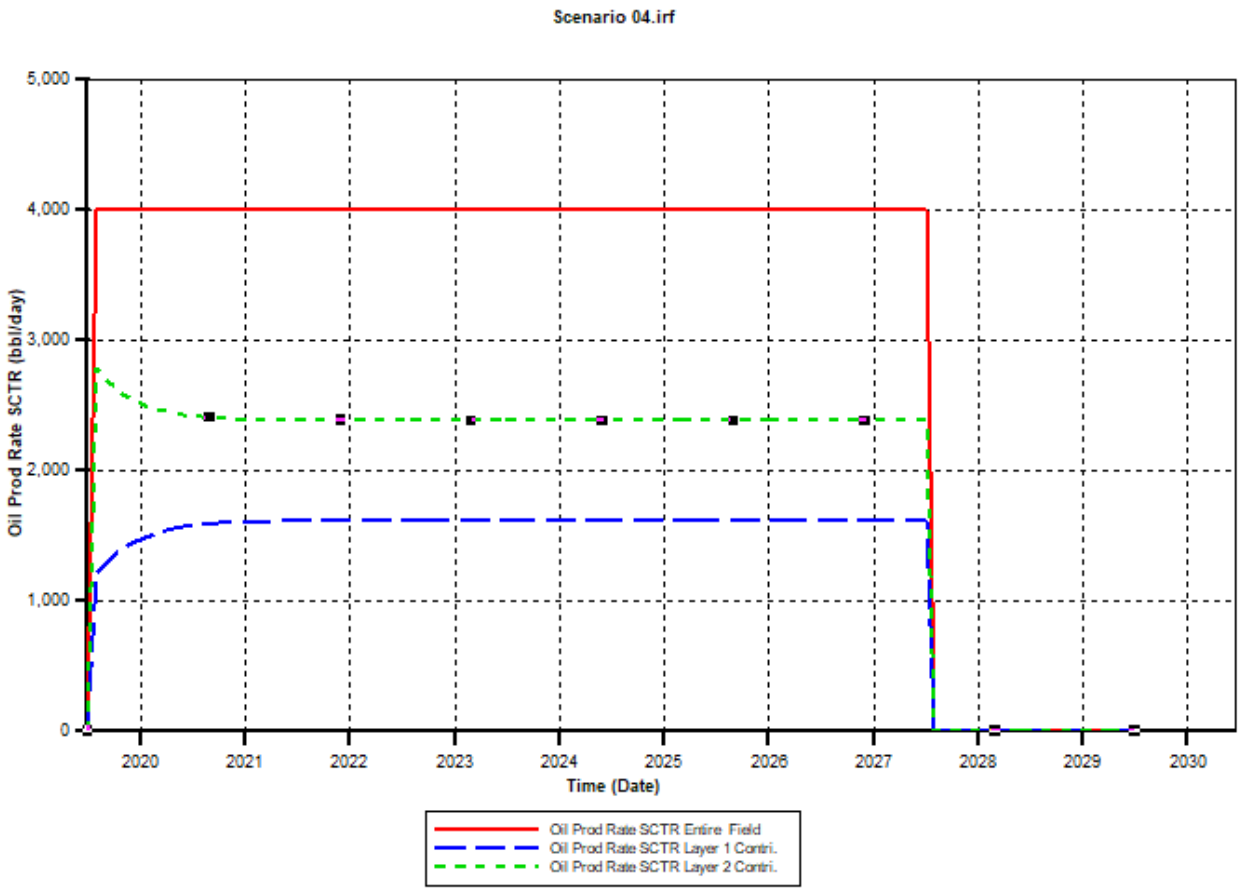

Figure 4. 17: Oil production rate when the viscosity of the upper layer was 1.21cp and the viscosity of the lower layer was 0.46cp.

4.2.8 Scenario 4b: Viscosity Investigation (Crossflow Situation)

When cross flow occurred within the layers and using the same parameters as in Section 4.2.7, the average oil production rate for the upper and lower layers was 3070.97 STB/day and 929.03 STB/day respectively and cumulative production rate of 9.069 MMSTB and 2.743 MMSTB respectively. The abandonment pressure was reached after 2953 days. Similar to other situations where cross-flow occurred, the flow rate for the layers were constant all through until the abandonment pressure was reached as seen in Figure 4.18 and the oil rate from the layer with lower viscosity was higher for the cross-flow situation than the situation where cross-flow did not occur between the layers.

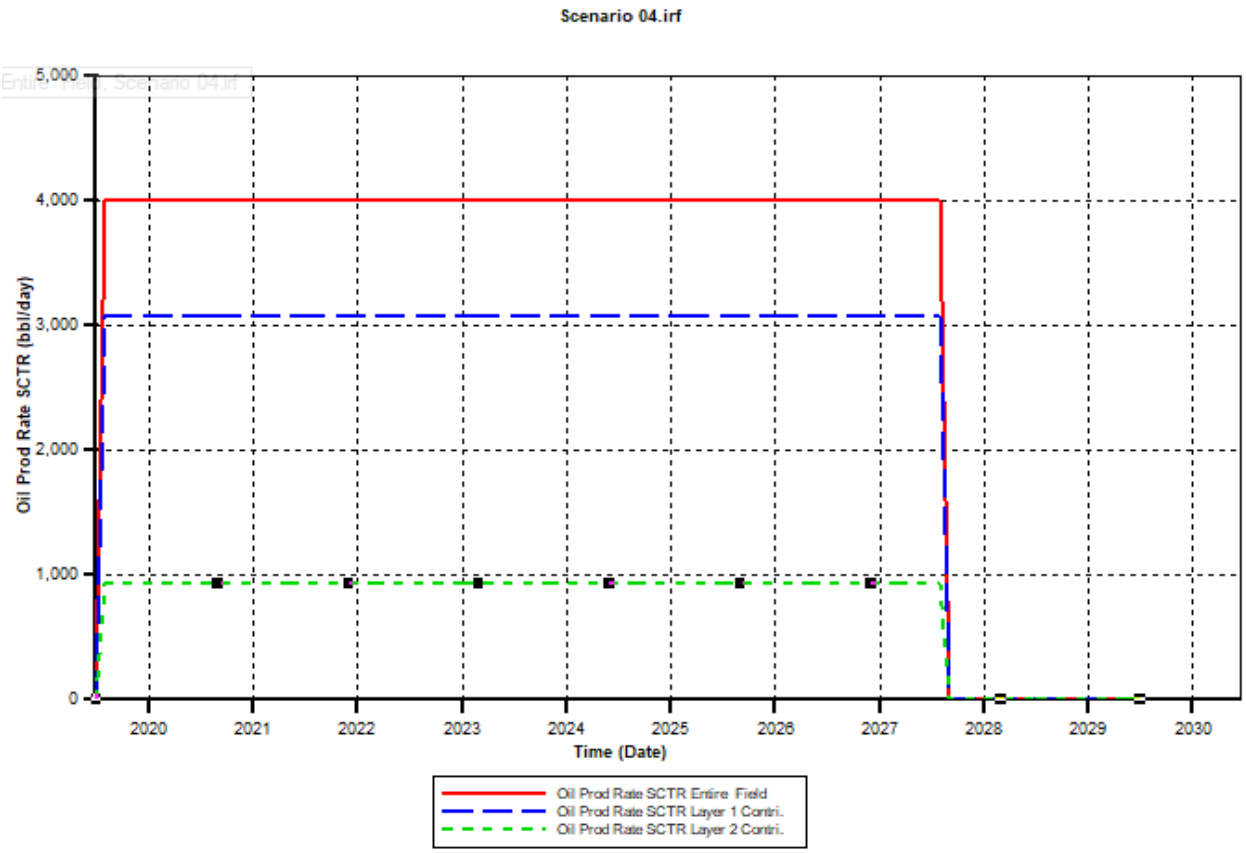

Figure 4. 18: Oil production rate when the viscosity of the upper layer was 0.46cp and the viscosity of the lower layer was 1.21cp

In the second simulation run, cross-flow occurred within the reservoir layers. The upper layer has a more viscous fluid with a viscosity of 1.21cp while the lower layer contains a less viscous fluid of viscosity 0.46cp. The average flow rate for the upper and lower producing layer was 925.39 STB/day and 3074.61 STB/day respectively and cumulative production rate of 2.733 MMSTB and 9.079 MMSTB respectively. The abandonment pressure was reached after 2953 days. From Figure 4.19, it can be seen that the oil production rate when cross-flow occurred within the layers was constant and higher than when crossflow did not occur within the layers.

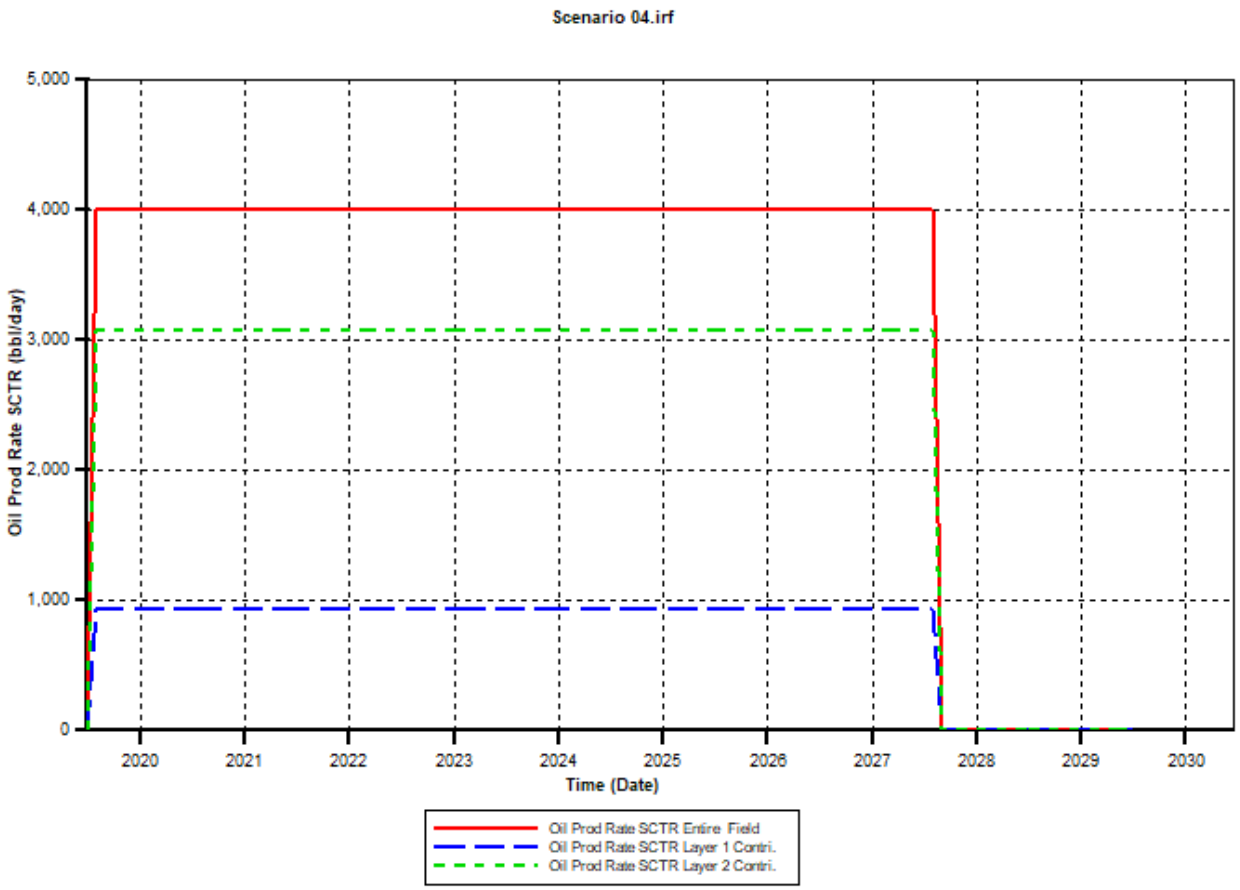

Figure 4. 19: Oil production rate when the viscosity of the fluid in the upper layer was 1.21cp and the viscosity of the fluid in the lower layer was 0.46cp.

4.3 DESIGN OF EXPERIMENT (DoE)

A design of experiment was conducted to investigate the magnitude in which rock and fluid properties will affect flow into the wellbore for a single-layered reservoir. In this experiment, the perforation of layer two was closed and the effect of reservoir properties such as pressure, permeability, thickness and viscosity were investigated. A 2 level 4 factors experiment was designed to carry out the investigation. This implies that the total number of experiments will be 2^4 i.e. 16 experiments. Table 4.1 shows the parameters investigated their minimum and maximum values of the investigated parameters and Table 4.2 shows the results obtained when the experiments were carried out.

Table 4. 1**:** Reservoir parameters and range of values

Factors	Minimum Value	Maximum Value
Pressure (psi)	1500	4000
Permeability (mD)	400	800
Thickness (ft)	40	100
Viscosity (cP)	0.46	1.21

Table 4. 2: Cumulative flow rate obtained from the experimental design

StdOrder	RunOrder	CenterPt	Blocks	Pressure (psi)	Permeability (mD)	Thickness (ft)	Viscosity (cP)	Cum. Flow Rate (STB)
1	1	1	1	3300	400	40	0.46	2804000.171
2	2	1	1	3700	400	40	0.46	3048000.186
3	3	1	1	3300	800	40	0.46	3416000.208
4	4	1	1	3700	800	40	0.46	3660000.223
5	5	1	1	3300	400	100	0.46	6092000.372
6	6	1	1	3700	400	100	0.46	6820000.416
7	7	1	1	3300	800	100	0.46	6456000.394
8	8	1	1	3700	800	100	0.46	7188000.439
9	9	1	1	3300	400	40	1.21	9326.634021
10	10	1	1	3700	400	40	1.21	56741.56918
11	11	1	1	3300	800	40	1.21	1832000.112
12	12	1	1	3700	800	40	1.21	2076000.127
13	13	1	1	3300	400	100	1.21	3784000.231
14	14	1	1	3700	400	100	1.21	4508000.275
15	15	1	1	3300	800	100	1.21	5356000.327
16	16	1	1	3700	800	100	1.21	5540000.338

The simulation was done under the situation of different formation pressure, viscosity, thickness and permeability. The cumulative flow rate obtained are presented in Table 4.1

From Figure 4.20, it is seen that original formation pressure affect flow rate the most in a single-layered reservoir.

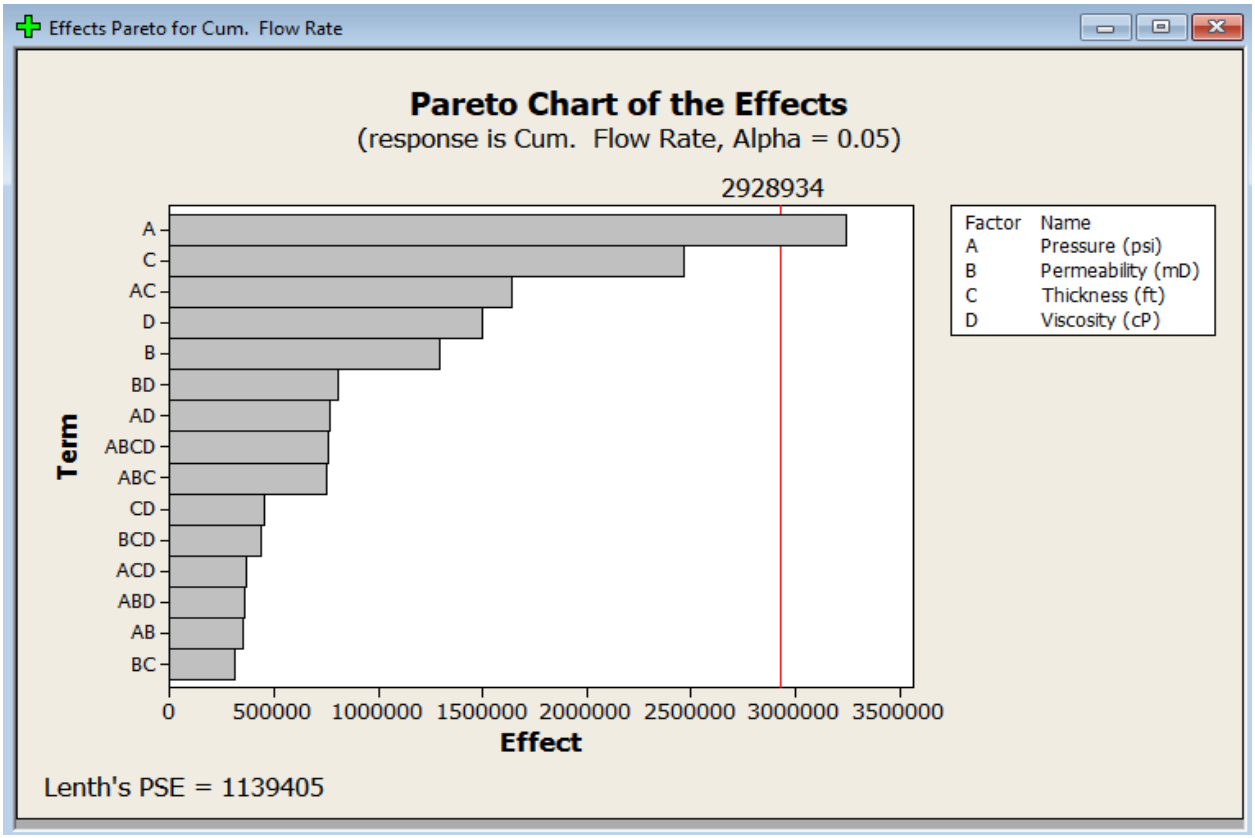

Figure 4. 20: Pareto Chart of the effect of rock and fluid properties to flow rate in a single-layered reservoir

A regression analysis was carried out to obtain a proxy model for the reservoir cumulative flow rate.

The regression equation obtained is:

Cum. Flow Rate = - 3037114 + 984 Pressure (psi) + 2626 Permeability (mD)
+ 60087 Thickness (ft) - 2720322 Viscosity (cp)

The R-Sq obtained was 97.5 %. This is a very high value indicating that the proxy model represents the cumulative flow rate very close enough to the actual value.

For the two-layered commingled system, it has been shown from the various simulation runs carried out, that the flowrate for each layer is directly proportional to the pressure drop (ΔP) permeability (k), thickness (h) and inversely related to the viscosity (μ). A simple model for the layers is:

For the upper layer:

$$q_{upper} = \frac{C\ k_{upper} h_{upper} \Delta P_{upper} h}{\mu_{upper}} \text{.....Eq. 4.1}$$

For the lower layer:

$$q_{lower} = \frac{C k_{lower} h_{lower} \Delta P_{lower}}{\mu_{lower}} \text{.....Eq. 4.2}$$

Where:

C = Constant

Total flow rate q_t into the wellbore is given as:

$$q_t = q_{upper} + q_{lower}$$

This is in agreement with literature as discussed in section 2.3. Hence, we can use pressure drop, rock and fluid properties to allocate production in a commingled system.

CHAPTER 5

CONCLUSION AND RECOMMENDATIONS

5.1 CONCLUSION

This work sought to allocate production from a two-layered reservoir. It also sought to investigate if pressure drop and rock and fluid properties can be used for production allocation. Several simulations were run to carry out the investigation of formation pressure regimes, permeability, thickness and viscosity in both cross flow and no-cross flow situations.

Based on the study, the following conclusions are drawn:

- Reservoir simulation can be used to allocate commingled production from stacked reservoirs.
- Pressure difference and reservoir rock and fluid properties affect commingled production from a layered reservoir.
- Darcy's flow equation is valid for radial system when the pressure drop and the rock and fluid properties are considered as confirmed from simulation results.
- For all scenarios involving cross flow, flow rate is constant and higher for layer with better rock and fluid properties when cross flow occurs than when there is no crossflow.
- For a single layer reservoir, formation pressure contributes the most to flowrate.

5.2 RECOMMENDATION

Future study should be carried out to validate the proxy model developed for a single layered reservoir. In this work most of the simulation runs were carried out such that the upper reservoir layer had higher pressures and better rock and fluid properties. For future works, the convention can be changed such that the lower reservoir layer will have a higher pressure and better rock and fluid properties and see their effect on flow rate into the wellbore.

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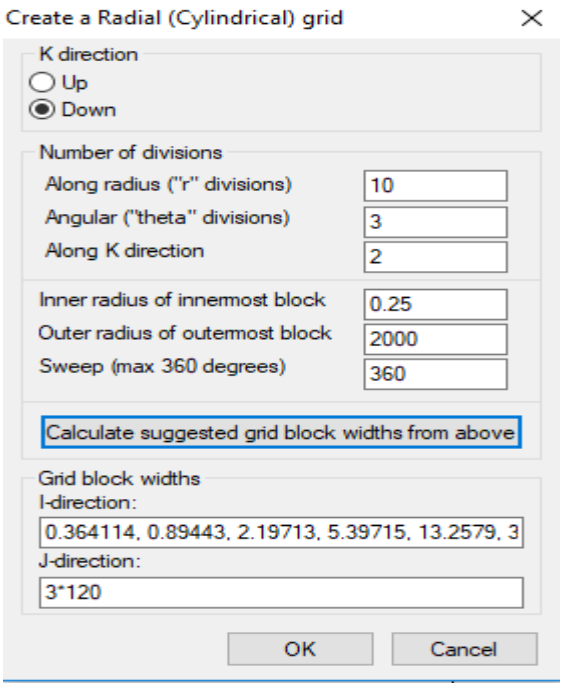
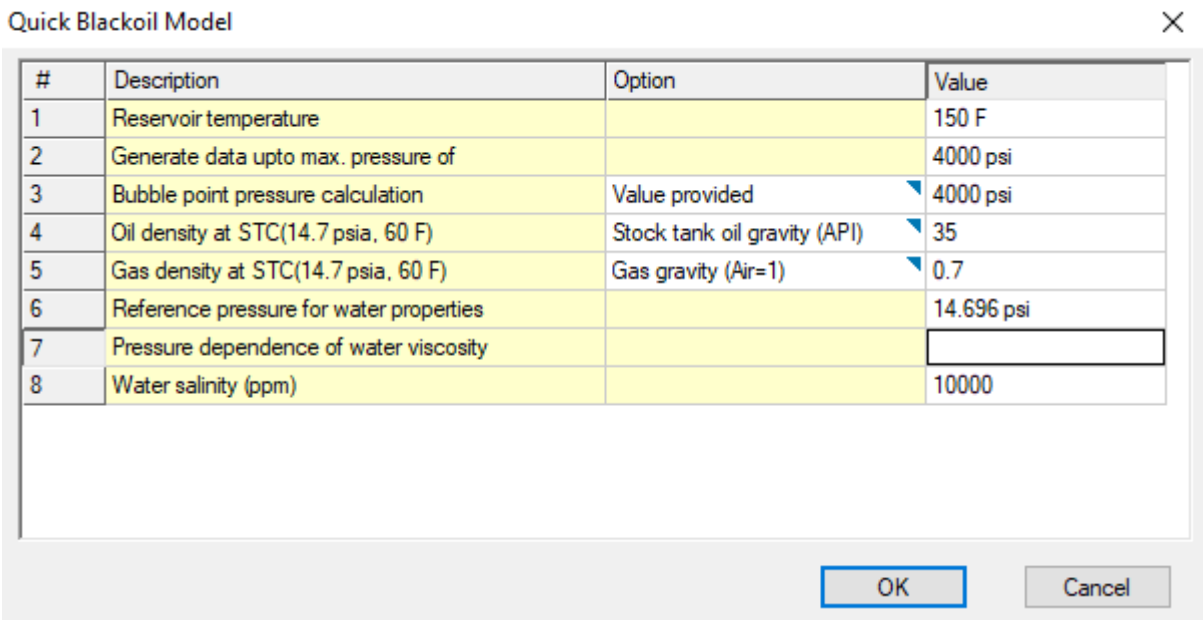
APPENDIX



Fluid 1



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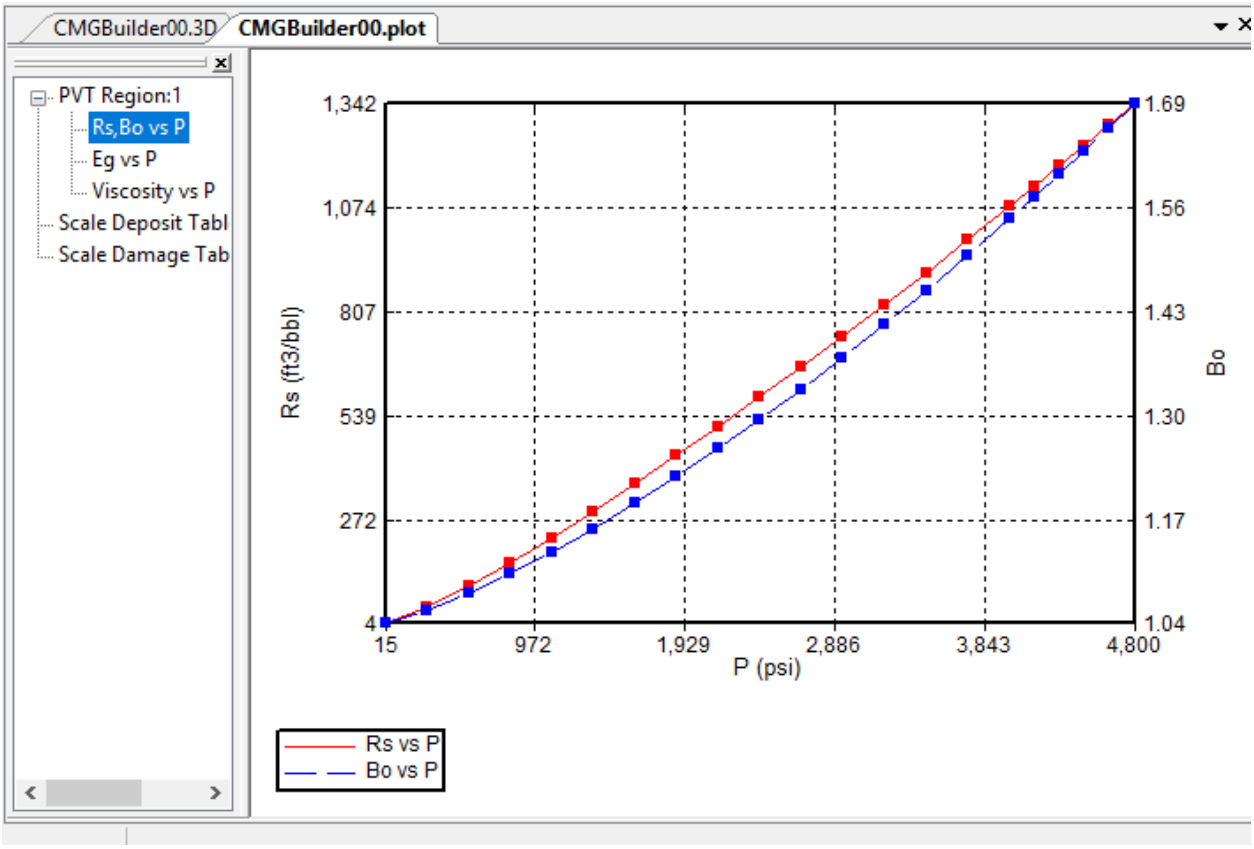
3	Bubble point pressure calculation	Value provided	4000 psi
4	Oil density at STC(14.7 psia, 60 F)	Stock tank oil gravity (API)	35
5	Gas density at STC(14.7 psia, 60 F)	Gas gravity (Air=1)	0.7
6	Reference pressure for water properties		14.696 psi
7	Pressure dependence of water viscosity		
8	Water salinity (ppm)		10000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Scale Damage Tab
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272
4
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1.56
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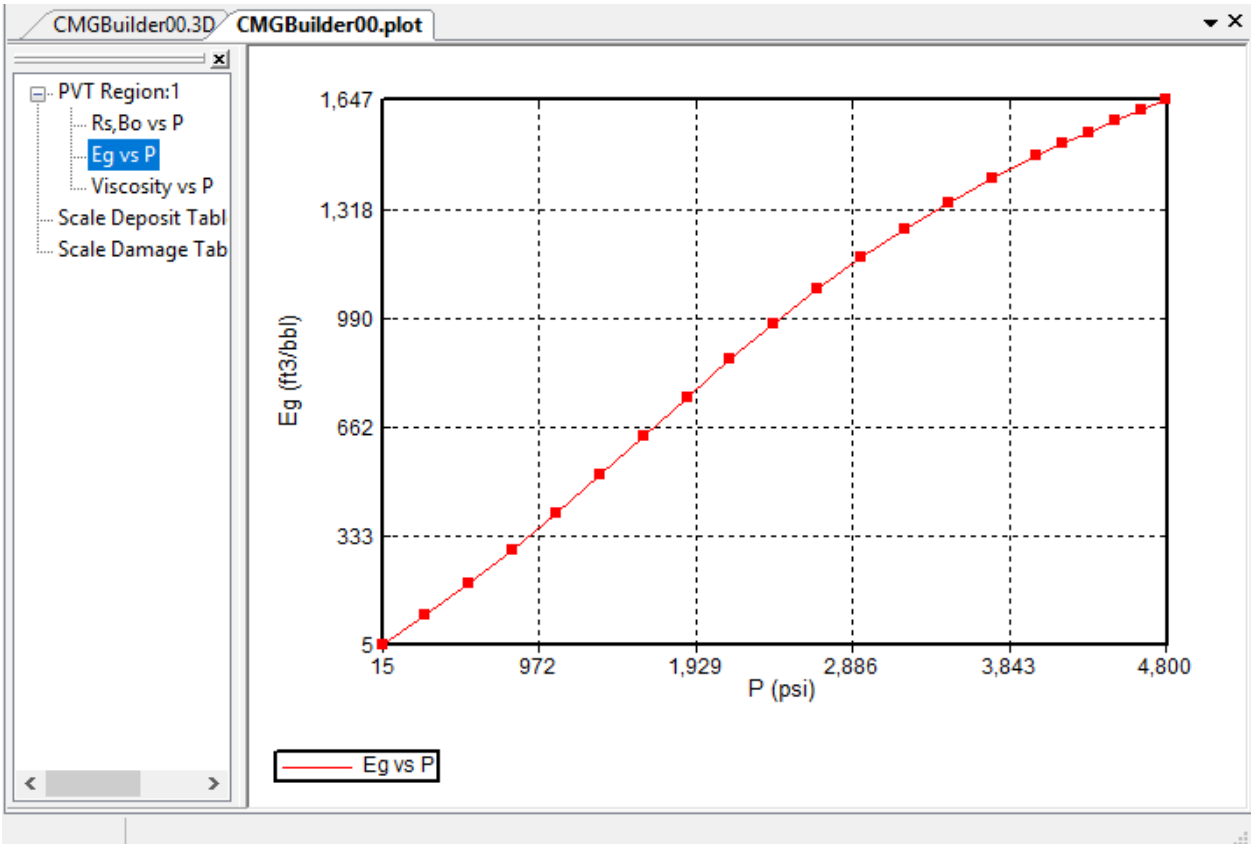
Rs vs P
Bo vs P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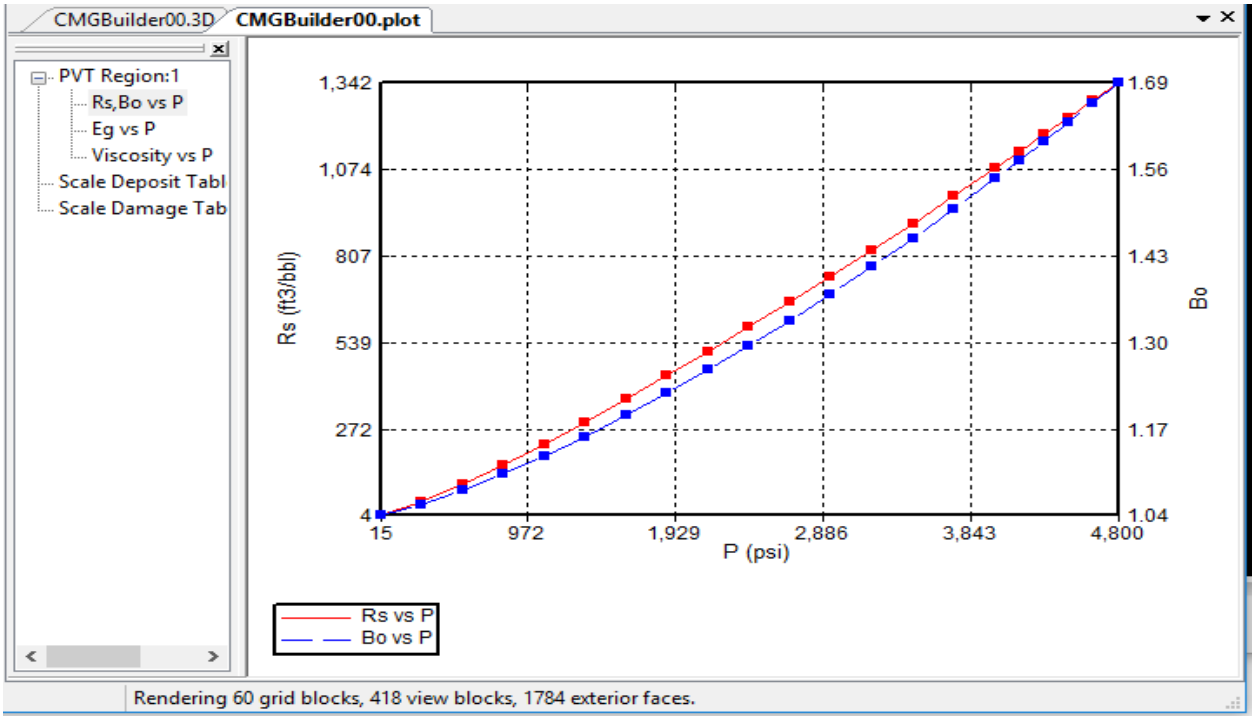
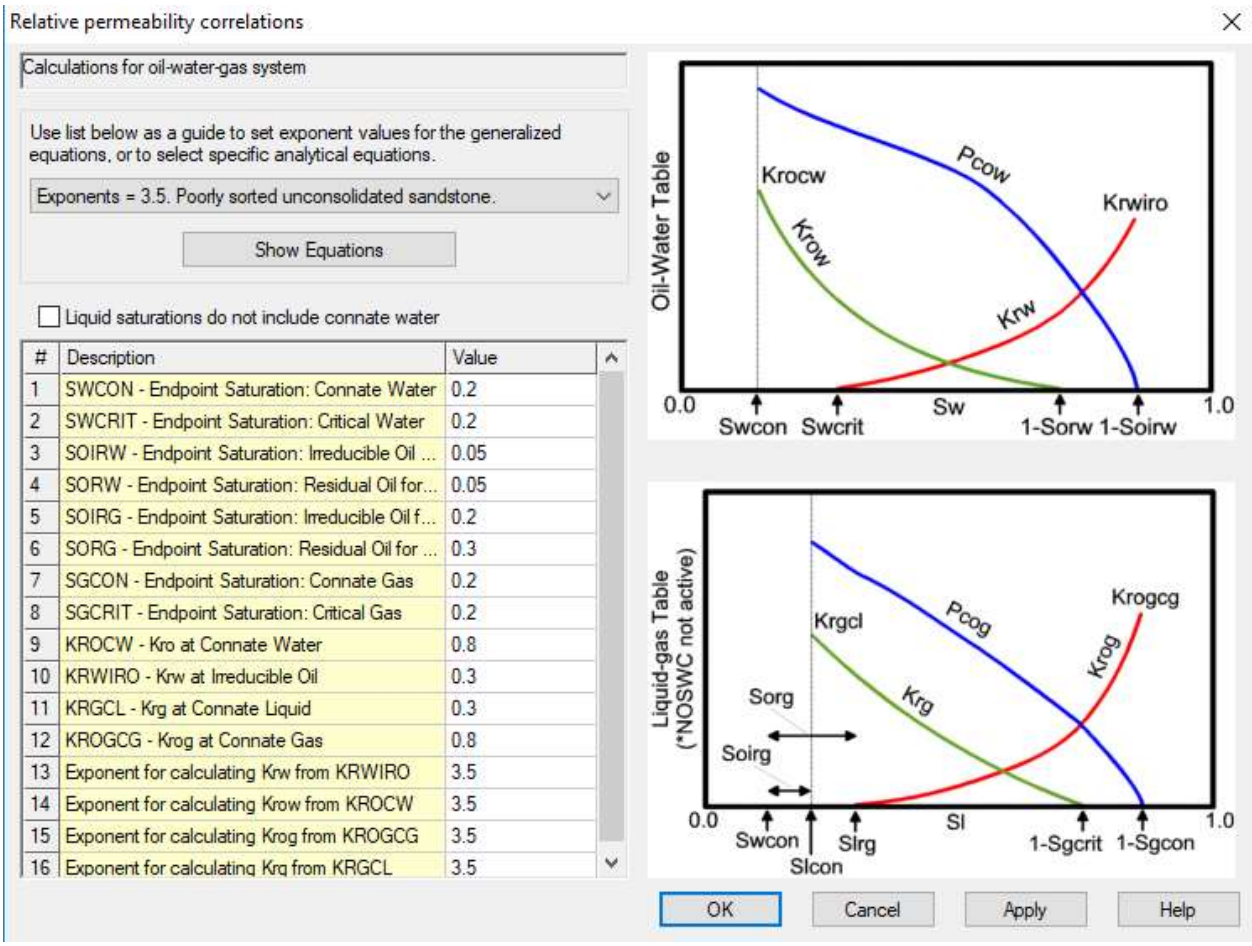
P (psi)
Eg vs P



Relative Perm



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4	0.340625	0.0008563	0.386787	
5	0.3875	0.00234375	0.292284	
6	0.434375	0.00511795	0.215548	
7	0.48125	0.00968792	0.154408	
8	0.528125	0.0166167	0.106787	
9	0.575	0.0265165	0.0707107	
10	0.621875	0.0400452	0.0443112	
11	0.66875	0.057903	0.0258345	
12	0.715625	0.0808306	0.0136479	
13	0.7625	0.109606	0.00625	
14	0.809375	0.145045	0.00228347	
15	0.85625	0.187996	0.000552427	
16	0.903125	0.239343	4.88281e-005	
17	0.95	0.3	0	

Water oil relative perm

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3	0.5	0.109606	0	
4	0.51875	0.087445	4.88281e-005	
5	0.5375	0.0686853	0.000552427	
6	0.55625	0.0529929	0.00228347	
7	0.575	0.0400452	0.00625	
8	0.59375	0.0295318	0.0136479	
9	0.6125	0.0211551	0.0258345	
10	0.63125	0.0146307	0.0443112	
11	0.65	0.00968792	0.0707107	
12	0.66875	0.00607098	0.106787	
13	0.6875	0.00353953	0.154408	
14	0.70625	0.00186987	0.215548	
15	0.725	0.0008563	0.292284	
16	0.74375	0.000312853	0.386787	
17	0.7625	7.56869e-005	0.501324	
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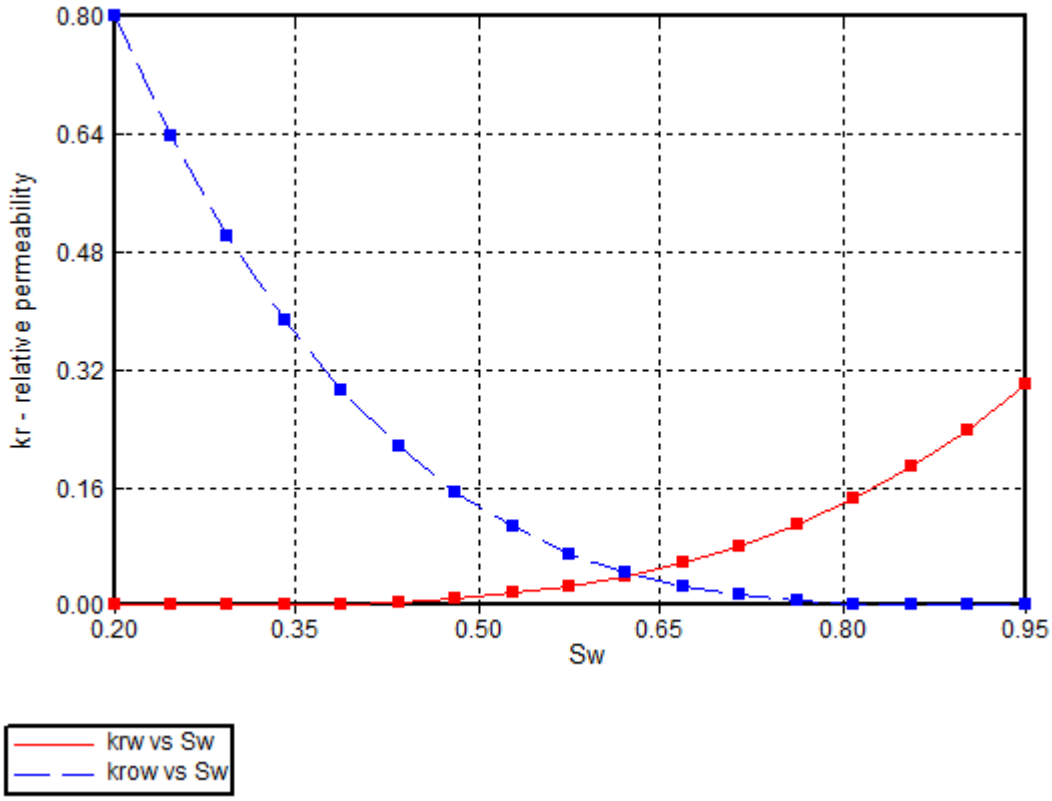
Liquid Gas relative perm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0.32
0.16
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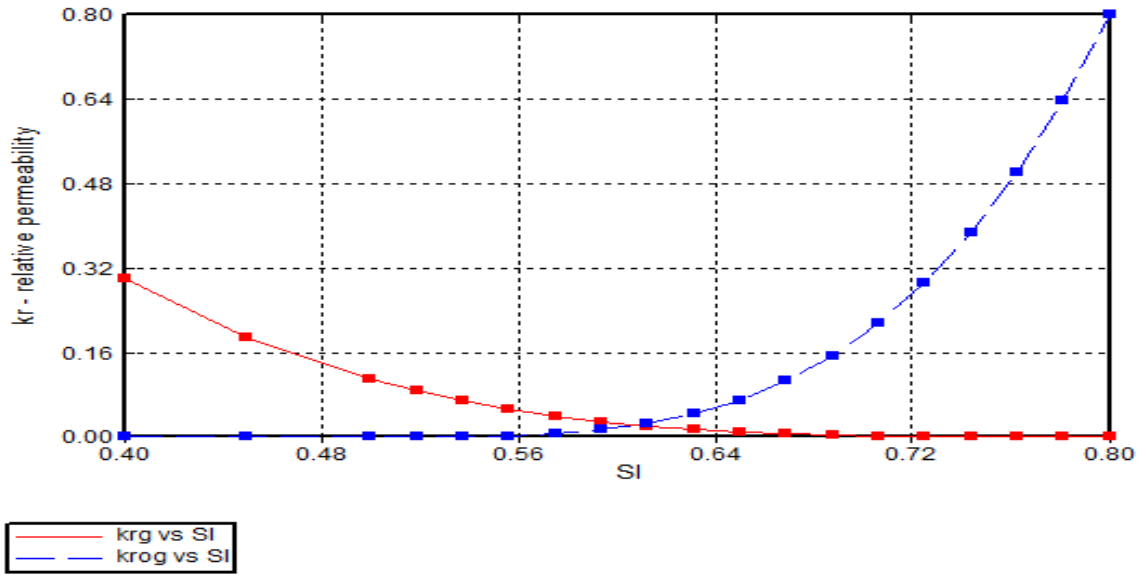
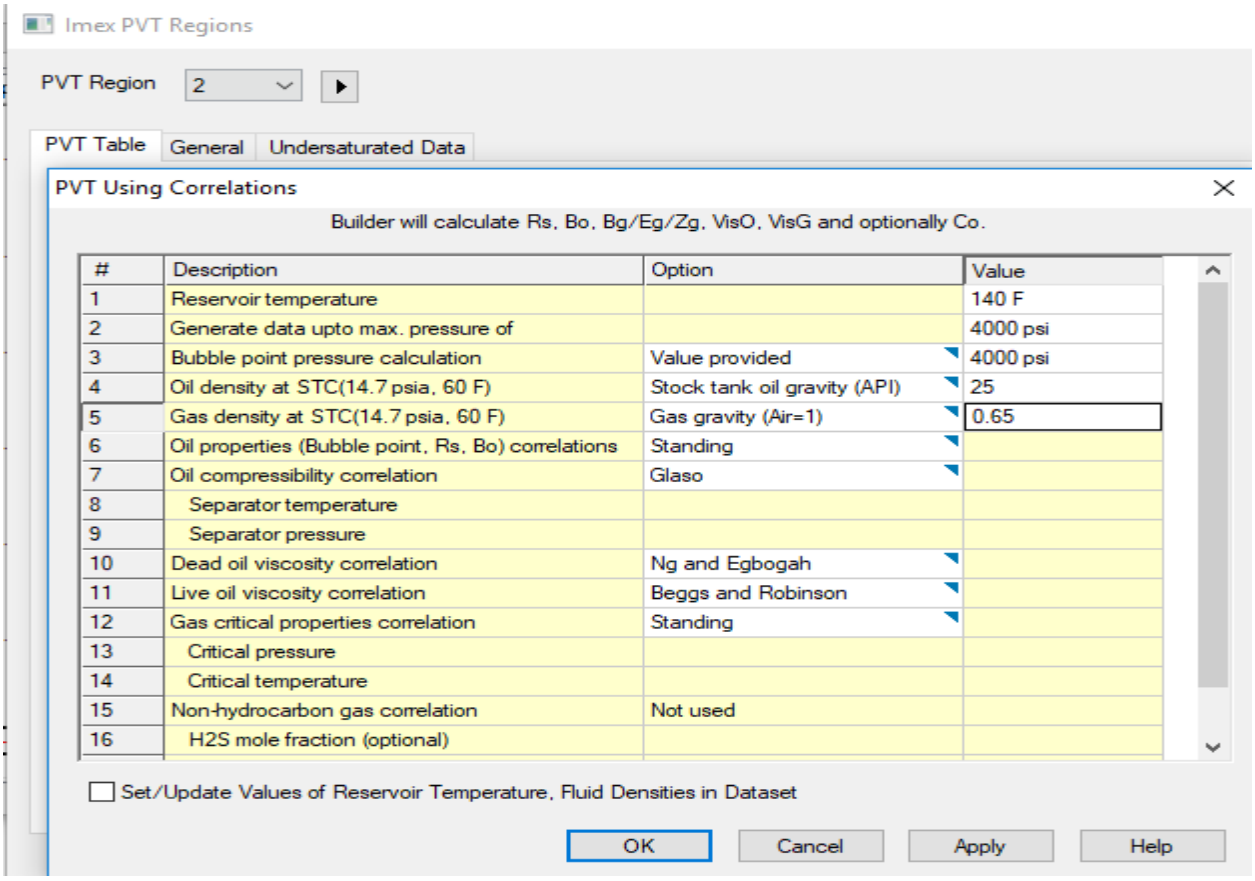
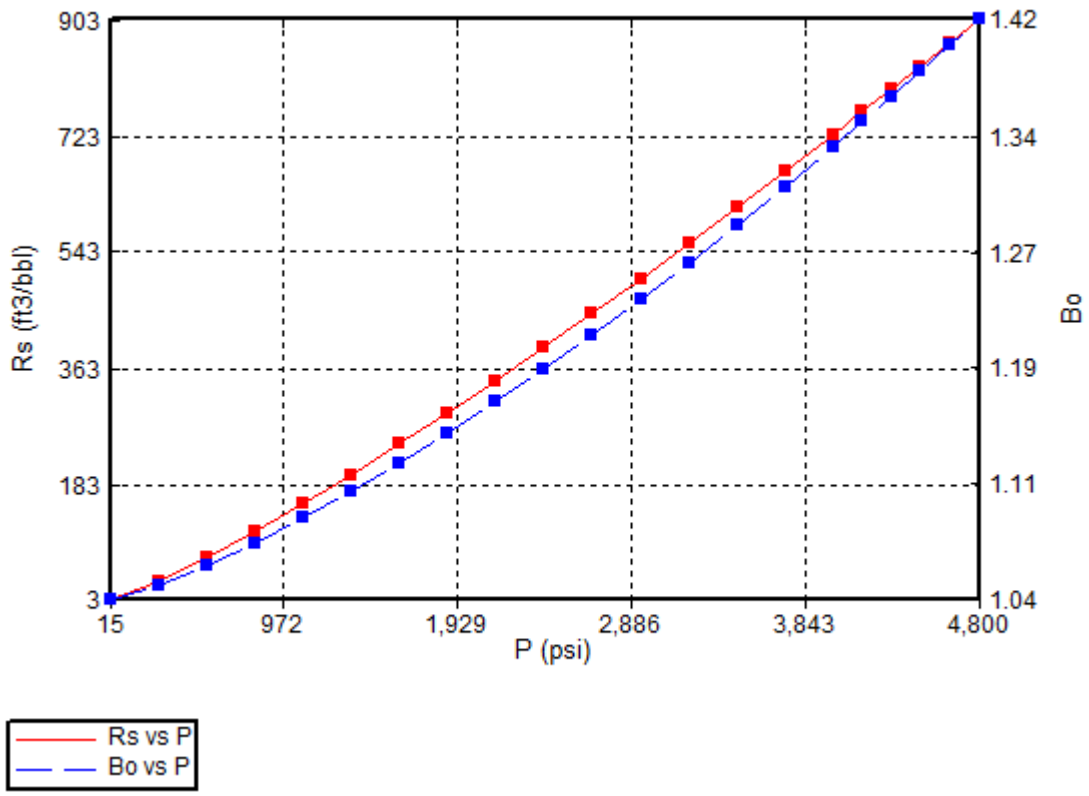
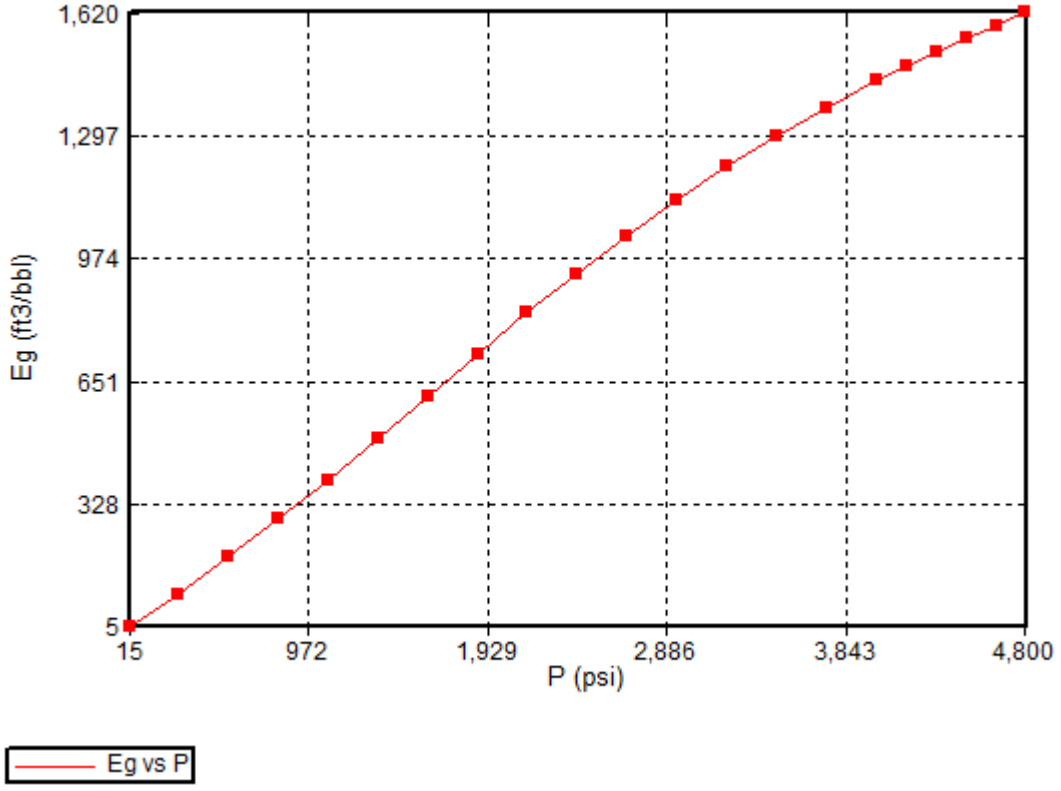
0.20
0.35
0.50
0.65
0.80
0.95
Sw
krw vs Sw
krow vs Sw

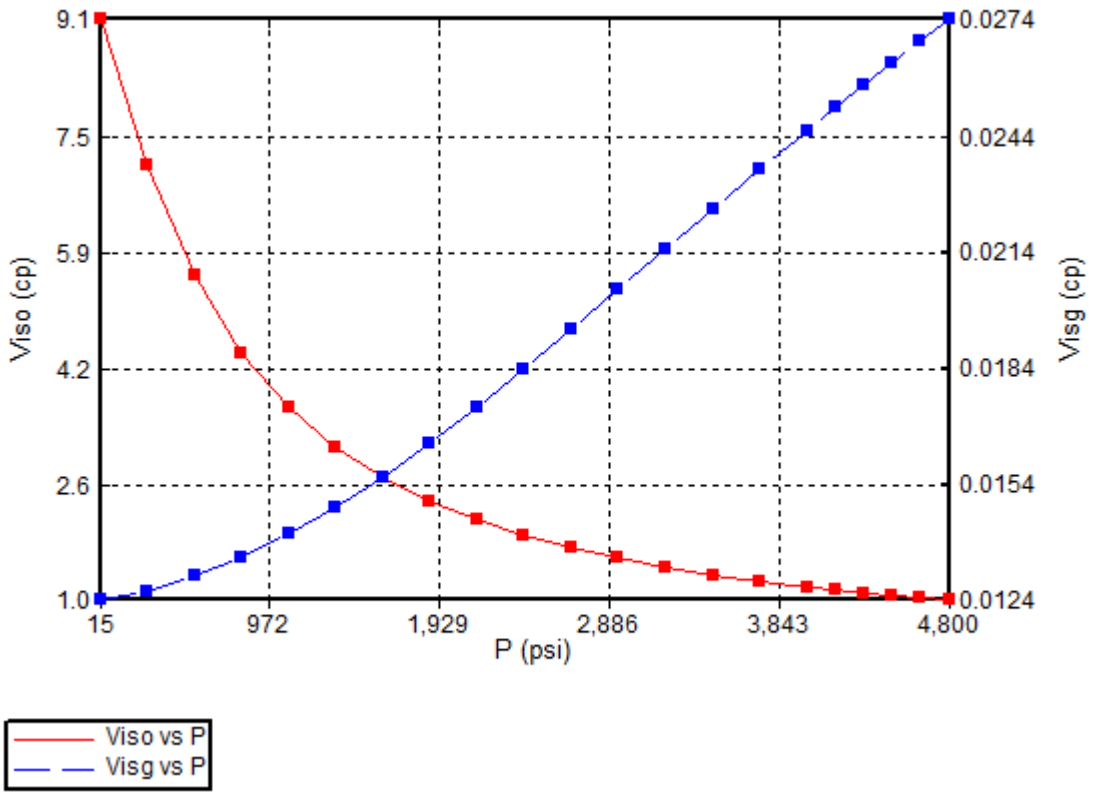

0.80
0.64
0.48
0.32
0.16
0.00
kr - relative permeability
0.40
0.48
0.56
0.64
0.72
0.80
Sl
krg vs Sl
krog vs Sl

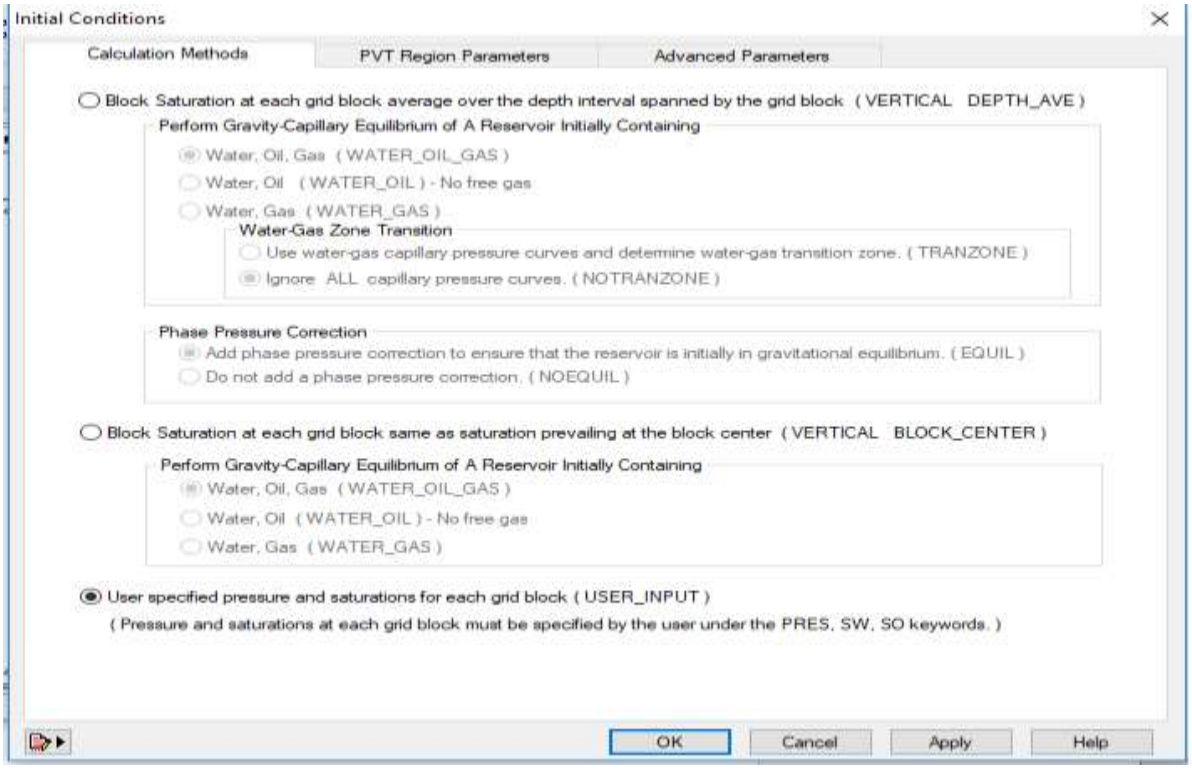


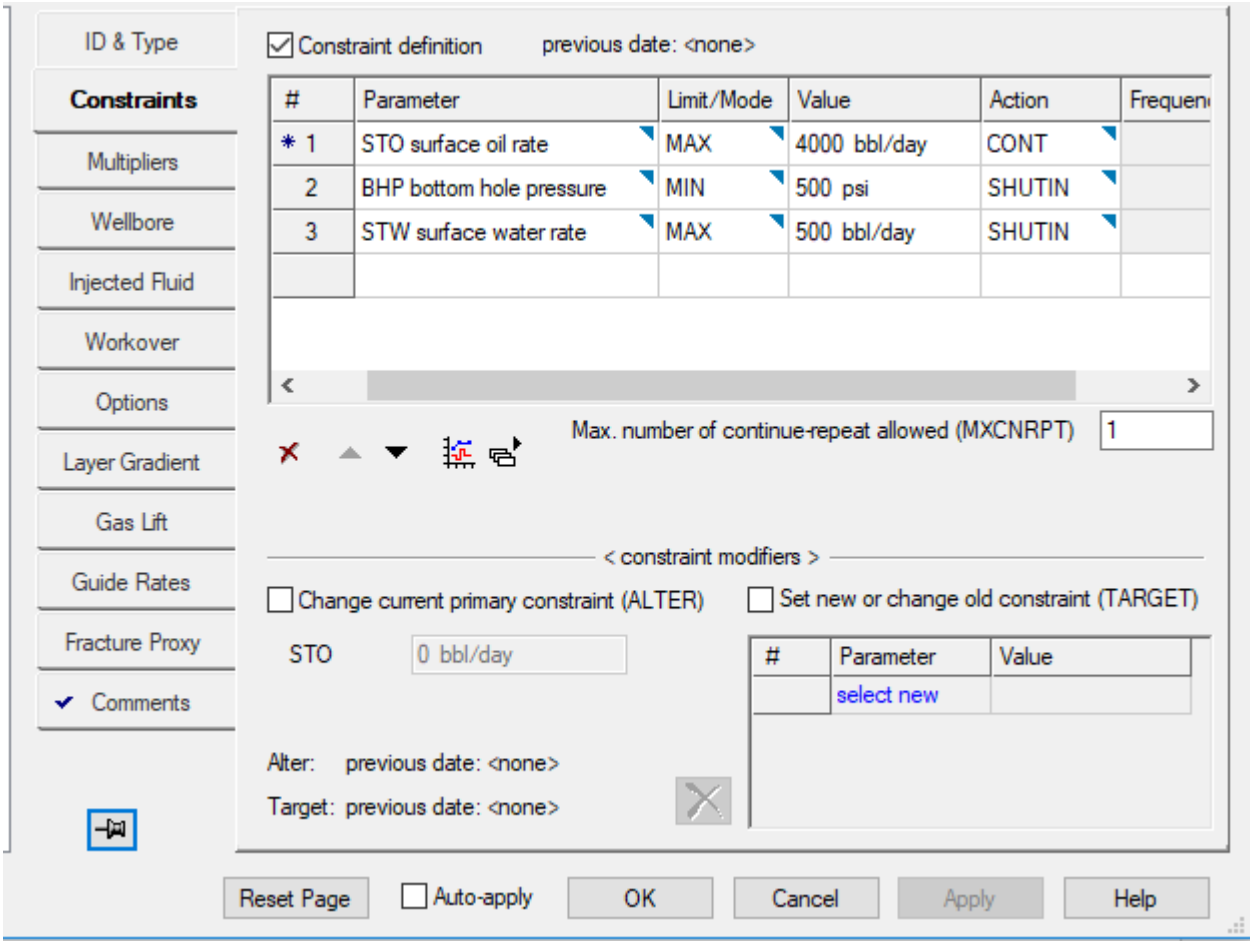
#	Description	Option	Value
1	Reservoir temperature		140 F
2	Generate data upto max. pressure of		4000 psi
3	Bubble point pressure calculation	Value provided	4000 psi
4	Oil density at STC(14.7 psia, 60 F)	Stock tank oil gravity (API)	25
5	Gas density at STC(14.7 psia, 60 F)	Gas gravity (Air=1)	0.65
6	Oil properties (Bubble point, Rs, Bo) correlations	Standing	
7	Oil compressibility correlation	Glaso	
8	Separator temperature		
9	Separator pressure		
10	Dead oil viscosity correlation	Ng and Egbogah	
11	Live oil viscosity correlation	Beggs and Robinson	
12	Gas critical properties correlation	Standing	
13	Critical pressure		
14	Critical temperature		
15	Non-hydrocarbon gas correlation	Not used	
16	H2S mole fraction (optional)		




1,620
1,297
974
651
328
5
Eg (ft3/bbl)
15
972
1,929
2,886
3,843
4,800
P (psi)
Eg vs P


9.1
7.5
5.9
4.2
2.6
1.0
Viso (cp)
0.0274
0.0244
0.0214
0.0184
0.0154
0.0124
Visg (cp)
15
972
1,929
2,886
3,843
4,800
P (psi)
Viso vs P
Visg vs P


Initial Conditions
Calculation Methods
PVT Region Parameters
Advanced Parameters
Block Saturation at each grid block average over the depth interval spanned by the grid block (VERTICAL DEPTH_AVE)
Perform Gravity-Capillary Equilibrium of A Reservoir Initially Containing
Water, Oil, Gas (WATER_OIL_GAS)
Water, Oil (WATER_OIL) - No free gas
Water, Gas (WATER_GAS)
Water-Gas Zone Transition
Use water-gas capillary pressure curves and determine water-gas transition zone. (TRANZONE)
Ignore ALL capillary pressure curves. (NOTRANZONE)
Phase Pressure Correction
Add phase pressure correction to ensure that the reservoir is initially in gravitational equilibrium. (EQUIL)
Do not add a phase pressure correction. (NOEQUIL)
Block Saturation at each grid block same as saturation prevailing at the block center (VERTICAL BLOCK_CENTER)
Perform Gravity-Capillary Equilibrium of A Reservoir Initially Containing
Water, Oil, Gas (WATER_OIL_GAS)
Water, Oil (WATER_OIL) - No free gas
Water, Gas (WATER_GAS)
User specified pressure and saturations for each grid block (USER_INPUT)
(Pressure and saturations at each grid block must be specified by the user under the PRES, SW, SO keywords.)
OK
Cancel
Apply
Help


ID & Type
Constraints
Multipliers
Wellbore
Injected Fluid
Workover
Options
Layer Gradient
Gas Lift
Guide Rates
Fracture Proxy
Comments
Constraint definition
previous date: <none>
Parameter Limit/Mode Value Action Frequen
* 1 STO surface oil rate MAX 4000 bbl/day CONT
2 BHP bottom hole pressure MIN 500 psi SHUTIN
3 STW surface water rate MAX 500 bbl/day SHUTIN
Max. number of continue-repeat allowed (MXCNRPT) 1
< constraint modifiers >
Change current primary constraint (ALTER)
Set new or change old constraint (TARGET)
STO 0 bbl/day
Parameter Value
select new
Alter: previous date: <none>
Target: previous date: <none>
Reset Page
Auto-apply
OK
Cancel
Apply
Help