Integrated Modelling and Optimization of Options for Developing Thin Oil Rim Reservoirs: Niger Delta Case Study

A DISSERTATION

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DOCTOR OF PHILOSOPHY

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ABSTRACT

The goal of an oil field development project is to accelerate the hydrocarbon production and maximize recovery at the lowest cost. Optimizing the production of oil from thin oil rim reservoirs poses a major challenge in the oil and gas industry because of the water and gas coning tendencies which limit the ultimate recovery from such reservoirs. Development of oil rims generally requires a lengthy study to unravel the complex interplay of the subsurface uncertainties and to determine technical feasibility, development concept and economic attractiveness. Simulations and experimental methods coupled with simple analytical solutions or correlations are typically used to identify the oil rate that minimizes coning and maximizes recovery. This research aims to optimize oil recovery from oil rims by generating models to be used to forecast production rates and increase the ultimate recovery over a range of uncertainties. In this work, a surrogate simulation model is developed to analyze oil rim dynamics and evaluate the impact of a range of subsurface uncertainties on the oil and gas recovery. Alternate development strategies have been considered, and the method of experimental design was used to obtain correlations for each development strategy. The lessons learned from the generic model were incorporated into a systematic study of an integrated reservoir management plan for developing an oil rim reservoir in the Niger Delta. Seven reservoir development strategies are evaluated using numerical reservoir simulation; and the optimum production strategy is selected. The evaluation of the best strategy includes optimization of well placement and economic analysis using the cumulative oil and gas recovery from the various development strategies. In the economic analysis several profitability indices such as net-present value, internal rate of return, and discounted payout period were utilized to identify the optimum development strategies. The results show that well placement has a significant impact on water and gas coning and on oil recovery. It is concluded that the development of thin oil rim reservoir requires an integrated reservoir management plan. Proper reservoir management is achieved when the reservoir producibility factors, operational constraints and economics of the project are considered in the field development planning.

Keywords

Oil rim, optimization, reservoir, strategy optimization, parameters, and management

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CHAPTER 1

1.0 INTRODUCTION

With increasing knowledge and improving technologies, more complex reservoirs (with respect to location and dimension) can be explored and produced, one of such is the thin oil rim reservoir. Oil recovery in these thin oil rim reservoirs is often difficult because coning or cresting of unwanted fluids is inevitable and it results in low rates of recovery. The objective of the oil and gas industry is to control water production as produced water has a major negative economic impact on the profitability of a field.

1.1 Concept of Gas and Water Coning

Gas coning is a phenomenon where the gas-oil contact (GOC) of a reservoir slowly moves towards a well as a result of high drawdown and eventually, the free gas is drawn into the well. At high production rates, a well will suffer a large gas influx which cannot be handled by the topside equipment. Similarly, water coning is a phenomenon where the oil-water contact (OWC) of a reservoir slowly moves towards a well as a result of high pressure-drawdown and eventually, the water is drawn into the well.

The major concern is therefore running economic and optimal operations despite the gas and water coning effects that could confine production below commercial rates and hinder recovery. Many authors have looked at both gas and water coning problems and have recommended ways of alleviating these problems in order to increase the economic life of the reservoir. Worldwide, the average recovery factor for thin oil rims is estimated at 20% (Samsundar et al., 2005). Due to high coning occurrences (High GOR/WOR) in the Niger Delta, most wells have been shut-in and a lot of recompletions are being made in order to combat this problem. Although horizontal and multilateral wells have been proposed for production maximization in preference to the conventional well, the placement of the horizontal well between the gas-oil contact and the oil-water contact is very important in maximizing the critical rate and minimizing the water and gas coning. It is common practice to reduce water coning in oil reservoir by perforating vertical wells as far above the oil-water contact (OWC) as possible, and to produce the wells at or below the critical rate. Similarly, wells are often perforated low in the oil column away from the gas-oil contact (GOC) in reservoirs where the gas cap overly the oil column. Water production is a harbinger of problems in an oil or gas well. The presence of a large amount of water can cause corrosion of the tubulars, scaling problems in susceptible wells, induction of fines migration or sandface problems. It can also result in the killing of the well by hydrostatic loading amongst other things. Total worldwide oil production averages some 75 million barrels per day and although estimates may vary, this is associated with the production of 300-400 million barrels of water per day (Gino et al., 2002). Control of produced water has been an objective of the oil industry since inception. The economic impact of produced water on the profitability of a field is huge. Production of one barrel of water requires as much or more energy as producing the same volume of oil. (Eoff et al., 2003). Successful oil rim development requires careful management of a wide range of subsurface uncertainties and generally lengthy study efforts are needed to assess the technical and economic feasibility. On individual projects, factors that need to be studied include stacked pay completion, drilling and completion techniques, future well workover plan, slot availability and project cost**. (Vo et al., 2000).** The research background and theory is presented to give a thorough understanding of main problem of oil rim reservoirs, the factors controlling coning and its impact on oil recovery.

1.2 Research Background and Theory

A critical investigation of the production profiles from oil rims worldwide is presented to know the major problems associated with oil rim production. A major problem is the extent of the water and gas coning relative to the type and location of the oil rim. The focus area of this research is a case study derived from the Niger Delta region of Nigeria. Thin-oil (or oil-rim) reservoirs are associated with oil columns existing between a gas-cap and an aquifer. They are defined as an "Ultra-Thin" when the oil column is less than 20% of the gross thickness. Notwithstanding these low pay thickness, these reservoirs can still hold a tangible volume of hydrocarbons-in-place in a doughnut or pancake configuration depending on how the gas-cap covers the oil zone. Many field examples of the characteristics and dynamic performance of various configurations have been published (Sulaiman & Bretherton, 1989; Evans, 1970; Prasser, 1988). Often times, the primary purpose to produce by-passed oil from oil rim reservoirs. But these reservoirs can also contribute as reliable sources of gas supply to the Nigerian Gas market. Thus, quick and cost-effective development of oil rims must recognize the complete hydrocarbons streams for a significant return on investment and to maintaining uninterrupted gas supply and meeting contractual obligations.

With a dedicated gas market, project economics can be enhanced by simultaneous production of the gas-cap and oil column which often require extended reservoir energy by water or gas injection. Unfortunately, extreme gas and water production can hamper the economics of the project. Therefore, developing oil rims presents many technical challenges for planning, development, and reservoir management. Considerations for pertinent issues such as gas offtake rates relative to water injection rates, permeability, fluid properties, and production management policies are crucial for quick assessment of oil rim reservoirs in the Niger delta and other hydrocarbon regions.

To improve recovery from the oil rims, the use of horizontal and multilateral wells has been reported in the Niger Delta (Vo et al., 2000). Intelligent horizontal wells are finding utilization in this province perhaps because of the abundance of thin oil rims in remote and challenging locations. However, the completion and simulation of the intelligent wells to concurrently monitor and react to reservoir conditions have become a serious challenge (Obuekwe, 2010). Reservoir completion and production parameters control reservoir dynamics. Consequently, oil column thickness, gas-cap size, permeability, reservoir architecture, oil properties, production policy, as well as producer arrangement and placement were identified as the key factors with a greater influence on recovery from the rim reservoirs. It is then expected that some of these variables have to reflect in prospective screening models for evaluating oil rim performance.

Several models (Osoro et al. (2005), Wyne et al. (2005), Kabir et al. (2004), Vo et al. (2000), and Irrgang (1994)) have been developed for conducting preliminary performance assessment of oil-rim reservoirs. These models vary in underlying concepts and functional forms. Apart from the inherent inconsistency, they are limited in the scope of applicability and often yield non-physical results that limit their robustness as screening and validation tools. The main reason arrogated for the explanation of non-robustness of these empirical and simulation-based correlations is the exclusion of key uncertainties and physics of oil-rim reservoir dynamics. Hence, a distinct approach is highly necessitated.

The following are common problems associated with oil rim reservoirs.

1.2.1 Gas/Water Coning

Coning, Cusping or Cresting occurs when the pressure drawdown created by a well is large enough to overcome the gravitational resistance of nearby water or gas causing these fluid(s) to be drawn into the well (Kromah and Dawe 2008). Water-oil interface tends to breakthrough towards a producer in a stable fluid-fluid displacement and water fingers develop in a more viscous oil zone in an unstable displacement. In many situations involving gas cap and/or water drives, usually a combination of these phenomena occurs and hence the loose usage of the term coning. This coning phenomenon is affected by the characteristics of the fluids (density and viscosity), rock properties (vertical and horizontal permeability), and geometry of the reservoir and well type and location (Al-Afaleg and Ershaghi 1993).

The development of gas and water cones for a horizontal well is shown schematically in the figure 1.1 and figure 1.2. Water and gas coning occurs as a result of the interplay between viscous and gravitational forces which acts upon the interface between the oil and water or gas. Removal of the fluid in the reservoir results in viscous forces while the density difference between the two fluids (oil and gas or water) results in the gravitational forces (Dandina, 2001). During the onset of oil production, as illustrated in figure 1.1, only the oil flows into the wellbore. After some time, a cone is formed by the unwanted fluids once the viscous forces exceed the gravitational forces as illustrated in figure 1.2. It grows toward the wellbore until there is a balance between the gravitational force and viscous force at some elevation. The unwanted fluid eventually breaks into the wellbore if the balance is not achieved (Umnuayponwiwat and Ozkan, 2000).

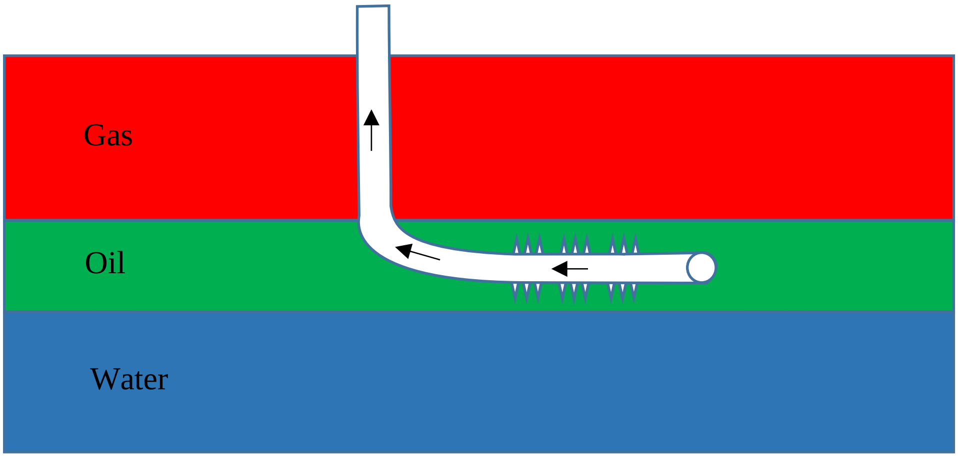


Figure 1.1 Schematic vertical cross-section through horizontal well and reservoir before coning occurs

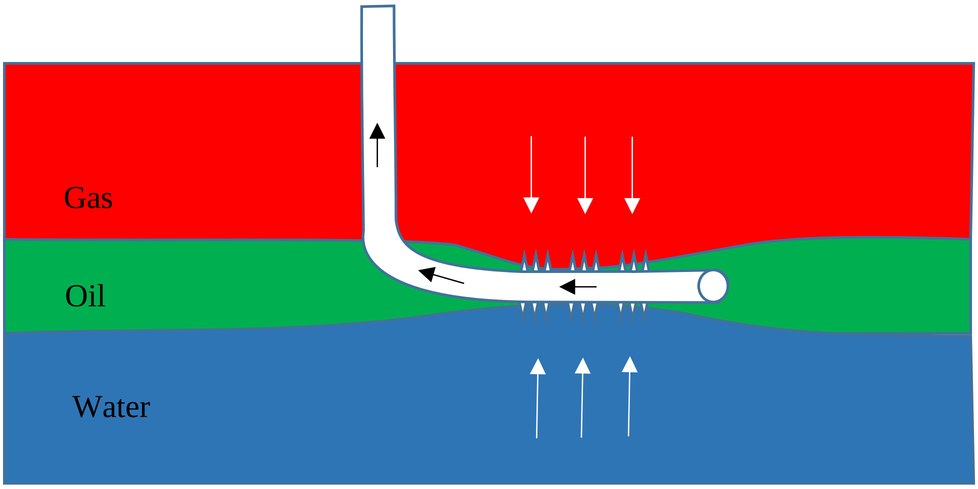


Figure 1.2 Schematic vertical cross-section through horizontal well and reservoir showing onset of water and gas coning.

The production rate at which there is a balance between gravitational and viscous pressure forces is known as the critical coning rate. Production below the critical coning rate will prevent unwanted water and gas from breaking through into the wellbore. Critical coning rates are usually quite small and not economically attractive (Jin and Wojtanowicz, 2011). Excessive coning of gas or water limits oil recovery due to poor reservoir sweep and loss of reservoir drive energy. However, gas coning could be desirable for lifting oil to the surface after water breakthrough (natural gas lift). The extent of coning can also greatly depend on local geological features such as shale barrier or faults and baffles (Pucknell et al., 2003). The movement of the fluid contacts during production can promote re-saturation of the gas-cap by oil thereby causing a reduction in the sweep efficiency. In addition to deformation of the fluid interfaces at the production wells due to gas coning and cresting, the position of the fluid contacts throughout the reservoir will change over time. The extent of the contact movement will depend on relative strength of the aquifer drive and gas cap drive. In reservoirs with strong aquifer drive, it is more likely that the oil-water contact will move upwards. Fluid contact movement is often non-uniform due to variations in sand development, the lateral extensiveness of the reservoirs, gas cap size and differences in aquifer strength. Production off-take control is often applied to wells in order to prevent the fluid contacts moving pass the perforation intervals (Olamigoke and Peacock, 2008). For a thin oil rim reservoir with a large gas-cap on top and a strong water aquifer below, the art of optimizing oil recovery is to keep the oil rim in continuous contact with the producing wells in the oil rim. The management of the GOC and WOC movement is very crucial. To achieve results, force balance between the aquifer drive, gas cap expansion and viscous withdrawal (production) should be carefully studied for a given reservoir at various stages of the production life cycle (Rasaq et al., 2010).Some of the terms applicable to understanding oil rim development are discussed below.

1.2.2 Re-saturation of the Gas-cap by Oil

The oil column is usually displaced upwards as a result of gas cap production under an active water drive (Vo et al 2001). This will leave a zone of bypassed oil behind the advancing water and a zone of residual gas behind the advancing gas. When there is an excessive gas cap production, a pressure gradient develops between the crest of the structure and the aquifer. As the gas withdrawal continues, the oil rim moves significantly, and the oil column will gradually “smear out” through the gas cap (Razak et al., 2010) This results in the loss of mobile oil and trapping of gas as illustrated in figure 1.3. The evolution of the fluid contacts over time is described in figure 1.3a though figure 1.3d patterned after the movement of oil rim during different stages of production in reservoir x in the Niger Delta.

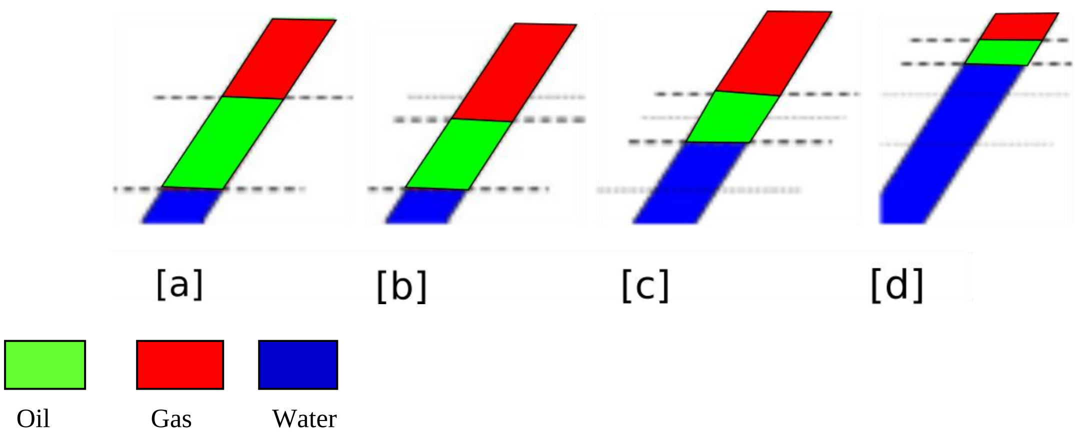


Figure 1.3 Movement of fluid contacts over oil rim reservoir life

(a) The oil rim is at static conditions.

(b) The GOC has moved downward due to gas cap expansion and oil production.

(c) The oil rim has moved upward due to displacement by the aquifer.

(d) Loss of mobile oil due to strong aquifer displacing oil into gas cap.

1.2.3 Sweep Efficiency

The sweep efficiency is the ratio of the produced volume of the oil to the volume of oil initially in place in the reservoir. As observed by Kydland and Olsen (1993), it is possible to minimize the remaining oil at abandonment by initially producing the gas cap and allowing the oil rim to move to the crest of the reservoir. This depends on the geometry of the reservoir and oil rim. An improvement in sweep efficiency can be achieved especially for strong water-drive. During gas cap blow down from a well positioned at the crest, the active aquifer would displace the oil column upward and re-saturate most of the original gas cap volume. Part of this oil may not be recoverable, as it remains residual, depending on the specific reservoir geometry, dominant drive mechanisms, and development strategy being adopted. In figure 1.4a shows the initial condition of the reservoir before production figure 1.4b is a result of gas cap blow down making the oil rim move to the crest of the reservoir, figure 1.4c shows that the oil rim is produced first with strict GOR control, a comparison of the two scenarios shows that the abandonment volume of 1.4b is higher than that of 1.4c. The sweep efficiency of 1.4b is higher than that of 1.4c

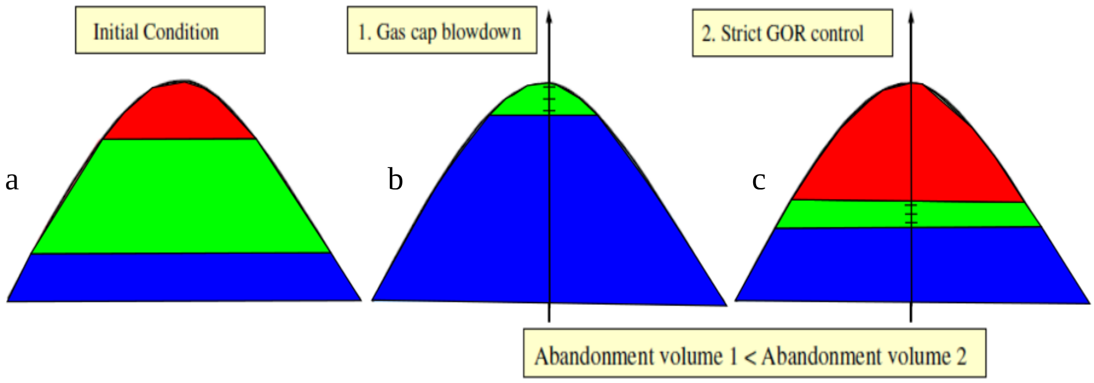


Figure 1.4 Schematic showing residual oil after gas cap blow down and strict GOR Control (Source: Guidelines for the Development and Management of Oil Rim Reservoirs 2008)

1.2.4 Practical Difficulties of Placing the Wells in Oil Rim

To properly place a horizontal well in an oil rim, the depths to the gas-oil contact (GOC) and the water-oil contact (WOC) must be known. The first option, and the costliest, involves drilling a vertical pilot hole to locate the GOC and WOC (Van der Harst, 1991). Once these depths are known, the well is side tracked and positioned at the required depth. Many studies focused in locating the well along the thin oil rim (Olamigoke and Peacock, 2009). Results of studies performed on the effect of well standoffs to fluids contacts on oil recovery indicated that wells have to be completed in the top half of the oil column (Suan, 2011).

1.3 Assessment of Oil Rim Development Concepts

The development of hydrocarbon reservoirs generally falls into three broad categories. Primary recovery relates to using the natural energy of the reservoir to drive production. Secondary recovery relates to supplementing the natural drive with additional energy via water or gas injection. Tertiary recovery relates to injection of fluids to change the chemical or physical properties of the in-situ hydrocarbons (Grigg et al., 1997). In principle, all three recovery mechanisms can be applied to oil rim reservoirs. In the following a brief discussion on the various oil rim development schemes is presented. This presentation includes sequential production of oil rim, then followed by production of the gas-cap; and simultaneous production of oil from the oil leg and gas from the gas-cap.

1.3.1 Sequential Development–Oil then Gas

Masoudi et al (2013) proposed that the sequential development is the conventional strategy for producing oil rim. This development concept initially targets wells drilled into the oil rim and attempts to manage the off-take to minimize movement of the rim. Oil recovery and production performance depends to a large degree on the balance of the water drive and gas-cap drive.

Conservation of gas-cap energy will generally lead to higher oil recoveries. Production rates are controlled to manage coning and cusping effects and so prevent excessive gas production. The GOC and WOC management is very crucial in this type of development. Force balance between the aquifer drive, gas cap expansion, and viscous withdrawal is very key to maximizing recovery at different stages of oil production. After the oil rim has become economically exhausted, the second phase is to produce the gas cap.

1.3.2 Alternative Phased Development–Gas then Oil

Behrenbruch and Mason (1993) showed that oil recovery could be maximized from an oil rim reservoir with a small gas cap ($m<0.2$) by blowing down the gas cap during the initial production phase, provided a strong aquifer exists. The essence of this strategy is to develop the gas cap first; and then allow the oil rim to move to the crest of the reservoir to be produced by recompleting the same crestal gas cap well rather than attempting to control off-take and manage coning and cusping effect. Re-saturation losses will occur using this production strategy. However, depending on the geometry of the reservoir, the remaining oil at abandonment should be less in this case than in the conventional case of producing the oil and then gas described above.

1.3.3 Concurrent Oil and Gas development

In this type of development, the gas cap is either developed fully or partially while the oil rim is produced. Development of the gas cap can take place either at the same time as the oil rim or be delayed to a later time depending on the particular subsurface conditions of the reservoir. The development scheme involves simultaneously producing oil and gas through either separate conduits or through a single conduit. Onwukwe (2011) suggested that the main driver would be to accelerate gas production whilst not significantly reducing the oil recoverable volumes. Producing oil and gas concurrently improves overall project value since gas development is not deferred till the end of oil production when the gas cap is blown down. By producing gas from the gas cap, energy is lost from the system and there is the risk of losing oil through, for example, saturation losses in the gas cap due to the presence of an active and strong aquifer.

According to Van Putten et al. (2007), there are two major approaches to concurrent oil and gas development:

- Limiting the oil rim movement and trying to manage the drive mechanisms accordingly. This can be achieved by increasing the support to the least dominant drive through injection to either the gas cap or aquifer. Alternatively, decreasing support to the most dominant drive through production from either the gas cap or the aquifer can limit oil rim movement. Reservoir pressure decline could, however, be excessive under this scheme.
- Allowing some controlled movement of the oil rim and applying recompletion technology to track the movement of the rim or use alternative well design and/or smart completion design to optimize oil recovery.

  The advantages of concurrent production include (Uwaga 2006):

  - Increase in early cash flow through accelerated sales.
  - Reduction of field operating life thereby reducing expenses.
  - Promote the acceleration of gas production from many associated reservoirs.

1.3.4 Gas only Development

This development strategy focuses totally on the gas cap and makes no attempt to produce the oil rim. This is generally applied when the oil rim is considered to be uneconomic to develop.

The gas recovery factor strongly depends on the size of the gas cap, aquifer size/support, residual gas saturation and availability of surface compression. For depletion systems with little or no aquifer support, gas recovery can be up to 80-90% with surface compression in late field life (Olamigoke and Peacock, 2008). The presence of a strong aquifer or lack of compression limits the extent of pressure decline and generally results in lower gas recovery in the range of 50-70% (Guidelines for the Development and Management of Oil Rim Reservoirs, 2008**).** The encroachment of an aquifer can result in large amounts of gas being trapped at high pressure as well as bypassing large areas of gas if water breaks through to the wells preferentially through high permeability zones (Al-Emadi et al., 2000). If a strong aquifer is suspected, it is recommended to produce the gas as quickly as possible to out-run aquifer encroachment, thereby resulting in trapping gas at lower pressure and maximizing gas recovery.

1.3.5 Gas and Water Injection to Stabilize Oil Rim Movement

Alternative development schemes involving the injection or subsurface separation of gas and/or water have been proposed and implemented by several groups reported in the literature (Cosmo and Fatoke, 2004). The basis for these development schemes is to stabilize the movement of the oil rim, manage the reservoir energy balance, and prevent excessive gas and water coning into the completion interval. In general, these development schemes have been applied to large oil columns that can support the additional costs of injection wells and surface facilities.

1.3.6 Subsurface Factors that affect Oil Rim Recoveries

There are a number of subsurface factors that affect the recovery process of oil rim reservoirs. Paris (2008) reported that the main subsurface factors quoted in a variety of different field studies include:

- Oil column size.
- Gas cap volumes/size
- Permeability
- Aquifer strength
- Oil viscosity

All of these factors play an important role in determining the fluid flow dynamics and recovery factor for a given oil rim configuration. In addition, the impact of other subsurface factors such as reservoir geometry (the presence of high permeability streaks, extensive shale breaks), degree of heterogeneity and magnitude of bed dip, well type and location and operating philosophy can also be significant (Dilib et al., 2015). Based on results of performance data in the industry, horizontal wells are more suitable for developing reservoirs with oil rims compared to conventional vertical wells. Other factors to consider when formulating the depletion strategy are well placement/positioning with respect to the fluid contacts, well length and spacing, and off-take constraints. Although, there are notional best practices for all of these factors, individual and tailored reservoir modelling is key to designing the optimum development strategy for a given oil rim case (Onwukwe, 2011).

Reservoir models need to be continuously updated with performance data so that sound technical decisions and field optimization can be undertaken in timely manner (Willett et al 2002).

1.4 Problem Statement

The major reoccurring problem in oil and gas production generally is the production of water due to the rise of oil-water contact, water coning, water fingering, water channeling, or a combination of these (Vo, et al., 2000; Osoro et al., 2005). Thinly bedded reservoirs are more sensitive to water coning and/or gas cusping due to the thin oil spread column. The phenomenon has posed serious production challenges in surface water handling, hydrocarbon recovery, economic, and environmental pollution (Mahgoup and Khair, 2015). Pioneering studies (Chaperon, 1986; Joshi, 1988; Yang and Wattenbarger, 1991) have developed prediction correlations based on critical oil rate, breakthrough time, and post-water breakthrough. However, these correlations cannot minimize the water coning tendency to its barest minimum. Several other water coning control strategies including conformance technology, horizontal well technology, downhole oil-water separation technology, and intelligent well technology have been developed (Okon et al., 2017). These resulted in a reduction of coning in wells but excessive bypassed oil has limited their field applications. Therefore, for thin oil rim reservoirs in the Niger Delta, there is no established approach for resolving water production due to water coning. Yet, several hundred million barrels of oil and trillions standard cubic feet of gas are still enclosed within the oil rim reservoirs as by-pass hydrocarbons. The low recovery of the by-pass oil from these reservoirs requires immediate attention. The best approach to optimize production from these oil rims is therefore through effective reservoir management which involves evaluation, monitoring, goal setting, and revision of a few strategies for efficient field development.

1.5 **Research Aim and Objectives**

The aim of this research is the evaluation of reservoir management strategies and the development of an integrated framework for improved hydrocarbon recovery from oil rim reservoirs in the Niger Delta.

Specific objectives include:

1. To develop a surrogate model by integrating experimental design and Response Surface Methodology for quick screening and selection of key uncertainties affecting oil, water, and gas production from the oil rim reservoir.

2. To use a case study to evaluate the technical feasibility of a range of alternative production strategies to adequately and timely managing the excessive water production for optimum exploitation of thin-bedded reservoirs within the Niger Delta.

3. To perform an economic evaluation of the selected development strategies based on the case study in (2) for profitability and possible recommendation for production of Niger Delta field oil rim.

4. To develop a template for optimum production from oil rim reservoirs in the Niger Delta Region of Nigeria.

1.6 Significance of Study

A review of some Niger-Delta oil rim reservoirs indicates that most of them are less than 80ft thick (Obuekwe, 2010; Kabir et al., 2004). A significant amount of oil is left behind due to gas/water coning resulting from high withdrawal rates and underbalance of drive mechanism. Cumulative oil production obtained from these oil rims ranges from 0.8 MMSTB to 4.6

MMSTB with recovery factors between 2% and 11%. (Olamigoke, 2008). The probable estimate of the oil rim reserves in the Niger Delta is about 1.2billion STB which is a very sizable amount and should be explored. In the course of this research, the gaps identified in this study are the lack of proper economic analysis, low oil recovery realized from producing these reservoirs as a result of oil bypass. Therefore, this study addresses the limitations in the previous study by performing a proper integrated oil rim management in a bid to optimize recovery. The expected outcomes this study are an integrated framework for the evaluation of oil rim development and quantifying the associated uncertainty using a surrogate model approach, selection and optimal placement of wells within oil rim reservoirs, and selection of the optimum development strategies using economic profitability indicators such as net present value (NPV), internal rate of return (IRR) and discounted pay out period(DPOP).The study also describes the impact of increased recovery of oil rims on the reserve base of the Niger Delta.

1.7 Scope of Study

This research focuses on the optimization of thin oil rim development under various development strategies. The case study considered for reservoir simulation is the Reservoir A in the Niger Delta region of Nigeria. The Niger Delta hosts many thin oil rims with huge gas caps. In this research, a surrogate reservoir model (SRM) which mimics the behavior of the reservoir model is developed. This model is applied in the examination of the uncertainty inherent in the production of thin oil rim reservoirs. The lessons learnt from the SRM are applied to an integrated study of Reservoir A derived from the Niger Delta. The case study of Reservoir A is used to demonstrate the technical and economic analyses required to identify the optimum strategy for developing a thin oil rim reservoir. The applicability of this work is for oil rims in green fields where there has been little or no hydrocarbon production.

1.8 Outline of Dissertation

The dissertation consists of seven chapters. Chapter 1 commences with an overview of the background and theoretical framework of this study, problem statement, the research aim and objectives, significance, and scope of the study. Chapter 2 is a literature survey on the various ways of optimizing production from oil rim reservoirs. The chapter starts with a brief review of the reservoirs in the Niger Delta region, and then various schemes of optimizing production from oil rim reservoirs were reviewed. Chapter 3 describes the methodology of using a surrogate model to simulate oil and gas production from thin oil rim reservoirs in order to identify parameters which have the most impact on oil rim recovery. The idealized models are used to investigate oil rim development under both conventional and concurrent oil rim and gas cap production. Chapter 4 describes the integration of numerical simulation with classical experimental design and response surface methodology to develop proxy/mathematical equations to relate all the independent variables (reservoir properties such as permeability, viscosity, anisotropy, the size of the gas cap or m factor) with the dependent variables (cumulative production and recovery factor). In Chapter 5, a field development plan is presented using a Niger Delta case study to evaluate seven oil rim production strategies. The optimum strategy was selected based on the highest cumulative oil and gas recovery and profitability indices derived from an economic analysis. Several conclusions derived from this research as well as the recommendations proposed for future works are discussed in Chapter 6. Chapter 7 highlights the contributions of this research to knowledge and lists the papers published in Scopus-indexed, peer reviewed journals based on the results from the study.

CHAPTER 2

2.0 LITERATURE REVIEW

An enormous amount of research work has been done so far on oil rim optimization. Several approaches have been used to optimize production from thin oil rims. Because the problem of coning is synonymous with oil rim reservoirs, efforts have been made to control it. These have been made possible through several analysis, proposing various analytical and empirical correlations, and simulation studies, etc. Many of these models have been put into practice in many oil rim fields encountering coning problems and have yielded results to various degrees. A review of development and production optimization of existing oil rims worldwide was undertaken especially in the areas of the same geological formations as the Niger Delta.

2.1 Vertical Well Development

Olamigoke (2008) reported that most of the Niger Delta oil rim reservoirs are less than 80ft thick and therefore vulnerable to coning problems. Typical rate behavior producing thin oil columns has been reported. Depending on the completion standoff to the fluid interfaces (GOC and OWC), the typical rate behavior for completion close to GOC. is as follows:

- Depending on the oil column thickness and gas cap size, higher GOR than that of the solution gas for a period of time is first observed before a reduction in gas and an increase in oil production.
- This stable production period of constant solution GOR, marks the time when the aquifer has charged up enough pressure to compensate or balance for the loss of pressure by fast gas production earlier. (The return of producing GOR to the solution level does not exclusively imply the gas cap has been exhausted).

- Later, when water starts reaching the well, oil production will decline with continuously increasing water cut, signifying a thinner oil column remaining.
- Continuing production with high offtake rate will see a rise in GOR later, again as a result of dominating gas production with a much thinner oil column remaining. The high GOR would reduce again only when much of the free gas has been depleted. At this stage, most of the producible oil has been recovered, leaving the well with high water cut.

Randle and Marcel (1953) did a study on GOR control in oil rim reservoirs produced from vertical wells. They suggested the unitization and overall reservoir management as the solution to the problem. Although they had some degree of success, it was noted that GOR could not be reduced permanently. The major shortcoming in their work was the low recovery from the reservoir and poor economic viability. Seage et al. (1984) described in their work the first phase of oil rim development in the Snapper N-1 reservoir of 13 to 26 ft oil rim thickness sandwiched between an active aquifer and a large gas cap. The well was completed by perforating top half of the column, at a 6ft standoff from the GOC in a bid to minimize gas coning, but high enough to allow for some anticipated upward column displacement due to gas withdrawal. They reported that 36% oil recovery was achieved.

Continuing on Seage et al's work (1984), **Prasser (1988)** examined the performance of vertical wells at the end of the first phase and in the second phase of the N-1 sands of the Snapper field. Gas production had been required to meet gas market demand. This production, from both gas completions and gas coning in oil wells, had caused the oil zone to steadily rise leaving a zone of residual oil behind the advancing water and a zone of residual gas behind the advancing oil zone. This provided opportunities for recompletions higher up in the same sand unit or into new sand units which were previously gas saturated. The Phase II wells were either producing wet or at high GOR, with water and gas generally arriving within a few months of start of production. This was because only two of the wells intersecting near full oil columns in good quality sand. Four of the wells showed zones of residual gas on the open hole logs. Due to early water breakthrough, it was inferred that it would have been a better strategy to perforate the wells over a thinner interval, closer to the GOC.

2.2 Water Coning Control

The pioneering work on water coning problem focused on coning mechanisms and experimental studies. The first paper published by **Muskat and Wyckoff (1935)** presented the fundamental physical principles underlying the behaviour of the water oil contact (OWC) when oil was produced from a partially penetrated well in the oil zone before water breaks through to well. They suggested that water coning induced by the pressure differential existing in the well and the reservoir, and the advance of the OWC was directly proportional to the pressure differential. **Muskat and Wycoff (1935)** also pointed out that it is impossible to eliminate bottom water when producing thin oil zone unless the production is reduced to economically low values. Their results indicated that water free oil production rate could be maintained for a short-penetrated well, and this rate decreased with increasing well penetration. The definition of the critical rate is the maximum allowable oil flow rate that can be imposed on a well to avoid a cone breakthrough. This critical rate would correspond to the development of a stable cone on elevation just below the bottom of the perforated interval in an oil-water reservoir.

Several methods of production optimization are being investigated, in this case, the control of water production is very paramount. It has been shown that the polymer treatment of producing wells can reduce water-oil ratios dramatically. **Thakur et al in 1974** conducted a numerical coning simulation study to investigate the effect of injecting polymers in oil wells. They concluded that injection of polymer solutions in a fraction of the reservoir near the producing well will cause an effective reduction in water saturation buildup near the well bore; this is achieved by the reduction of the mobility ratio of water to a favorable mobility that can reduce water coning and thus the water production. **Bourenane et al (2004)** studied the optimization of perforated completions of a horizontal well in thin oil rims. They conducted a parametric study to analyse the effect of most relevant reservoir parameters on the horizontal well performance. The limitations of this work were that it considered reservoir homogeneity and ignored reservoir heterogeneity and it neglected the effects of water and gas coning which are major factors in the production of oil from thin oil rim reservoirs.

Singhal in 1993 suggested three major well completions and production operations that have been tried with various degree of success.

i. Placing barriers to movement of water and gas around the well. This involves introducing gas around the water, oil, gas or chemicals such as gels, foams, polymers, cementing agents to preferentially reduce permeability or relative premeability to water or gas.
ii. Modification of the flowing pressure distribution around wells by producing water or gas via separate completion intervals in the same well,reversing coning of oil into water or gas zone.
iii. Minimising operating cost via sub-surface water seperation and disposal of the seperated water in the same well.

Gino Di Lullo at al in 2002 discussed the use of visco anionic surfactant (VAS) system which acts as a permeability blocker (SPB).This method involves the use of a water-based fluid originally developed for fracturing purposes.Viscoelasticity is achieved by the addition of three components to the water: anionic surfactants, a functional pH buffer and an anionic surfactant. **Khan (1970)** used a three dimensional scaled laboratory model to observe coning behaviour in a reservoir with natural water drive. His results indicated that the degree of water coning and the value of the water cut increased with production rate, the mobility ratio and the ratio of aquifer to oil-sand thickness. He discovered that the mobility ratio had great influence on the water cut and the degree of water coning at a given total production value; the higher the mobility ratio, the faster water coning develops. **Sobocinski and Cornelius (1965)** presented a correlation to calculate the breakthrough time, which is the time needed for water to enter the perforation after the beginning of the oil production. Based on the experimental and modelling data, they developed a correlation to estimate the breakthrough time using dimensionless cone height and dimensionless breakthrough time.

2.3 Numerical Studies of Water Coning

Welge and Weber(1964) applied a two phase, two-dimensional model using the alternating direction implicit procedure(ADIP) in gas and water coning simulation. They employed special computational techniques after cone breakthrough to achieve reliable results and keep calculation cost within reasonable limits. The results got from simulations matched the producing histories of a laboratory sandpacked model and those of various producing wells experiencing water or gas free production as a result of coning. In this work, they suggested that the average horizontal and vertical permeability and the Kv/Kh ratio are critical parameters in the coning study. **Pirson and Metha(1967)** developed a computer program to simulate water coning based on the Welge and Weber's mathematical model. They studied the effects of various factors such as mobility ratio between oil and water, vertical to horizontal pearmeability , specific gravity differential between the two phases, and flow rate on the advance of a water cone. The cone shapes were drawn and the results were found to agree with known phenomena. In comparison with Muskat's approximate method, they found that Muskat's method gave higher critical rate because the water oil transition zone was ignored. **Macdonald and Coats(1970)** evaluated three methods for simulation of water coning behaviour. They improved on the small time step restriction of coning problems suggested by previous authors by making the production and transmissibility terms implicit. They reported that this implicit modification could increase the simulation speed much more than the traditional IMPES (implicit pressure explicit saturation) method. **Letkeman and Ridings(1970)** presented a numerical coning model based on the implicit transmissibilities and linear interpolation which permits the use of much larger time steps than those in IMPES simulators. The model exhibited stable saturation and production behaviour during cone formation and after breakthrough. Their work used modified equations to make coning simulation practical and economical.

Bryne and Morse (1973) presented a systematic numerical coning study which included the effects of reservoir and well parameters. Their results showed that the critical oil rate decreased with the increase of well penetration depth, decrease in water breakthrough time. , They reported that WOR (water oil ratio) increased significantly when the production rate increased, however, the ultimate recovery was independent of the production rate. The wellbore radius had no impact on water breakthrough time and WOR.

Miller and Rogers (1973) presented detailed coning simulation study to evauate water coning problem for a single well in a reservoir with bottom water. They used a single well grid system in radial coordinates to determine the most important parameters in water coning during both short term and long term production. Their results for critical oil rate matched Schols' (1972) critical rate correlation. **Mungan (1975)** presented experimental and numerical studies on water coning in an oil well producing under two phase, immiscible and imcompressible flow conditions. His results indicated that the numerical model simulated the experiments adequately. Increasing the production rate or the wellbore penetration led to earlier water breakthrough; however, oil recovery was independent of the production rate. The oil recovery at any given WOR became greater when the ratio of gravity to viscous forces increased. High vertical permeability decreased the oil recovery, while the opposite was true for horizontal permeability. **Chappelear and Hirasaki (1976)** developed a correlation to evaluate the critical oil production rate for a partially perforated well in a reservoir with bottom water. Their coning model was derived by assuming vertical equilibrium and segregated flow in two-phase, two-dimensional reservoir. **Kuo and DesBrisay (1983)** used a numerical simulation to determine the sensitivity of water coning behavior to various reservoir parameters. Based on the simulation results, they developed a simplified correlation to predict the water cut in bottom water drive reservoirs.

Chaperon (1986) proposed a simple correlation to estimate the critical rate of a vertical well in an anisotropic formation. The correlation accounted for the distance between the production well and reservoir boundary.

Holyland et al (1989) presented two methods to predict critical oil rate for a partially penetrated well in an anisotropic bottom water drive reservoir. The first method was an analytical solution, and the second was a numerical solution to the coning problem. Based on **Muskat and Wyckoff's (1935) work,** they developed a correlation to predict the critical rate in steady state. **Guo and Lee (1993)** demonstrated that the existence of the unstable water cone depended on the vertical pressure gradient beneath the wellbore. They found that when the vertical pressure gradient was higher than the hydrostatic pressure gradient of the water, an unstable water cone developed. Based on the simulation data, they developed a correlation to calculate the critical oil rate and determine the optimised well penetration length

2.4 Water Coning Control Methods

Kishman et al (1991,1992), Widmyer(1995), Shirman(1998) have developed practical solutions to delay water breakthrough time and minimize the severity of water coning in vertical wells. The basic methods include, seperation of oil and water in the OWC using horizontal impermeable barriers, controlling fluid mobility in the reservoir, increasing the distance between the bottom perforation and the original OWC, and production of oil and water by downhole sink wells and so on. **Thakur and Thachuk (1974)** conducted a numerical coning simulation study to investigate the effect of injecting polymers in oil wells. They concluded that injecting the polymer radially in the reservoir will produce the best effect of water coning reduction. **Karp et al (1962)** studied several factors involved in cresting, designing and location of horizontal barriers to control water coning. They evaluated different designs of the horizontal barriers, such as barrier radius, thickness, permeability and position. An experimental apparatus was established, to test the effects of different cement barriers for different reservoirs. They reported that reservoirs with high density or high viscosity crude oils, low permeability or thin oil zones were not suitable to use this technology, while on the other hand, this technology might impede the water drive in the field. **Smith and Pirson (1963)** investigated the effect of fluid injection to control water coning in oil and gas wells. They examined the position and length of the completion interval, point of fluid injection, viscosity of injected fluid and thickness of the oil and water sections. They found that the WOR was reduced by the injection of water at the point below the producing interval and the reduction was improved if the injected fluid was more viscous than the reservoir oil. Results from the experiment showed that the optimum point of fluid injection was the point closest to the bottom of the producing interval that did not interfere with the oil production when the rate is normal. The injection point moved down with the increase of production rate for maximising the coning control efficiency. However, more and more fluid should be injected back into the reservoir with the increase of time. **Pirson and Metha (1967)** discovered that the horizontal barriers just delayed the water breakthrough time while it did not provide an absolute solution to the problem of water coning. Water bypassed the barrier and breakthrough to the production interval when the cone radius became greater than the barrier. It was considered useful when the horizontal fracture is available to form such an impermeable barrier. **Rajan and Luhning (1992)** used a patially scaled physical model of the radially symmetric flow around a production well to study the effect of gas injection containing oil. They discovered that gas injection into the heavy oil saturated sand ack appeared to assist in the reduction of the fluid water-oil ratio. **Thomas et al (2002)**, did an analysis of axial and radial velocity gradient which appears to hold promise as a means by which a water shut-off treatment can be performed. A two-phase, two-dimensional (azimuthal symmetry) numerical model of water coning was developed and used for analysis of water shut-off treatments. This model was used to "fit" field data and then employed to gain insight into water shut-off applications. They concluded from their results that early application of water shut-off is better than after the cone is fully developed. **Ashiem and Oudeman(1997)** in their research, investigated the option of varying the perforation density in order to create a uniform production and injection profile along the wellbore as illustrated in figure 2.1. They discovered that the uniform inflow design may produce some marginal reduction in productivity when compared to uniform perforation density method. The sweep efficiency is higher and there is attendant delay in the water breakthrough time and ultimate recovery.

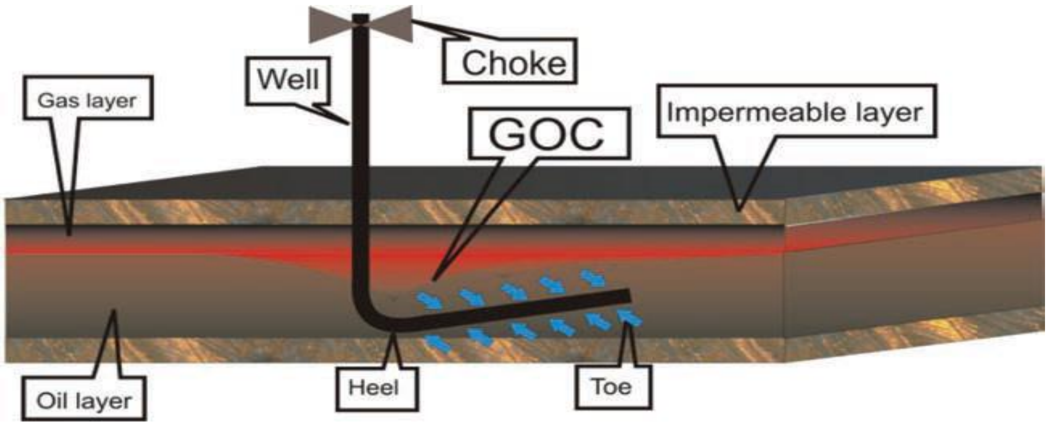


Figure 2.1 inflow of fluid into the perforations Source : Ashiem and Oudeman(1997)

2.5 Use of Relative Permeability Modifiers

Relative permeability modifiers(RPM) were introduced to the oil and gas industy more than two decades ago as an option to selectively reduce water production. This type of treatment is very simple to deploy and requires no zonal isolation **(Julio and Eoff 2013)**. This RPM system is based on hydrophobically modified water soluble polymer that, once absorbed to the surface of the rock, selectively reduces the water effective permeability with little or no damage to the oil and gas production. **Kisman et al (1991, 1992)** proposed two methods that can be used to reduce the water cut in the well by injection of a composite slug comprising of water wetting agent into the reservoir. This is to modify the reservoir matrix to increase its water-wetting characteristic, and injecting non-condensable gas for further extending the matrix surface modification. The slug of a water wetting agent ensured the main path of the flowing gas slug through the water zone where it would increase the gas saturation area. The relative permeability to water would be reduced. This method could delay the water breakthrough time and reduce the water cut in the produced fluids. Mobility control implies injection of chemical additives such as surfactants and polymers or other geling agents into the water phase to control its mobility. **Paul et al (1998)** proposed the injection of water-soluble polymeric gels to control the bottom water mobility. They designed different types of polymeric gels for various water properties and carried out a series of experiments in the laboratory to examine their effectivenss.

2.6 Downhole Oil-Water Seperation(DOWS) Technology

Widmyer(1955) developed a technique of downhole water seperation to reduce surface water production. This technique enables water seperation in the wellbore and is reinjected downhole while the oil is produced to the surface.

2.7 Dual Completion With Tailpipe Water Sink

Wojtanowicz and Xu (1991) proposed a method using dual completion configuration below and above the OWC. The configuration of the well includes completion of the well above WOC to produce oil, and below the OWC to produce water, serving as a drain to control the rise of the water cone (Tailpipe Watersink). The limitation is that, the method is particulary effective for low flow rates.

2.8 Downhole Water Loop Technology

Wojtanowicz and Xu (1995) proposed a downhole water loop technology (DWL) to cut back volume of the formation water produced. In this method, a dual completion of the well was situated in the water zone and oil zone using a water loop equipment (seperated by a parker) in addition to the conventional completion in the oil zone. The water loop installation included a submersible pump which drained the formation water around the well from the water sink, and then reinjected to the water zone through the water source perforations. The flow potential theory is used to develop expressions for the streamlines and isopotential lines for a number of cases of 2D fluid flow in the DWL well system as shown in figure 2.2 below. This method was found to increase the production from the reservoir but the economic feasibility was not carried out in their study.

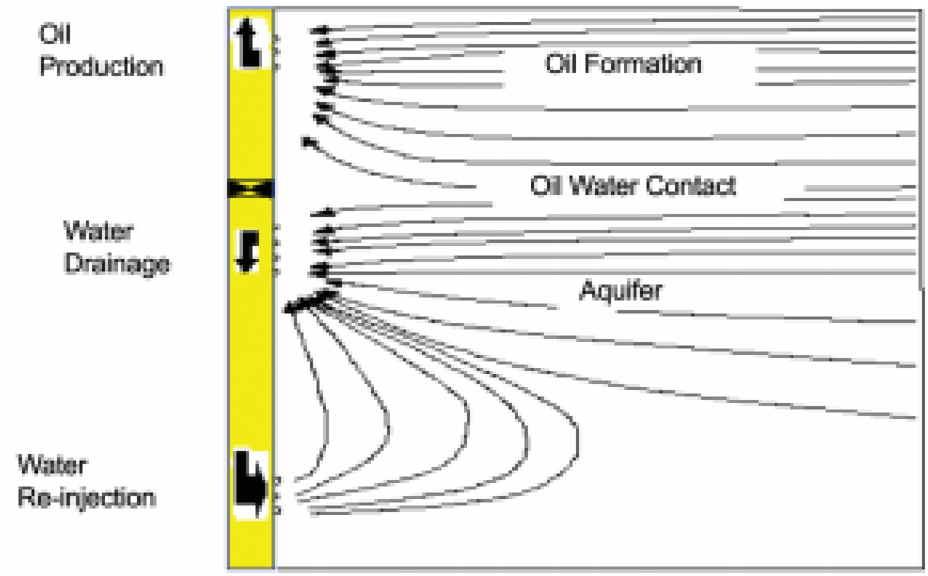


Figure 1.2 Flow Streamlines from Uniform Source and Point Source to Point Sink in 2D System (Wojtanowicz and Xu, 1995).

2.9 Downhole Water Dump Flooding

Water coning, the upward encroachment of water into a perforated zone of a well is one of the main problems in many petroleum fields especially in strong bottom water drive reservoirs. **Widmyer RH (1955)** proposed a new method that can reduce water coning and be economic in commercial production; this method is known as the “Downhole Water Sink (DWS)”. This method involves the use of dual completion achieved by the perforation of the hydrocarbon and water zones. According to the pressure balance principle, DWS can delay the GWC or

OWC uplift when hydrocarbon has been exploited. This results in the delay/prevention of water coning. However, according to **Buranatavonsom(2011),** this method needs to produce a large amount of water up to the surface which causes the incremental cost of water disposal. So in his method water was not produced to the surface and there was no need to drill a water well for water production. , This therefore minimised the drilling cost and water treatment system. Gas perforation interval (h_{pg}/h_g) was identified as the main factor which results in cummulative gas and water production.

2.10 Simultaneous Production of Oil and Gas Reserves From A Single Wellbore

Reservoir simulation has been used to study the ability of concurrent wells to enable the simultaneous production of oil and gas with minimal impact on the oil recovery. The proposed concept (concurrent production) can significantly impact the available gas reservoirs by delivering a cost effective technology solution. In oil rim reservoirs with water drive as the dominant drive mechanism (i.e., reservoirs with strong aquifers), concurrent oil and gas development is attractive. These types of reservoirs are usually produced at high gas offtake rates with limited reduction in oil recovery. **Billiter and Dandona(1999)** presented a unique methodology of simaultaneously producing from the oil column and gas cap while injecting water in the GOC to create a barrier between the oil and water columns. The results showed an increase in production, improving the net present value of the project. The applicability of this method is limited to oil rim reservoirs with large, low deep angle gas cap .**Decroux et al (2000)** presented a full field compositional simulation model to history match an oil rim in offshore Abu Dhabi. The reservoir contained a large gas cap underlain by a thin saturated oil rim initially .The history matched model was used to propose a development scenario. Horizontal wells located close to the GOC producing at high gas-oil ratios would lead to high oil recovery with a recovery factor of 30% achievable. High heterogeneity of the formation would however be a limiting factor. **Inikori and Wojtanowicz (2002)** presented a study of two innovative concepts of “smart” completions for water cresting. It involves segregating production of oil and water in a dual completion with zonal isolation. The result of this research indicates that dual completions have the capability of reducing the incidence of by-passed oil at the toe of the horizontal well.

Cosmo and Fatoke (2004) used idealized modelling to establish parameters affecting oil recovery under concurrent oil and gas production. Optimum production was realized by placing the horizontal well midway the oil column. **Uwaga et al (2006)** investigated the feasibility of intermittent production of the gas cap with continuous oil production from an oil rim reservoir in the Niger Delta. After assessing the impact of gas offtake rate, offtake frequency and period to sustain each cycle on oil recovery, they concluded that the proposed development strategy is feasible if reservoir and fluid uncertainties are properly managed. However, the optimization of the frequency and cycle time for the swing option was not considered. **Kabir et al., (2008)** proposed a two-stage/single-stage depletion strategy that were based on horizontal well completions. The first option was well completion below the gas-oil contact (GOC), while the second, which took place just after the first well is allowed to water out, requires the placement of the horizontal well at the crest or at the GOC depending on the size of the gas cap. In order to maximize the recovery, a stable gravity flooding is required. This approach is only possible where gas monetization is not an issue due to the very high initial GOR production which may result to loss of energy before significant oil rate takes place. Also, the oil from the rim could be displaced into the large gas cap which ultimately resulted to smearing.

In an oil rim development, understanding of the oil rim mobility is very crucial over the life span of the field. This is especially important for small, thin rims as this determines the feasibility of its development. The movement is typically determined by two dominant drive mechanisms. Water and gas expansion drives. The aquifer pushes the rim upwards, unless a big gas cap keeps the pressure up and the rim down. Before production starts, the two forces are in pressure equilibrium; on the onset of production, the reservoir pressure will start to decline and the oil rim will start moving.

2.11 Horizontal Well Technology

There are many reasons why a horizontal well is preferred to a vertical well in production from oil rim reservoirs. The two main reasons are increased production rates and increase in recovery of reserves. Increased production rate is due to the fact that a horizontal wellbore exposes more formation to production than does a vertical well. Because more formation is exposed, the pressure drop from the formation into the wellbore is significantly less than in a vertical well. This is even true where the producing rates in the horizontal well are much greater than in a vertical well. This is significant because of the reduction in water or gas coning, and less tendency to produce sand, while producing the well at higher rates. In many cases, increasing production cannot by itself economically justify the cost of a horizontal well, but the added benefits of preventing coning and reducing sand production are of significant cost benefit. The production rate of oil or other fluids from a reservoir is controlled by pressure gradients between the reservoir and the borehole. With conventional wells, it is broadly recognized that most of the reservoir pressure decline occurs close to the well. In order to achieve greater production rate, it is necessary to decrease the resistance to flow within the reservoir, particularly in the near wellbore region. The construction of wells which penetrate the reservoir horizontally, provides an alternative means for improving contact with the reservoir. The improvement offered by horizontal wells allows lower fluid velocities at the wellbore while still providing total flows which are economical. Because horizontal drilling allows a large portion of wellbore to remain in a single zone of interest, a greater area of pay zone can be exposed. Therefore, horizontal drilling may be defined as implementation of a horizontal wellbore designed to take optimum advantage of the three dimensional geometry of a reservoir. Recently, horizontal drilling has been applied to oil and gas reservoirs to provide economic production of marginal reserves. In many specialized applications, substantial productivity gains have resulted from the use of this rapidly developing technique.

Several authors have proposed horizontal well technology as a solution for reservoir development with water coning issues **(Vijay et al 1998; Vo et al 2000; Al Kaioumi et al 1996).** Vertical well acts like a point source concentrating all the pressure drawdown around the bottom of the wellbore, while the horizontal well acts like a line sink and so distributes the pressure drawdown over the entire length of the wellbore. The nature of the inflow of fluid into a horizontal well remains a chalenge to many analysts. Three models have been presented to explain the pattern of flow in the horizontal well (i.e., Infinite Conductivity, Uniform flux and Finite Conductivity). Infinite conductivity works on the assumption that there is no pressure loss in the wellbore; uniform flux assumes that the fluid influx into the wellbore from the reservoir is constant along the horizontal length of the well, and finite conductivity is more encompassing because it incorporates the effect of friction pressure loss in the wellbore and the changes in the fluid flux distribution along the wellbore. The most controversial and least accepted of these three is the uniform flux assumption. Mathematical equations have been developed for the evaluation of the horizontal well performance in coning control. Many methods have been proposed from the literature to calculate the productivity index of a horizontal well for either a steady state or a pseudo-steady state condition. Methods like those of **Joshi (1988), Ozkan et al (1989), Babu and Odeh (1989)**. For wells with high deviation angles, a method proposed by **Peng (1992)** can be used to compute steady state productivity of deviated wells. **Kuchuk (1988)** proposed a method to calculate the steady state productivity of a horizontal well in a reservoir with a gas cap or underlying bottom aquifer.

Geiger (1984) developed a correlation for the evaluation of the productivity index of single-phase oil production or the pre-water breakthrough oil production rate in an isotropic reservoir. Consequently, he also developed a correlation for comparison of the performance of vertical and horizontal well, in an isotropic reservoir.

Joshi (1991) analysed the critical rate for gas coning in vertical and horizontal wells and showed that the there is a critical ratio of critical oil production using horizontal and vertical wells. **Joshi (1991)** further showed the critical production rate for a gas-oil system and an oil-water system.

Ben Wang et al (1993) used Joshi's (1991) equation for scaling of productivity of a horizontal well over vertical well. **Chigbo et al (1989)** observed that horizontal well technology for the development of thin oil rims in an unconsolidated sand deposit in a deltaic environment may be erroneous and dangerous. However, they did not show results of further studies to validate their claim. **Yang and Wattenberger (1991)** developed several correlations from numerical simulation studies for predicting water-oil-ratio (WOR) as well as the critical rate and time to water breakthrough for horizontal wells. They considered a closed outer boundary reservoir in transient state.

Peng and Yeh (1995) concluded in their research that the use of horizontal wells is a proven technology for the reduction of coning problems and recovery improvement in reservoirs underlain with water. However, recent field experience shows that the reduced pressure drawdown is not a total solution to the influx of water into the wellbore. Horizontal wells, by their nature and geometry, have inherent problems. One of which occurs when water breaks into the wellbore causing rapid increase in the water cut. **Wangenhofer and Hatzignatou (1996)** conducted a parameter sensitivity analysis to evaluate the influence of various factors and reservoir fluid and rock properties on the breakthrough time and optimal well location. They developed a correlation to predict the time at which gas and water cone simultaneously into the horizontal well, and the optimum location of the horizontal well with respect to the water-oil and gas-oil contacts. **Ehlig-Economides (1996)** proposed that a dual horizontal well completion, one in the oil zone and one in the water zone could reduce the water cresting problem in horizontal wells. Results were not presented in this research to validate the proposition. **Asheim and Oudeman (1997)** recommended an optimal performance scheme that reduces perforations at the heel and increases the perforation density towards the tail end of the horizontal well; and this, therefore, redistributes the fluid influx model to possibly achieve uniform influx pattern.**Permadi et al (1997)** conducted a laboratory experiment to study water coning behavior in a horizontal well with a stinger inserted. They concluded that system without stinger yielded better early recovery performance. While the horizontal with stinger flattens the cone of water and reduces rate of water cut increase, leading to a significantly improved recovery. .**Achi (2008)** presented a comprehensive analysis of horizontal wells in the field and investigated aspects of the failures and successes observed in the wells. By benchmarking the current well performance, this research presented some suggestions for well design and strategies for completions of prospective wells. **Obah et al**

(2012) carried out a generic dynamic simulation study to generate oil production profiles for oil rim reservoirs in the Niger Delta,. This work resulted in the development of three decline curve based models used to forecast oil production for oil rim reservoirs. The impact of uncertainty parameters was accessed using Plackett-Burman experimental design. Generation of a probabilistic forecast range for decision making was done using the Monte Carlo simulation approach. The Limitation of this work is that the models were not updated with production data and is only applicable to two horizontal wells and a specific range of data.

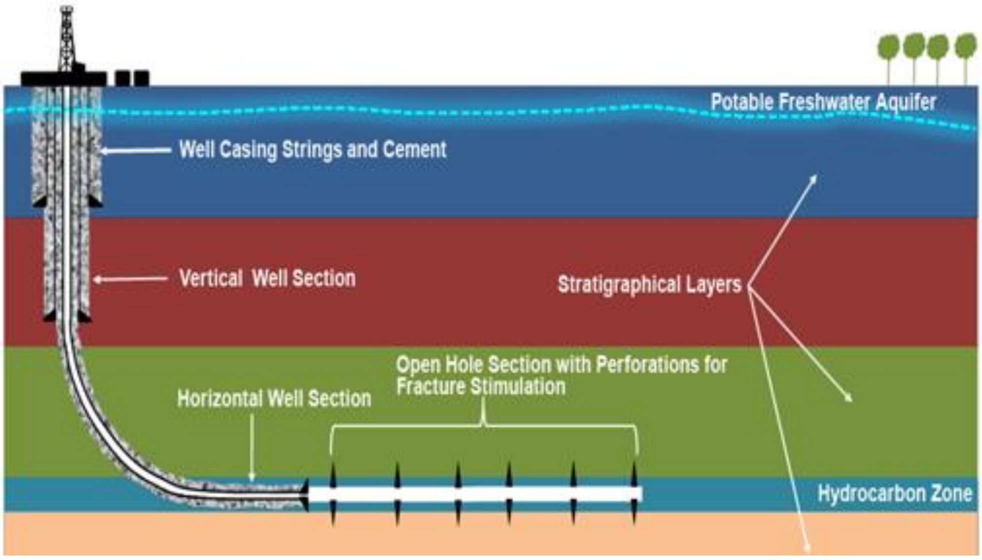


Figure 2.3 Horizontal well Technology (Source: Northern Territory Department of Mass and Energy, Energy Directorate Petroleum Operations,2014)

Horizontal well technology application as illustrated in figure 2.3 has been used widely in many countries for oil recovery enhancement for water drive reservoirs **(Makinde et al., 2011)**. As a horizontal well can have low drawdown, a horizontal well can have larger capacity to produce oil as compared to a vertical well, other things being equal. Thus, the critical rate may be higher in horizontal wells than in vertical wells. Horizontal wells may also be applied to reduce gas coning rate, in gas -cap driven wells.

2.11.1 Horizontal Well Completion with Stinger

This type of method involves the redistributing of the pressure losses along the wellbore by inserting a piece of pipe of a smaller diameter into the completion/production liner .This smaller piece of pipe is usually called stinger. **Brekke and Lien (1992)** reported that stinger completion method, in the combination with reduced perforation density could provide up to 25% increase in well productivity during the first part of the production life. This production well with stinger creates improved sand face pressure profile by the control of the inflow of fluid along the wellbore. This process helps to redistribute the frictional pressure loss along the perforated part of the well.

Permadi et al (1997) conducted an experiment to study the behaviour of the water coning under a horizontal wellbore with a stinger inserted. For the stinger length, they consider various oil viscosity and initial oil column thickness to investigate their effects on the optiml length of the stinger. It was concluded in this work that systems without stinger yielded better early performance early in the production life of the reservoir, while systems with stinger ultimately have the highest recovery rate because the stinger flattens the water cone and reduces the rate of water cut increase. However, most previous studies of stinger completions took place in homogeneous reservoirs and are not equipped to deal with the multipoint water cresting breakthrough caused by fractures or permeability contrast in a heterogeneous bottomwater reservoir. **Haitao et al (2014)** proposed a new improved stinger-completion (ISC) using semi-analytical coupled model of reservoir and wellbore flow which considered the impacts of well trajectory, permeability distribution, formation damage caused by drilling and completion, and variable mass flow in a horizontal wellbore. By discrete numerical calculation of the new model, pressure, inflow, and water-cresting profiles can be acquired; and consequently, a design method of ISC was also proposed to be used successfully in a heterogeneous, bottomwater reservoir for stable oil production by controlling the water-cut and optimizing the structure, length, and diameter of the stinger. The successful field application of ISC in the LU-X horizontal well used as a case study in this work also confirms the feasibility and effectiveness of ISC.

2.11.2 Pseudo-Horizontal Well Technology

Pseudo horizontal well is an alternative to horizontal and vertical well, it incorporates the following features;

a. Its well length is comparable to that of a horizontal well
b. The well intersects and completes all the productive layers from the top to the bottom of the reservoir, this is a major advantage of a vertical well.
c. The slope to the horizon is quite small.

Zakirov and Zakirov(1996) in their research presented the use of a pseudo-horizontal well as an alternative to horizontal and vertical well. They showed in their work that this type of well combines the advantages of the horizontal and vertical well . In this work, a layered reservoir was used to show the advantages over the horizontal and vertical wells. Although similar to slanted wells, pseudo-horizontal wells are characterized by a smaller slope to the horizon. They came to the conclusion that pseudo-horizontal wells are attractive alternative in the case of layered reservoirs since they jointly accumulate the advantages of horizontal and vertical wells and the wells eliminated the risk of getting negative results,which is a major advantage to the horizontal well. The major limitation in the use of this type of well is that its application is limited to layered heterogeneity reservoirs. Generally, (Joshi 1988) reported that horizontal wells can be used effectively in the following applications: in naturally fractured reservoirs, reservoirs with water and gas coning problems, in gas production, low and high permeability reservoirs and in EOR applications especially in thermal EOR. A long horizontal well provides a large reservoir contact area and therefore enhances injectivity of an injection well. The major disadvantage of a horizontal well is that only one pay zone can be drilled per horizontal well. The cost is 1.4 to 3 times more than a vertical well depending on the drilling method and the completion technique employed (**Joshi, 1988)**.

2.12 Production of Oil Rim below WOC(Reverse Coning)

Another proposed solution to the coning problem is to complete the well some distance below the WOC **(Haug et al, 1991)**. This method increases the distance between the perforations and the GOC. This method is refered to as inverse coning and relies on oil down-coming into the completions through the water zone . Wells completed below the GOC were studied by **Van Lookeren (1965)** and has been further investigated by **Cottin and Ombret (1973)**. Some successful experiments with inverse coning in vertical wells have been reported in Eastern Europe **(Kurbanov, A.K. and Sadchikov, 1964; Ovnatanov, S.T. and Karpentov, 1966; Hornyos, J., Simon, S. and Ori, V, 1968)**. Correlations for critical rates and time to gas/water breakthrough in horizontal wells are presented in literature **(Joshi, 1991).** This goes a long way to show that the distance from the completions to the coning fluids strongly influences both time to breakthrough and the maximum liquid rate which can be produced while avoiding the production of free gas.

2.13 Intelligent well completions (Smart Well Technology)

In a bid to optimise the development of both oil and gas hydrocarbon resources, a novel concurrent approach was proposed by **Sascha (2008)** . In this approach, the gas cap and the oil rim are produced simaultaneously from the start of the production through a single well conduit. He concluded that for reservoirs with water drive as the dominant drive mechanism, a concurrent oil and gas development will be attractive as compared to reservoirs with gas cap expansion as the dominant drive mechanism. **Fajhan(2007)** investigated the impact of utilizing the downhole inflow control valves (ICVs) on the performance of horizontal wells and quantification of the increase in recovery achieved by controlling the production from the various sections of the horizontal well completed in a thin column. The conclusions are as follows:

- Intelligent well completions provide an effective tool for managing and increasing production per well fro m thin oil rim reservoirs
- A control strategy that aims to delay the unwanted fluid's breakthrough prior to controlling the unwanted fluid's production yields the greatest value in thin oil column reservoirs.
- A suitable control strategy for single-phase production is the maintenance od a uniform pressure drawdown profile along the horizontal wellbore.
- The preferd ICV comtrol strategy when confronted with simaultaneous gas and water influx into the well is to focus on controlling the gas.
- Combined control at both the well and ICV level provides control of unwanted fluids while maximising the fluid influx.
- Optimized conventional well design by efficient use of geological models togethr with real-time log and other drilling information are essential elements for optimal, intelligent well construction.
- The (relative) activities (sizes and connectivity) of the gas cap and aquifer are to determine the optimum well placement an maximum Intelligent well value.

Jackson et al (2001) identified the benefits of the use of intelligent wells as follows:

- Ability to monitor the pressure of and flow from the reservoir to develop a strategy which optimizes recovery.
- Saving cost from the elimination of rig intervention both for recompleting or the drilling of subsequent wellbore laterald later in the life of a well.
- Personnel safety improvement as workover activity is downhole.
- Project economics improvement as a result of rate acceleration and added reserves.

Inikori et al (2002) presented two inovative concepts of smart completions for controlling water cresting in horizontal wells. The two concepts are known as "tail water sink" and "bi-lateral water sink." They studied water cresting in horizontal wells using a new 'generalized relation' for the evaluation of the friction pressure losses in the wellbore.The technology involves the segregated production of oil and water in a dual completion with zonal isolation. It was concluded that the dual completions are capable of reducing the incidence of by-passed oil with the horizontal wells and improve oil recovery by over 7 %. **Snaith et al (2003)** highlighted the advantages of a multizone selective completion used in an oil rim in in the Lion Duke field. The oil rims are overlain by large gas cap with heterogenous sandstones. The horizontal well cuts across 5 separate oil rims crossing 2 faults with a 5-zone selective completion. It resulted in higher production and higher ultimate recovery. **Clarke et al(2006)** studied the use of intelligent completion in improving production from a dual lateral well before full gas blowdown in a 45m thick Lennox Oil Rim. The use of the intelligent completion resulted in higher recovery and the success of this work led to a fieldwide application of auto gas lift to allow continuos lift at high watercuts and low pressures. **Mohammed et al. (2010)**

proposed a smart development strategy in a field case study on the IKU6 reservoir in the Ekeh field of the Niger Delta Basin. In this technique, an intelligent multilateral well was used to simultaneously produce oil and gas from the same wellbore through thin oil rim with large gas cap. Apart from being cost effective relative to conventional technique, a reduction of excess production of unwanted fluids (water) was also recorded during oil and gas production using intelligent well technology. However, as beneficial as this technology has proven, its applicability is limited only to reservoirs with production and injection using horizontal wells that are completed and equipped with permanent downhole sensors and valves.

2.14 Water Injection Optimization

Keng et al (2012) presented a delineated concept and strategy in their work on the subject of thin oil rim reservoirs. The force balance between the gas cap expansion, aquifer expansion, and viscous withdrawal was demonstrated by showing the model simulated water-oil and gas-oil contact movement. The study included the placement of a system of water injectors at the selected sector periphery and at the gas oil contact, together with the optimization of infill well placement and the selected idle well reactivation. This effort showed a potential of improving the current recovery factor from 35% up to 51%, way beyond theoretical vertical displacement efficiency. **Keng et al (2012)** made the following conclusions in this study;

- Periphery and fencing water injection at the GOC and WOC respectively has the capacity to improve the lateral and area sweep to augment vertical sweep by the bottom water, this in turn increases the well productivity.
- The fencing water injection has the ability of creating a flow barrier to keep oil rim from spreading/moving into the gas cap.

- Water injection increases the reservoir pressure and increases the well draw-drown pressure.

One major limitation with this work is that the periphery water injection may further incur loss of oil rim oil into the gas cap at a later time.

Onyeukwu et al., (2012) investigated the technical feasibility of gas and/or water injection in an oil rim under various subsurface uncertainties. The development concept involves completion of a horizontal gas injection well in the gas cap while the horizontal oil producer was completed in the rim. Alternatively, another dedicated horizontal water injector well was completed in the aquifer leg while the horizontal oil producer was completed in the rim. The results show that simultaneous gas and water injection could increase the oil recovery factors. The limitation of their finding is they considered only the technical aspects of oil and gas recovery in their analysis. Beyond consideration of only oil recovery versus sub-surface uncertainties, the final investment decision will largely be based on many considerations the chief of which is the economic viability of the project. **Iyare, and Marcelle-de Silva (2012)** studied the effect of gas cap and aquifer sizes on oil recovery from a thin oil rim using a single well numerical reservoir simulator model. They constructed a single-well, homogeneous, three-dimensional model for a thin oil rim reservoir with a strong water drive to evaluate the effect of completion location and gas cap size on recovery. Four well locations were varied, i.e., (i) above the GOC, (ii) at the GOC, (iii) in the middle of the oil column, and (iv) below the OWC for varying gas cap sizes. Gas cap sizes corresponded to gas cap to oil pore volume ratio (m-factor) values of 0.05, 0.5, 1, 2.2 and 5 were also investigated. They concluded that for a reservoir with a large gas cap, a horizontal well completed close or below OWC can improve the ultimate oil recovery. The limitation of this work is that aquifer size was not considered as part of the sensitivity parameters.

2.15 Gas Lift Option

Recham and Bencham(2004) in their work demonstrated the benefits to be gained from performance analysis of gas-lifted vertical and horizontal wells in an oil rim reservoir. An artificial lift method was employed in which gas was injected into the production tubing. .A multiphase network hydraulic simulator was used to analyse the combined well and flowline performance. The results show that the optimum gas-lift system should be placed at the point where an incremental expense for gas injection is equal to the incremental revenue produced at that injection rate. They reported that numerous flowing wells showed increased oil flow rates when placed on gas-lift.

2.16 Oil Rim Production by Gas Injection Optimization

Kabir et al (1998) did a reservoir simulation study to show that 10% to 14% incremental oil recovery is achievable by reinjecting the produced gas directly into the oil rims. This innovative oil rim injection technique provides direct displacement of bypassed and unaccessed oil as well as pressure maintenance. This technique also enables targeting of multiple layers with a single wellbore.

2.17 Simultaneous Water and Gas Injection (SWAG)

Sohrabi et al (2005) demonstrated that in near miscible SWAG injection, the oil recovery continues significantly and almost all the oil contacted by the gas was recovered. A major limitation of this technique is that in SWAG injection with high gas-water ratio, extra amount of injected gas does not significantly improve the oil recovery. **Uwaga et al (2006)** investigated the feasibility of intermittent production of the gas cap with continuous oil production from an oil rim reservoir in the Niger Delta. They studied the impact of parameters such as offtake rate, offtake frequency and period to sustain each cycle on oil recovery, and concluded that the proposed development strategy is feasible if reservoir and fluid uncertainties are properly managed. However, the optimization of the frequency and cycle time for the swing option was not considered. **Hsiu-Hsyong (1998)** in his paper presented the principles of using horizontal grids for the representation of the inherent properties of horizontal wells and contacts in the simulation of recovery in oil rims. Using the results of the optimization of horizontal well placement on the horizontal grid, he concluded that horizontal grid is a better representation of the coning phenomena resulting in higher recoveries; and that the optimal vertical position of the horizontal well can be accurately predicted. A major limitation in his work is that the results obtained were not supported by field data.

2.18 Surrogate Reservoir Modelling

A Surrogate Reservoir Model (SRM) replicates the traditional full field numerical reservoir simulator accurately. The use of SRM has been reported in the literature. **Mohagheh et al (2009)** presented an application of SRM in a giant oil field in the Middle East. The objective of their study was to identify wells that are candidates for rate relaxation in order to obtain higher oil production at constant water cut in reservoirs characterized by thin oil column (30 – 77 ft) and overlain by thick gas cap. They reported that the development of thin oil rim reservoirs is very challenging due to complexity of the fluid system (volatile oil, retrograde condensate gas cap gas), complex field-scale geology (compartmentalization, fracturing, and rapid lithological variation), and inherent heterogeneity in reservoir properties (e.g., permeability ranges from 100 to 15,000 mD). The reservoirs in the giant Middle East oil field also experienced strong water drive which posed the observed threat of high water cut. To evaluate and select the best strategy for optimal oil production from these fields, Mohagheh et al.(2009) deployed surrogate modeling methodology as an alternative to the time consuming and costly full-field simulation of horizontal wells in the reservoirs.

The need for using SRM to quantify uncertainty is significant when one considers the number of geologic realizations required to capture the inherent geologic heterogeneities in model properties **(Heath et al., 2012)**. The number of geologic realizations of the reservoir must be statistically significant in order for the uncertainty analysis to be meaningful. An increase in the number of the independent parameters defined in a reservoir characterization problem causes an increase in the number of realizations needed for quantifying uncertainty with statistical significance. A full-field model (FFM) is a representation of a set of several independent variables **(Peaceman, 1993)**. Given the high number of grid blocks even in a moderate size FFM, one can imagine that the number of realizations needed in order to have a statistically significant dataset will be relatively large. Nevertheless, even after application of all the approximations and techniques such as Latin Hyper Cube and Design of Experiment (Mohaghegh et al., 2006), the number of the simulation runs required for a reasonably accurate uncertainty analysis remains quite high. Thus, SRM plays an important role in addressing the problems of quantifying reservoir uncertainty.

.2.19 Oil Rim Reservoir Management

There are several definitions of reservoir management. Many authors like **Humphrey (1986)**, **Talash (1988)**, **Thakur (1990)**, **Caldwell (1994)**, and **Satter (1994)** have attempted to define reservoir management concisely and clearly. The fact that many attempts have been made and there is still no generally accepted definition of the term emphasizes the various viewpoints on exactly what reservoir management is within our industry. **Sawabini (1997)** defined reservoir management as “an orderly and repititive process that integrates all the reservoir characteristics to predict its performance using sound reservoir engineering principles so as to prudently design the needed surface facilities and subsurface equipment, develop, monitor, control, and maximise its recovery for the duration of its productive life in an integrated synergistic approach, economical and timely fashion." Reservoir management can also be defined as "the recurring process in which an oilfield operator makes use of mathematical modelling, data and expertise to optimise reservoir profitability or some other stated objective about oil field performance" **(Saputelli et al., 2005).**

There are several objectives in reservoir management. They include but not limited to , profit maximization, decreased risk, recovery maximization, minimization of capital expenditure and operating costs, and increase in oil and gas production. In this work, the reservoir is managed so as to improve the recovery and an uncertainity analysis is performed so as to decrease the risk factor in the production from the thin oil rim. Resevoir simulation done in this work is a key factor in reservoir management. After the development concept has been selected and implemented, managemnt of the oil rim reservoir throughout the production life of the reservoir is very pertinent. The different strategies required for effective reservoir management must be examined. Some guiding principles and general considerations for developing an effective oil rim reservoir management include:

- Reservoir Survellance. As the name implies, this covers a very wide range of activities that are related to monitoring well and reservoir performance so that informed decisions can be made to adjust the operating conditions or implement corrective action in a bid to maximise recovery.

- Well Test Control. The optimal development concept for a particular oil rim might involve producing the well under a certain GOR limit. Regular well testing and pro-active well control will be required to ensure the reservoir is operated within the specific limits.

Surface facilities are subject to different operating conditions, production rates and pressures depending on the oil rim development concept being applied. The facilities used need to be tuned to accommodate the specific development concept being applied so that the optimum recovery can be achieved.

From the foregoing literature review, it is worthy of note that a lot of efforts (i.e., correlations based on critical rate, breakthroughh time) have gone into the study of the production and development strategies of thin oil rims. Several other water coning control strategies including conformance technology, horizontal well technology, downhole oil-water separation technology, and intelligent well technology have been developed. Although, it was discovered that with many of these methods there is a reduction in coning, the excessive bypassed oil has limited their field application. These studies have not used an integrated approach to optimimising production from these oil rim reservoirs. This study employs the best approach to optimize production from these oil rims through effective reservoir management which involves evaluation, monitoring, goal setting, and revision of a few strategies for efficient field development. The research presents a thorough analysis of the various strategies that can be used to develop the oil rim reservoir, and very importantly, a comparison of the economics of each of the strategies to support informed decision making.

CHAPTER 3

3.0 METHODOLOGY

The methodology of this study involves developing a surrogate reservoir model (SRM) that approximates the behavior of the Full Field Reservoir Model (FFRM) of an oil rim system within the Niger Delta. The developed SRM was deployed in lieu of FFRM to facilitate the process of evaluation of the uncertainty inherent in the production of the thin oil rim reservoirs. The lessons learnt from the evaluation using the SRM were applied to an integrated study of an oil rim reservoir (Reservoir A) from the Niger Delta. From the case study, we demonstrate the technical and economic feasibility of various development strategies for optimum exploitation of the selected and similar thin oil rim reservoirs within the study area. The proposed methodology is described in the sub-sections that follow.

3.1 The Need for Surrogate Model

Prediction of multiphase flow in a reservoir is usually performed using reservoir simulation software. Running a simulation study can be too expensive and time consuming depending on the complexity of the model. For example, an increase in the number of reservoir layers or formation thickness would increase the number of grid cells in a full-field model. The number of cells in the model can rapidly approach several millions thereby increasing the time required for each simulation run. Although parallel processing can help to a certain degree in mitigating this problem, it cannot close the gap between real-time processing and simulation needed to quantify uncertainty associated with geologic models (Massonnat, 2000). Simulation used to evaluate multiple production objectives and constraints can take many hours or even days to complete using full field model; hence, the use of a surrogate model (SRM) in simulation studies. The SRM helps in the quick understanding of the mechanisms governing the process of oil recovery. In addition, it is computationally cheaper to use as uncertainty evaluation tools (Graf et al., 2011).

3.1.2 Surrogate model development

Figure 3.1 shows the workflow used for the development of SRM adopted for this research. The first step involved collection of data (porosity, permeability, reservoir thickness, gas size, oil column, well geometry, fluid properties, etc.) from oil rim reservoirs within the study area, performing a data quality control, and statistical analysis using descriptive statistics. Table 3.1 shows the average reservoir properties of oil rim reservoirs in the Niger Delta. Figure 3.2 shows the 3-Dimensional model obtained by considering the average properties.

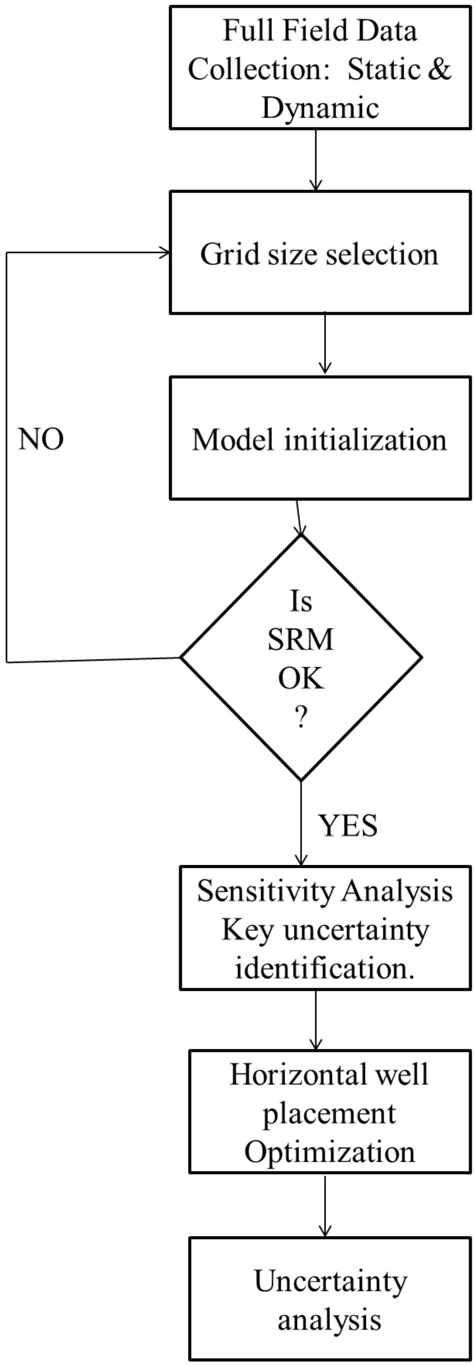


Figure 3.1 Workflow diagram for development of SRM

Table 3.1 Fluid and rock properties of Base Model

Parameter	**Value**	**Unit**
STOIIP	45	MMSTB
GIIP	40	BSCF
Average horizontal permeability	1500	mD
Average vertical permeability	12	mD
Average Oil Column height	50	ft
Porosity	0.27	fraction
Initial Reservoir Pressure	3800	psi
Connate Water Saturation	0.2	
Water-Oil-Contact	9750	ft
Gas-Oil-Contact	9696	ft
Datum Depth	9750	ft
Pressure at Datum Depth	3900	psi
Irreducible water Saturation	0.2	
Net-to-Gross ratio	0.80	
Critical Gas Saturation	0.05	

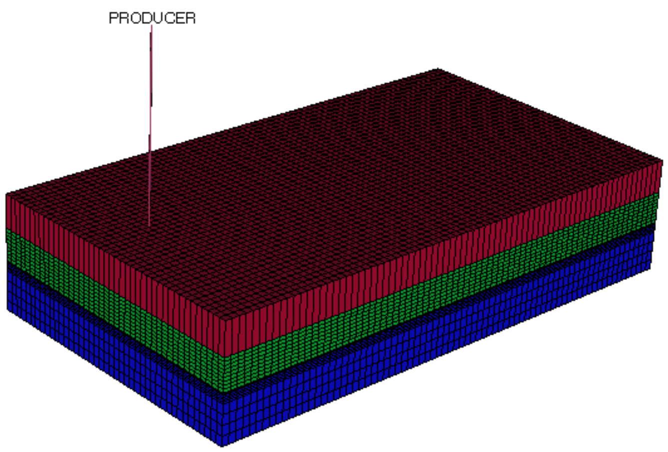


Figure 3.2: Schematic diagram of the SRM elemental volume for a well-based SRM

3.1.3 Grid size selection

The selection of appropriate grid size for simulation was achieved by sensitivity analysis. In this analysis, cumulative recovery and the average reservoir water-cut were selected as output responses of interest. A structured grid which consists of only one basic shape arranged in a regular repeating pattern so that the topology of the grid is constant in space was selected. In our gridding system, some local grid refinement was done around the fluid contacts to have finer grid cells for tracking the movement of water and gas fronts accurately, and to study its impact on oil recovery and water production profile.

Four different grid sizes defined in x- y- and z-directions (24×14×24, 43 x21 x24, 57×28×24, and 71×35×24) were evaluated and based on the water breakthrough time, the simulation run time and observed field production profiles, the best grid size was selected.

3.1.4 Model initialization

Initialization of the model was performed to ascertain that the average properties, pore volume and pressure and saturation distributions in the generic system gave acceptable Stock Tank Oil-In-Place (STOIIP) and Gas-Initially In-place (GIIP). The key determinant conditions are the values of the STOIIP and GIIP. The standard deviation of ±10 MMSTB from the mean value was selected for the STOIIP, which is less than the acceptable margin of error within the Niger Delta.

3.1.5 Simulation Constraints

The Constraints applied to the reservoir model are

- Initial production rate of 2000stb/day
- Minimum BHP 1000psi
- Maximum allowable water cut of 80%

3.1.6 Sensitivity analysis

This analysis was performed by simulating the reservoir model using the selected SRM to determine reservoir properties with significant impact on the production profiles. Certain parameters show little or no impact when changed from their minimum to maximum level. These parameters were fixed at their base case value unlike the heavy hitters that cause abrupt changes in the final response when changes were made between their range limits. The rationale for this is to prune down the number of adjustable parameters for efficient management and to reduce computational costs (Schiozer et al., 2004). The parameters investigated were classified into (i) reservoir and fluid properties, and (ii) well properties.

The following reservoir and fluid parameters were considered as uncertainty for the sensitivity analysis: viscosity, vertical-to-horizontal permeability anisotropy (kv/kh), aquifer strength, oil rim thickness, gas cap size or m factor, oil rim thickness, and permeability.

To ensure that no parameter was left out, the analysis was performed by considering the following two development concepts:

a Oil rim only development concept

b Concurrent oil and gas development concept.

In the oil rim only development concept, only the oil rim column (18 – 81 ft) was perforated. In other words, there was neither production nor injection from the gas cap. For the concurrent oil and gas development, a horizontal well was placed in the oil zone to produce oil and a vertical well was placed in the gas cap to produce gas, this occurs simultaneously.

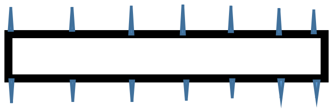
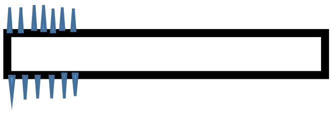
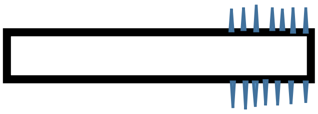
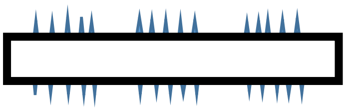
In the second category, horizontal well length, perforation length, well type, well placement, and well orientation were treated as uncertainties.

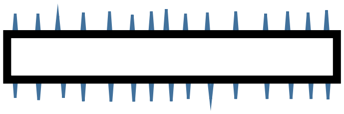
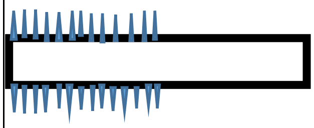
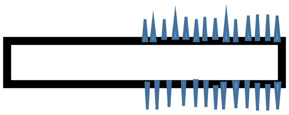
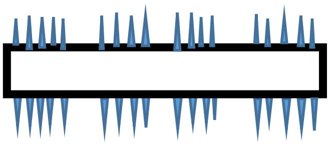
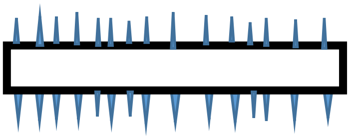
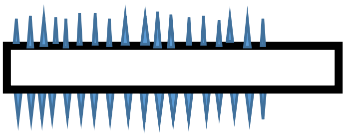
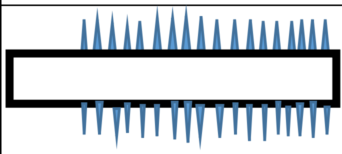
To obtain the optimal horizontal well placement, the following placements positions were investigated:

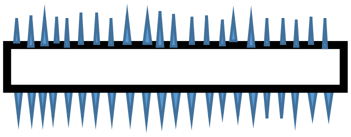
(a) Placement at the water-oil-contact (OWC),
(b) Placement at the mid-oil-rim, and
(c) Well placement near gas-oil-contact (GOC)

To obtain the optimum perforation length, sensitivity analysis was performed for twelve different scenarios of perforation density. Table 3.2 shows the details of 12 perforation schemes analyzed in this research.

Table 3.2 Perforation schemes

Case	Diagram	Description
1		20% perforation density uniformly distributed along the entire length of the horizontal length
2		20% perforated uniformly from the heel to the toe
3		20% perforated uniformly from the toe to the heel
4		50% perforation density distributed at 3 open intervals along the entire well length

5		50% perforation density uniformly distributed along the entire length of the horizontal length
6		50% perforated uniformly from the heel to the toe
7		50% perforated uniformly from the toe to the heel
8		80% perforation density distributed at 3 open intervals along the entire well length
9		80% perforation density uniformly distributed along the entire length of the horizontal length
10		80% perforated uniformly from the heel to the toe
11		80% perforated uniformly from the toe to the heel

12		100% perforation density uniformly distributed along the entire length of the horizontal length

3.2 The need for Uncertainity

Decisions made in the process of reservoir management and field development are always related to risks involved as a result of the uncertainties that are present in the process. Most of the investments are made during the early stage of field development when the uncertainties are greater, and this makes the process even more critical. For a mature field, uncertainties are present, but the decisions are not very critical compared to a green field. There are many uncertainties that can influence the success of an exploration and production project. The most common uncertainties occur in the geological model: volumes in place, continuity, faults, etc. The recovery factor is a function of the reservoir properties and production strategy and the economic model is principally composed of prices. There are also other uncertainties such as technological, operational, and political but they often have a secondary role. Methodologies to measure the impact of uncertainties are frequently not well defined because the impact of these uncertainties varies with time and the amount of information available. Most of studies about risk measurement are related to the exploration phase where the uncertainties due to reservoir performance prediction have little impact and where probabilistic treatment combined with Monte Carlo techniques may be sufficient to reach the required precision (Newendorp, 1975; Garb, 1988). Nevertheless, the importance of considering uncertainties in the decision-making process is unquestionable. Recently, the necessity of better accuracy in the process is becoming more common. Better accuracy is possible due to advances in the hardware and software, and geological modeling. The use of reservoir simulation in the process is also increasing because it increases the reliability, improves the quality of the results, and provides the output of other important variables such as water and gas production, pressure, detailed production strategy.

The use of the surrogate reservoir model (SRM) to demonstrate the uncertainty analysis for oil rim development is presented in the next Chapter.

CHAPTER 4

4.0 UNCERTAINTY ANALYSIS AND QUANTIFICATION

In this chapter, numerical simulation was integrated with classical experimental design and response surface methodology to develop proxy/mathematical equations which relate all the independent variables (reservoir properties) with the dependent variables (production forecast, recovery factor etc.). Classical experimental designs are set of algorithms formulated to achieve different objectives. One of these is for estimating design points based on the numbers of process parameters. In this Chapter we discuss the use of factorial (2-Level) and Box-Behnken (3-Level) algorithms for parameter screening and proxy modelling, respectively. All experiments were performed using the numerical model developed in chapter 3. The detail of the modifications to the SRM is discussed in section 4.1.

4.1 Reservoir Configuration and Well Placement

Generally, the configuration of thin oil reservoirs is usually described as doughnut or pancake. There have been numerous field examples of the dynamics and characteristics of these two reservoir configurations. The "doughnut" and "pancake" type schematic diagrams are shown in Figure 4.1. Note that figures labeled a (i) and b(i) show the top-view of the doughnut and pancake type reservoirs, respectively; both indicating the positions of the fluid contacts. The figures labeled a (ii) and b(ii) in Figure 4.1 are the frontal views of the doughnut and pancake type reservoirs, respectively. For the purpose of this work, the doughnut type reservoir was used for performance evaluation and thus, the SRM developed in chapter 3 was modified to capture this peculiarity. A horizontal well was placed between the gas-oil-contact (GOC) and oil-water-contact (OWC) and allowed to produce for 30 years.

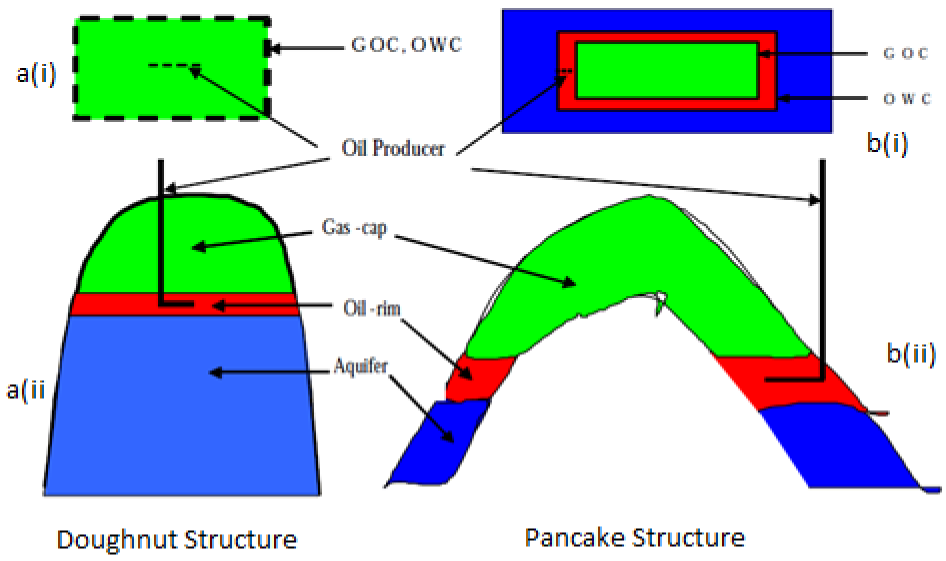


Figure 4.1: Idealised Models of Oil Rim Reservoirs (Source: Lawal et al., 2010)

4.2 Horizontal Well Completion and Optimization

4.2.1 Selection of best well perforation strategy

Well completion optimization for the improvement of the inflow performance of a horizontal well can pose a lot of complexities. When there is a selective completion of the horizontal well, it is not necessary that the productive length is the entire well length. To save cost, an optimum perforation length is determined by performing a sensitivity analysis for various cases of perforation density to determine the optimum perforation density. The Surrogate base model developed is used to assess the impact of perforation density/distribution on oil recovery. In order to determine the optimum perforation density, the SRM is employed to simulate the twelve different completion scenarios using Eclipse black oil simulator as explained in the methodology in chapter 3. Figure 4.2 shows the results of the simulations (more details of the sensitivity analysis are found in the appendix).

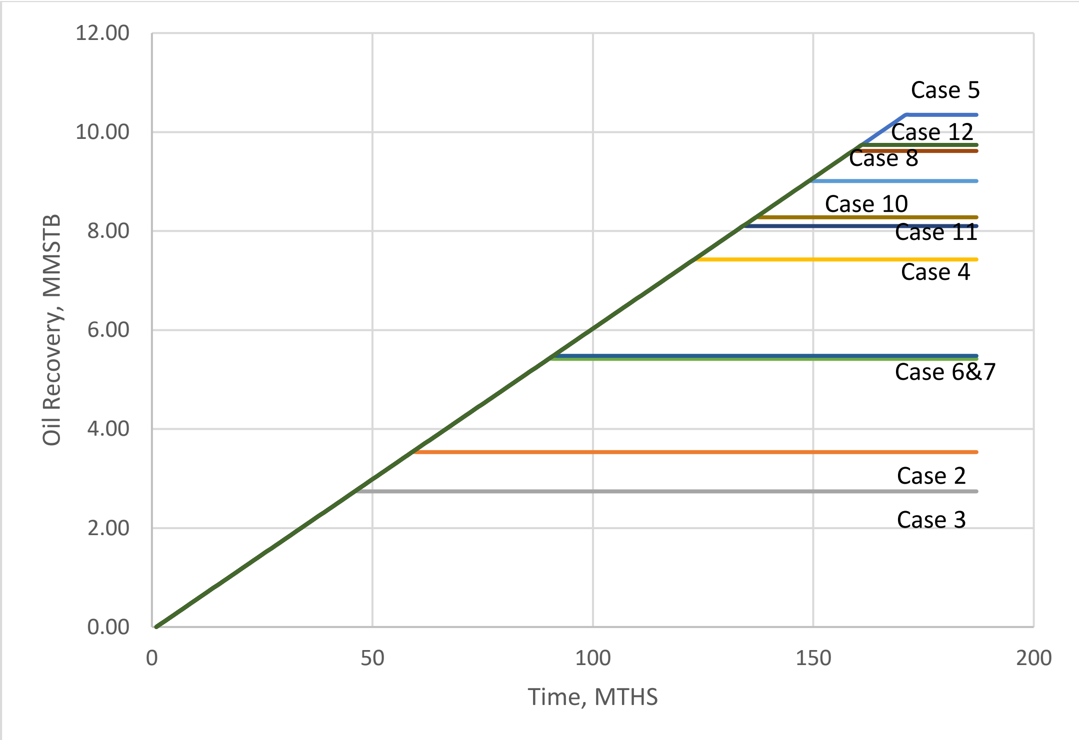


Figure 4.2 Cumulative oil production for the different perforation Cases for the 16 years

It is observed from Figure 4.2 that case 5 which is the 50% perforation density distributed at 3 open intervals along the entire well length has the highest cumulative oil production at the end of the 16 years of simulation. Case 3 has the least cumulative oil produced. For all the cases the trend is very similar, i.e., there is increase in production until at a particular stage the trend becomes constant, at this stage the constraint of the water cut begins to take effect. Once the water cut is 0.9 the production automatically stops, and the trend becomes horizontal, meaning the cumulative oil production is constant. From the sensitivity analysis conducted on the horizontal well completion, it can be deduced that:

- Horizontal well performance is directly affected by the distribution/location and length of the perforated intervals.
- The same fraction length uniformly perforated across the entire length of the well yields higher oil production when compared to when perforated length is concentrated at the toe or heel.
- Production of oil is slightly higher for the same perforation length concentrated at the heel than at the toe.
- The higher the length of fraction perforated the less dependent is the production on the distribution.
- The more uniform the distribution of the perforations along the entire length of the reservoir, the lower the gas oil ratio(GOR)

From the results obtained, the completion type in case 5 will be used for further analysis and simulations.

4.2.2 Selection of best well placement strategy

The performance of horizontal well based on oil recovery at different oil rim heights was simulated for 10 years to evaluate well placement. Three placement options were evaluated in this study based on cumulative recovery; and the option with highest oil recovery and lowest cumulative water production was selected for uncertainty analysis. These options include:

(i) Well placement near the gas-oil-contact (GOC).

(ii) Well placement near the oil-water-contact (OWC).

(iii) Well placement mid-way between the GOC and OWC (conventional)

Figure 4.3 shows the results for the three placement strategies evaluated in this work. It was observed that oil rim height presents significant uncertainty for the oil recovery. As the height of the oil rim increased, the higher the oil recovery obtained from all the strategies. However, for a fixed oil rim height, placing the horizontal well near the OWC recorded higher recovery than placement at the middle of the rim or near the GOC. The horizontal well placed near the OWC for an 80-ft oil rim height appears to give the highest cumulative oil recovery and will be considered for further evaluation.(Details of the various sensitivity analysis carried out can be found in the appendix)

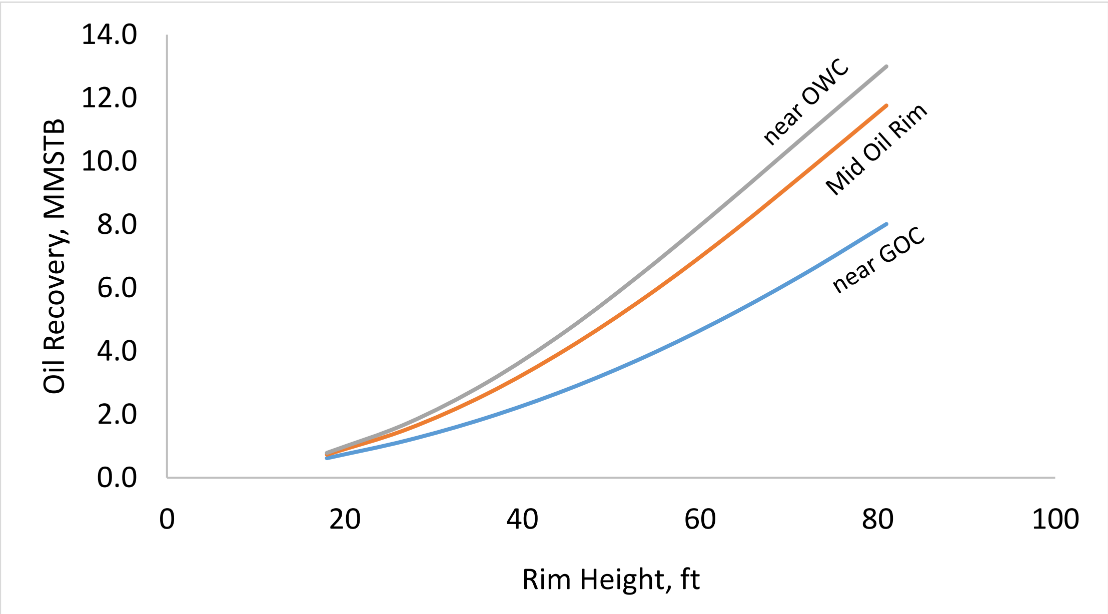


Figure 4.3 Performance of horizontal well based on Oil recovery at different Oil Rim Heights after 10 years of simulation.

4.2.3. Impact of horizontal permeability on oil recovery

As shown in figure 4.4a the recovery increases with permeability for a fixed oil rim height. Therefore, horizontal permeability was observed to have significant impact on cumulative production from our analysis. This factor was incorporated in all simulations to optimize the oil-rim development.

To evaluate the best well placement for purpose of long-term field development, 30-year simulations were run for a fixed permeability (1000 mD) and Oil rim height (80 ft). The choice of 1000 mD was evident in Figure 4.4a where a further increase from 1000 to 2000 mD resulted to a fractional change in cumulative recovery for a horizontal well placed at the mid-oil rim. Figure 4.4b shows the evolution of cumulative recovery for various placement strategies with a permeability of 1000 mD. These results confirmed the observations from the 10-year simulation runs. It is evident that placing the horizontal well near the OWC yields highest recovery efficiency with about 17 MM STB recoverable reserves relative to other strategies evaluated in this study.

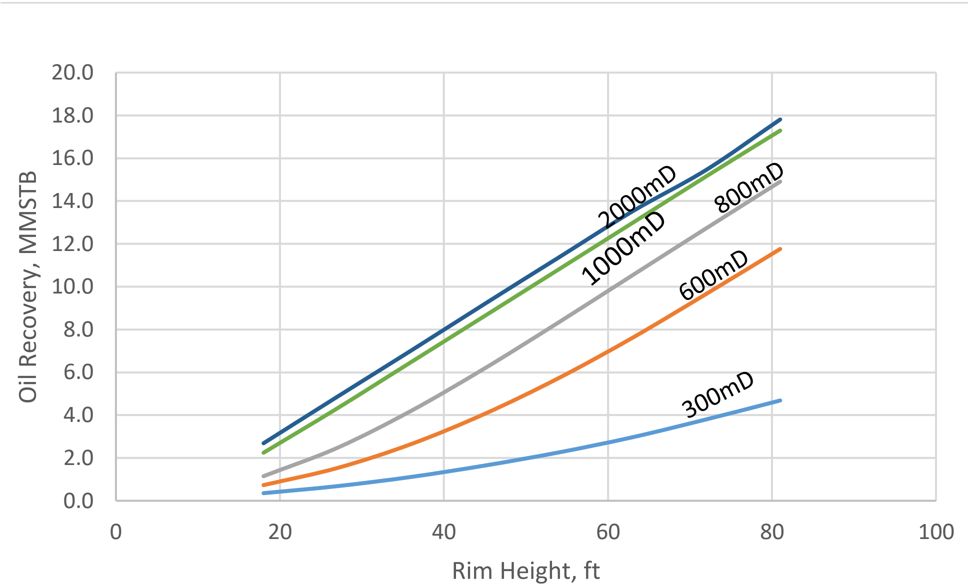


Figure 4.4a Cumulative production for different reservoir permeabilities and 10 years of simulation

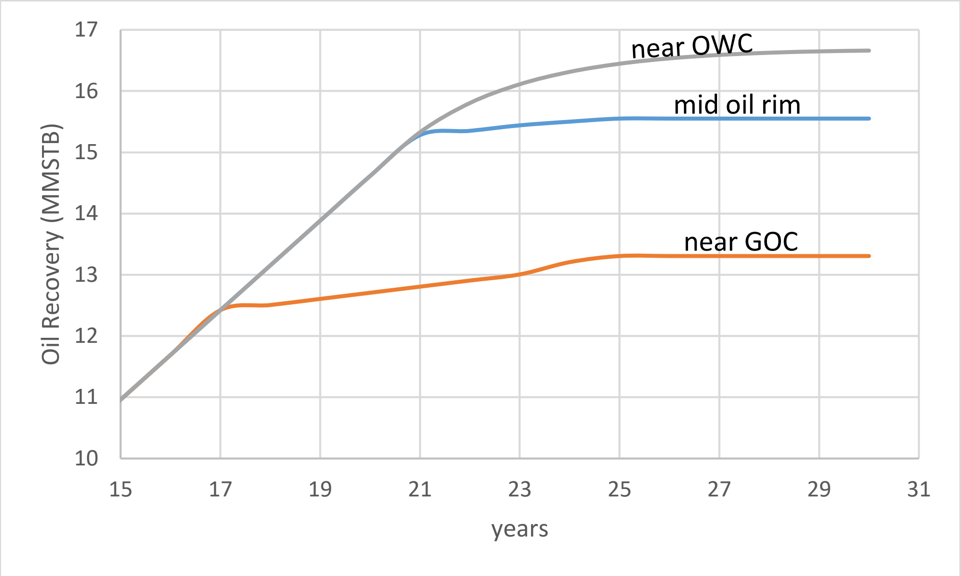


Figure 4.4b Cumulative production for different well placement strategies for 1000 mD and 30 years of simulation

4.3 Uncertainty analysis

In deciding whether or not to go for a particular project, a choice will have to be made between different concepts of field development. A thorough understanding of the volumetric uncertainty and its range estimation are paramount input for risk mitigating action. In most reservoirs, there is always some degree of uncertainty associated with it, due to the fact that most reservoirs are complex/heterogeneous. Uncertainty arises due to lack of knowledge and understanding of the reservoir. Uncertainty analysis has become increasingly important in reserves estimation and in field development optimization. The optimal valuation and exploitation of a field requires a realistic reservoir description, and a rigorous quantification of uncertainty in the model so as to construct a realistic reservoir model and reduce uncertainty. Evaluation of the complete range of uncertainty requires the quantification and storage of the different structural scenarios and geological models. Identification of important uncertainty elements and fixing of the less impactful ones. Knowledge of the required action after identification is paramount in order to reduce the uncertainty to an acceptable level; this will require refining the interpretation, model refinement and data gathering. All estimated reserves have some degree of uncertainty or probability distribution as a result of the amount of unreliable production data available at the time of estimate and on the interpretation.

4.3.1 Parameter screening

The regular 2-level experimental design was deployed to identify "heavy hitters" associated with different reservoir development strategies. Using the parameters listed in Table 4.1, a total of 16 experiments were performed for each option implemented using the SRM with horizontal well near the OWC. Table 4.2 presents the design matrix and the response obtained based on numerical simulation in Eclipse software. Analysis of the data in Table 4.2 was carried out to determine the contribution of each uncertainty factor following the significant test for the regression used in the analysis of variance (ANOVA). The two hypotheses used for the test are as follows.

a. The null hypothesis: all treatments are of equal effect:

$$H_o: \beta_1 = \beta_2 = \beta_k = 0 \qquad (4.1)$$

b. The alternative hypothesis: some treatment is of unequal effects:

$$H_1: \beta_j \neq 0 \quad for\ at\ least\ one\ j. \qquad (4.2)$$

To reject the null hypothesis $H=$ 0 at least one of the variables explains significantly the variability observed in the response so that the model is valid. Figure 4.5 shows the results obtained for all the options evaluated expressed in a Pareto chart. It was observed that, the horizontal permeability, well lateral length, size of the oil rim, fluid viscosity and gas cap size have significant impacts on oil recovery after 20 years of simulation.

Table 4.1 Model Uncertainty parameters and their range of values

Oil rim parameters	Low	Mid	High
Height(ft)	30	55	80
Permeability(mD)	500	1000	1500
Viscosity (cP)	0.5	1.25	2
Bottom Hole Pressure(psia)	600	900	1200
Kv/Kh(dimensionless)	0.001	0.036	0.07
Well Length (ft)	600	650	800
Gas cap size, m-factor(dimensionless)	0.5	2.25	4

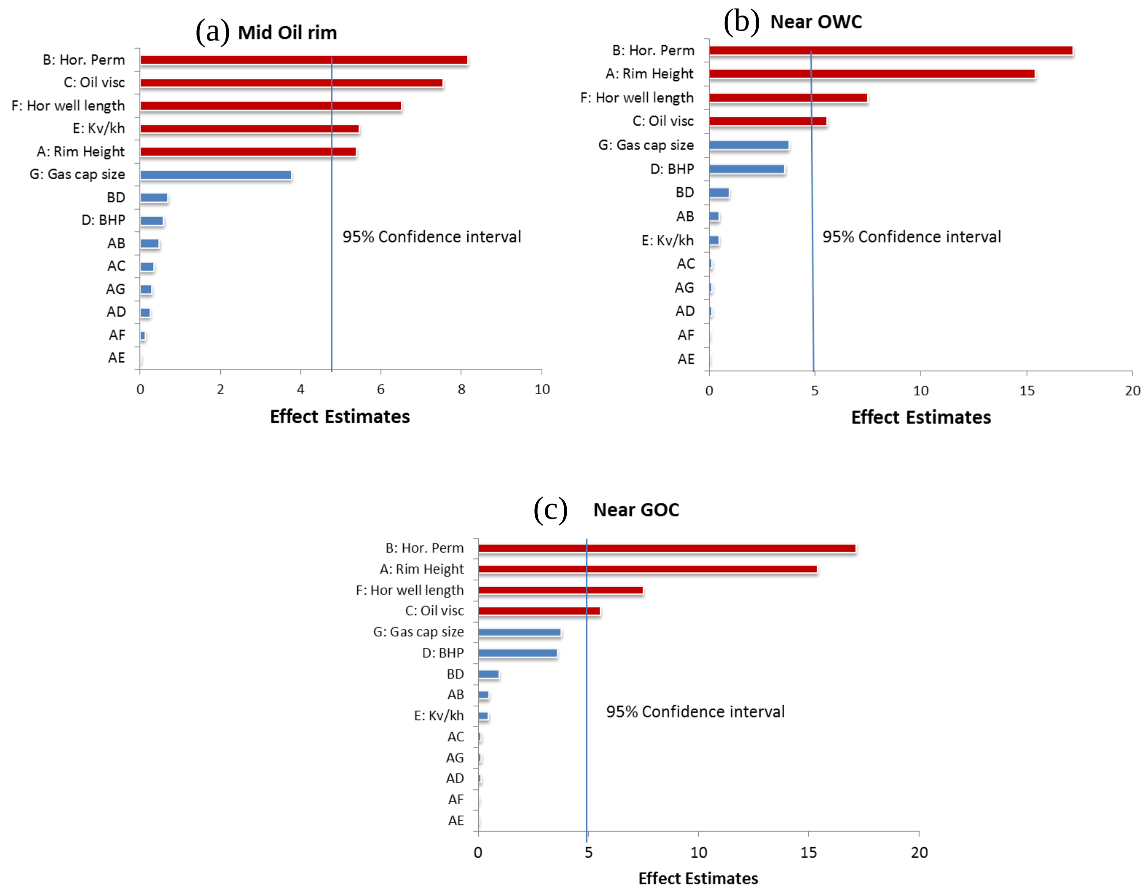


Figure 4.5: Pareto chart showing the impact of parameters on oil recovery for different development options after 20 years of simulation. (a) Shows the horizontal well located at the middle of the rim (b) shows the horizontal well located near the OWC(c) shows the horizontal well located near the GOC.

4.4 Proxy model development

For practical applications in realistic field cases, the bottom-hole pressure (BHP) and vertical-to-horizontal permeability anisotropy ratio, k_v/k_h, were included in the uncertainty analysis. These two parameters were not significant according to the Pareto Chart of Figure 4.5. However, for the development of most representative surrogate model, there is need to include them to avoid leaving some uncertain parameters behind. The overall increase in number of experiments as a result of this inclusion was offset and taken care of by the judicious selection of appropriate experimental design used for this task.

4.5 Design of Experiment

The DOE is a way of planning experiments carefully in advance so as to ensure valid and objective results. The goal here is to select best design without compromising the efficiency. There are different types of design of experiment for purpose of developing mathematical models and for optimization purposes. Occasionally, classical experimental designs are characterized by poor sampling especially when the ranges of uncertainties are too close. By using these designs (response surface designs) often resulted to poor proxies due to poor navigation within the sample space (Arinkoola et al., 2015). In this study, a uniform experimental design was developed by modifying the Latin Hypercube design and implemented for parameter sampling, while response surface methodology was adopted for model development. The design matrices with responses are presented in Tables 4.2 and 4.3 for the weak and strong aquifers, respectively.

Table 4.2: Recovery under uncertainty (Weak Aquifer Case)

Height (ft)	Perm (mD)	Visc (cP)	BHP (psi)	k_v/k_h	Well Length (m)	Gas Cap Size m-factor	Recovery (MMSTB)

30	500	0.5	600	0.001	600	0.5	10.86
43	767	0.9	760	0.019	653	1.4	7.35
57	1033	1.3	920	0.038	707	2.4	8.97
70	1300	1.7	1080	0.056	760	3.3	15.24
33	567	0.6	640	0.006	613	0.7	10.32
47	833	1	800	0.024	667	1.7	7.83
60	1100	1.4	960	0.042	720	2.6	11.22
73	1367	1.8	1120	0.061	773	3.5	17.25
37	633	0.7	680	0.010	627	1.0	7.47
50	900	1.1	840	0.029	680	1.9	8.22
63	1167	1.5	1000	0.047	733	2.8	12.24
77	1433	1.9	1160	0.065	787	3.8	19.41
40	700	0.8	720	0.015	640	1.2	7.26
53	967	1.2	880	0.033	693	2.1	8.82
67	1233	1.6	1040	0.052	747	3.1	13.92
80	1500	2	1200	0.070	800	4.0	21.06

Table 4.3: Recovery under uncertainty (Strong Aquifer Case)

Height (ft)	Perm (mD)	Visc (cP)	BHP (psi)	k_v/k_h	Well Length (m)	Gas Cap Size m-factor	Recovery (MMSTB)
30	500	0.5	600	0.001	600	0.5	10.659
43	767	0.9	760	0.019	653	1.4	8.844
57	1033	1.3	920	0.038	707	2.4	10.296
70	1300	1.7	1080	0.056	760	3.3	18.678
33	567	0.6	640	0.006	613	0.7	11.187
47	833	1	800	0.024	667	1.7	9.504
60	1100	1.4	960	0.042	720	2.6	13.827
73	1367	1.8	1120	0.061	773	3.5	21.285
37	633	0.7	680	0.010	627	1.0	8.712
50	900	1.1	840	0.029	680	1.9	10.032
63	1167	1.5	1000	0.047	733	2.8	15.048
77	1433	1.9	1160	0.065	787	3.8	23.925
40	700	0.8	720	0.015	640	1.2	8.58
53	967	1.2	880	0.033	693	2.1	10.824
67	1233	1.6	1040	0.052	747	3.1	17.061
80	1500	2	1200	0.070	800	4.0	25.806

Tables 4.4 and 4.5 are the ANOVA tables for both model and factor selected in the weak and strong aquifers cases. The model F-value of 369 and 7971 for weak and strong aquifer cases implies the model is significant. It shows that there is only a 0.01% chance that a "model F-value" this large could occur due to noise. Values of "Prob > F" less than 0.05 indicates that the model terms are significant. In this model A, B, C, D, E, F and G are significant in both cases of the weak and strong aquifers. Also, the interactions, AB, AC, AD, AF, AG, BD, and ABD are significant in both cases at the 90% confidence limit. The final equations are presented as Equation 4.3 and Equation 4.4 for the weak and strong aquifer systems, respectively. The correlation coefficients for the two model equations for the weak and strong aquifer systems are 0.998 and 1.00, respectively.

Figures 4.6 and 4.7 are parity plots for the two models, respectively. These graphs represent plots of the predicted production forecast versus the actual experimental values of reserves. If the prediction methods were a perfect fit of the experimental data, then all of the points would lie on the $x = y$ line.

Table 4.4: Analysis of Variance of Cumulative Recovery for Oil Rim Model Development (Weak Aquifer

Source	Sum of Squares	DF	Mean Square	F Value	Prob > F	
Model	297.75	14	21.27	369.23	0.0408	significant
A (Height)	9.46	1	9.46	164.16	0.0496	
B (Permx)	4.16	1	4.16	72.25	0.0746	
C (Viscosity)	7.78	1	7.78	135.14	0.0546	
D (BHP)	22.75	1	22.75	395.02	0.032	
E (Kv/Kh)	27.41	1	27.41	475.79	0.0292	
F (Well Length)	42.38	1	42.38	735.77	0.0235	
G (Gas cap size)	14.86	1	14.86	258	0.0396	
AB	51.62	1	51.62	896.25	0.0213	

AC	1.7	1	1.7	29.57	0.1158	
AD	18.79	1	18.79	326.25	0.0352	
AF	10.6	1	10.6	183.94	0.0469	
AG	5.9	1	5.9	102.52	0.0627	
BD	39.69	1	39.69	689.06	0.0242	
ABD	40.64	1	40.64	705.57	0.024	
Residual	0.058	1	0.058			
Cor Total	297.81	15				

Table 4.5: Analysis of Variance of Cumulative Recovery for Oil Rim Model Development (Strong Aquifer)

Source	Sum of Squares	DF	Mean Square	F Value	Prob > F	
Model	486.1	14	34.72	7970.88	0.0088	significant
A (Height)	14.15	1	14.15	3249	0.0112	
B (Permx)	2.89	1	2.89	663.06	0.0247	
C (Viscosity)	14.78	1	14.78	3393.06	0.0109	
D (BHP)	48.25	1	48.25	11077.56	0.006	
E (Kv/Kh)	31.1	1	31.1	7140.25	0.0075	
F (Well Length)	64.57	1	64.57	14823.06	0.0052	
G (Gas cap size)	15.68	1	15.68	3600	0.0106	
AB	69.98	1	69.98	16065.56	0.005	
AC	6.37	1	6.37	1463.06	0.0166	
AD	31.66	1	31.66	7267.56	0.0075	
AF	30.19	1	30.19	6930.56	0.0076	
AG	12.01	1	12.01	2756.25	0.0121	
BD	74.75	1	74.75	17161	0.0049	
ABD	69.71	1	69.71	16002.25	0.005	
Residual	4.36E-03	1	4.36E-03			
Cor Total	486.1	15				

The model equations are:

$$\begin{aligned} Recovery\ (Weak\ Aquifer) = {} & -34.302 + 0.861A + 0.018B - 0.027C + 0.016D + 37.934E \\ & +0.034F - 1.314G - 5.2662E - 0.004AB + 0.017AC \\ & -5.695e-004AD - 3.25e-004AF + 0.013AG - 1.287e-005BD \\ & +4.250e-007ABD \end{aligned} \tag{4.3}$$

and

$$
\begin{aligned}
Recovery(StrongAquifer) = {} & -7.276 + 1.172A + 0.022B - 0.59C + 0.0209D + 40.413E + 0.050F \\
& -1.654G - 6.682e - 0.004AB + 0.033AC - 7.441e - 0.004AD \\
& -5.494e - 0.004AF + 0.019AG - 1.620e - 0.005BD \\
& +5.566e - 007ABD
\end{aligned} \tag{4.4}
$$

The terms in Equations 4.3 and 4.4 are defined as:

A = height of the oil rim

B = horizontal permeability (Permx)

C = oil viscosity (Viscosity)

D = bottom-hole pressure(BHP)

E = horizontal-to-vertical permeability anisotropy ratio (Kv/Kh)

F = length of the horizontal well (Well Length)

G = size of the gas cap (m)

AB = A×B

AC = A×C

AD = A×D

AF = A×F

AG = A×G

BD = B×D

ABD = A×B×D

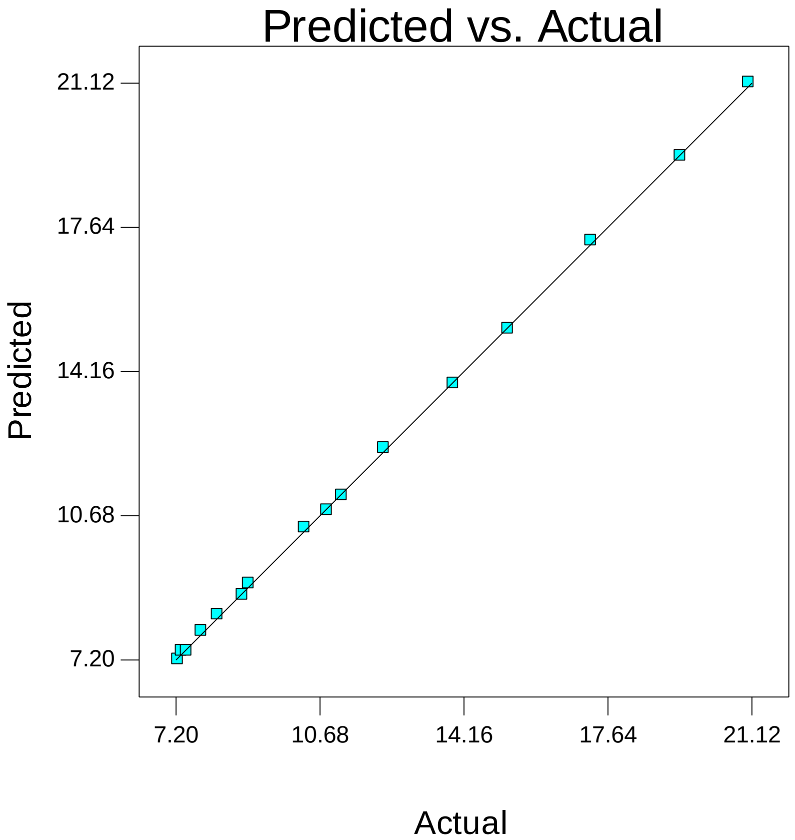


Figure 4.6: Comparison of the actual and predicted reserves (strong aquifer case)

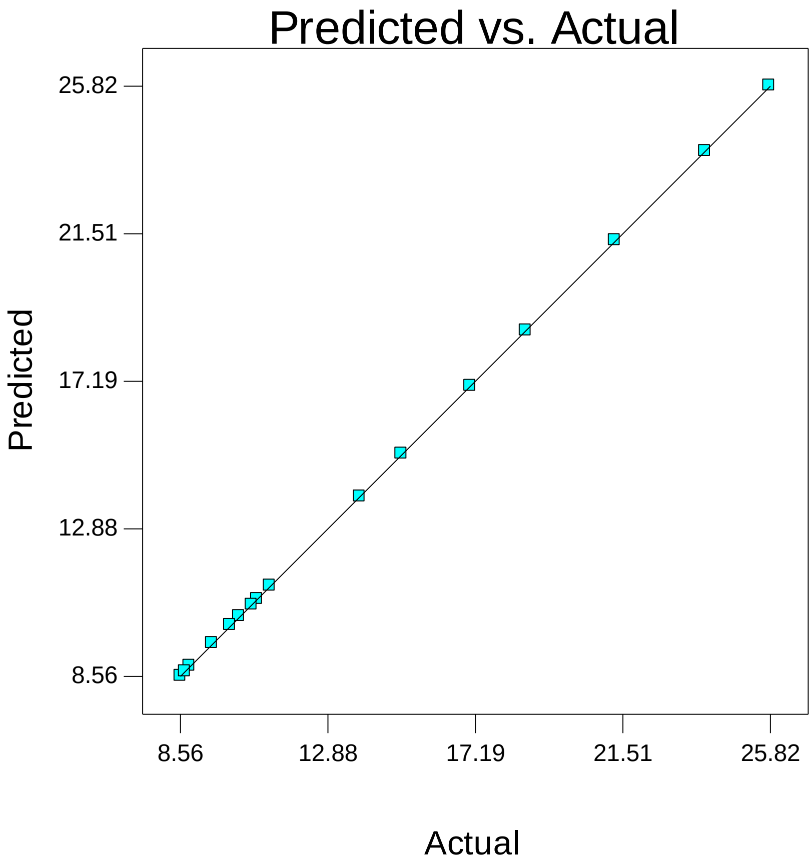


Figure 4.7: Comparison of the actual and predicted reserves (Weak aquifer case)

4.6 Validation of response surface models

To assess the validity and accuracy of the response surface models, the estimates from equations (4.3) and (4.4) were compared to the recovery from history matched oil rim Reservoir A in the Niger Delta. Reservoir A has a rim thickness ranging from 10 – 80 ft, horizontal permeability from 100 – 2000 mD, viscosity from 0.3 – 1.3 cp, oil gravity from 20 – 40 ^{o}API, gas cap size, m-factor from 0.2 - 5 (dimensionless); and aquifer strength ranging from 1 – 100. The history-matched model of Reservoir A was used for the forecast after 30 years under the following conditions: oil rim height, H=80 ft, horizontal permeability, Permx=1500 mD, viscosity=2 cp, BHP = 1200 psi, k_v/k_h= 0.070, well horizontal length = 800 m and gas cap size of 4.2. Figure 4.8 shows the comparison of the actual field oil recovery with the model prediction. The results indicate that the developed mathematical models captured the field oil recovery very well and can be used to provide information to support proper management of the field.

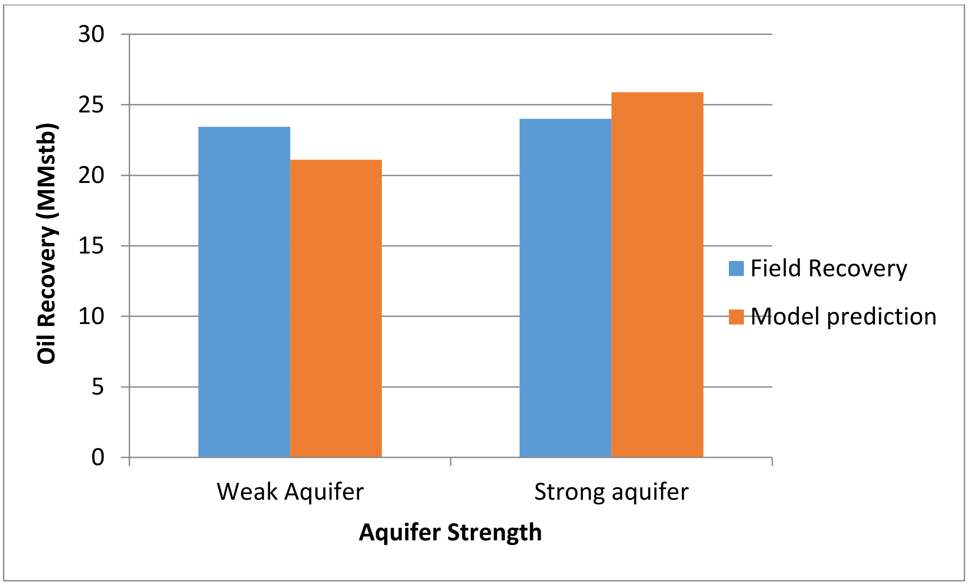


Figure 4.8: Comparison of oil recovery from actual Reservoir A and surrogate model prediction

4.7 Uncertainty quantification using Monte Carlo simulation

This is a technique applied to capture risk and uncertainty impact in project management, financial and various other forecasting projects. The probability distribution of outcomes is produced by using the probability distribution of the input data. The Monte Carlo technique (Hammersley and Hands comb, 1983) was used to combine the uncertain attributes and to generate values for model input variables. One million iterations were made while assuming the uniform distribution functions for the input parameters. The risk curves generated were in terms of cumulative oil production.

Figure 4.10 shows the cumulative probability distribution and sensitivity of different parameters on the forecast reserves. The impact of the major uncertain parameters for the two aquifer systems was quantified using the Monte Carlo simulations. It clearly shows that the horizontal well length is the dominant factor in both aquifer cases. The spread in production profiles (P10–P90 range) from the deterministic forecast volume (P50) from the two aquifer cases is shown in Table 4.6. The table also indicates the range of the uncertainty in the forecast.

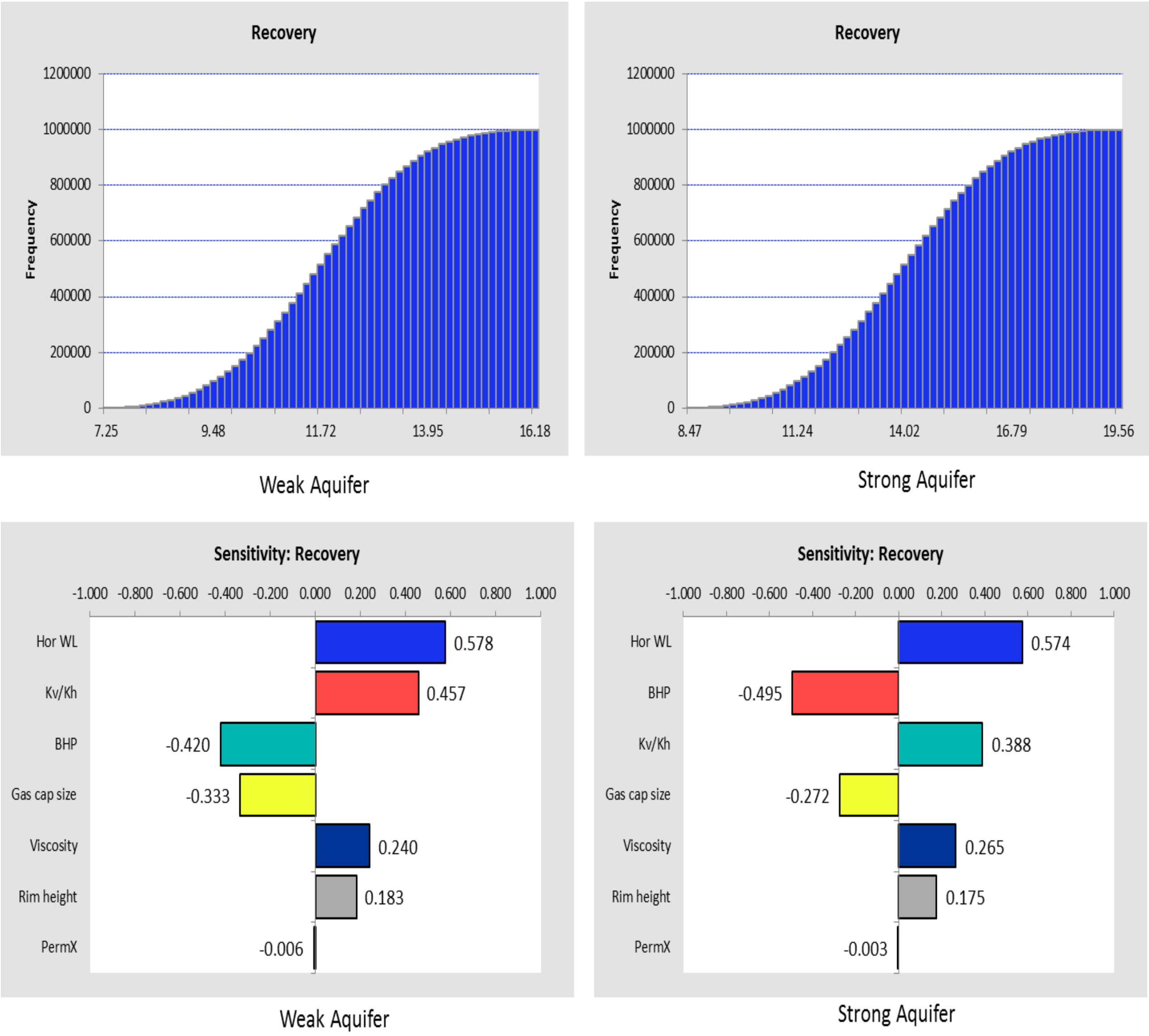


Figure 4.10: Recovery forecast and parameter sensitivity for both weak and strong aquifer cases

Table 4.6: Production Forecast distribution

Probability	Weak aquifer forecast (MMBBL)	Strong Aquifer Forecast (MMBBL)
P0	5.95	6.64
P10	9.59	11.38
P20	10.31	12.26
P30	10.84	12.92
P40	11.29	13.49
P50	11.72	14.03
P60	12.15	14.56
P70	12.61	15.13
P80	13.13	15.78
P90	13.83	16.64
P100	17.49	21.18

4.8 Concluding remarks on proxy mathematical model development

The results show that numerical simulation using surrogate model is suitable for the evaluation of oil rim development instead of running full field model. Selection and optimal placement of wells within oil rim reservoirs are critical for the reservoir development and management. Placing the well just above the oil-water contact (OWC) offers more economic value than the placement of the well at the middle of the rim, or near the gas-oil contact (GOC). It is shown that horizontal permeability was the dominant reservoir factor that controlled the recovery from thin column reservoirs in the short term. However, in the long term, the lateral length as well as the reservoir anisotropy exhibited greater influence on the reserves forecast.

The use of modern experimental design method such as the uniform design as demonstrated in this study offer more reliable proxy model for uncertainty quantification. The impact of the uncertainty on the forecast reserves was demonstrated using the Monte Carlo simulation. The posterior summaries of the parameters alongside their uncertainties given by P0, P10, P50, P70, and P90 quartiles were obtained. The results show that the strength of the aquifer plays an important role in the recovery of oil from thin column reservoirs. The approach used in this study and the examination of the different uncertainty probabilities can serve as framework for evaluating similar oil rim reservoirs.

CHAPTER 5

5.0 FIELD DEVELOPMENT PLAN

In this chapter, an integrated reservoir management study is discussed. The case study is patterned after Reservoir A, a thin oil rim reservoir located in the Niger Delta. The study demonstrated the need for an integrated approach as the key to the successful development of thin oil rim reservoirs.

Note: The material presented in this chapter has been published in a peer reviewed journal (Aladeitan et al, 2020). The journal publication closely mirrored the content of the chapter.

5.1 Integrated Reservoir Management

The development of thin oil rim reservoirs over the years has been characterized by low oil recovery factors due to water and or gas coning. The oil rim reservoir studied in this work is attractive because it contains several hundred million barrels of oil and about one trillion standard cubic foot of gas in-place. The complexity of the geology and heterogeneities of the Niger Delta oil rim makes its development and reservoir management a challenging task. This chapter presents a study of the systematic, integrated reservoir management approach for developing an oil rim reservoir (Reservoir A) in the Niger Delta. Seven reservoir development strategies including oil only depletion, produced gas reinjection, water injection and gas cap blow down are evaluated using numerical reservoir simulation; and the optimum production strategy is selected. The evaluation of the best strategy includes optimization of well placement and economic analysis of the cumulative oil and gas recovery from the various rim development strategies. The Net Present Value (NPV), Internal Rate of Return (IRR), and Discounted Payout Period were the profitability indices used in the economic analysis. The results show that well placement has a significant impact on water and gas coning and on oil rim recovery. Availability of injection water and gas must be considered in the integrated reservoir development plan. Proper reservoir management is achieved when the reservoir producibility factors, operational constraints, and economics of the project are considered in the field development planning.

5.1.1. Review of previous studies

Production from thin oil rim reservoirs is challenging because excessive water production and early gas breakthrough in production wells result in low recovery factors. The prevalence of water and gas coning in these reservoirs is attributed to their thin bedded nature. Complications to reservoir development arise when such reservoirs are sandwiched between strong aquifers and large gas caps. However, majority of these reservoirs are of economic value due to their lateral extents with substantial volumes of oil and gas reserves regardless of their small thicknesses. Several strategies have been developed to mitigate these problems for effective and efficient exploitation of the oil rim assets. A few publications are presented in this work to highlight some of the problems and suggested solutions for developing oil rims. Several studies on production of oil rim reservoirs indicate that the recovery factor is a function of the rim height, residual oil saturation, well type, well spacing and distance between the fluid contacts (Kydland et al., 1993; Cosmo and Fatoke, 2004; Ehlig-Economides, 1996, and Kabir et al., 2008). In 1993, Kydland et al. studied well placement in a 22-26m thick oil rim zone in the Troll field. They reported maximum oil production by completing the wells in the lower part of the oil rim, close to the oil-water-contact; and implemented a gas injection scheme to control the aquifer inflow into the oil zone. Satter et al. (1994) reported the need for an integrated reservoir management team to develop thin oil rim reservoirs. Their team-based approach recommended the integration of geosciences and engineering professionals, tools, technology, and data to produce oil rim reservoirs. In a related work, Evans (2000) suggested decision analysis as a framework for conducting integrated reservoir management by combining geological studies and environmental impact assessment. Evans proposed that decision analysis is a vehicle for the integration of disciplines of reservoir engineering, geochemistry, geological studies, and risk analysis with a view to optimizing the asset net present value. Reservoir characterization is also important in developing thin oil rim reservoirs. Ikomi et al. (2002) reported drilling of side-tracks from existing wells in the Awoba Field X in the Niger Delta. The results of the side-track wells provided an improved understanding of the reservoir characteristics and data on the production performance of the wells in the field. They proposed that this data will be integrated into the field development plan to manage the remaining reserves in Field X. In a study on production optimization, Hasan et al. (2009) indicated significant increase in oil recovery factors in an oil rim reservoir when a binary integer programing, a production optimization technique, was used to set the choke and rates in the production and injection wells. Razak et al. (2010) reported improved oil recovery factors (by 35-48%, which is higher than the theoretical recovery efficiency) in their work by implementing reservoir management strategies tailored to the forces controlling water and gas coning tendencies in thin oil rim reservoirs. They highlighted the impact of force balance changes (coning tendency) by increasing the viscous withdrawal with the use of horizontal wells, coupled with gas re-injection to obtain higher recovery efficiency. Iyare and Marcelle-De Silva (2010) carried out an investigation on well placement using a single-well numerical simulator to study the effect of gas cap and aquifer sizes on production of a thin oil rim reservoir. Their results indicated that placement of the horizontal well below the water-oil-contact (WOC) is more favorable for a large gas cap reservoir; and the well should be placed above gas-oil-contact (GOC) for a reservoir with a small gas cap and large aquifer. Ahmed and

Abrai (2014) carried out a research on the optimum field management plan for a thin oil rim reservoir in the Nile Delta in Egypt. They proposed the use of horizontal wells for production, and gas-recycling/re-injection in the oil zone to impede the bottom aquifer and improve the sweep efficiency. Balogun et al. (2015) employed analytical and simulation methods to study the development of a 3m-thick oil rim reservoir overlain by a huge gas cap in the Niger Delta. They considered two development scenarios, sequential and concurrent oil and gas production; and their results indicated that the development of the oil rim was not economically feasible, and therefore recommended a gas-only development strategy. Ogolo et al. (2017) performed a simulation study of a Niger Delta oil rim reservoir. They used horizontal wells to produce the reservoir and considered gas injection as an option to improve recovery factor and minimize water production. Their study indicated recovery factors of 25-44%. The limitation of their work is the high GOR produced by the horizontal well. A surrogate modelling approach was proffered as a solution to oil rim production optimization (Aladeitan et al., 2019). Their study proposed that surrogate models provide a framework for understanding the reservoir and fluid properties that impact oil production from thin oil rim reservoirs. The study evaluated a few reservoir development strategies to show the impacts and associated uncertainties of the reservoir and fluid properties (e.g., the rim height, reservoir anisotropy, oil viscosity, horizontal permeability, aquifer strengths, and bottom-hole pressure) on production performance and oil recovery from thin oil rim reservoirs.

5.1.2. Scope of integrated reservoir management plan

The literature review of the above-mentioned studies underscore the need for improved well placement, reservoir characterization, water and/or gas injection/re-injection, and production optimization in an integrated reservoir development plan in order to produce thin oil rim reservoirs. In this work, we study well placement, water and gas injection, and production optimization as an integrated reservoir management approach to develop a thin oil rim reservoir (Reservoir A) in the Niger Delta.

5.2 Location of study area and Reservoir Description

The Niger Delta is a major hydrocarbon producing basin in Nigeria, where extensive exploration and exploitation has been going on since the early 1960's after the discovery of oil in commercial quantity in 1956. Reservoir A is located in the coastal swamp of the Niger Delta, some 40km north of the present-day coastline, and about 40km South West of Port Harcourt (Figure 5.1). Its aerial extent spans approximately 30sq km. It was discovered in 1957. The field is characterized by fault lines on the west of the field and mild crestal faulting parallel to the main boundary fault. The field consists of three major fault lines lying almost parallel to each other (Figure 5.2). A major east to west boundary fault bounds the oil rim reservoirs and therefore explains the depositional and structural history of the field. The reservoir is divided into two regions along its Z-axis by a thick shale layer. The reservoir is overlain by a large gas cap and underlain by a large aquifer.

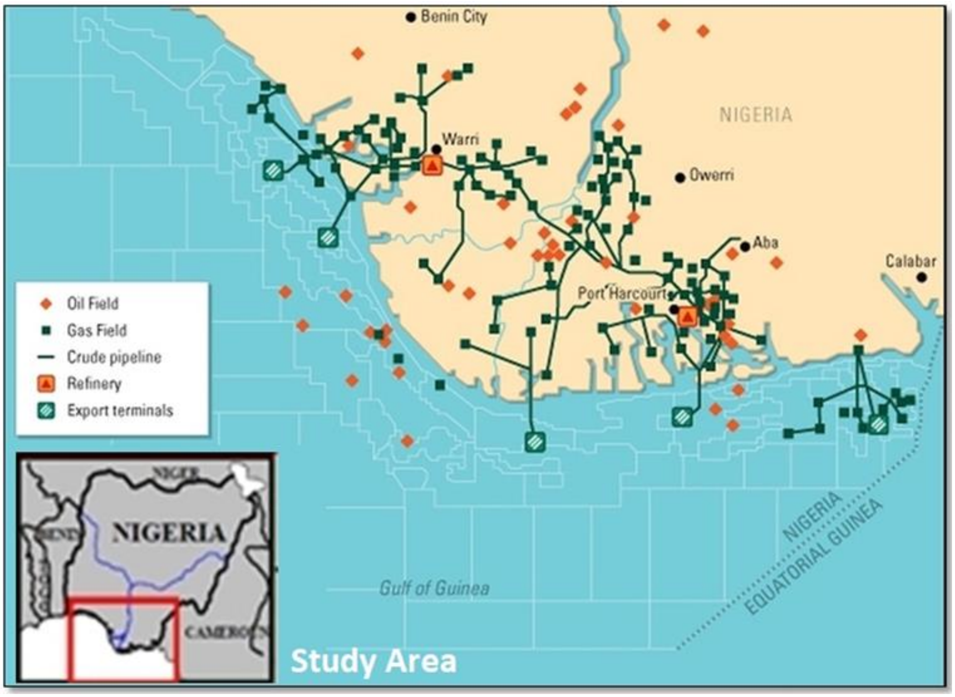


Figure 5.1 Map showing oil and gas fields in the Niger Delta Basin
(Adapted from Platts.com, 2015)

5.3 Integrated study methodology

The challenges of producing from oil rim reservoirs are often enormous because of the coning of gas and water into the reservoir during production which leads to very low recovery factors. The case study considers the development of a thin oil rim zone sandwiched between a large gas cap and a large aquifer thereby complicating its production. To maximize profit, a sound reservoir management plan is developed using reservoir simulation. In our methodology, learnings from the first stage of drilling/production are implemented in later phases leading to higher recovery factors and more cost-effective wells. Challenges encountered, solutions and reservoir development plan at various stages are highlighted in this study.

The methodology of study includes the following procedural steps:

1. Construction of a dynamic reservoir model from a static model
2. Placement and optimization of production and injection well locations in the reservoir
3. Identification of reservoir development strategies

4. Simulation of reservoir production performance for each development strategy

5. Analysis of simulation results to identify technically feasible strategies

6. Economic analysis of technically feasible production strategies

7. Selection of optimum reservoir development strategy based on the cumulative oil and gas recovery and economic analysis.

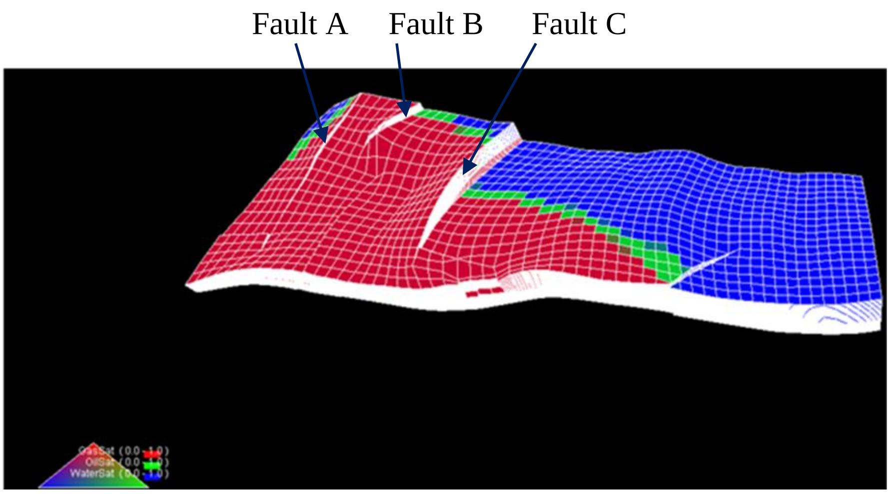


Figure 5.2 Simulation model of Reservoir A. Note three faults and the thin oil rim (green) overlain by a gas cap (red) and an underlying aquifer (blue)

5.3.1 Dynamic reservoir model

A three-phase, three-dimensional, dynamic, black-oil model of Reservoir A in the Niger Delta was built from a static model using a commercial software. The oil rim height is an average of 75ft, and the reservoir is sandwiched between a large overlying gas cap and a large aquifer (Figure 5.2). Table 5.1 summarizes the reservoir, rock and fluid properties used in building the dynamic model. The grid dimensions from the static model was upscaled from 58×18×83 to 58×18×40 in the x, y, and z directions with grid sizes of ΔX= 180ft, ΔY= 50ft, ΔZ= 16ft, respectively. The PVT data and relative permeabilities were derived from correlations using input data obtained from an analog field. The reservoir is divided into two vertical regions separated by a thick-shale layer. After model initialization, the stock tank oil in place (STOIIP) is about 56 million stock-tank-barrels (MMSTB), and the initial gas in place (IGIP) is approximately 966 billion standard-cubic-feet (BSCF).

Table 5.1: Fluid and rock properties of Reservoir A

Parameter	**Value**	**Unit**
STOIIP	56	MMSTB
IGIP	966	BSCF
Average horizontal permeability	1043	mD
Average vertical permeability	10.4	mD
Average Oil Column height	75	ft
Porosity	0.27	fraction
Initial Reservoir Pressure	3976	psi
Connate Water Saturation	0.2	
Water-Oil-Contact (region 1)	8751	ft
Gas-Oil-Contact(region 1)	8671	ft
Datum Depth(region 1)	8750	ft
Pressure at Datum Depth (region 1)	3789	psi
Water-Oil-Contact(region 2)	9363	ft
Gas-Oil-Contact(region 2)	9283	ft
Datum Depth(region 2)	9183	ft
Pressure at Datum Depth(region 2)	3976	psi
Irreducible water Saturation	0.2	
Net-to-Gross ratio	0.82	
Critical Gas Saturation	0.05	

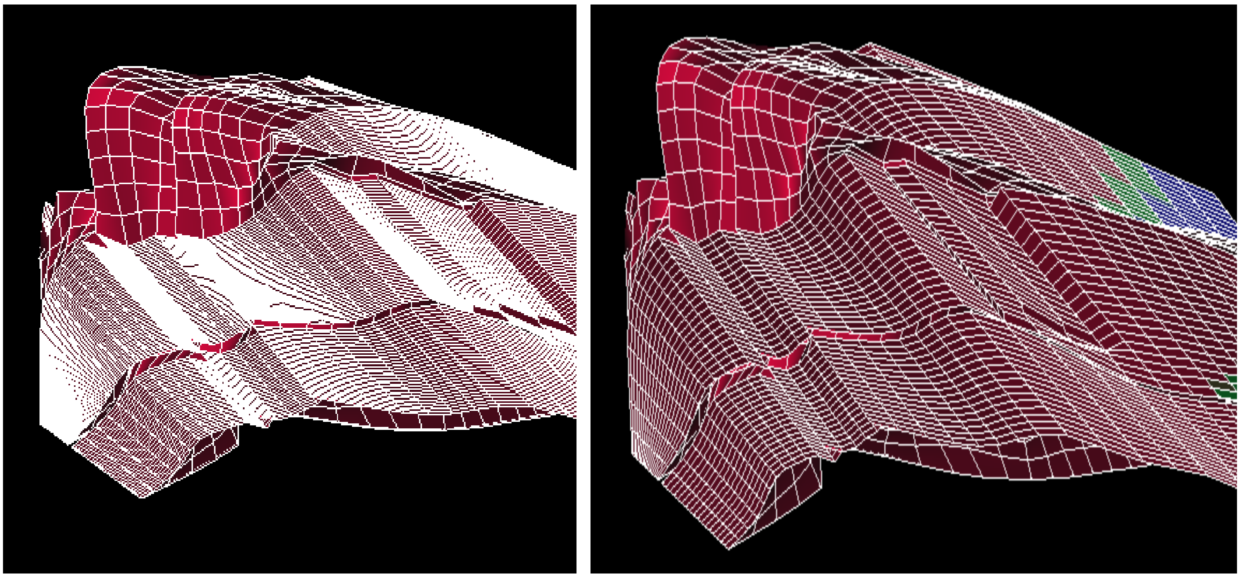
5.3.1.1 Upscaling of static model

Upscaling techniques were developed for flow simulations to transform the detailed description of a geologic model into a coarse reservoir grid. This involves the substitution of a heterogeneous property region consisting of fine grid cells with an equivalent homogenous region. The equivalent single coarse grid inherits an effective property value from the heterogeneous property region of the fine grid system. The goal of upscaling is to obtain a reservoir model that retains the essential features and averaged effective properties from the geologic model. The upscaled model is used to run fluid flow simulations with reduced run times compared to the original fine-grid model. In this work, the original geologic model with grid dimensions of 58×18×83 in the x- y- and z-directions was upscaled to 58×18×40 reservoir flow model. Figure 5.3 illustrates the model upscaling used in the study. The quality of the model upscaling was checked as described in the following section.

5.3.1.2 Model upscaling quality control

To check the quality of the upscaling, waterflooding simulations were conducted. First, two upscaled models were obtained from the fine-grid (58×18×83) geologic model. The upscaling was carried out in the vertical direction only (z-direction) to obtain the two coarse models with grid dimensions of 58×18×40 and 58×18×30, respectively. Upscaling quality check involved simulation of water flooding by drilling thirteen staggard pairs of production and water injection wells. The waterflood was simulated for 50 years to monitor the flood performance using the results of cumulative oil production and water-cut. Figures 5.4 and 5.5 show the results of cummulative oil production and water cut for the three different grid sizes--the fine-grid model with 58×18×83 grid cells, and the 58×18×40 and 58×18×30 upscaled models, respectively.

The results from Figures 5.4 and 5.5 illustrate that the fine-grid model with 58×18×83 grid cells shows highest recovery, lowest water cut, and longest water breakthrough time. After comparing the simulation results and run times of the three upscaled grid systems, the optimum coarse model with 58×18×40 grid cells was selected because of the shorter simulation run time; and the results of the cummulative oil recovery and water cut that are closer to those obtained from the original fine-grid model. This is the model carried forward for the simulations of the integrated field development studies. The upscaled model is shown in Figure 5.3.



a) Original Geologic Grid 58×18×83 b) Upscaled Grid 58×18×40

Figure 5.3 Upscaling of geologic model from 58×18×83 to 58×18×40 reservoir grid

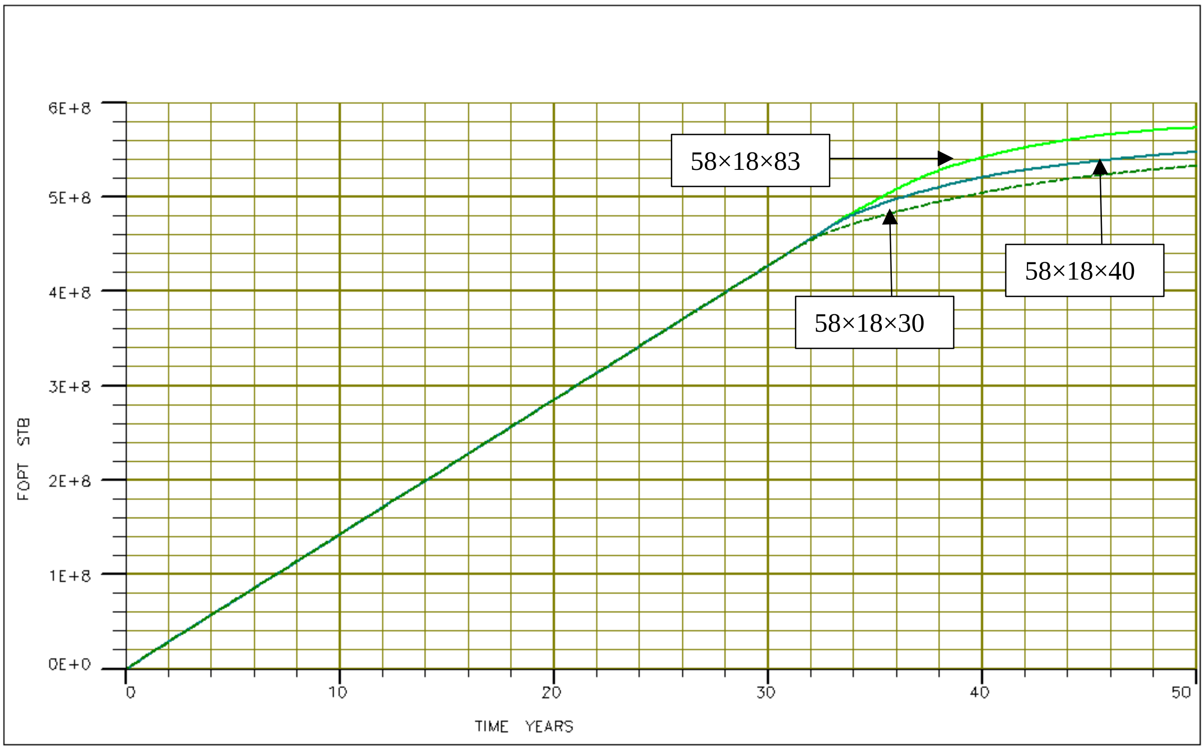


Figure 5.4 Comparison of the cumulative oil production for 50-year waterflood using models with grid sizes 58×18×83, 58×18×40 and 58×18×30

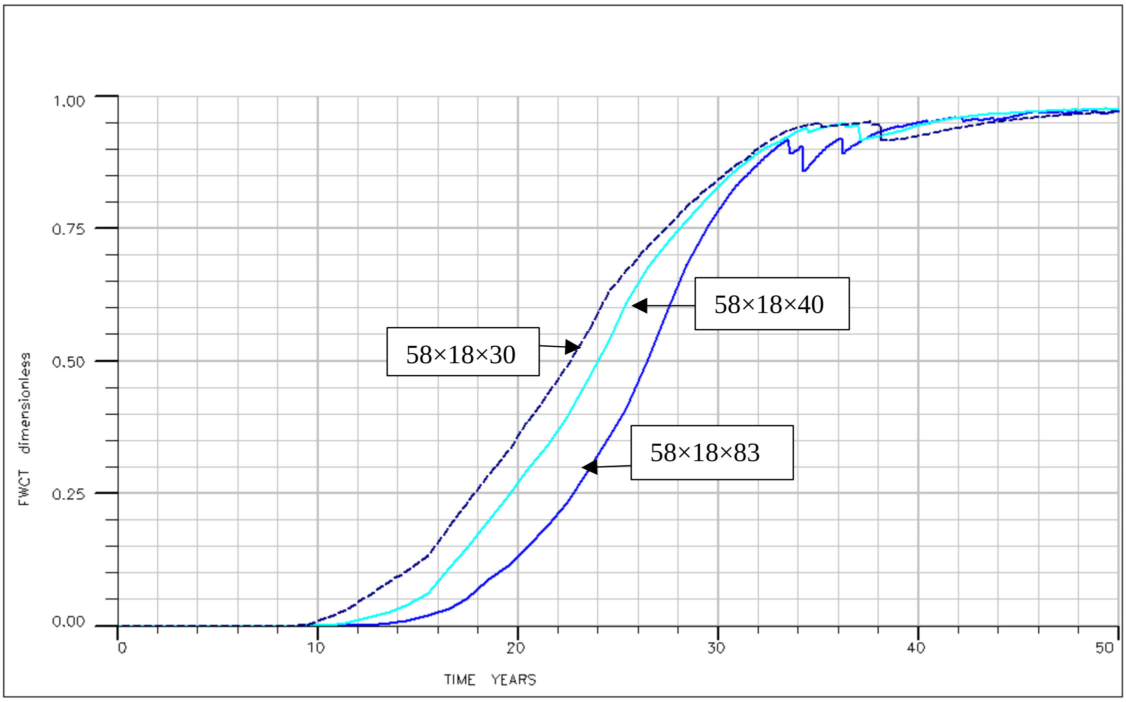


Figure 5.5 Comparison of the field water cut for 50-year waterflood using models with grid sizes 58×18×83, 58×18×40 and 58×18×30

5.3.2 Well placement and optimization

After building the dynamic model as shown in Figure 5.2, the next step of this study was to determine the proper placement of the oil production wells to maximize recovery. The well placement at various stages during the simulation was based on evaluation of the distribution (or map) of porosity-thickness weighted hydrocarbon saturations, i.e., *HphiSo*, defined in Equation 5.1 as a function of the grid block height, net-to-gross ratio, porosity, and oil saturation.

$$HphiSo = Z \times NTG \times \phi \times So \qquad \text{(Equation 5.1)}$$

Where

Z = grid block height (ft), NTG = Net-to-gross thickness (fraction)

ϕ = porosity (fraction)

So = oil saturation (fraction)

For the initial placement, the wells were drilled at locations with high porosity-thickness weighted initial oil saturations, i.e., high *HphiSoi*. In this case, Soi is the initial oil saturation. To optimize the placement of infill-well, a new *HphiSo* map is generated at any time to evaluate the saturations at potential locations of the well. In some cases, the location of a well can be optimized by comparing the well’s cumulative production of oil, water cut or gas-oil-ratio (GOR) from two or three candidate locations. Then, to place the well, the location that gives the highest cumulative oil production, lowest GOR and Water cut is selected. The gas wells are placed in the crestal region of the gas cap using the corresponding porosity-thickness weighted gas saturation (*HphiSg)* maps, where Sg is the gas saturation. Figure 5.6 shows a typical *HphiSo* map used to identify locations of production wells in the model.

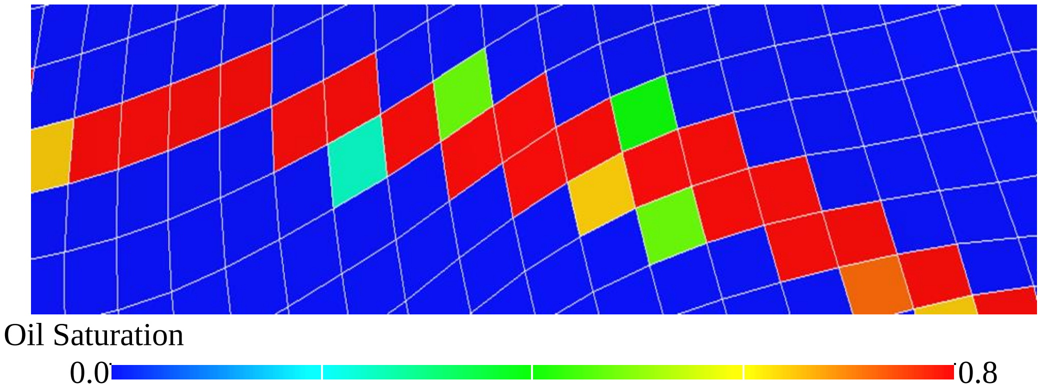


Figure 5.6: Typical map of *HuphiSo* for well placement and optimization

5.3.3 Reservoir development strategies

After model initialization, a 20-year reservoir simulation study was executed. Seven reservoir development strategies were investigated. The strategies included:

Strategy 1: Base Case Production (Base)—only oil is produced from the rim reservoir for the 20-year period of depletion.

Strategy 2: Oil and Gas Concurrent Production (OGCP)—oil is produced from the oil zone while gas is produced concurrently from the gas cap zone throughout the 20-year production period.

Strategy 3: Oil and Gas Sequential Production (OGSP)—oil production is like the Base Case but gas production from the gas cap is introduced after ten years, i.e., simultaneous oil and gas production for the 11th year to the end of production.

Strategy 4: Oil and Produced Gas Reinjection(OGRej)—oil production is like the Base Case but after 5 years, a percentage of produced gas (produced solution gas and the gas coned from the gas cap) is reinjected into the gas cap of the reservoir for pressure maintenance.

Strategy 5: Oil and Produced Gas Reinjection followed by Gas Cap Blowdown (OGRejGB) This strategy is like Strategy 4, but the gas cap is blown down after 15 years of production.

Strategy 6: Oil Production and Water Injection (OPWinj)—oil production is like the Base Case with simultaneous water injection from the start of production.

Strategy 7: Oil Production with Water Injection and Produced Gas Reinjection (OPWinjGRej). This strategy is like Strategy 6 but after 5 years, a percentage of produced gas is reinjected into the gas cap of the reservoir to support the pressure.

5.3.4 Production forecast parameters and constraints

Table 5.2 lists the production parameters and constraints used in the simulation of reservoir performance during the implementation of the seven depletion strategies. The parameters and constraints were defined to reflect common field operating procedure in the Niger Delta. Additional constraints and limiting parameters are described later in the study for specific field development strategies.

Table 5.2: Production forecast constraints and parameters for Reservoir A

Item	**Unit**	**Value**
Oil flow rate	STB/day per well	2000
Gas flow rate	MSCF/day per well	6000
Minimum oil rate	STB/day per well	200
Horizontal well length	ft	1500
Maximum water cut	fraction	0.98
Maximum gas-oil-ratio, GOR	SCF/STB	5000
Simulation Run time	Year	20

5.3.5 Simulation of reservoir performance

Simulation of reservoir performance was carried out for the seven strategies identified in this study for the development of Reservoir A. In each case, six oil production wells (1500ft long horizontal wells) were drilled in the reservoir. The oil wells were produced for 20 years in all cases.

Strategy 1: Base Case Oil Production (Base). For the Base Case, only oil was produced from the oil zone using the six wells completed in Reservoir A. Each well was set at an initial production rate of 2000 STB/Day. The simulation was conducted for 20 years to obtain the reservoir performance under this scenario.

Strategy 2: Oil and Gas Concurrent Production (OGCP). In Strategy 2, the six horizontal oil production wells were completed in the oil leg; and three vertical gas producers were completed in the gas cap zone. The wells came on stream at the same time with an average take off rate of 2000 STB/day per oil well. For the gas wells, the initial offtake rate was set at 6000 MSCF/day per well. All oil and gas wells produced for 20 years.

Strategy 3: Oil and Gas Sequential Production (OGSP). For the OGSP strategy, the oil production wells produced initially at 2000 STB/day per oil well for 20 years. At the beginning of the 11th year, three vertical gas wells were completed and produced from the gas cap with an initial production rate of 6000 MSCF/day per well. The gas wells were produced for the next ten years until the end of the simulation run.

Strategy 4: Oil and Produced Gas Reinjection (OGRej). The oil production wells were operated initially at 2000 STB/day per well. Like the Base Case, the oil producers were operated for 20 years. Note, beginning in the 6th year, 6000 MSCF/day of gas (i.e., produced solution gas and the gas coned from the gas cap) is reinjected into the gas cap of the reservoir. Produced gas reinjection was operated for 15 years.

Strategy 5: Oil and Produced Gas Reinjection followed by Gas Cap Blowdown (OGRejGB)

For the OGRejGB development strategy, Reservoir A was operated for 15 years as described in development Strategy 4. Produced gas of 6000 MSCF/day was reinjected into the Gas cap; however, at the end of 15 years, gas reinjection was stopped, and oil production continued with a blow-down of the gas cap for another 5 years. This simulation was done to evaluate the impact of gas cap blow down on the how to best maximize the asset value of Reservoir A.

Strategy 6: Oil Production and Water Injection (OPWinj)

In this strategy, Reservoir A was operated like the Base Case, i.e., oil was produced from the six horizontal wells with simultaneous water injection from the start of production for 20 years. Strategy 6 (OPWinj) was studied in this work to evaluate the impact of simultaneous water injection on production performance and economics of developing the asset.

Strategy 7: Oil Production with Water Injection and Produced Gas Reinjection (OPWinjGRej)

For the OPWinjGRej strategy, the reservoir was developed majorly as described in Strategy 6; but at the beginning of the 6th year, 6000 MSCF/day of produced gas is reinjected into the gas cap of the reservoir for 15 years to support the reservoir pressure. That is, simultaneous oil production and water injection for 20 years combined with 15 years of reinjection of all produced gas after 5 years from the start of the project.

5.4 Results and Discussion

The results obtained from the production forecasts are discussed in this section. Major observations, including predominant drive mechanisms and operational challenges from the results are also discussed. A comparison of the results from the different development strategies was carried out to determine the best candidate based on the cumulative oil and gas recovery. The results also served as input to the economic analysis presented later in this work.

5.4.1 Strategy 1: Base Case Oil Production

Figure 5.7 shows the results of producing only oil from the oil leg of Reservoir A for 20 years. The predominant drive mechanism in this strategy is the gas cap expansion and water drive. Similarly, some wells shut down after exceeding the water cut limit between the 17th and 18th year, thereby causing a second decline in gas production as shown in Figure 5.7. The ultimate recovery is 17.5MMSTB of oil and 27.6BSCF of gas as depicted in the Figure 5.7.

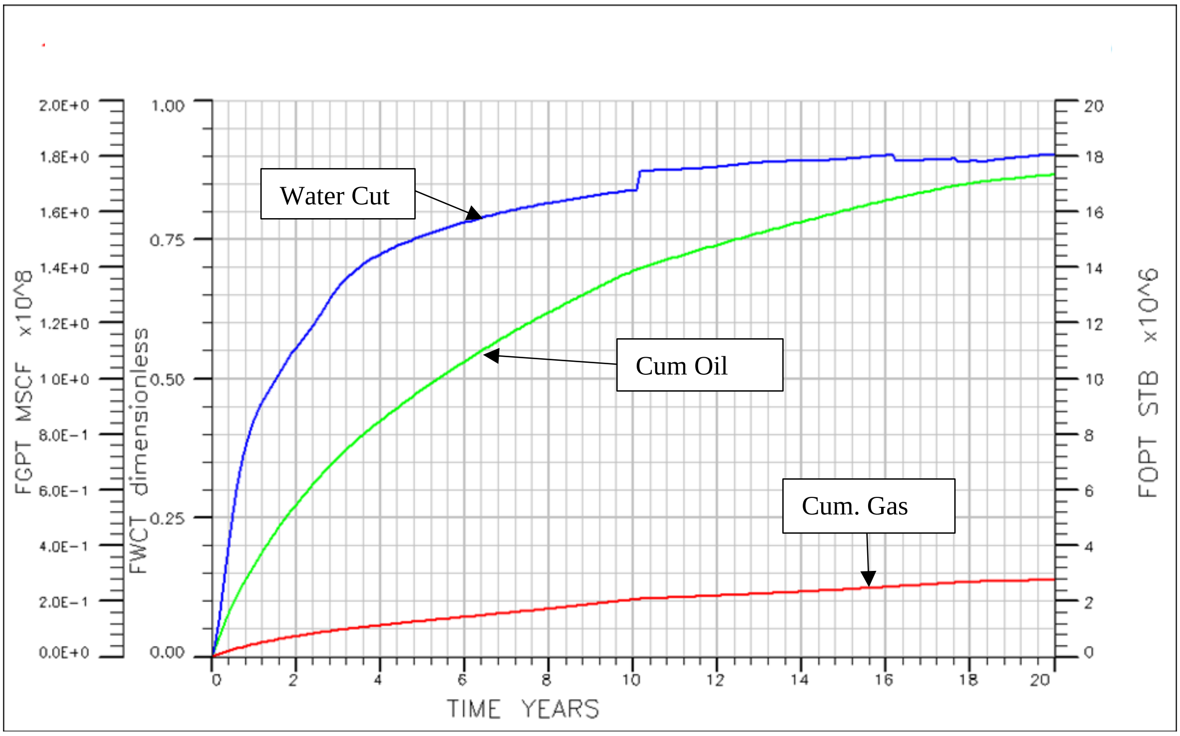


Figure 5.7: Cumulative oil production, cumulative gas production and water Cut of Base Case (Strategy 1)

5.4.2 Strategy 2: Oil and Gas Concurrent Production (OGCP)

The results of the reservoir performance for the OGCP development strategy are shown in figure 5.8. The major drive mechanisms are the solution gas drive, gas cap expansion and water drive. The main challenge for the application of the OGCP strategy in Reservoir A is the high water cut. In figure 5.8, the 10th year shows a sharp increase in water cut. Notice that the trend of the cumulative oil production becomes less steep after the 10th year because some wells shut in as a result of high water cut. The ultimate recovery indicated 17.5 MMSTB of oil and 158 BSCF of gas at the end of the simulation.

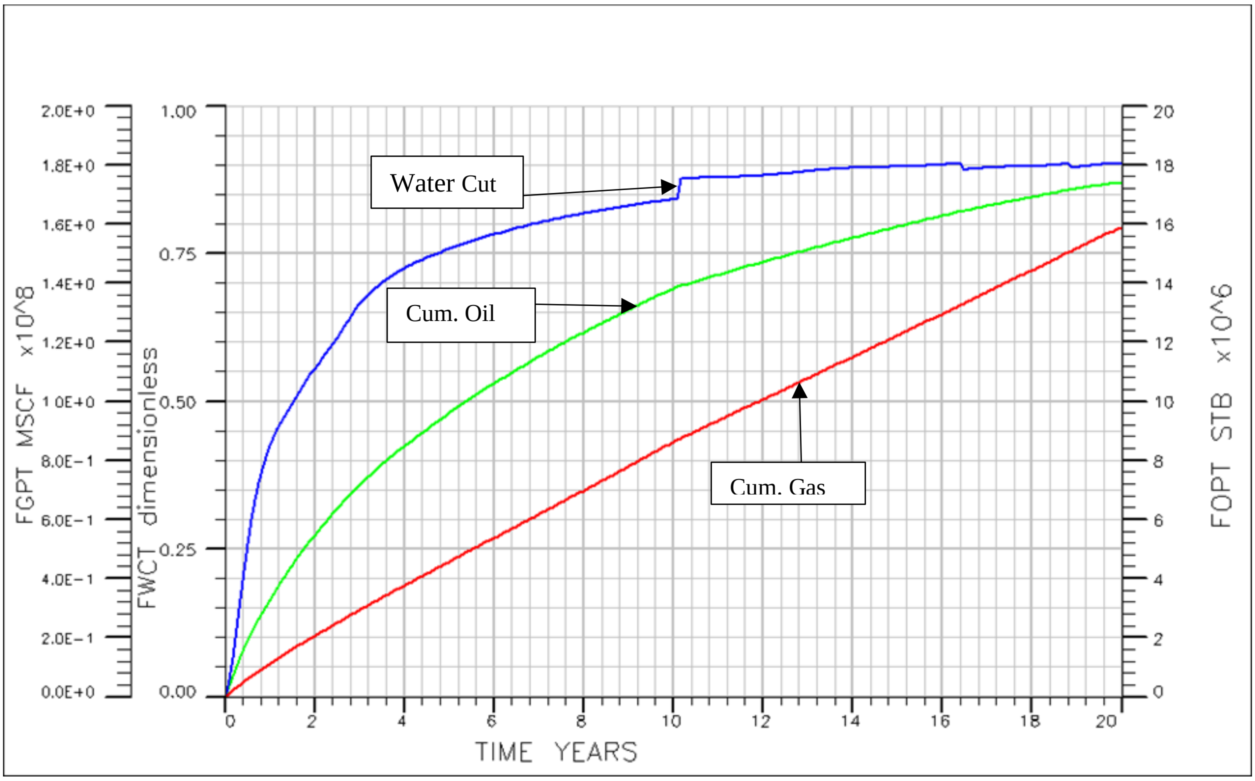


Figure 5. 8 Cumulative oil production, cumulative gas production and water cut for concurrent oil and gas production (Strategy 2)

5.4.3 Strategy 3: Oil and Gas Sequential Production (OGSP)

Figure 5.9 shows the results of the simulation of the OGSP development strategy. The oil production profile of the reservoir for the first ten years of the OGSP is like the first 10-year trend observed in Strategy No 1 (Base Case). The predominant drive mechanisms in the OGSP strategy are solution gas drive, water drive, and gas cap expansion. The main challenge here is the high water cut. Cumulative oil recovery is 15.2 MMSTB and 89.3 BSCF of gas is produced as depicted in figure 5. 9.

5.4.4 Strategy 4: Oil and Produced Gas Reinjection (OGRej)

For the OGRej development strategy, the six horizontal oil production wells came on stream at the same time with an initial oil production rate of 2,000 STB/day per well. The wells were produced for 20 years. At the beginning of the 6th year, 6000MSCF/day of produced gas (i.e., produced solution gas and the gas coned from the gas cap) is reinjected into the gas cap with 4 gas injection wells. For this case, the Reservoir A is developed by 20 years of oil production along with 15 years of produced gas reinjection into the reservoir. Figure 5.10 shows the results of the oil, gas, and water production performance for this OGRej strategy. The predominant drive mechanisms in this reservoir development strategy are the gas cap expansion drive, solution gas, and water drives. The results also indicate that the main operational challenges are handling the high water cut and high GOR during the development of Reservoir A. From the field production data shown in figure 5.10, the predicted cumulative oil recovery is 18.7 MMSTB and 113 BSCF of gas produced after 20 years of simulation.

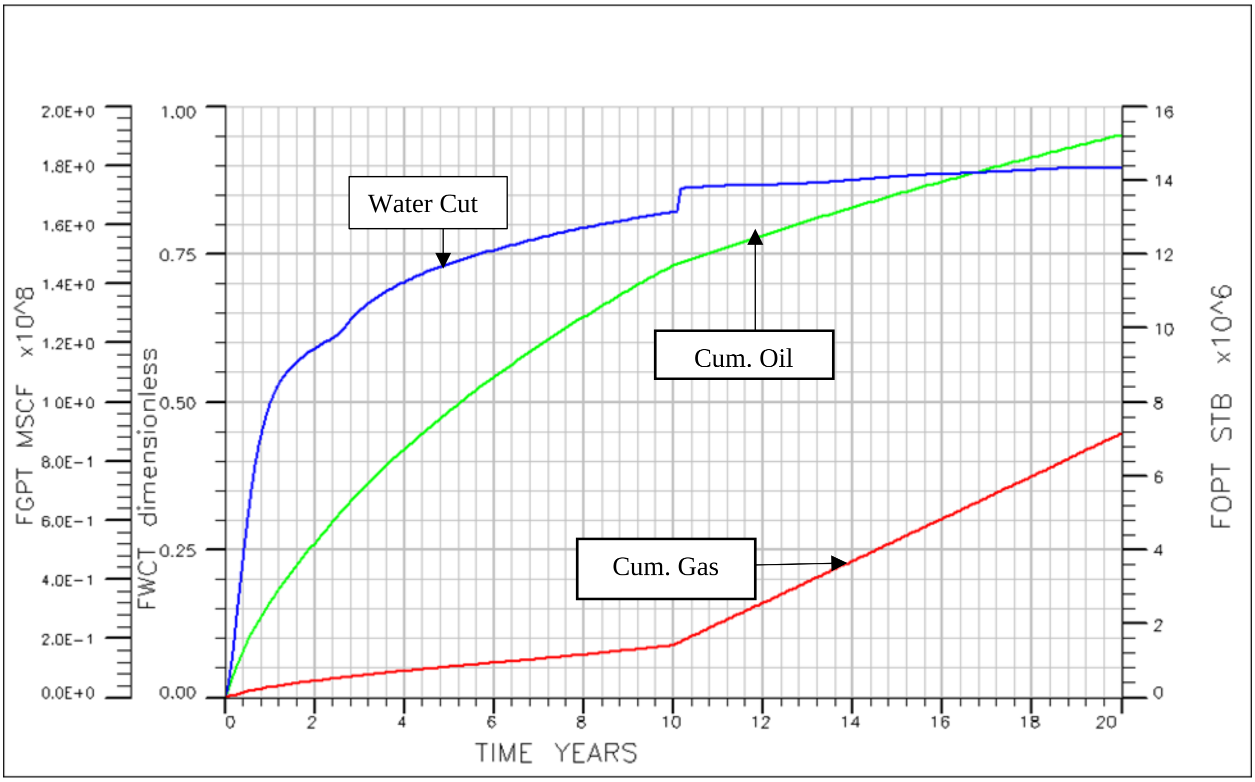


Figure 5.9 Cumulative oil production, cumulative gas production and water cut for sequential development (Strategy 3)

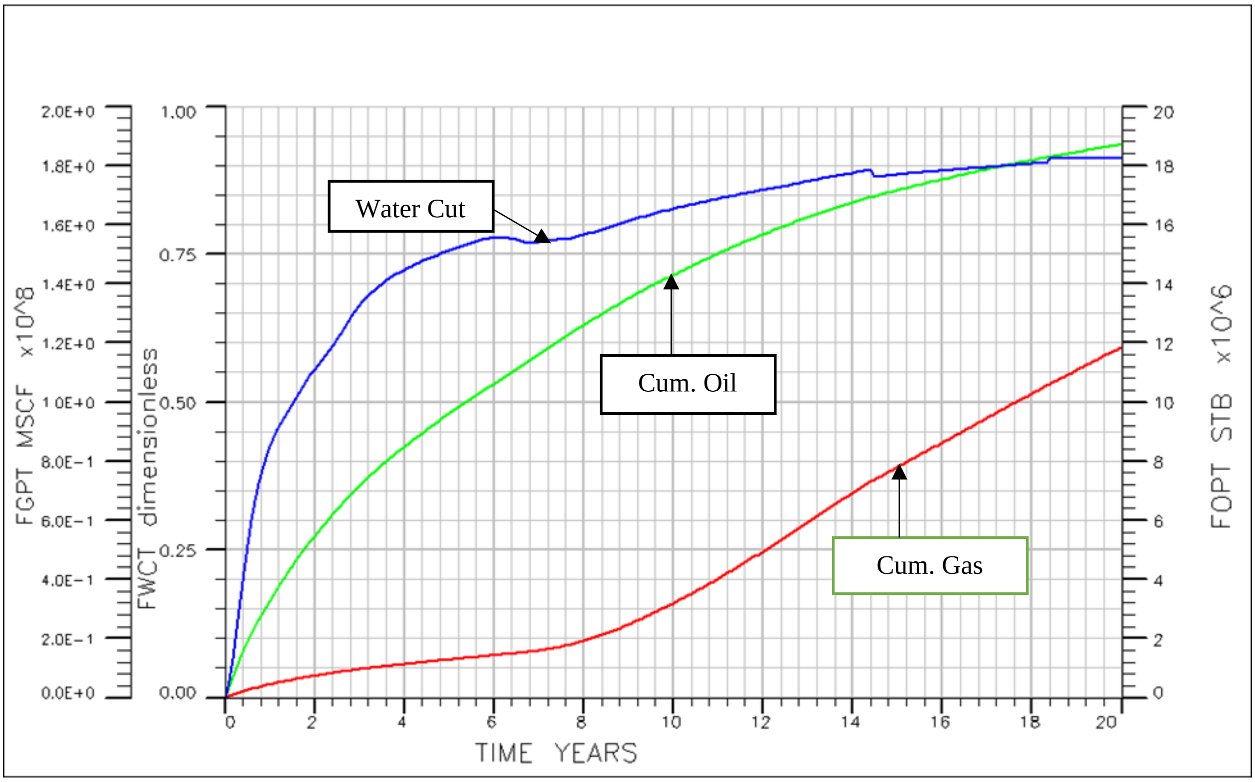


Figure 5.10 Cumulative oil production, cumulative gas production and water cut for oil production with produced gas reinjection (Strategy 4)

5.4.5 Strategy 5: Oil production supported by Gas Reinjection then Gas Cap Blowdown (OGRejGB)

For the OGRejGB development strategy, Reservoir A was operated for 20 years using the following scheme: oil production for 20 years; 6000MSCF/day of produced gas reinjection was done for 10 years beginning 6th year; and then a blowdown of the gas cap for another 5 years. Figure 5.11 shows the results of the simulations. In figure 8 the proposed predominant drive mechanisms are solution gas drive combined with gas cap expansion and water drive during the first 15 years. Limited gas expansion drive during Year 16-20 when the gas cap blow down was operating in Reservoir A. Handling the high water cut and GOR is the key field operational challenge to be contended with during the implementation of this development strategy. The cumulative 20-year production is 18.7 MMSTB of oil and 125 BSCF of gas.

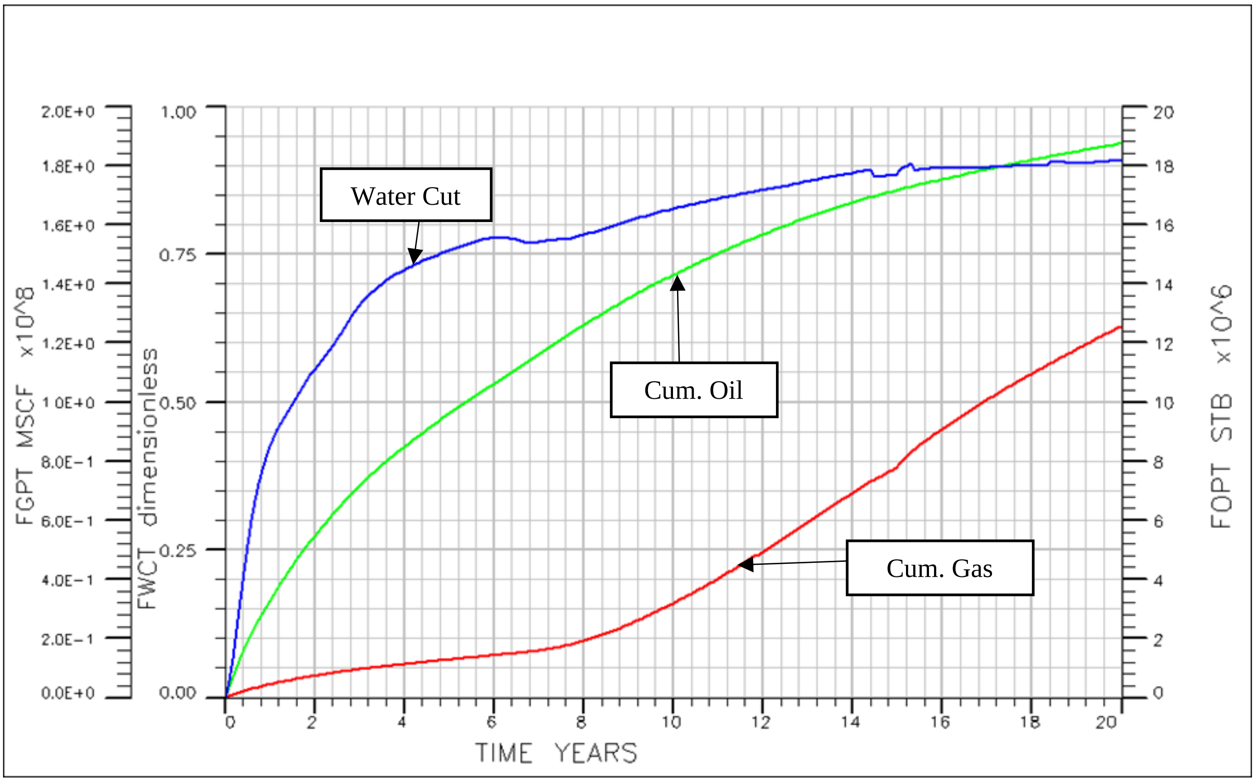


Figure 5. 11 Cumulative oil production, cumulative gas production and water Cut for oil production with gas reinjection then gas blow down (Strategy 5)

5.4.6 Strategy 6: Oil Production supported by Water Injection (OPWinj)

For the OPWinj development strategy, the six horizontal oil wells completed in Reservoir A were produced for 20 years. At the same time, two other wells were injecting water to support the pressure in the reservoir. The results of the 20-year production are shown in Figure 5.12. The predominant drive mechanisms are gas cap expansion, solution gas drive, and water drive from the aquifer and injection wells. Operational challenges are majorly the handling of the high water cut and GOR. A cumulative recovery is 18.1 MMSTB of oil and 34.8 BSCF of gas is produced using Strategy 6 to develop Reservoir A.

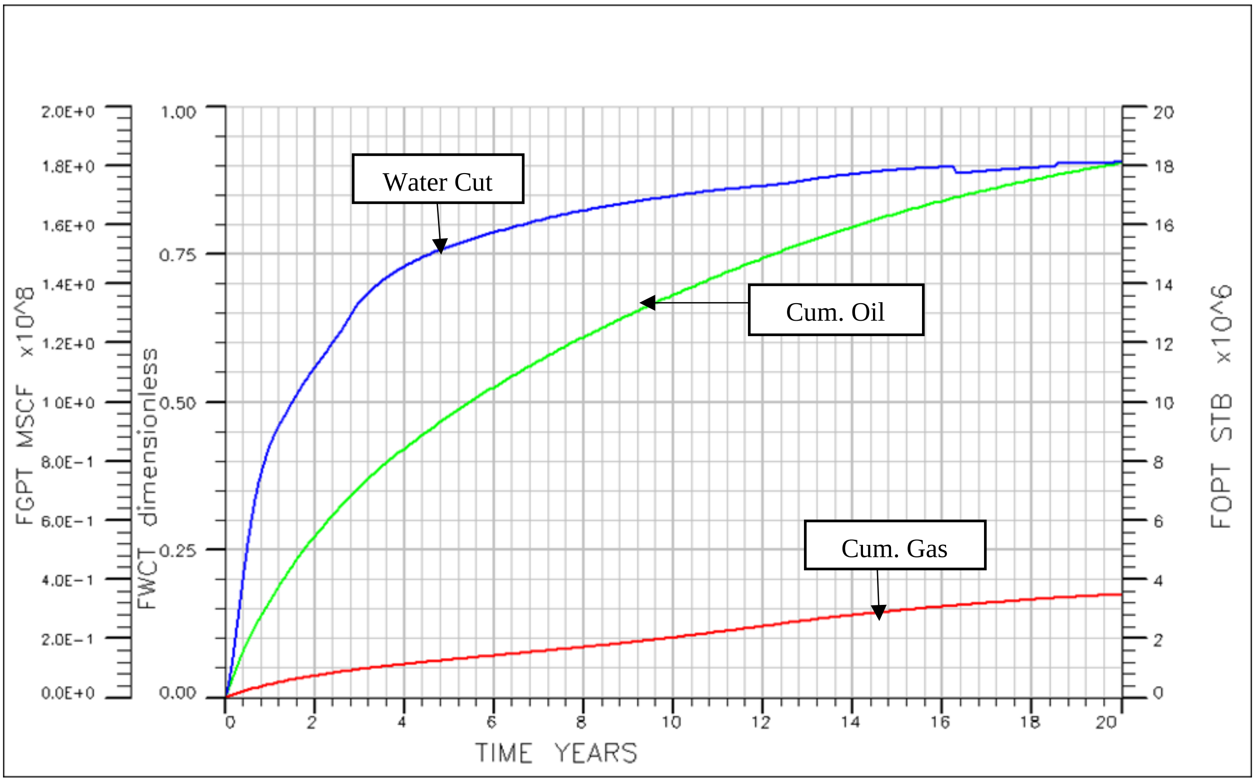


Figure 5. 12 Cumulative oil production, cumulative gas production and water cut trend for oil production with water injection (Strategy 6, OPWinj)

5.4.7 Strategy 7: Oil Production supported by Water Injection with Produced Gas Reinjection (OPWinjGRej)

The OPWinjGRej development strategy combined oil production with simultaneous water injection. Unlike, Strategy 6, 6000MSCF/day of the produced gas was reinjected into the gas cap of the reservoir using 4 gas injection wells at the beginning of the 6th year for 15years. The water injection wells come on stream at the same time with the oil producers. Figure 5.13 shows the results of the 20-year simulation of developing Reservoir A using Strategy 7. The predominant drive mechanisms in this strategy are solution gas, water drive and gas cap expansion drives. As shown in Figure 5.13, there is a sharp increase in the cumulative gas produced around the 8th year. This increase in gas production may attributed to the gas reinjection program introduced after 5 years of production. The ultimate production predicted from the simulation is 18.62 MMSTB of oil and 115 BSCF of gas.

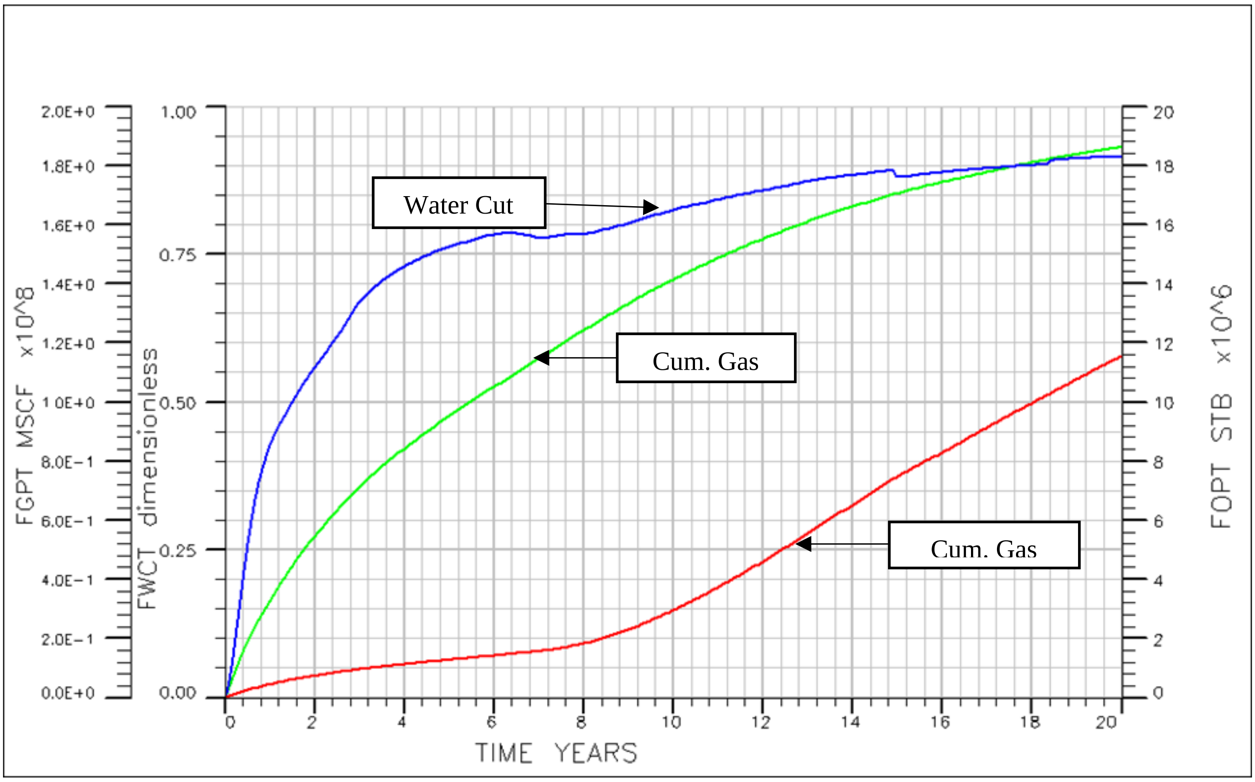


Figure 5.13 Cumulative oil production, cumulative gas production and water cut profiles for oil production with water and gas injection (Strategy 7, OPWinjGRej)

5.5 Comparison of the cumulative oil and gas production for the development strategies

The comparisons of the cumulative oil and gas produced during the 20-year simulation of all seven reservoir development strategies are shown in Figures 5.14 and 5.15. Figure 5.14 indicates that the best four strategies with high cumulative oil recovery are Strategy 4(oil production with produced gas reinjection), Strategy 7(oil production supported by simultaneous water and gas reinjection), Strategy 5(Oil production supported by Gas Reinjection then Gas Cap Blowdown) and Strategy 6 (oil production supported by water injection). Figure 5.15 also shows the strategies with the highest cumulative gas production.

They are in order of cumulative gas produced: Strategy 2(oil and gas concurrent production), Strategy 5(Oil production supported by Gas Reinjection then Gas Cap Blowdown), Strategy 4(oil production supported by produced gas reinjection), and Strategy 7(oil production supported by simultaneous water and gas reinjection).

It is not enough to conclude that the development strategy with the highest cumulative oil production is the optimal strategy without considering the project economics for Reservoir A. The economic analysis presented in the following section is used to determine the best strategy that is not only technically feasibly but also economically attractive.

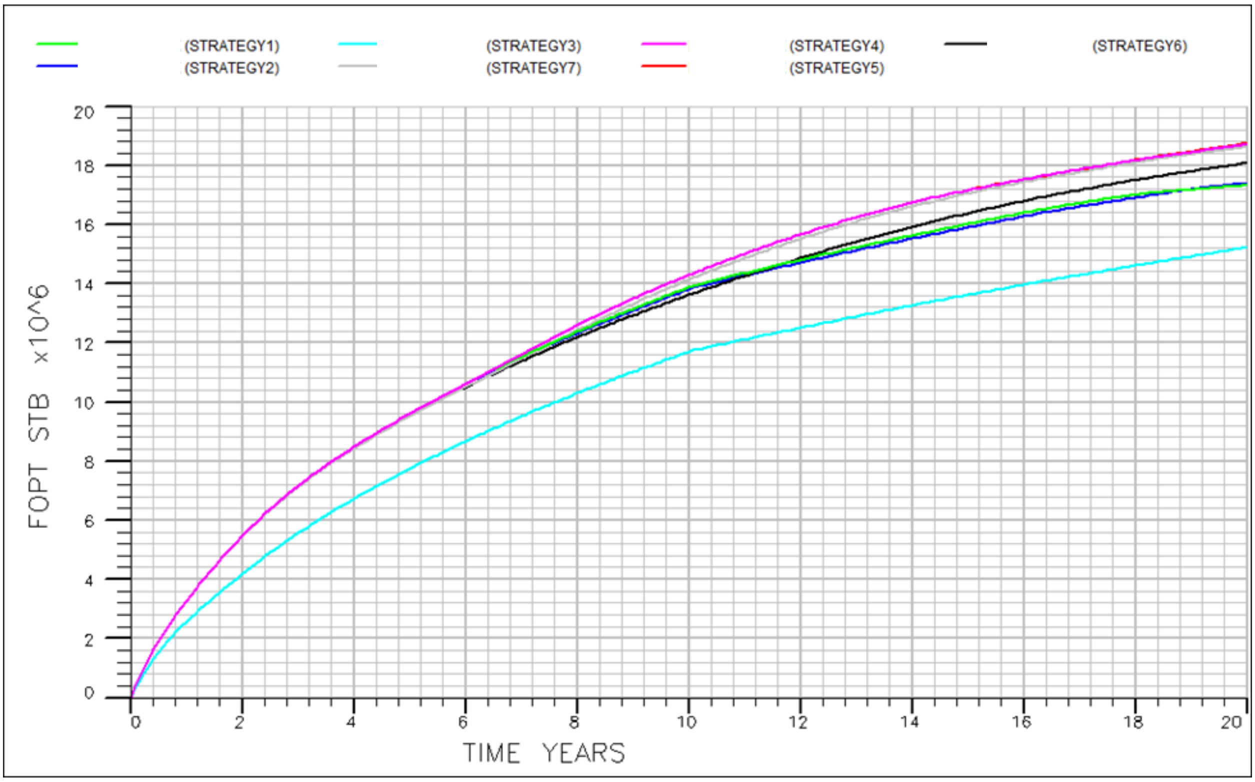


Figure 5. 14: Comparison of Cumulative oil production of all the 7 strategies

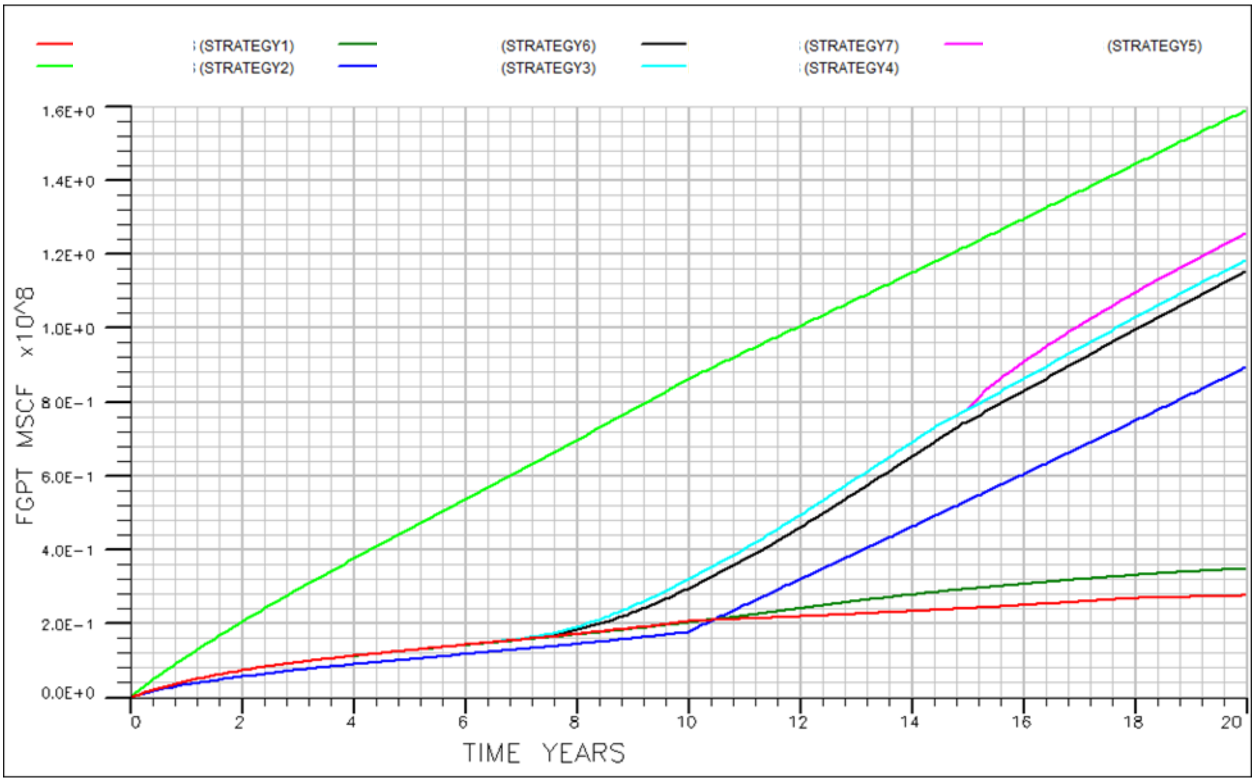


Figure 5.15: Comparison of Cumulative gas production of all 7 strategies

Technical oil and gas recovery for different scenarios only tell half of the story about the optimum oil rim development. The final decision will be based on a wider range of considerations not the least of which will be the economics. Each development scenario will carry different infrastructure and well costs resulting in different economic indicators. In this work, economic evaluation will be carried out using three economic tools or performance indicators, i.e., the Net present Value (NPV), Internal Rate of Return (IRR), and Discounted pay out Period (DPOP). These economic performance indicators will be used to determine the acceptability and profitability of the chosen development concept. We define these profitability indicators in the following section.

Net Present value (NPV)--is the difference between the present value of cash inflow and outflow over a given period. The period of the project in this case is 20 years. This is the most popular petroleum evaluation criterion; it is employed in capital budgeting and investment planning in a bid to analyze the profitability of a projected investment. It is characterized by the recognition of time value of money and application of equal weights to all incomes in the future. The discount rate in NPV reflects presumably future investment opportunities and its suitability or use with probabilities. The definition of NPV is given by (Mian, 2002)

$$NPV = \sum_{i=1}^{n} (CF)_i * R_i \qquad \text{(Equation 5.2)}$$

Where

$(CF)_i$ = cash flow in year i

R_i= Discounted rate in year i, defined as

$$R_i = \frac{1}{(1+\tau)^{i-1}} \qquad \text{(Equation 5.3)}$$

Note in Equation 5.3, τ=interest rate, %.

The NPV of a project is evaluated as follows (Mian 2002)

- If NPV > 0, the project is adding value.
- If NPV = 0, the project is marginal.
- If NPV < 0, it implies that the project is destroying value.

Internal Rate of Return (IRR) -- is the discount rate that makes the net present value (NPV) of all cash flows from a project equal to zero. IRR is employed in capital budgeting or the estimation of the profitability of potential investments. Interest rate earned from investment is sometimes referred to as rate of return, discounted rate, internal yield, and marginal efficiency of capital (Mian, 2002). It is a profitability index that is widely accepted; this concept introduces the time value of money into the profitability decision rule. It is independent of size of cash flow and can be calculated on a before- or after-tax basis. It is quite useful in the measurement of the relative profitability of ventures having about the same project life and cash flow pattern; hence its suitability to be used in this study. As a profitability indicator, the higher the IRR, the more profitable is the project. The IRR is calculated using (Mian, 2002)

$$NPV = \sum_{i=0}^{n} \frac{CF_i}{(1+IRR)^i} = 0 \qquad \text{(Equation 5.4)}$$

where

$(CF)i$ = cash flow in year i

n= number of time periods

Discounted Pay Out Period (DPOP) -- is the time the project will pay back its initial investment. It is given by (Mian 2002)

$$DPOP = \ln\left(\frac{1}{1-\frac{O_1 \times r}{CF}}\right) \div \ln(1+r) \qquad \text{(Equation 5.5)}$$

Where

O_1 =Initial Investment (Outflow)

R = Discount rate

CF = Periodic Cash flow

The assumptions and parameters used in the economic model are listed in Table 5.3. These parameters are typical for profitability analysis used in the Niger Delta.

Table 5.3: Economic Analysis Parameters for Development of Reservoir A

Item	Unit	Value
Discount Rate	%	15
Oil Price	$/ BBL	55
Gas Price	$ /MSCF	3.2
Tax Rate	%	20
Operating Expenditure	M$	10% of revenue
Gas Production well cost	M$	18
Oil Production well cost	M$	15
Gas Injection well cost	M$	20

The profitability of implementing the seven strategies was evaluated using the economic indices defined in Equations 5.2 to 5.5. Table 5.4 shows the results of NPV, IRR and DPOP obtained from the economic analysis. From the results of the economic analysis, it can be concluded that Strategy 2(oil and gas concurrent production) is the optimal development strategy for producing Reservoir A since it has the highest NPV, IRR and minimum DPOP.

Table 5.4: Profitability indexes of the strategies for developing Reservoir A

Strategy	NPV ($MM)	IRR (%)	DPOP
1	220.25	20.0	3
2	335.02	24.2	3
3	159.58	10.0	6
4	287.34	21.4	3
5	270.27	21. 1	3
6	219. 15	18. 1	4
7	214.26	13. 2	4

5.6 Concluding remarks on oil rim development

Oil rim reservoirs are very challenging to develop, therefore proper reservoir management is invaluable. Economic optimization is the ultimate goal of reservoir management. The economic analyses and comparison of various development strategies aid in making the best business decision to achieve maximum profitability. It is very important to maximize NPV of a candidate project by optimizing the capital investment, operating expense, oil production, and reserves and by using any tax benefits that may be applicable to the operation.

Based on the results of this study, it can be shown that cumulative oil production alone is insufficient in the determination of the best strategy since a superior reservoir producibility does not guarantee economic attractiveness of developing the project. The oil and gas concurrent development strategy is found to be the best option to produce Reservoir A in the Niger Delta since it yields the highest values of the economic profitability indicators with the minimum payout period.

CHAPTER 6

6.0 PARAMETRIC ANALYSIS OF SELECTED FIELD DEVELOPMENT STRATEGIES

In this research an evaluation of seven strategies have been done. This represents how to maximize the hydrocarbon recovery from the reservoirs given the seven different production strategies. From results obtained from the hydrocarbon production, it was observed that 4 out of the 7 strategies yielded good fluid recovery. Hence, the four top strategies will be tested against the most impactful parameters affecting hydrocarbon recovery. From this analysis, the four parameters with most impact on recovery are the permeability anistotropy (Kv/Kh), gas cap size (m), horizontal permeability, and oil rim height .The surrogate model developed in chapter 3 is used for simulation using the various impactful parameter ranges.

6.1 Analysis of the four most promising strategies for the oil Rim Reservoir

The 4 strategies identified as most promising in this work are;

- Oil production with produced gas reinjection
- Oil production supported by simultaneous water and gas reinjection
- Oil production supported by Gas Reinjection then Gas Cap Blowdown
- Oil production supported by water injection

Using the range of parameters listed in Table 6.1, simulations of the oil reservoir production for the four most promising strategies were run for 20 years. The results of this analysis are discussed below.

Table 6.1: Range of Impactful Parameters used in further analysis

Parameter	**Range**	**Unit**
Oil Rim Height	10,30,50,80ft	ft
Permeability	500, 1000, 1500, 2000	mD
Gas cap size, m-factor	0.5, 1, 2,3, 5	
Anisotropy (Kv/Kh)	0.001 , 0.01, 0.1, 1	

6.2 Analysis of Results from the four Promising Production Strategies

The results of the 20-year simulations considering the range of the most impactful parameters on oil recovery are shown as graphs in the following section. Table 6.2 is a summary of the results. The four most promising production strategies are discussed.

6.2.1 Oil production with produced gas reinjection

The results for this strategy, oil production with produced gas reinjection, are shown in figures 6.1 through 6.4.

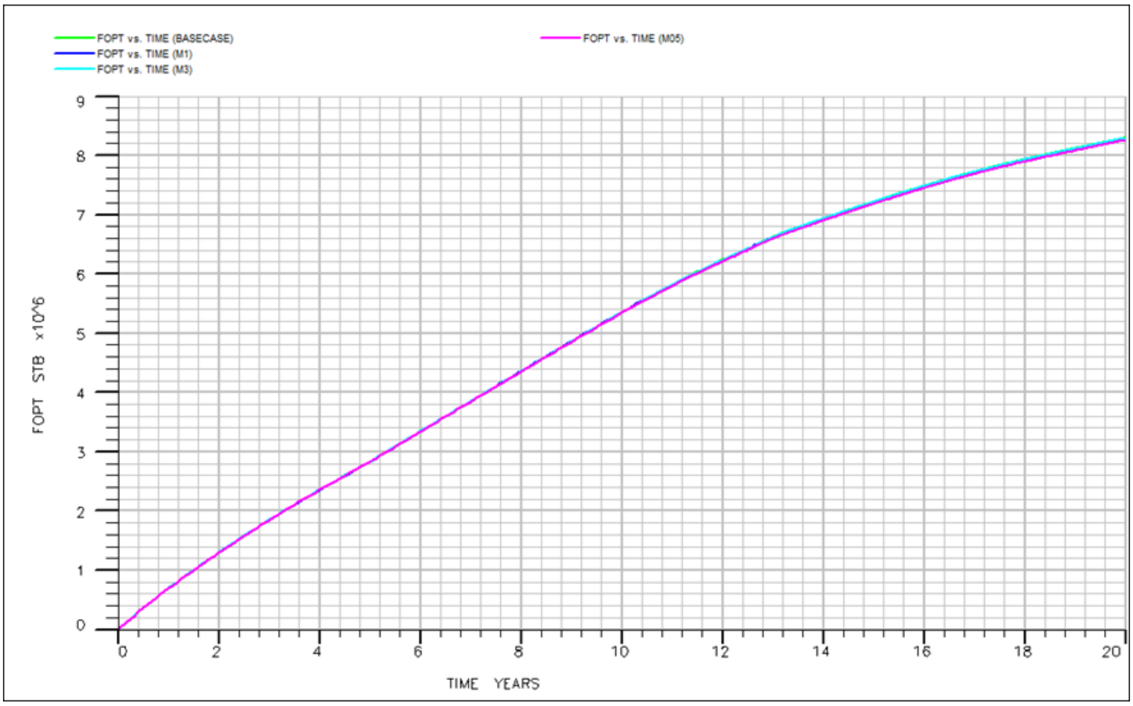


Figure 6.1 Impact of gas cap size (m-factor) on Oil Production for Strategy of oil production with produced gas reinjection

It can be deduced from figure 6.1 that the gas cap size has very little impact on oil production. At the end of the 20-year simulation the total oil production is relatively the same, i.e., approximately 8.2 MMSTB.

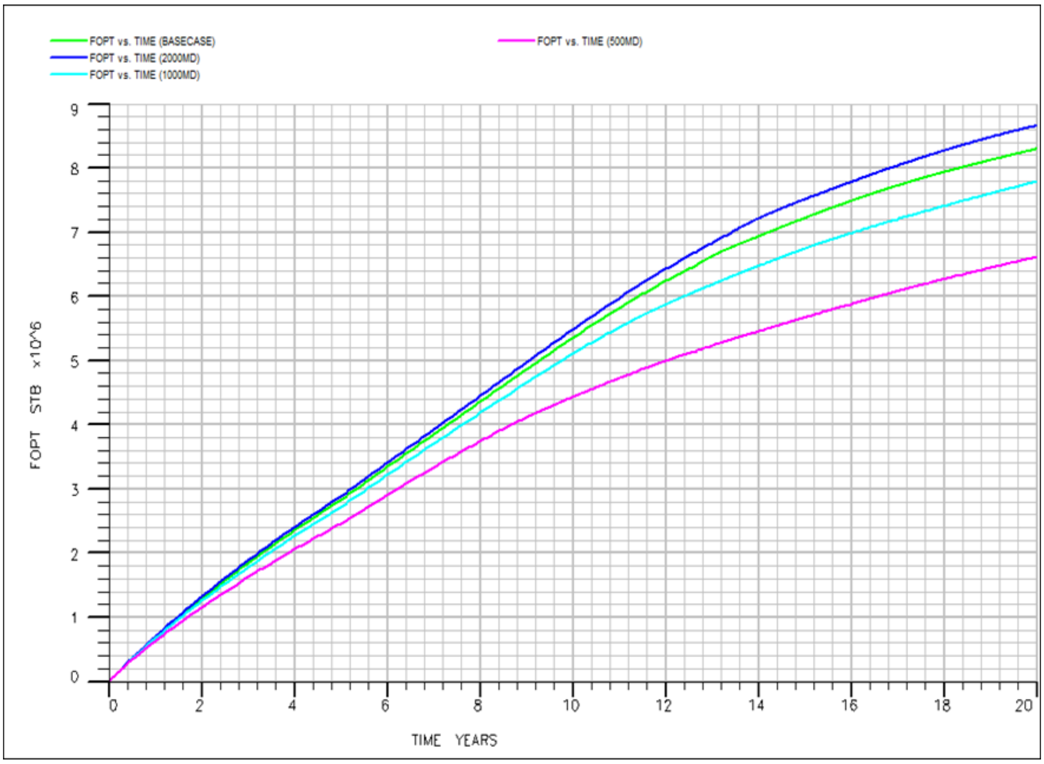


Figure 6.2 Impact of Permeability on Oil Production for Strategy of oil production with produced gas reinjection

In figure 6.2, the highest recovery of 8.7MMSTB is from the highest permeability of 2000MD while the lowest recovery is from the reservoir with the lowest permeability of 500MD. In summary, the higher the permeability the higher the oil recovery from the reservoir.

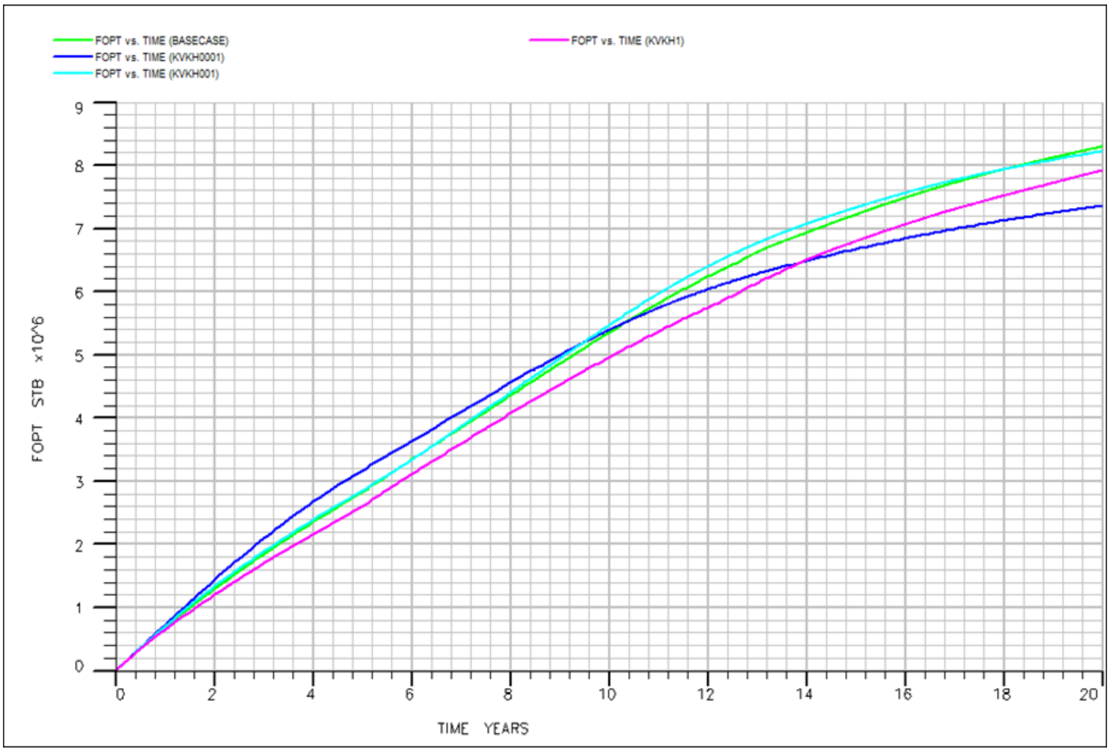


Figure 6.3 Impact of Anisotropy Kv/Kh on Oil Production for Strategy of oil production with produced gas reinjection

In Figure 6.3 above the higher the anisotropy the lower the oil recovery for the first 9 years; the trend changes after the 10th year where reservoir with the anisotropy of 0.001 starts experiencing a decline in oil production rate with time. This is as a result of water coning and shutting down of one of the wells since it has reached its water cut limit. The Kv/Kh ratio of the base case, i.e., 0.1 gives the highest recovery.

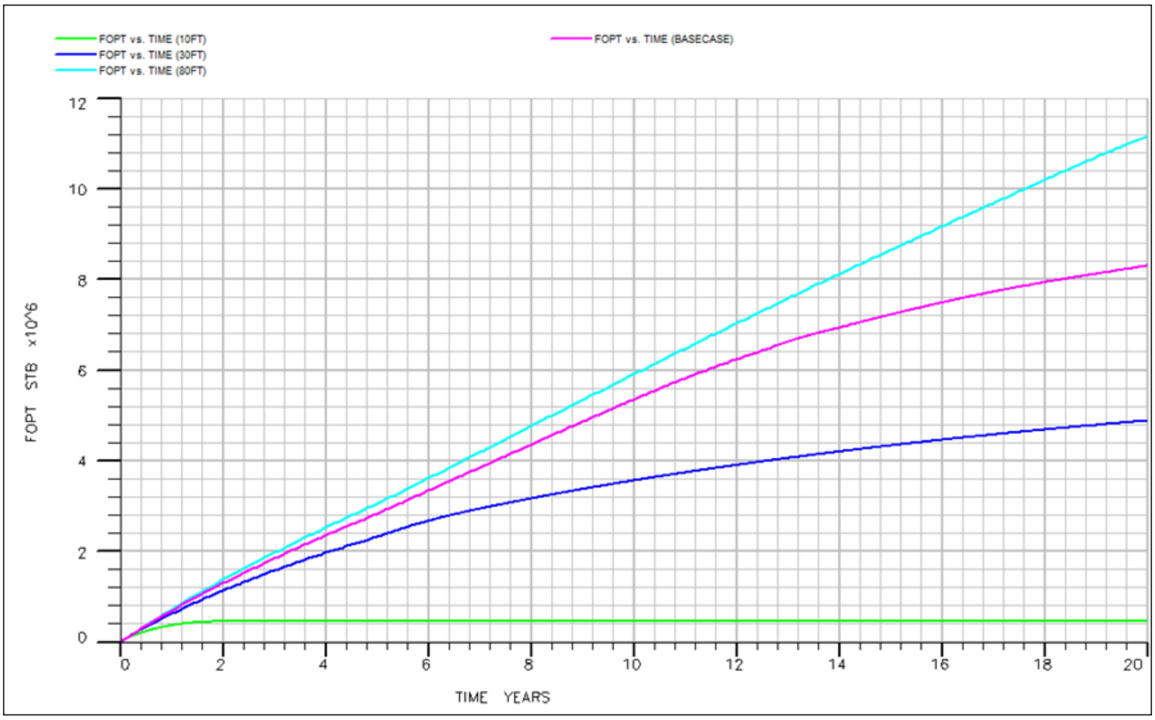


Figure 6.4 Impact of Rim Height on Oil Production for Strategy of oil production with produced gas reinjection

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Figure 6.4 indicates that a rim height of 80ft has the highest oil recovery. In summary, the higher the rim height the more the oil produced. The lower the rim height the more oil and water coning and the less the oil recovery.

6.2.2 Oil production supported by simultaneous water and gas reinjection

Figure 6.5 through 6.8 illustrate the results for this strategy, oil production supported by simultaneous water and gas reinjection.

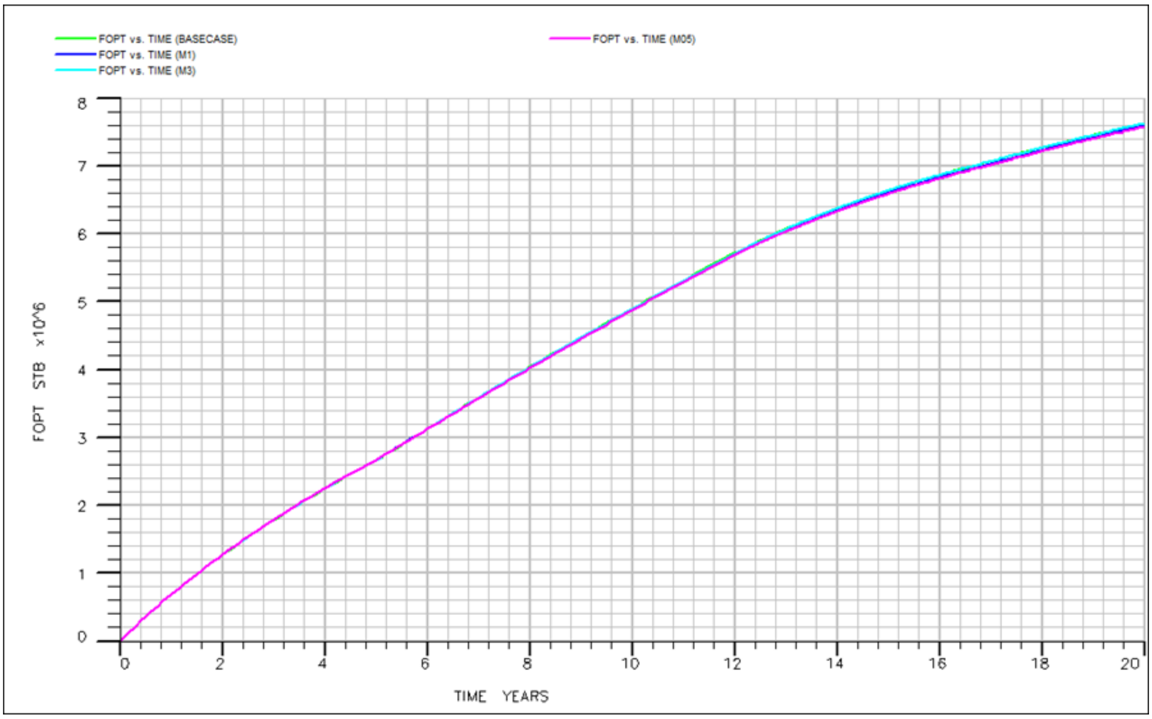

Figure 6.5 Impact of gas cap size (m-factor) on Oil Production for the Strategy of Oil production supported by simultaneous water and gas reinjection

It can be deduced from figure 6.5 that the gas cap size has very little impact on oil production. It is observed that the impact of water drive is more significant than the impact of gas drive on oil production.

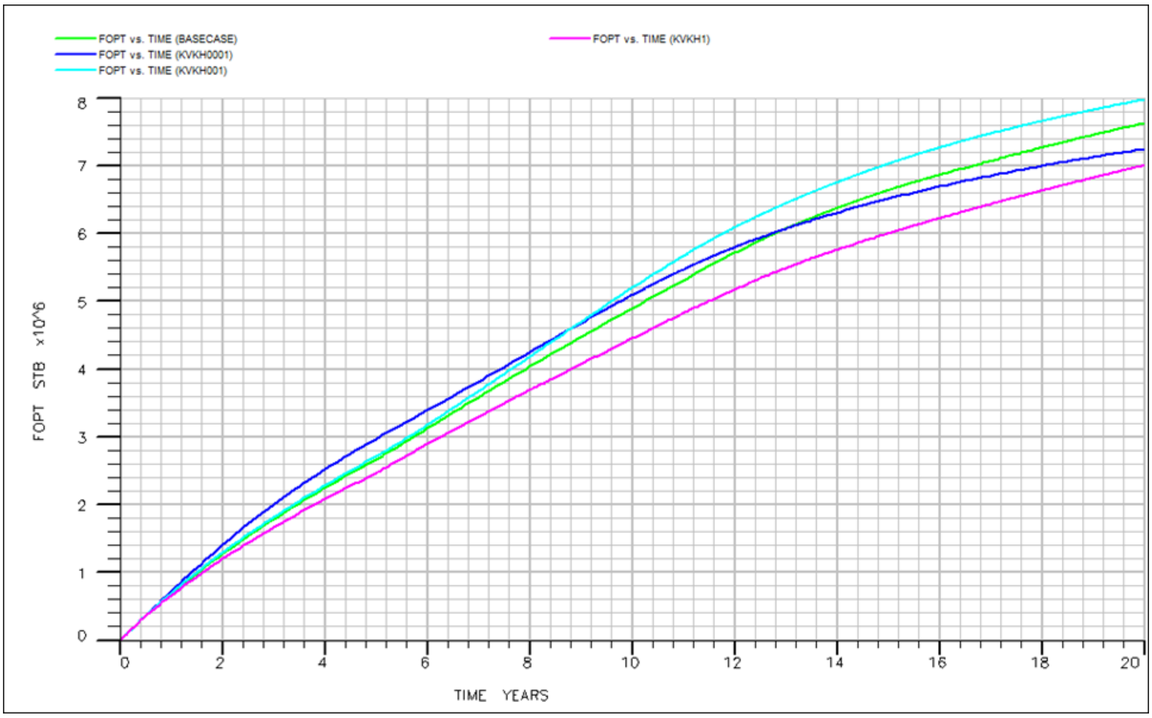

Figure 6.6 Impact of Anisotropy Kv/Kh on Oil Production for the Strategy of Oil production supported by simultaneous water and gas reinjection

In Figure 6.6 above the higher the anisotropy the lower the oil recovery for the first 8 years; the trend changes after the 9th year where reservoir with the anisotropy of 0.001 starts experiencing a decline in oil production rate with time. This trend is as a result of water coning and the shutting down of one of the wells since it has reached the highest water cut limit.

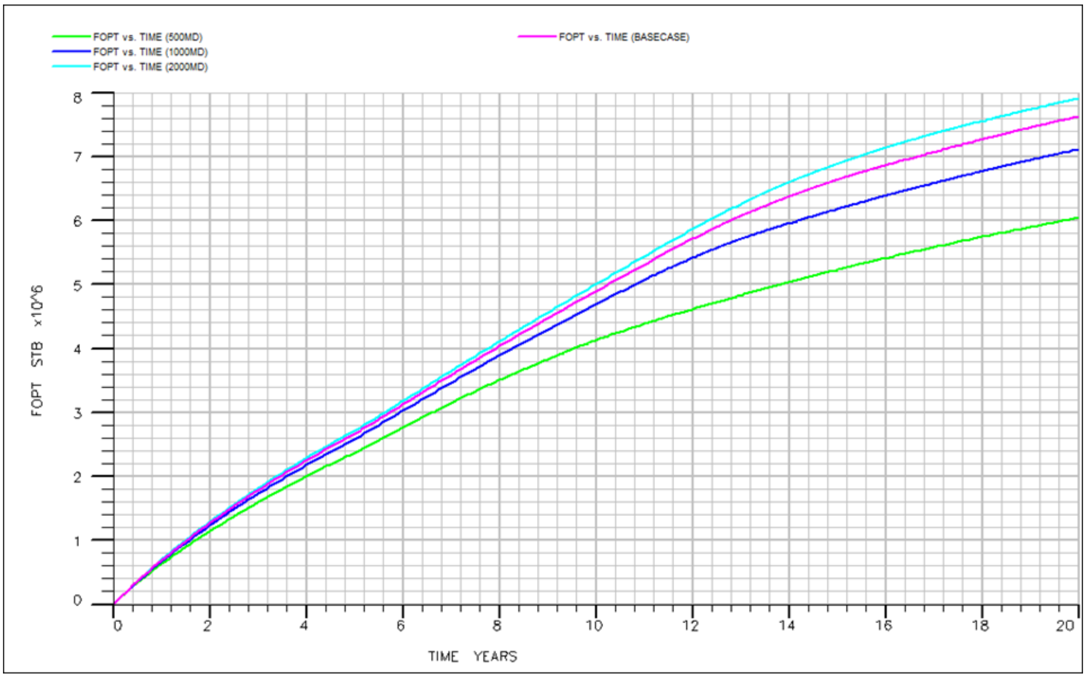

Figure 6.7 Impact of Permeability on Oil Production for the Strategy of Oil production supported by simultaneous water and gas reinjection

In figure 6.7, the highest recovery of 7.9 MMSTB is from the highest permeability of 2000MD while the lowest recovery is from the reservoir with the lowest permeability. In summary, the higher the permeability the higher the oil recovery from the reservoir.

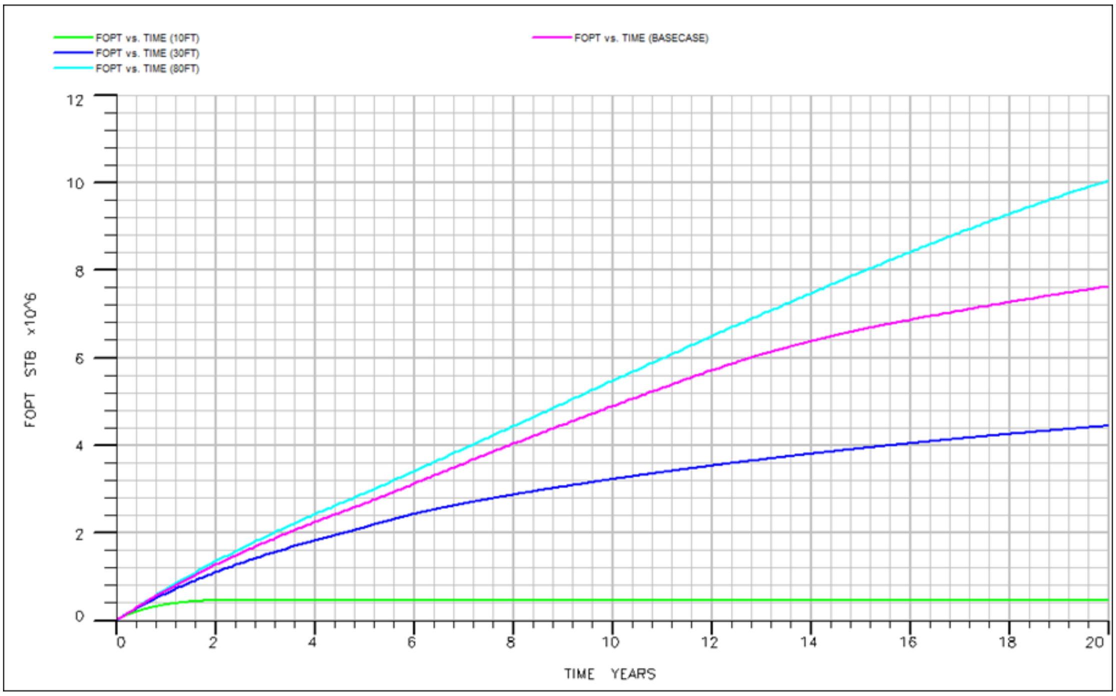

Figure 6.8 Impact of Rim Height on Oil Production for the Strategy of Oil production supported by simultaneous water and gas reinjection

Figure 6.8 indicates that a rim height of 80ft has the highest oil recovery of 10MMSTB. It is observed that the higher the rim height the more the oil produced. The lower the rim height the more oil and water coning and the less the oil recovery.

6.2.3 Oil production supported by Gas Reinjection then Gas Cap Blowdown

In Figure 6.9 through 6.12 are shown the results of the third promising production strategy, i.e., oil production supported by gas reinjection then gas cap blowdown.

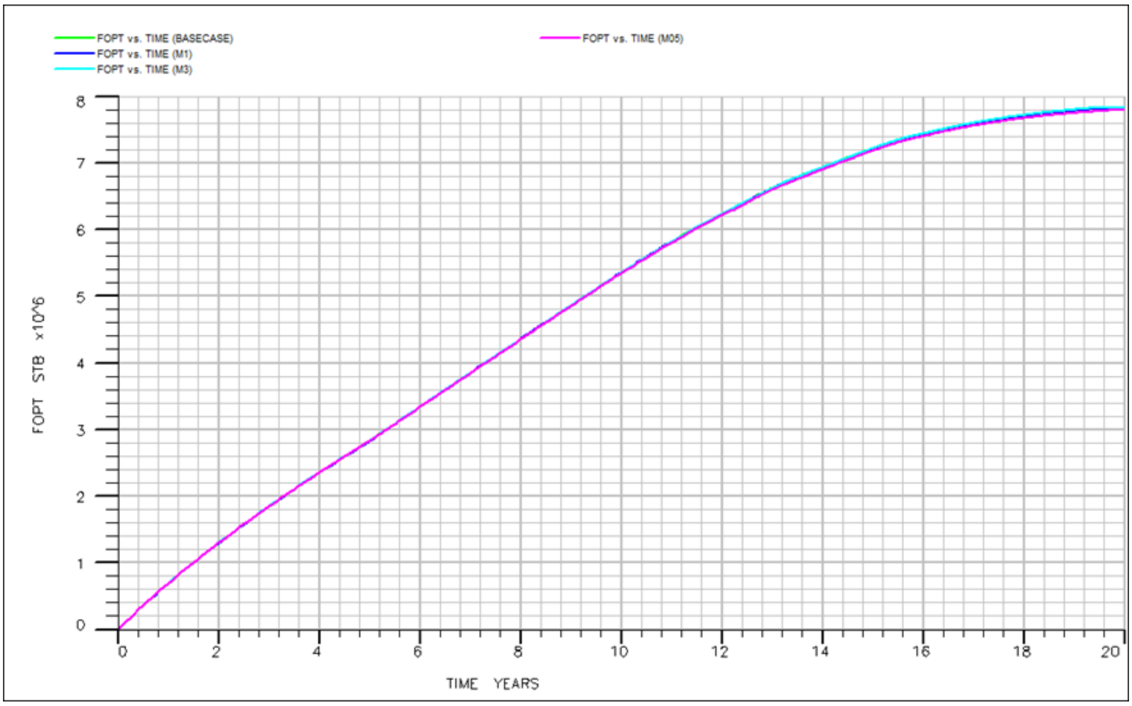

Figure 6.9 Impact of gas cap size (m-factor)on Oil Production for the Strategy of Oil production supported by gas reinjection then gas cap blowdown

It can be deduced from figure 6.9 that the gas cap size has very little impact on oil production.

All the gas cap sizes give relatively the same volume of oil production.

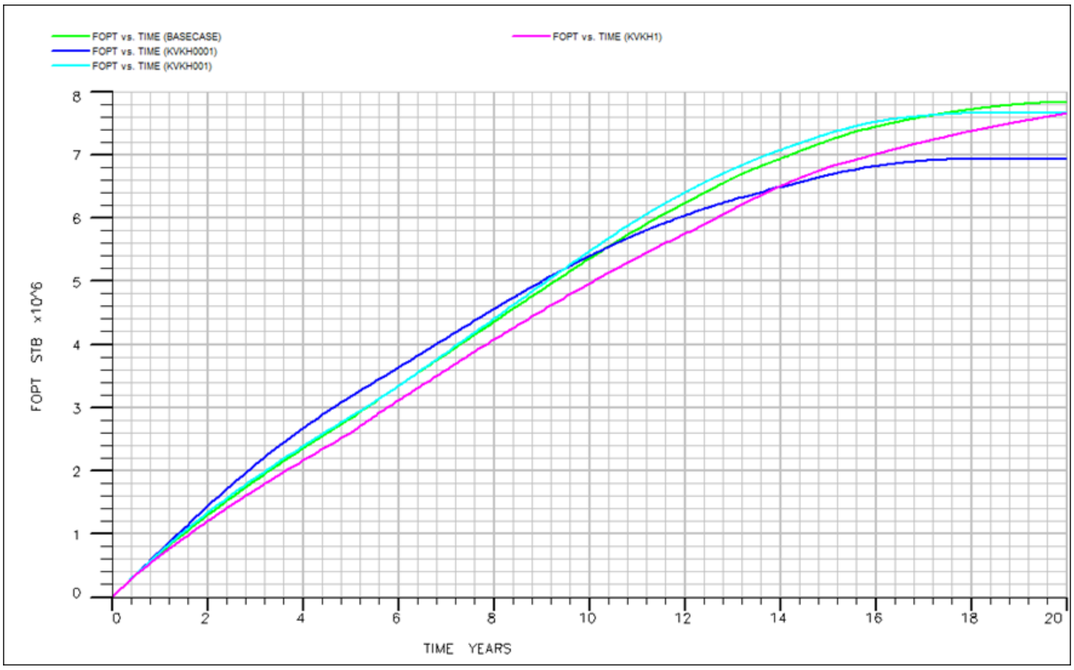

Figure 6.10 Impact of Anisotropy Kv/Kh on Oil Production for the Strategy of Oil production supported by gas reinjection then gas cap blowdown

In Figure 6.10 it is observed that the higher the anisotropy the lower the oil recovery for the first 9 years; the trend changes after the 9th year where reservoir with the anisotropy of 0.001 starts experiencing a decline in oil production rate with time. This can be explained by the excessive water coning and the shutting down of one of the wells since it has reached its highest water cut.

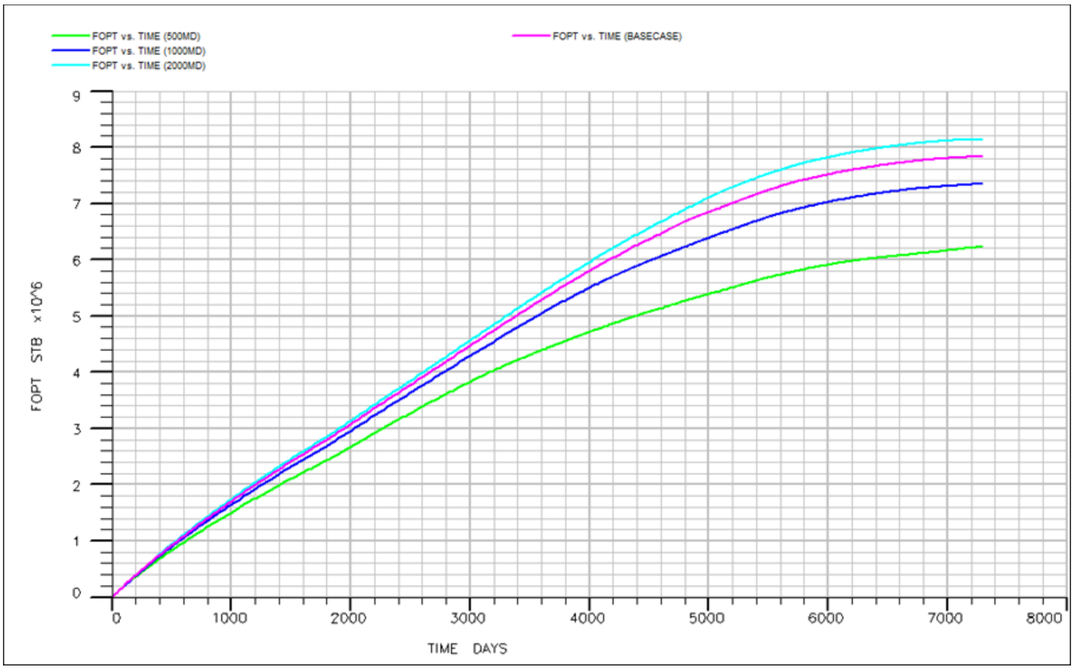

Figure 6.11 Impact of on Permeability Oil Production for the Strategy of Oil production supported by gas reinjection then gas cap blowdown

In figure 6.11, the highest recovery of 8.2 MMSTB is from the highest permeability of 2000MD while the lowest recovery is from the reservoir with the lowest permeability. In summary, the higher the permeability the higher the oil recovery from the reservoir.

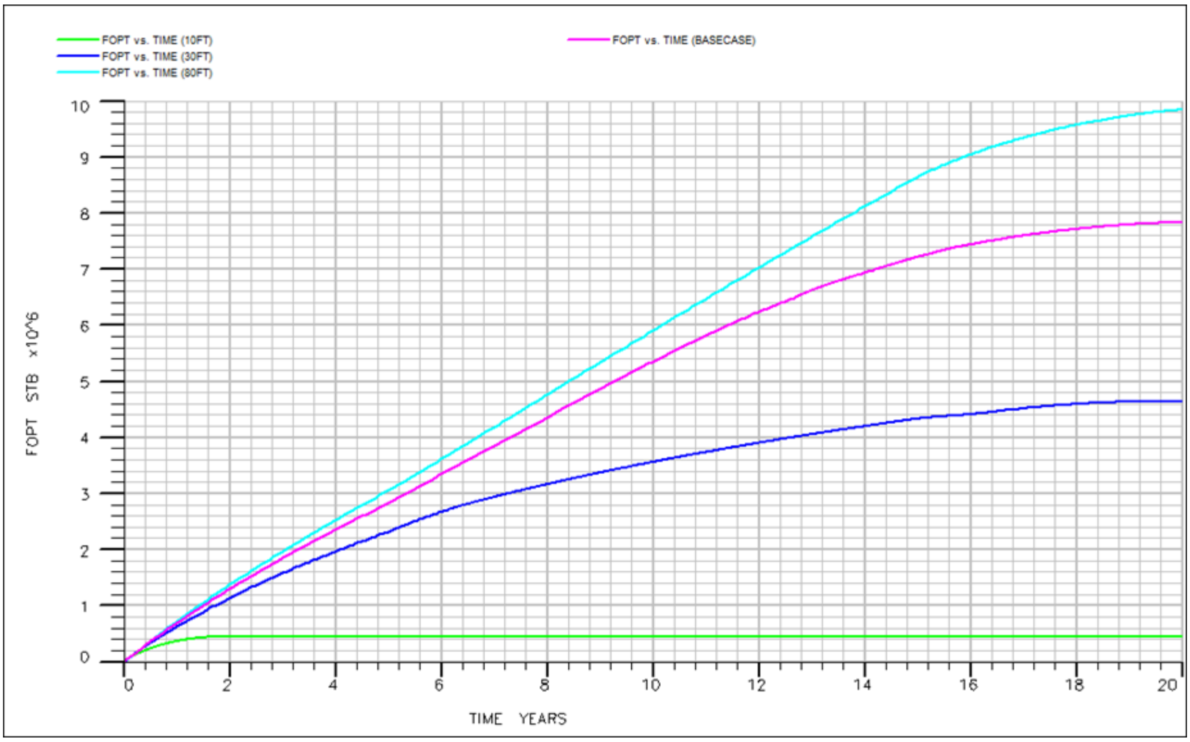

Figure 6.12 Impact of Rim Height on Oil Production for the Strategy of Oil production supported by gas reinjection then gas cap blowdown

Figure 6.12 it is observed that a rim height of 80ft has the highest oil recovery. Note that the higher the rim height the more the oil produced. The lower the rim height the more gas and water coning and the less the oil recovery.

6.2.4 Oil production supported by water injection

Figures 6.13 through 6.16 display the results of the simulations of the fourth production strategy of oil production supported by water injection.

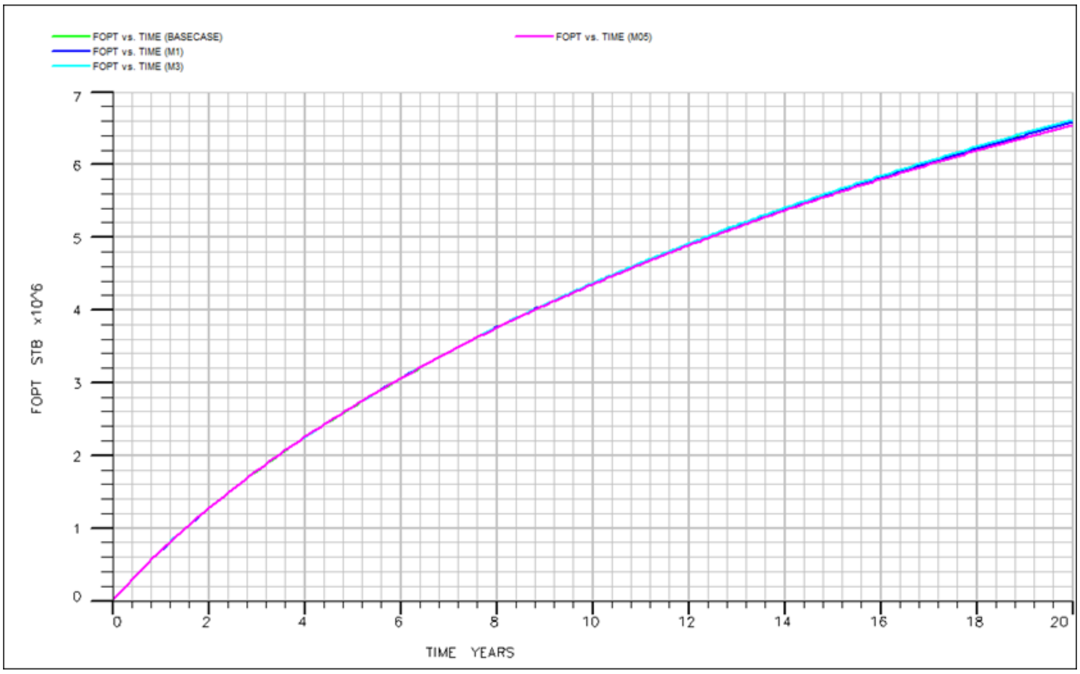

Figure 6.13 Impact of gas cap size (m-factor) on Oil Production for the Strategy of Oil production supported by water injection

It can be deduced from figure 6.13 that the gas cap size has very little impact on oil production, as the trend shows relatively the same volume of oil production.

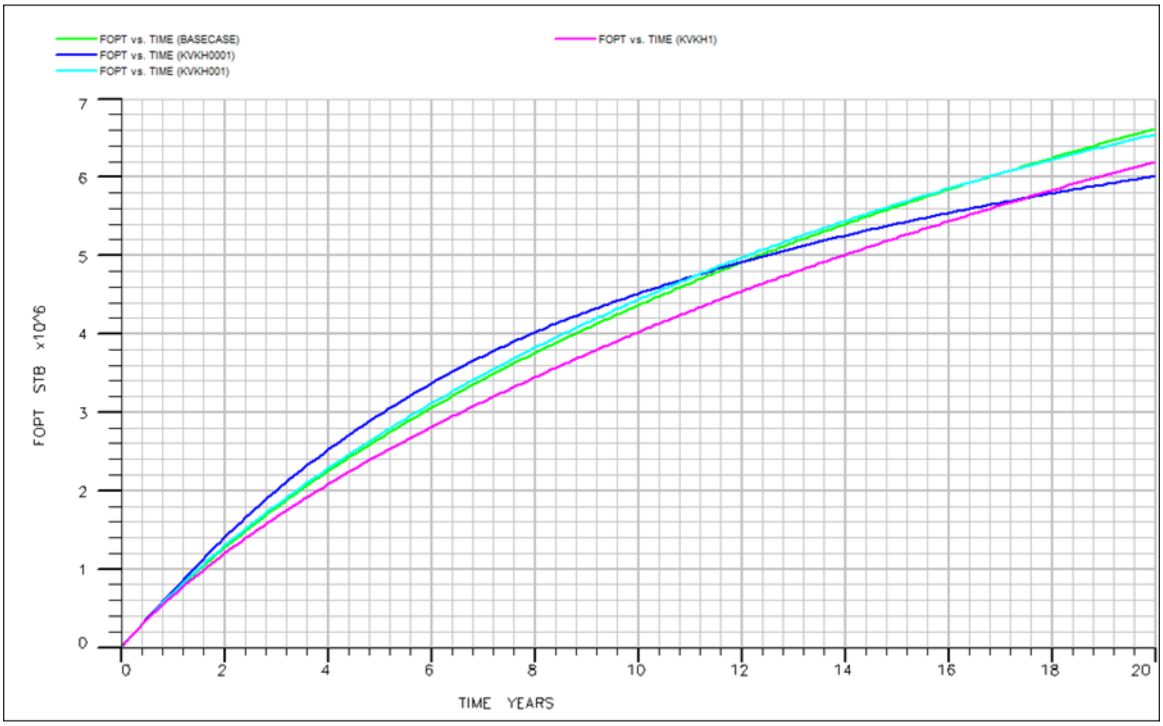

Figure 6.14 Impact of Anistropy Kv/Kh on Oil Production for the Strategy of Oil production supported by water injection

In Figure 6.14 above the higher the anisotropy the lower the oil recovery for the first 9years, the trend changes after the 9th year where reservoir with the anisotropy of 0.001 starts experiencing a decline in oil production rate with time. It is likely that the trend can be attributed to excessive water coning and the shutting down of one of the wells upon exceeding its highest water cut limit.

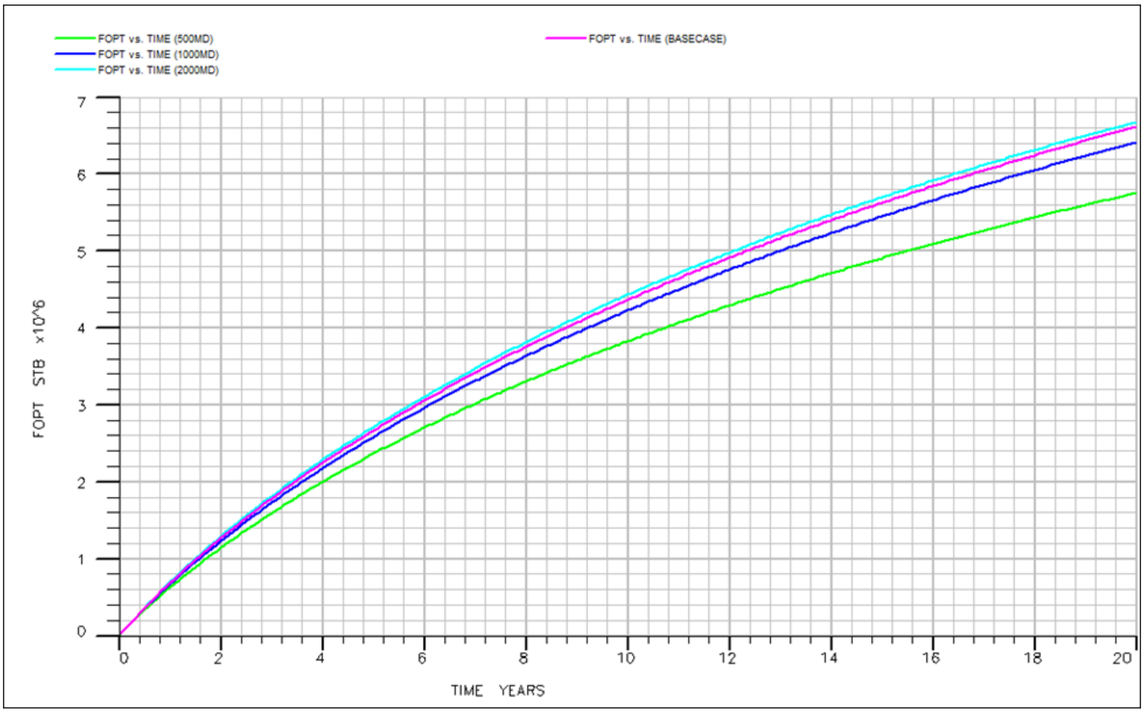

Figure 6.15 Impact of on Permeability Oil Production for the Strategy of Oil production supported by water injection

In figure 6.15, the highest recovery of 6.5MMSTB is from the highest permeability of 2000MD while the lowest recovery is from the reservoir with the lowest permeability. In summary, oil recovery from the reservoir increases with the permeability.

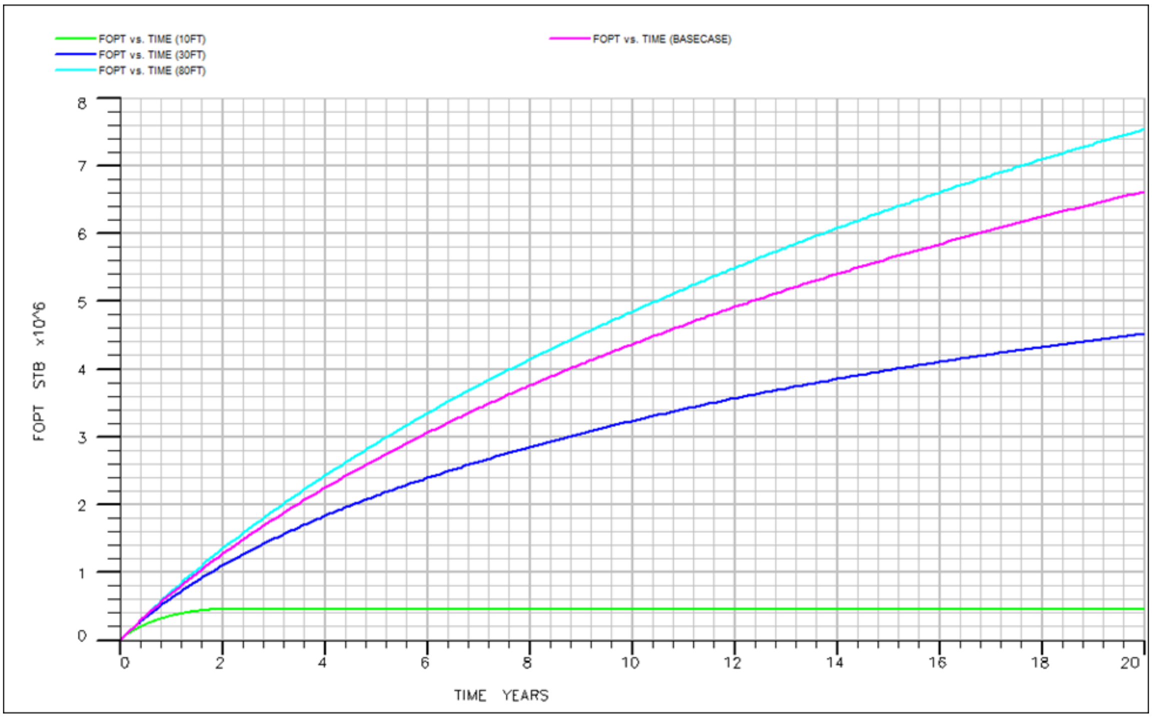

Figure 6.16 Impact of oil rim Height on Oil Production for the Strategy of Oil production supported by water injection

The results in Figure 6.16 indicates that a rim height of 80ft yielded the highest oil recovery of 7.50MMB. The cumulative oil produced increased with the rim height. The low rim heights tend to promote excessive gas and water coning; and thus less oil recovery.

Table 6.2 below shows the cumulative recovery for the four most promising strategies considering variations of the impactful parameters identified from the uncertainty analysis.

Table 6.2 Production strategies vs impactful reservoir parameters

		Reservoir Parameter

		Permeability anisotropy (k_v/k_h)	Gas cap size (m)	Horizontal permeability mD	Oil rim height ft
Strategy	Oil production with produced gas reinjection	(8. 16) MMSTB	(8.25)MMSTB	(8.63) MMSTB	(13.3)MMSTB
	Oil production supported by simultaneous water and gas reinjection	(8.00) MMSTB	(7.60)MMSTB	(7.97)MMSTB	(10.10)MMSTB
	Oil production supported by Gas Reinjection then Gas Cap Blowdown	(7.80) MMSTB	(7.72)MMSTB	(8.18) MMSTB	(9.83)MMSTB
	Oil production supported by water injection	(6.61) MMSTB	(7.60)MMSTB	(7.85)MMSTB	(7.55)MMSTB

Table 6.2 above shows the effect of various reservoir parameters on oil production with the four (4) most promising production strategies. For all four strategies, the oil rim height has the greatest impact on hydrocarbon production; the only exception is strategy of oil production supported by water injection where the permeability has the greatest impact on hydrocarbon production. The utility of this analysis summarized in Table 6.2 is described as follows. For example, consider a candidate reservoir (e.g., Reservoir C) in the Niger Delta region. Table 4.2 can be used as the first qualitative filter for identifying the best strategy to produce Reservoir C depending on its reservoir properties. If Reservoir C has very good permeability, then the best strategy to use in this case will be oil production supported by simultaneous water and gas reinjection.

CHAPTER 7

7.0 CONCLUSIONS AND RECOMMENDATIONS

The conclusions derived from the study are presented in this chapter. A set of recommendations is given for future studies to enhance the proposed methodology and results from this work.

7.1 Conclusions

This study was designed to evaluate an integrated approach to optimally develop thin oil rim reservoirs. The first phase of the study addressed the issue of identifying the impactful parameters affecting the production of oil rims. This was achieved by developing a generic model to simulate the production of a thin oil rim reservoir. The generic model indicated that permeability anisotropy (k_v/k_h), gas cap size (m), horizontal permeability, and rim height have the most impact on production of oil rims. In a bid to understand the long-term oil rim production and the associated uncertainties, a surrogate reservoir model (SRM) was developed as part of this study. In the second phase of the study, the SRM along with a Monte Carlo simulation technique were used to quantify the uncertainties associated with the most impactful parameters controlling oil rim production. Finally, an integrated reservoir simulation study was carried out to evaluate the producibility and economics of the development of a thin oil rim (Reservoir A) located in the Niger Delta. In the case study, seven (7) different production strategies were evaluated. Economic feasibility of the seven reservoir development strategies was analyzed using three profitability performance indicators, net present value (NPV), internal rate of return (IRR), and discounted pay out period (DPOP). The optimum development strategy was identified based on the maximum cumulative oil recovery and economic profitability after 20 years of production of Reservoir A.

The following conclusions can be derived from the results of this study:

1. Development of a generic oil simulation model helped in identifying the impactful parameters on oil recovery in thin rim reservoirs.
2. The most impactful parameters are, permeability anisotropy (k_v/k_h), gas cap size (m), horizontal permeability, and oil rim height.
3. The results of the study show that numerical simulation using surrogate model is suitable for the evaluation of oil rim development and quantifying the associated uncertainty instead of running a full field model.
4. Selection and optimal placement of wells within oil rim reservoirs are critical for thin column reservoir development and management. Placing the well just above the oil-water contact (OWC) offers more economic value when compared to well placement at the mid-rim location or near the gas-oil contact.
5. The strength of the aquifer also plays an important role in the recovery of oil from thin column reservoirs.
6. The use of modern experimental design method such as the uniform design demonstrated in this study can offer a more reliable proxy model for uncertainty quantification.
7. Development of thin oil rim reservoirs is challenging because of water and gas coning tendencies in these reservoirs; and it requires an integrated reservoir management planning to be successful.
8. The results of this integrated reservoir management study applied to Reservoir A located in the Niger Delta show that cumulative oil production alone is insufficient to determine the best reservoir production strategy since a superior reservoir producibility does not guarantee economic attractiveness of developing the project.

9. The results of this integrated study show that the oil and gas concurrent development strategy is the best option to produce Reservoir A in the Niger Delta. This strategy yielded the highest values of the economic profitability indicators of NPV and IRR with the minimum discounted payout period.

7.2 Recommendations and Suggestion for future Works

The following recommendations are suggested as areas of future research to enhance the work presented in this study:

1. The risk analysis of various production strategies in the integrated reservoir management should be considered as an area for further research. This can be integrated with a robust uncertainty analysis to support technical aspects of the proposed integrated reservoir management of thin oil rim reservoirs.
2. Development of water and gas coning models is recommended as future work. This will improve the prediction of the water and gas coning behavior of the reservoir. Oil rim reservoirs have high tendencies for water and gas coning.
3. Application of multi-criteria, decision making methods should be employed to scientifically rank the strategies in order of preference. This will be a rigorous way to improve the identification of the optimum reservoir development strategy.
4. Gas injection at the gas-oil contact (GOC) can be considered in a future research for optimization of oil production in oil rim reservoirs.

CHAPTER 8

8.0 CONTRIBUTIONS TO KNOWLEDGE

The major contributions to knowledge and a list of peer-reviewed publications derived from this study are presented in this Chapter.

8.1 Major Contributions

This study has contributed in the following ways;

1. A framework was developed in this study that allows quick assessment, economic evaluation, and implementation of development strategies for effective management to improve economic recovery of oil rim reservoirs within the Niger Delta.
2. A robust, accurate and reproducible computational procedure was formulated for timely screening, classifying, uncertainty assessment and development of generic recovery proxies for oil rims. The procedure was demonstrated by integrating the classical experimental design, numerical simulation, and response surface methodology.
3. A template has been made available for easy identification of strategies that will yield the highest recovery depending on the impactful parameters of the reservoirs.

8.2 Published Research Articles

The major findings from this research have been reported in peer-reviewed technical journals. The publications derived from the research have advanced our knowledge in three areas: well placement in thin oil-rim reservoirs; the need to use surrogate models to examine the impactful parameters and their associated uncertainties, along with the mechanisms governing the reservoir behavior of horizontal wells drilled in thin oil-rim reservoirs; and the importance of developing an integrated reservoir management plan to maximize recovery from thin oil-rim reservoirs. The following publications clearly demonstrate that the methodology and results proposed in the research are sound and have been accepted by the scientific community as advancement of our knowledge related to the development and management of thin oil-rim reservoirs.

Aladeitan, M. Yetunde, Arinkoola Akeem O., Udebhulu Okhiria D. and Ogbe David O **(**2019). Surrogate Modelling Approach: A Solution to Oil Rim Production Optimization. Cogent Engineering Journal. **(Published)**

Aladeitan, M. Yetunde, and Arinkoola Akeem O **(**2019). Well Placement Optimisation for Enhanced Oil Rim Production; Niger Delta Case Study. **Accepted for publication** by International Journal of Engineering and Technology (UAE)

Aladeitan, M. Yetunde, Arinkoola Akeem O., and Ogbe David O **(**2020). Integrated Reservoir Management in a Niger Delta Oil Rim Field. Cogent Engineering Journal. **(Published)**

Aladeitan, M. Yetunde and Akinyede M Opeyemi (2016). Optimization of Oil Rim Development by Improved Well Design. Journal of Scientific and Engineering Research, Vol 3 Issue 4 **(Published)**

NOMENCLATURE

API	American Petroleum Institute
BCF	Billion cubic feet
BSCF	Billion standard cubic feet
BTT	Breakthrough time
cp	Centipoise
DPOP	Discounted pay out period
FFM	Full field model
FGOR	Field Gas Oil Ratio
FGPT	Field Gas Production Total
FOPT	Total field oil production
FVF	Oil Formation Volume Factor
FWCT	Field Water Cut
GOR	Gas-oil ratio
IRR	Internal rate of return
k	Permeability
M	Thousand
mD	Millidarcy
MM	Million
MMSCF	Million standard cubic feet
MMSTB	Million Stock-Tank-Barrel
NPV	Net Present Value
OVISC	Oil viscosity

P10	10% Probability of forecast
P50	50% Probability of forecast
P90	90% Probability of forecast
PERMX	Horizontal permeability
PERMZ	Vertical permeability
PORO	Porosity
PV	Pore Volume
SCF	Standard cubic feet
STB	Stock-Tank-Barrel
STOIIP	Stock oil initially in place
SWI	Initial water saturation
WBT	Water breakthrough time
WCT	Water cut
WPT	Total water production

SYMBOLS

Bo	Oil formation volume factor
Bofinal	Final Oil formation volume factor
μ	Viscosity
ϕ	Porosity

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APPENDIX

Sensitivities on Anisotropy (kv/kh)

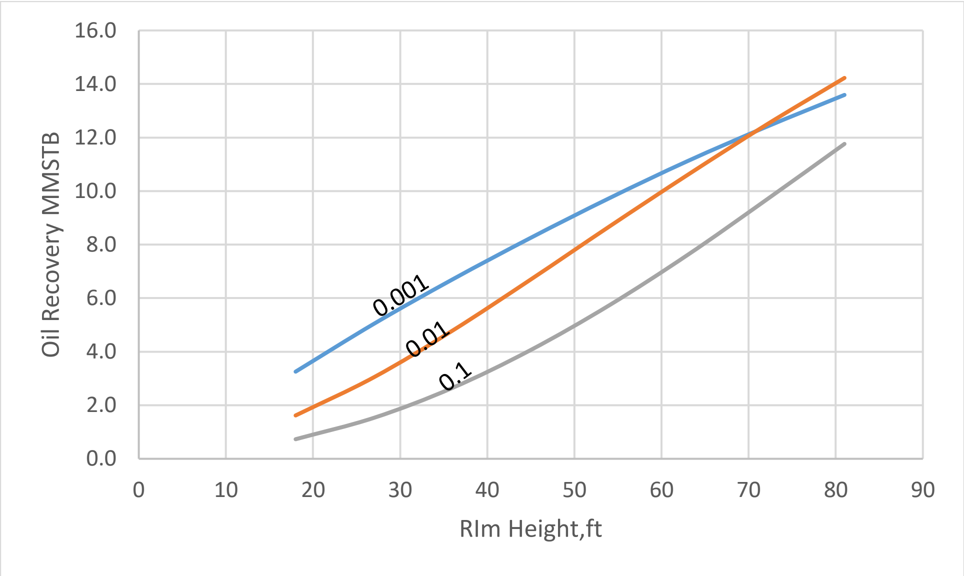

Figure A1: Effect of kv/kh on Oil Recovery at varying Oil Rim Thickness(Oil only)

It is obvious from the plot shown in Figure 3.1 that oil recovery increases with decreasing kv/kh, but from an oil rim thickness of about 75ft and above the trend reverses for kv/kh values of 0.01 to 0.001.

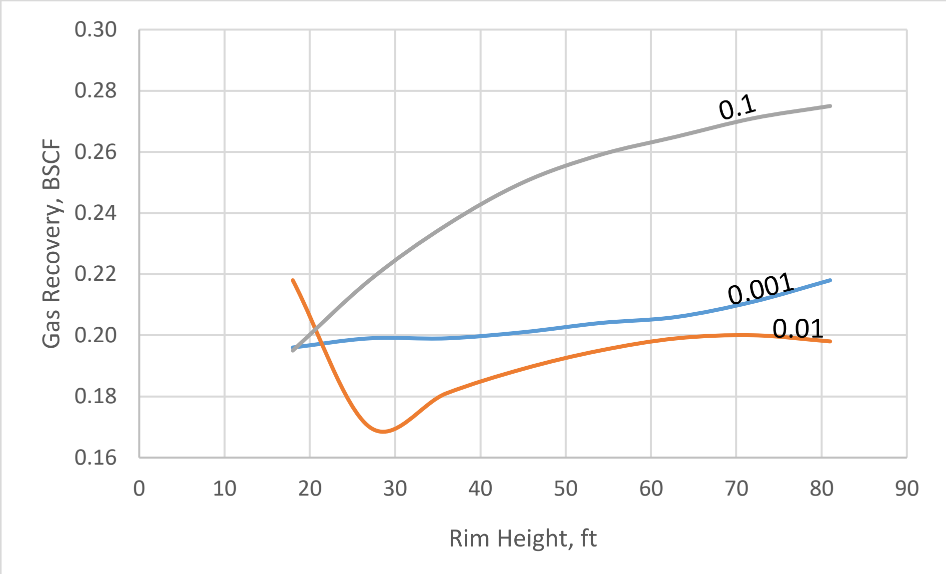

Figure A2 Effect of kv/kh on Gas Recovery at varying Oil Rim Thickness(Oil only)

Sensitivities on Gas Cap Size

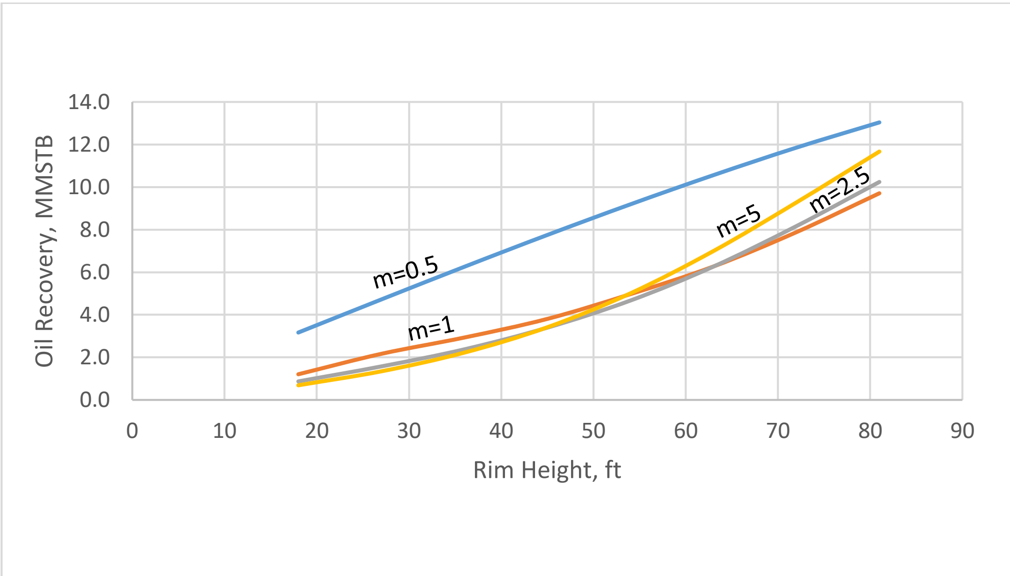

Figure A3 Effect of Gas Cap Size on Oil Recovery at Varying Oil Rim Thickness(Oil only)

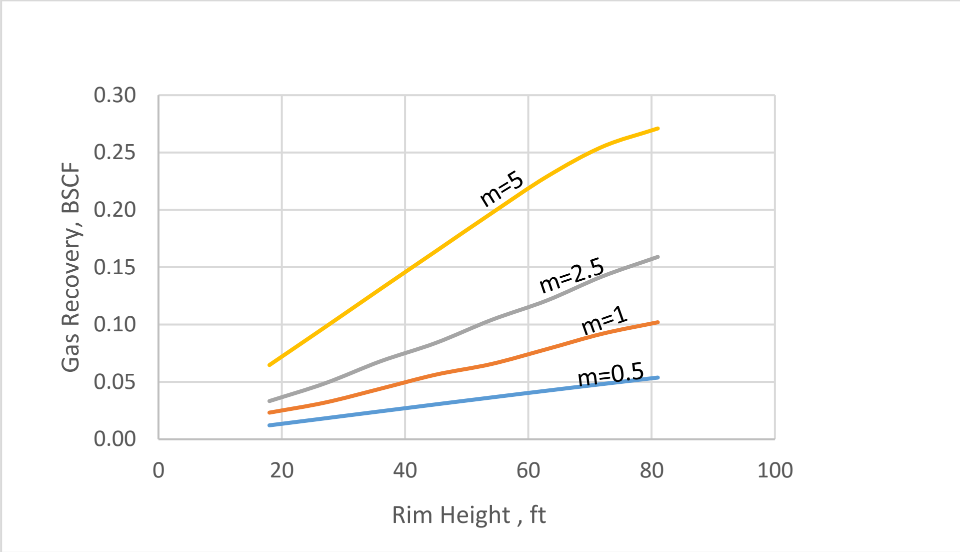

Figure A4 Effect of Gas Cap Size on Gas Recovery at Varying Oil Rim Thickness

It can be deduced from the figure 3.5 above that the higher the value of the m the higher the gas produced for the various oil rim thicknesses.

Sensitivity on permeability

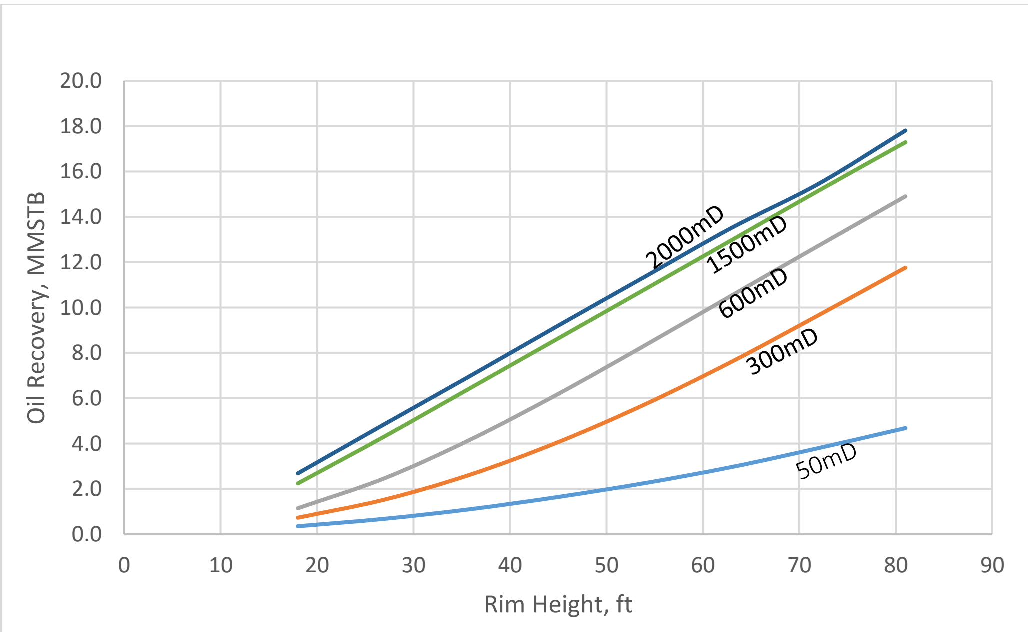

Figure A5 Effect of Permeability on Oil Recovery at varying Oil Rim Thickness

The graph (Figure 3.6) above indicates that oil recovery increases with increasing permeability at various oil thicknesses, there is a higher decline in oil recovery from permeabilities lower than 600mD.

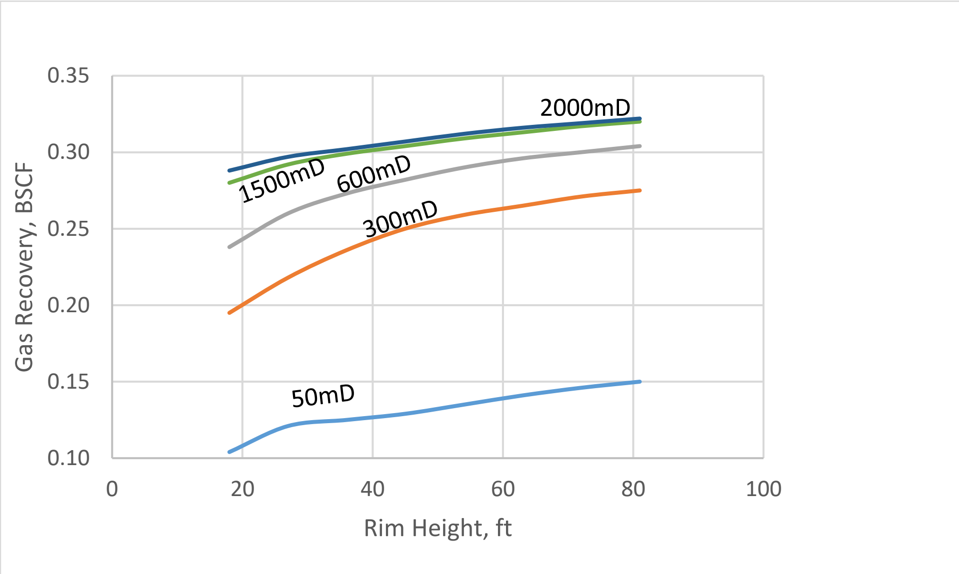

Figure A6 Effect of Permeability on Gas Recovery at varying Oil Rim Thickness

Sensitivities on viscosity

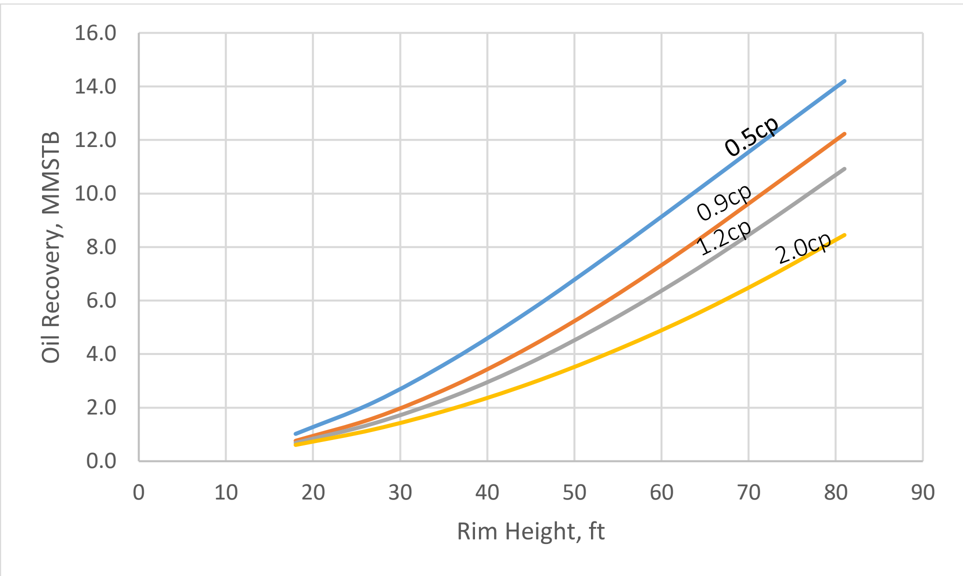

Figure A7 Effect of Viscosity on Oil Recovery at varying Oil Rim Thickness

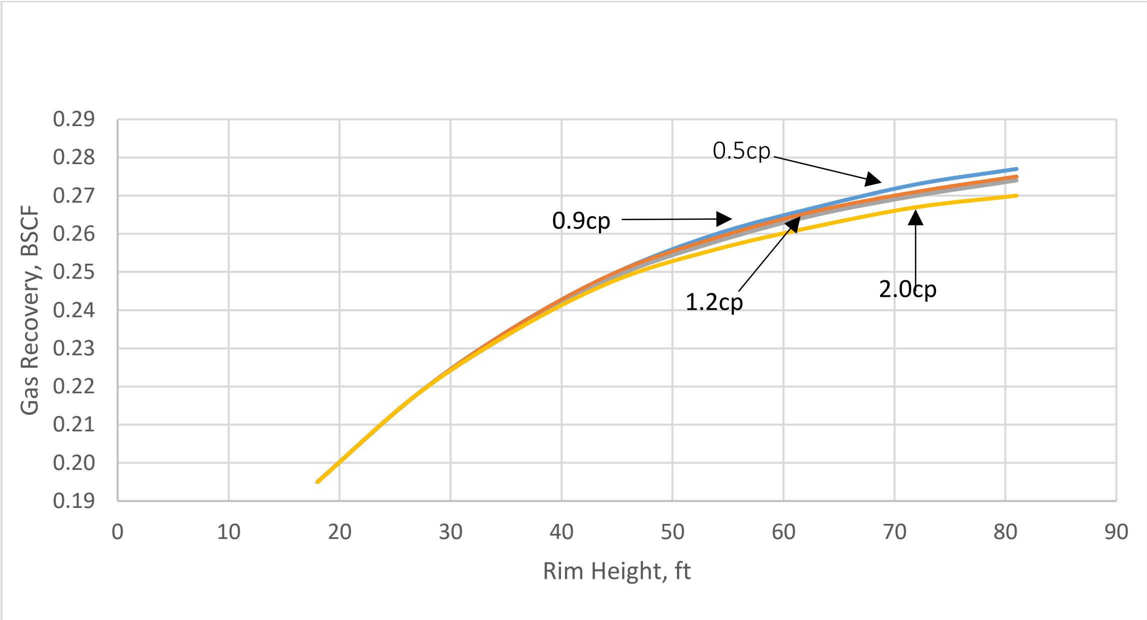

Figure A8 Effect of Viscosity on Gas Recovery at varying Oil Rim Thickness

Sensitivity on Horizontal well placement

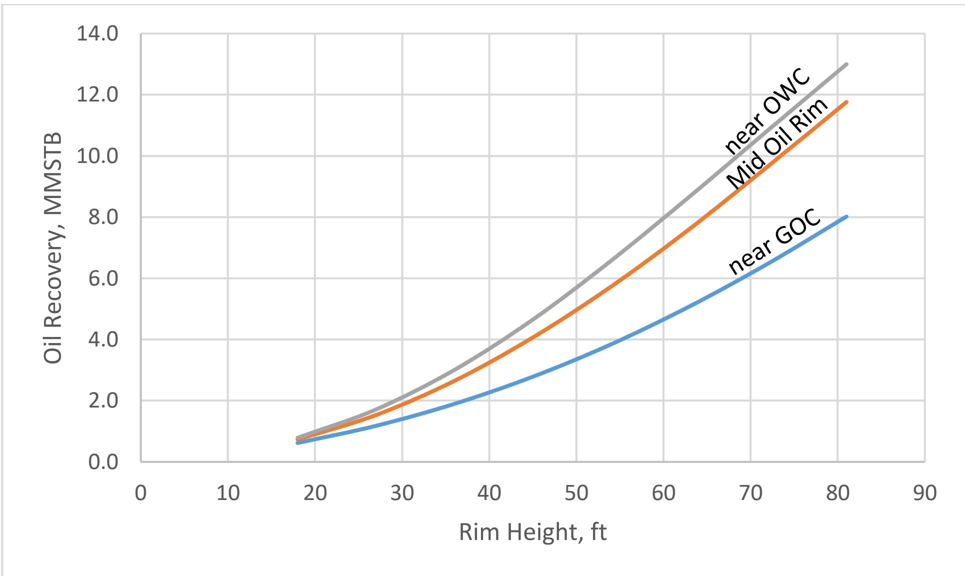

Figure A9 Effect of Horizontal Well Placement on Oil Recovery at varying Oil Rim Thickness

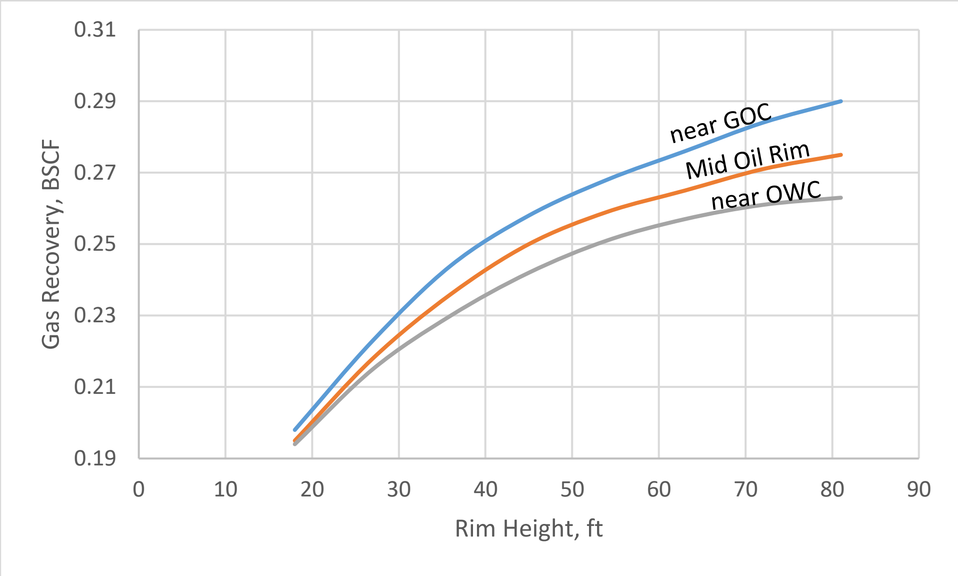

Figure A10 Effect of Horizontal Well Placement on Gas Recovery at varying Oil Rim Thickness.

Sensitivity on horizontal well length

For this particular sensitivity analysis, the well lengths considered ranges from 410-820m.

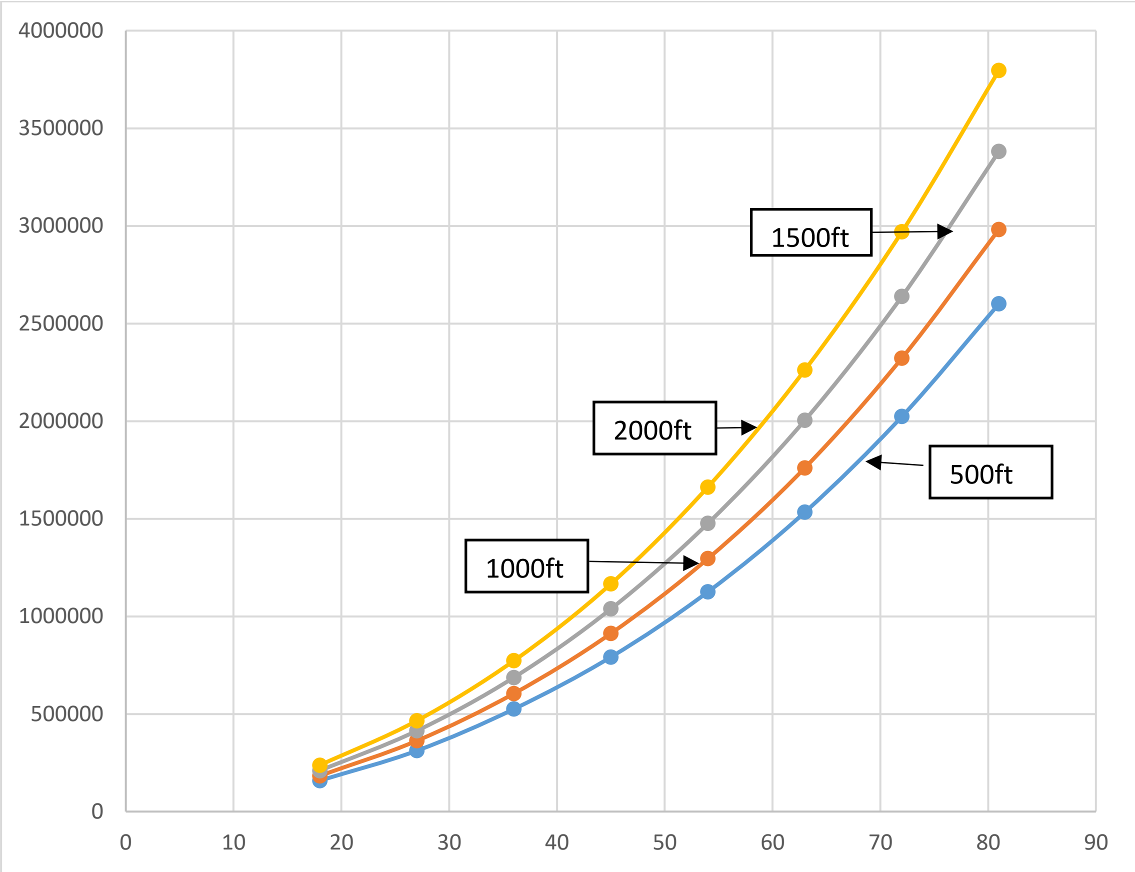

Figure A11 Effect of Horizontal Well Length on Oil Recovery at varying Oil Rim Thickness (Region A)

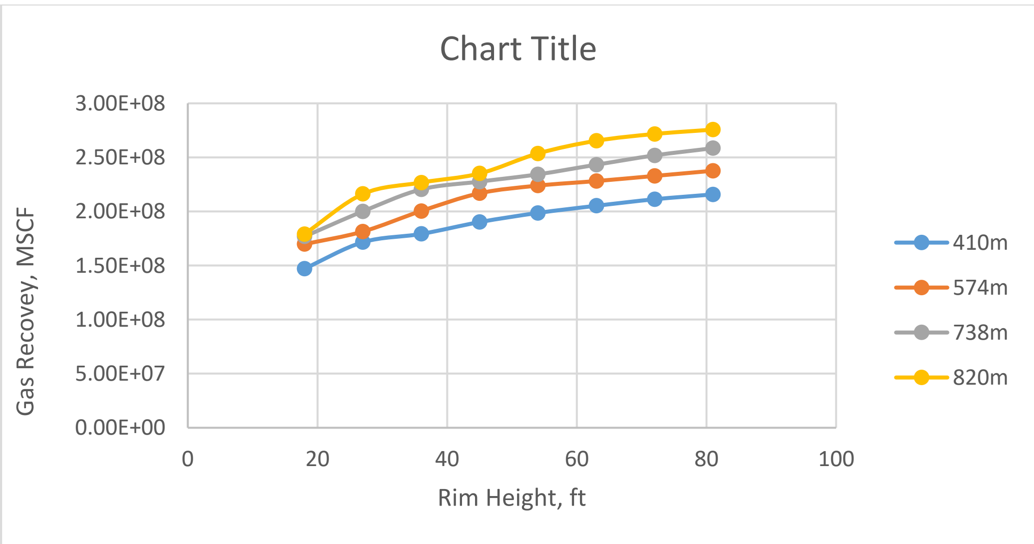

Figure A12 Effect of Horizontal Well Length on Gas Recovery at varying Oil Rim Thickness (Region B).

Sensitivity on Well Configuration

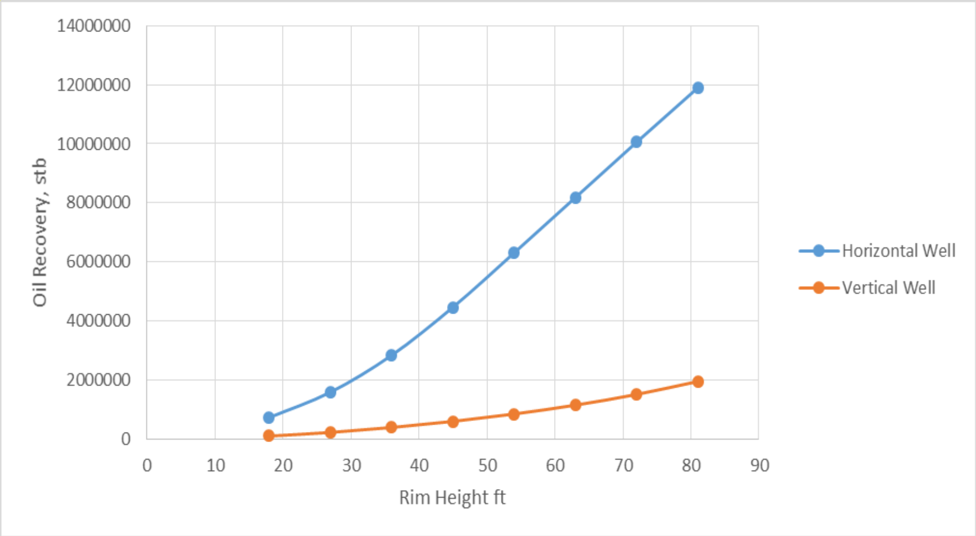

Figure A13 Effect of Well Configuration on Oil Recovery at varying Oil Rim Thickness

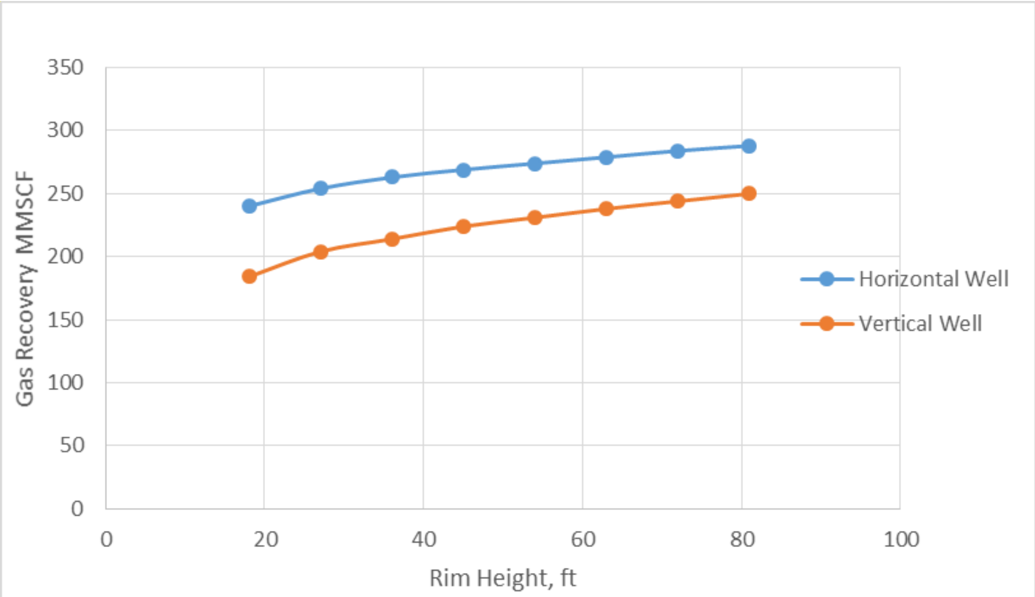

Figure A14 Effect of Well Configuration on Gas Recovery at varying Oil Rim Thickness

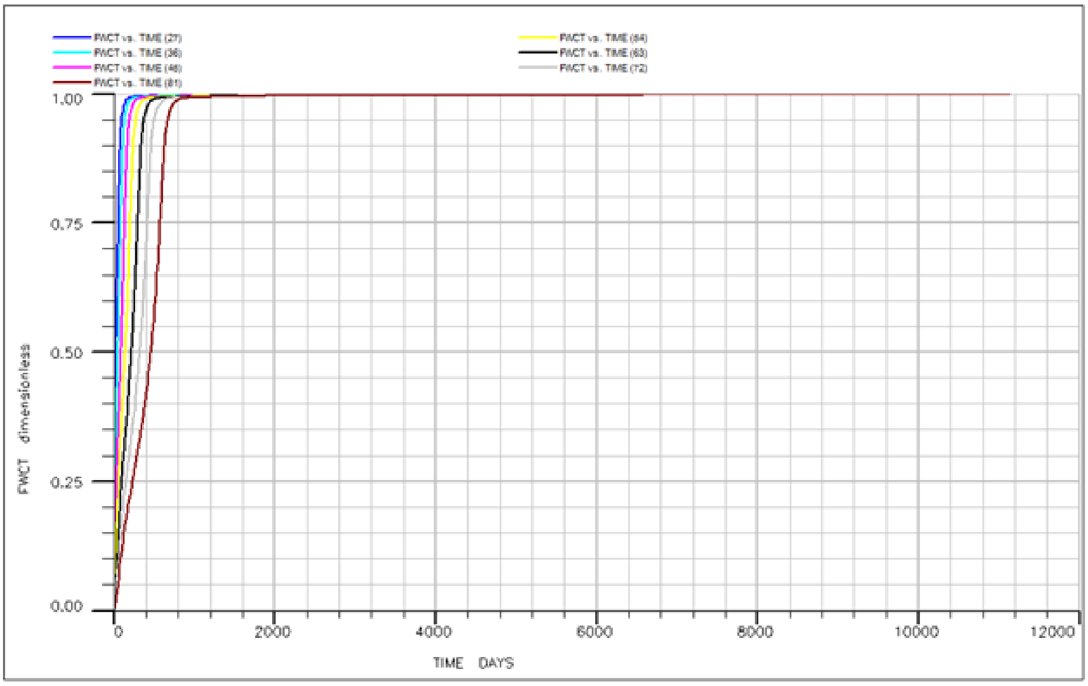

Figure A15 Water- Cut for Vertical Well- Oil Rim only Development Concept

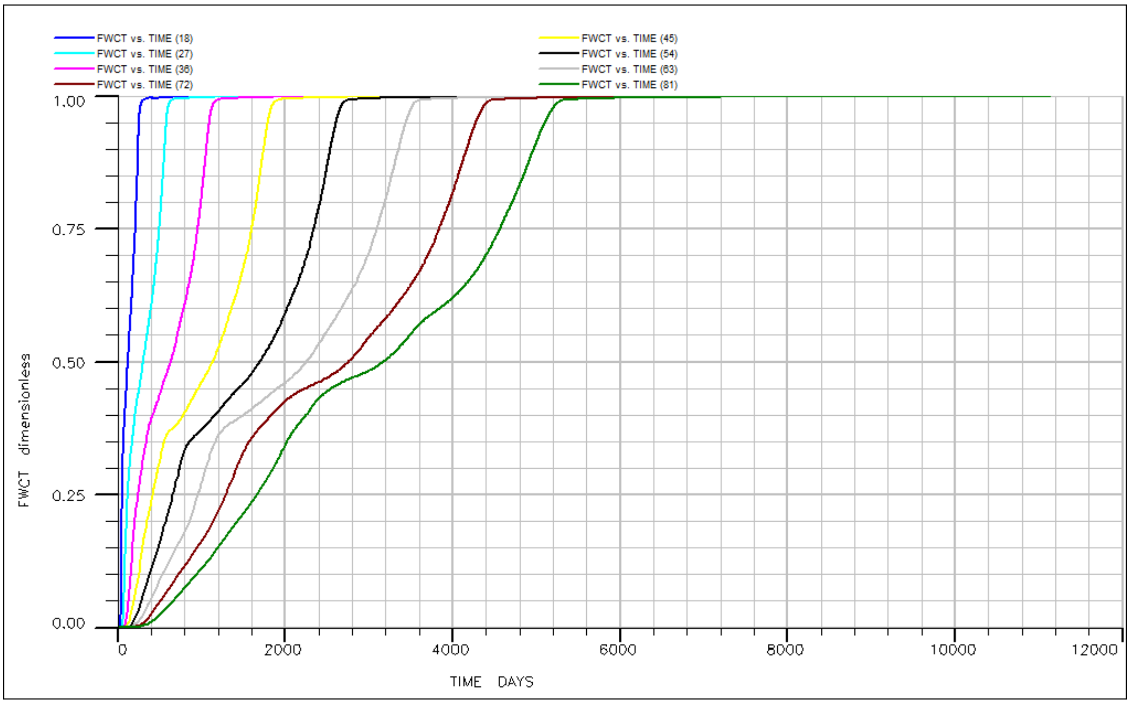

Figure A16 Water-Cut for Horizontal Well at different Oil Rim Thickness- Oil Rim only Development Concept

Sensitivity on BHP

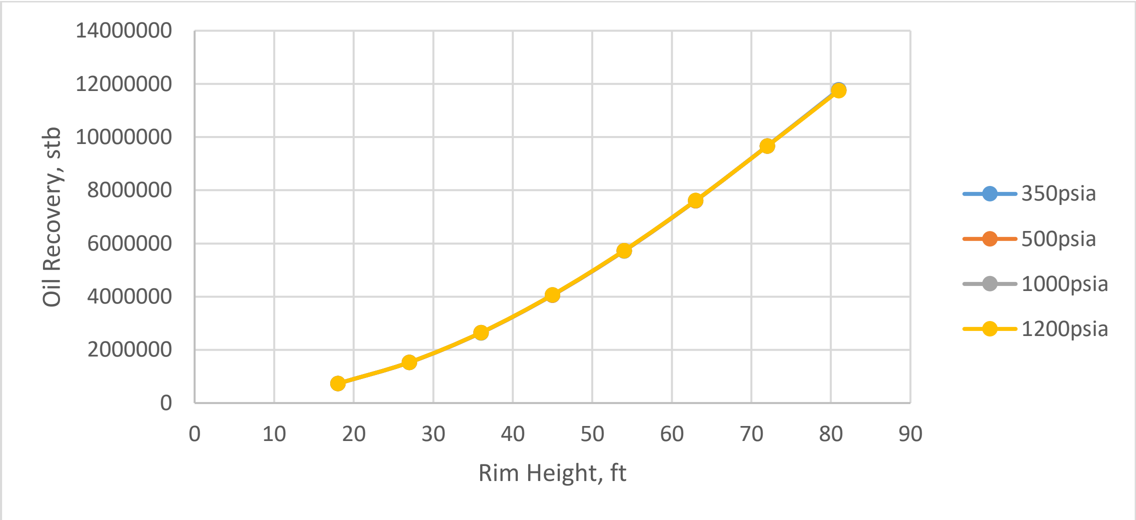

Figure A17 Effect of BHP on Oil Recovery at varying Oil Rim Thickness

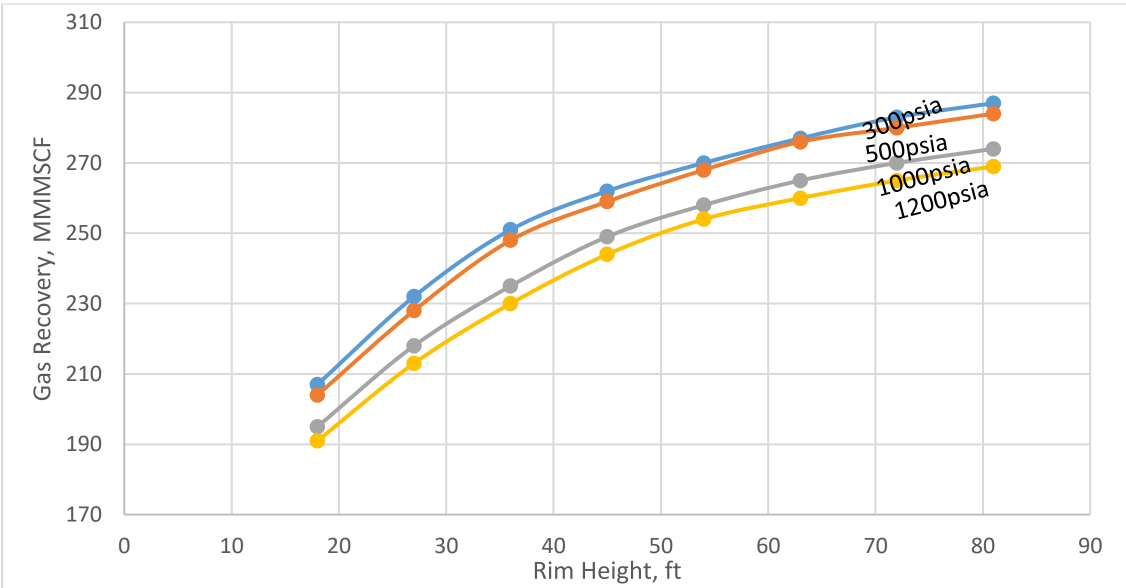

Figure A18 Effect of BHP on Gas Recovery at varying Oil Rim Thickness

Concurrent Oil and Gas Development Concept

Sensitivity on Aquifer strength

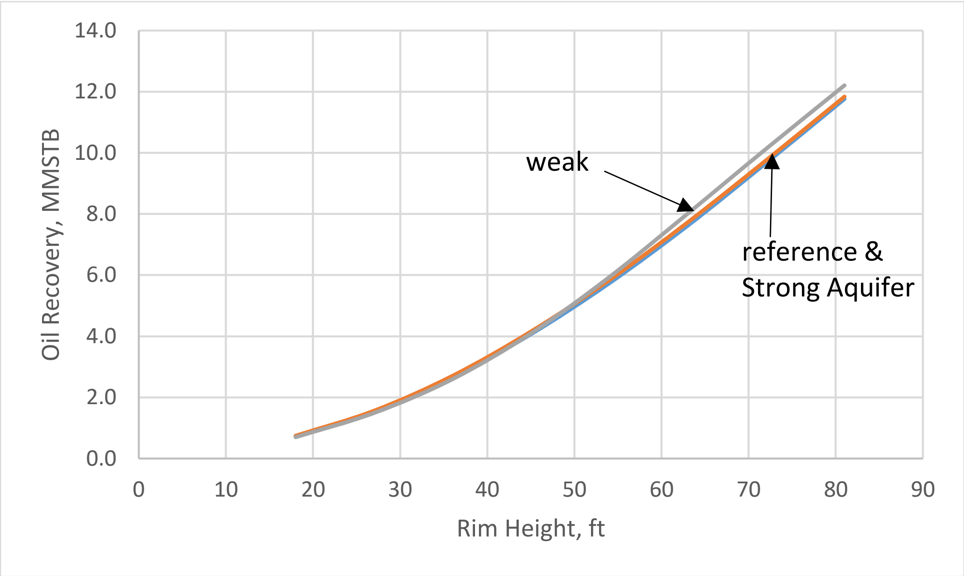

Figure A19 Effect of Aquifer strength on Oil Recovery at various oil rim thickness

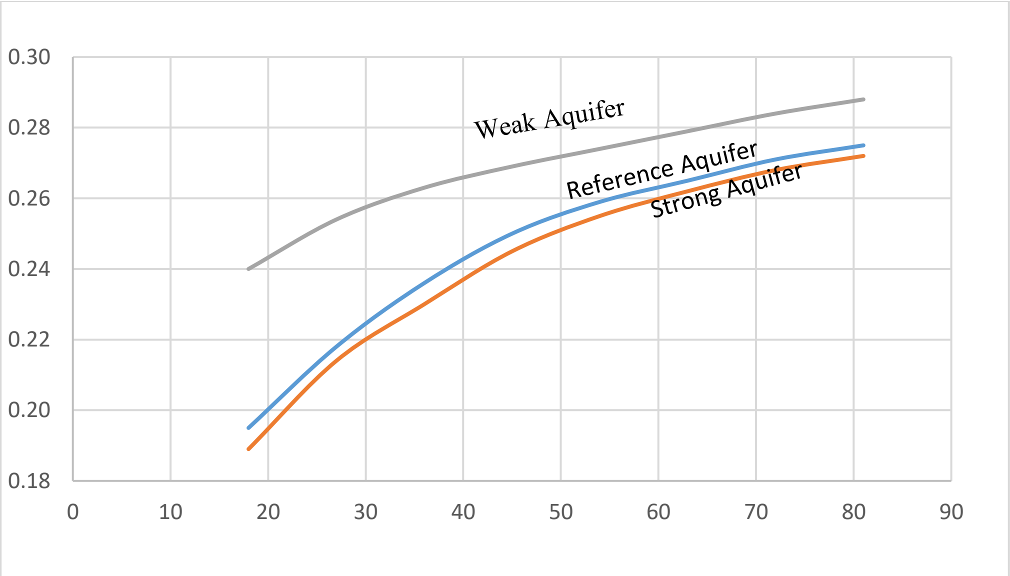

Figure A20 Effect of Aquifer strength on Gas Recovery at various oil rim thickness (Concurrent)

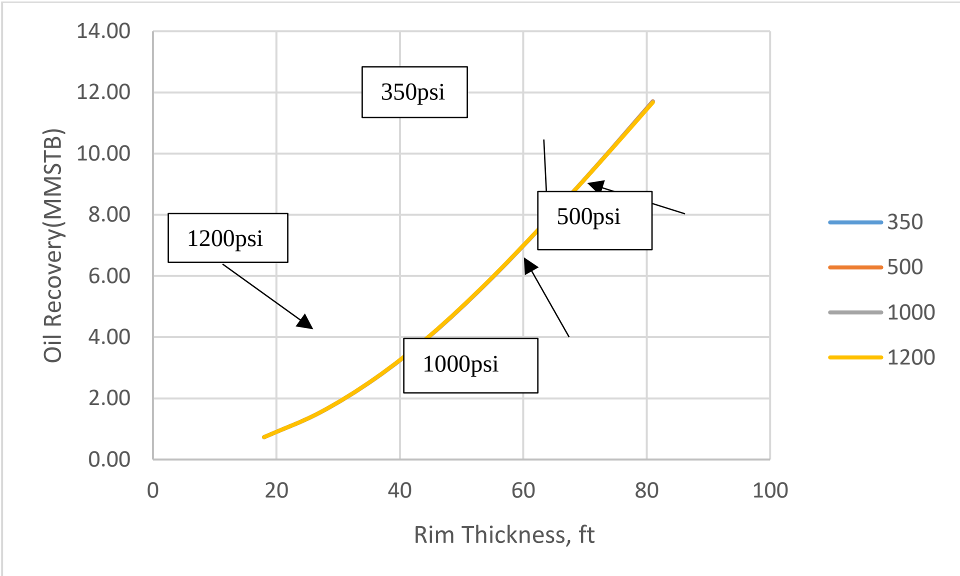

Figure A21 Effect of BHP on Oil Recovery at various oil rim thickness (Concurrent)

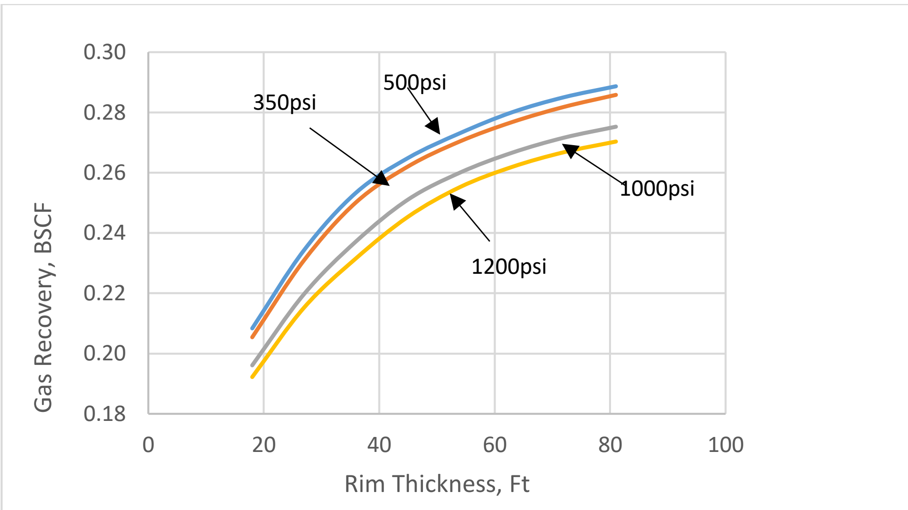

Figure A22 Effect of BHP on Gas Recovery at various oil rim thickness (Concurrent)

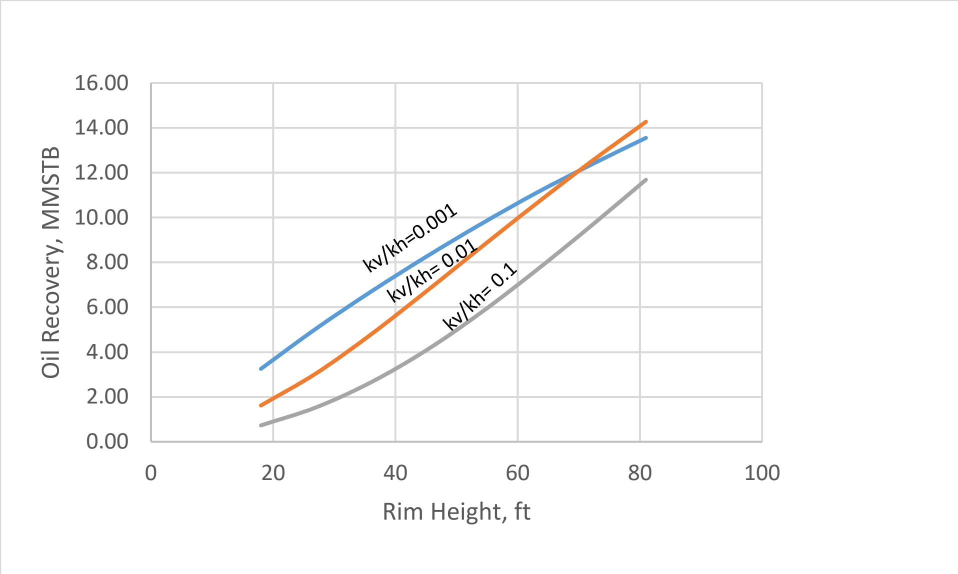

Figure A23 Effect of anistrotopy kv/kh on Oil Recovery at various oil rim thickness

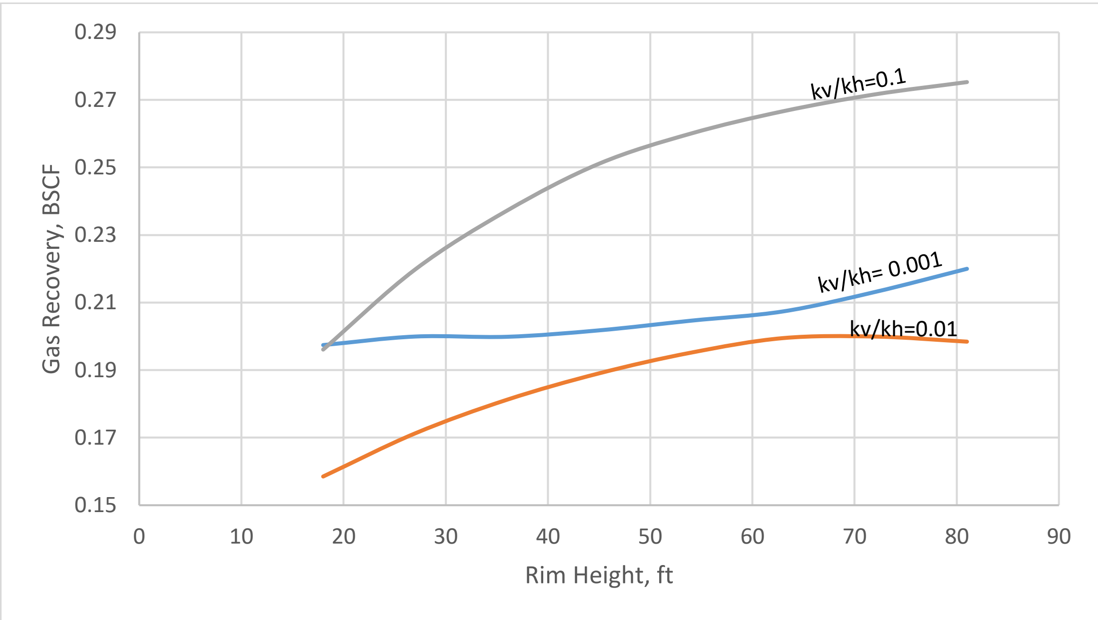

Figure A24 Effect of kv/kh on Gas Recovery at various oil rim thickness (Concurrent)

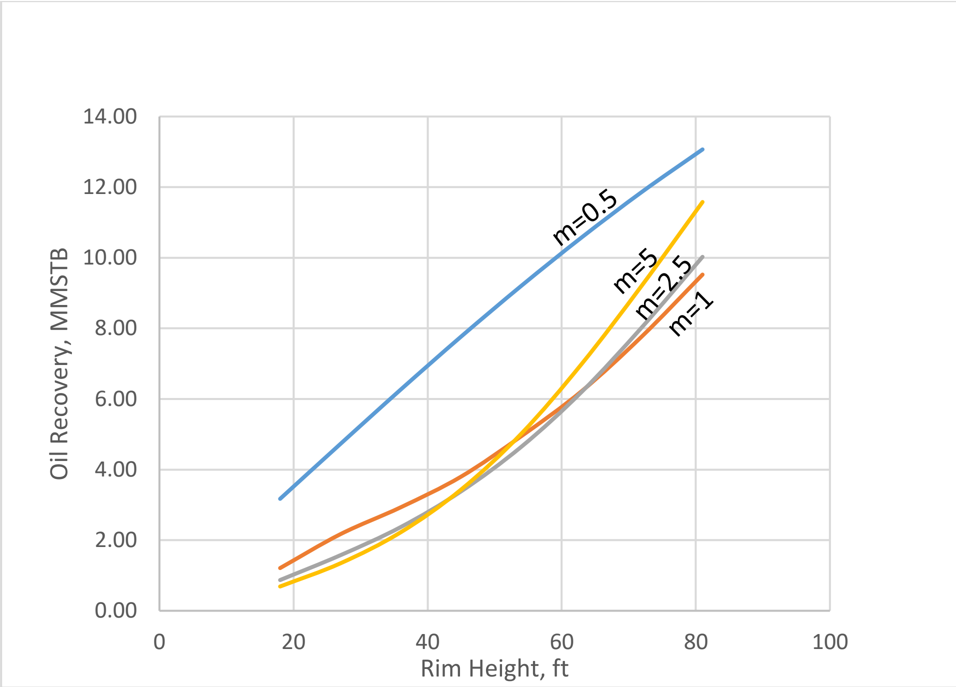

Figure A25 Effect of m-factor on Oil Recovery at various Oil Rim thickness (Concurrent)

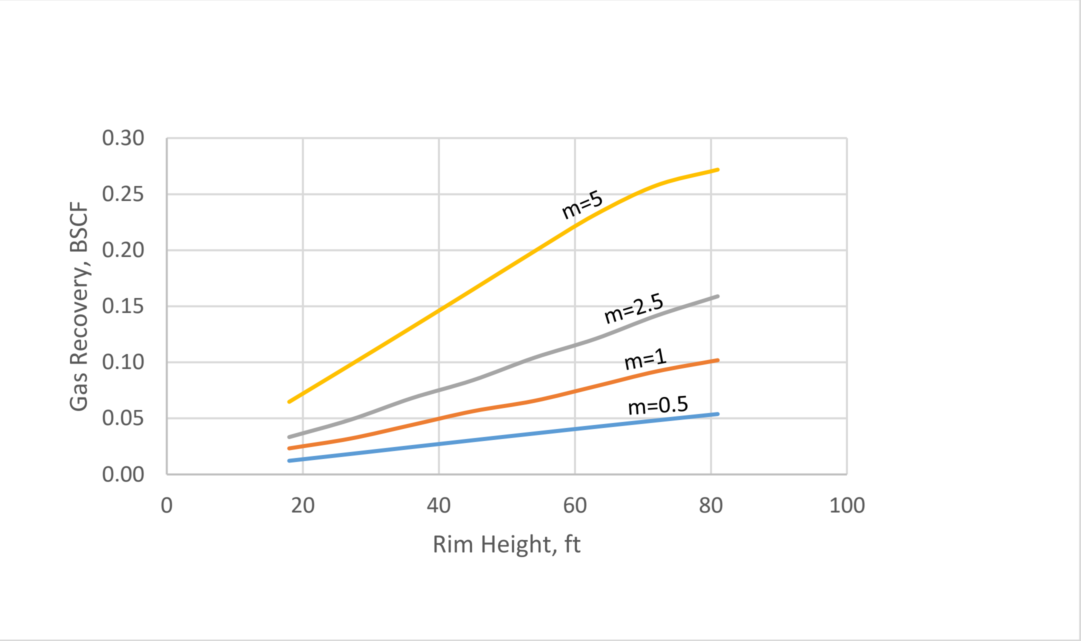

Figure A26 Effect of m-factor on Gas Recovery at various Oil Rim thickness

Sensitivity on well length

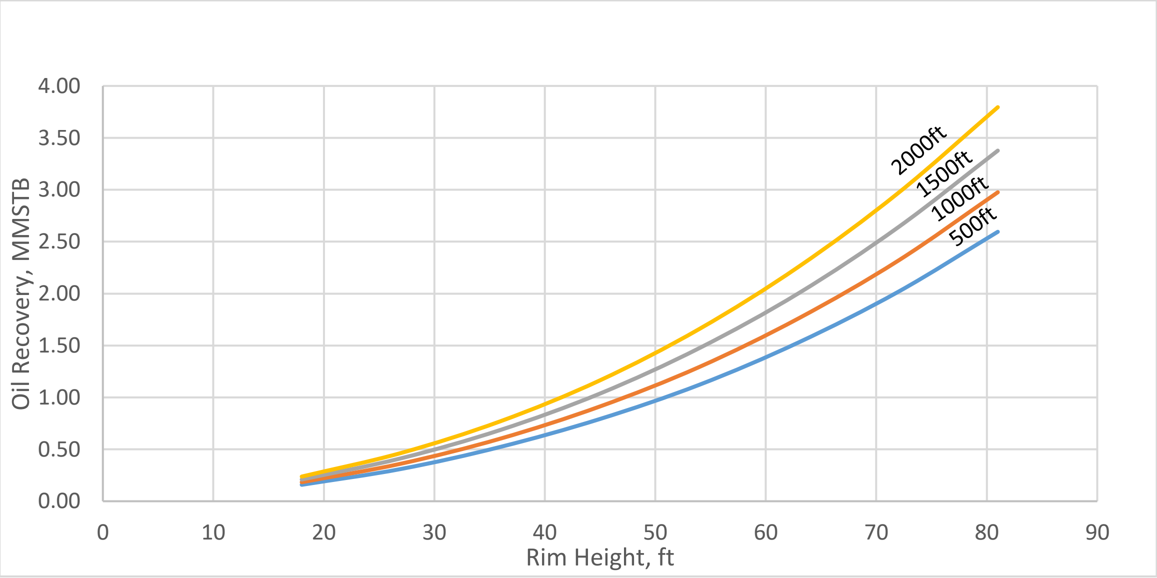

Figure A27 Effect of Horizontal Well Length on Oil Recovery at various Oil Rim thickness

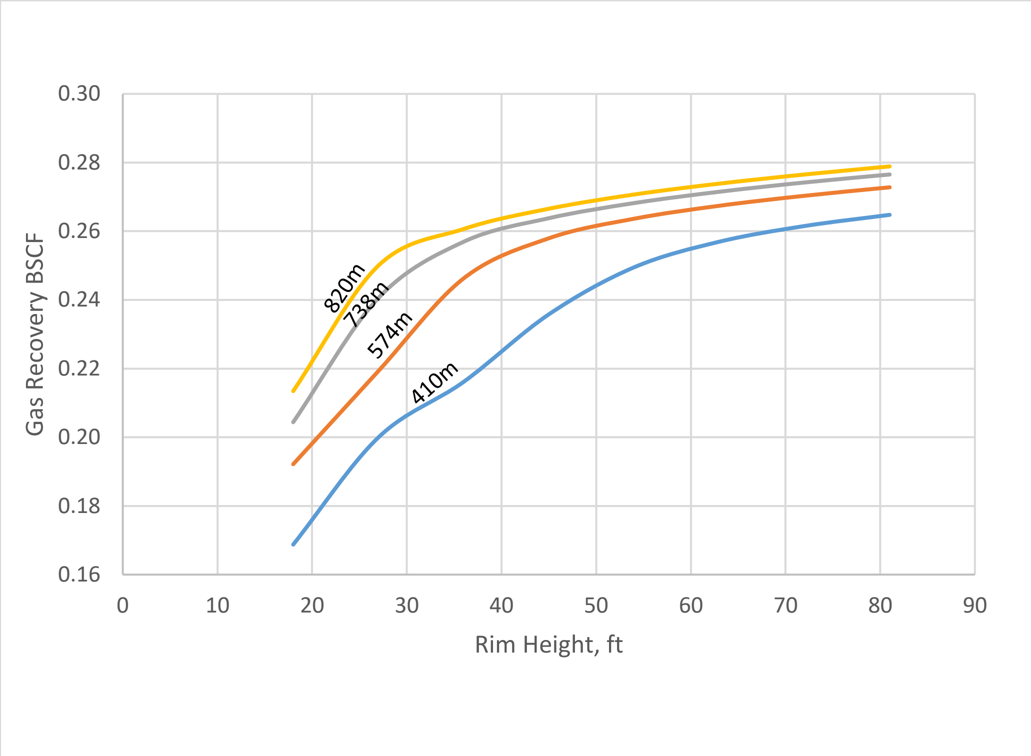

Figure A28 Effect of Horizontal Well Length on Gas Recovery at various Oil Rim thickness

Sensitivity on permeability

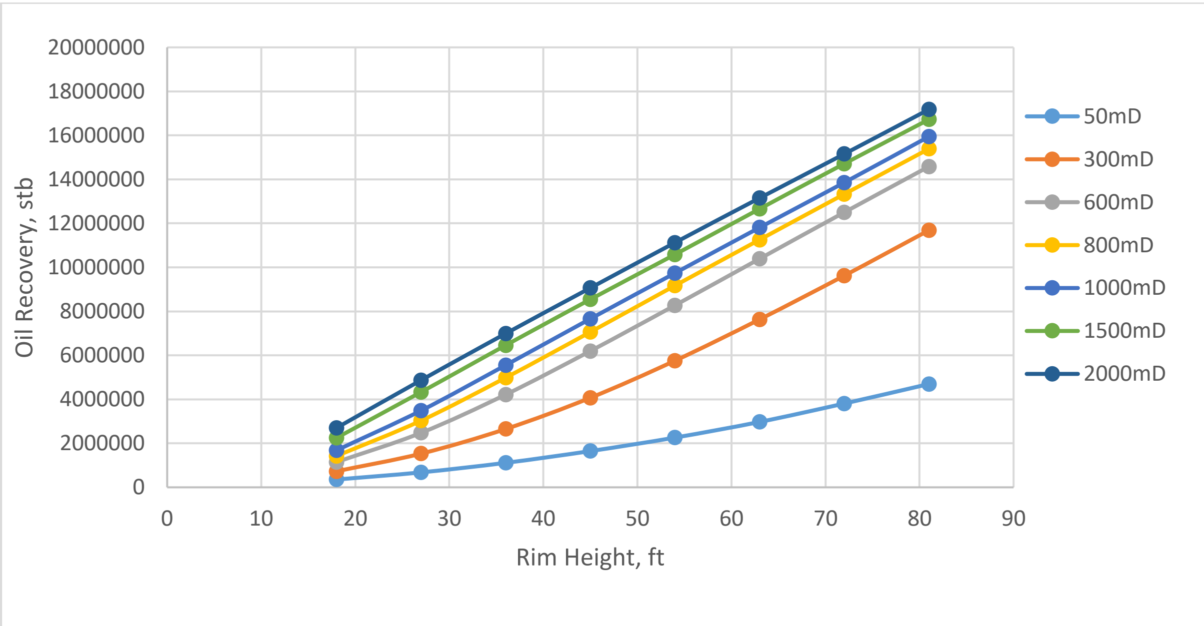

Figure A29 Effect of Permeability on Oil Recovery at various Oil Rim thickness

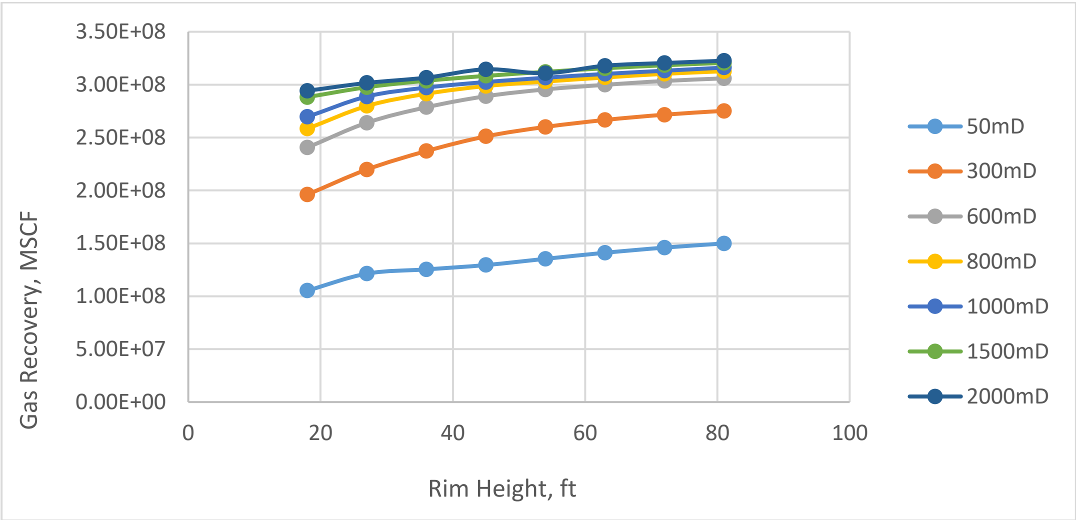

Figure A30 Effect of Permeability on Gas Recovery at various Oil Rim thickness

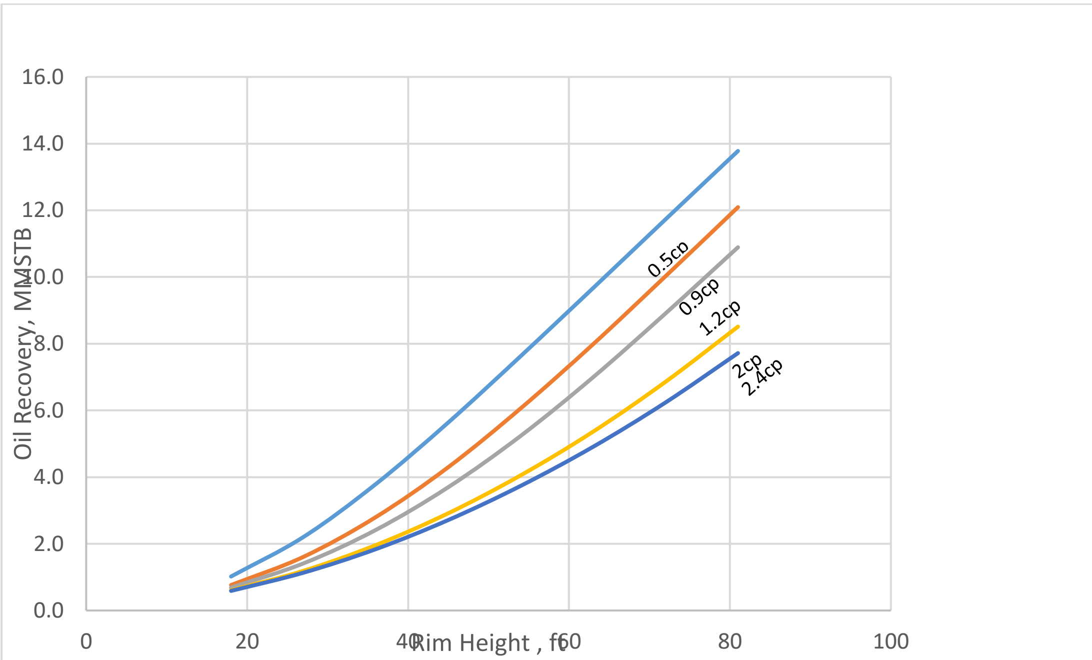

Figure A31 Effect of Viscosity on Oil Recovery at various Oil Rim thickness

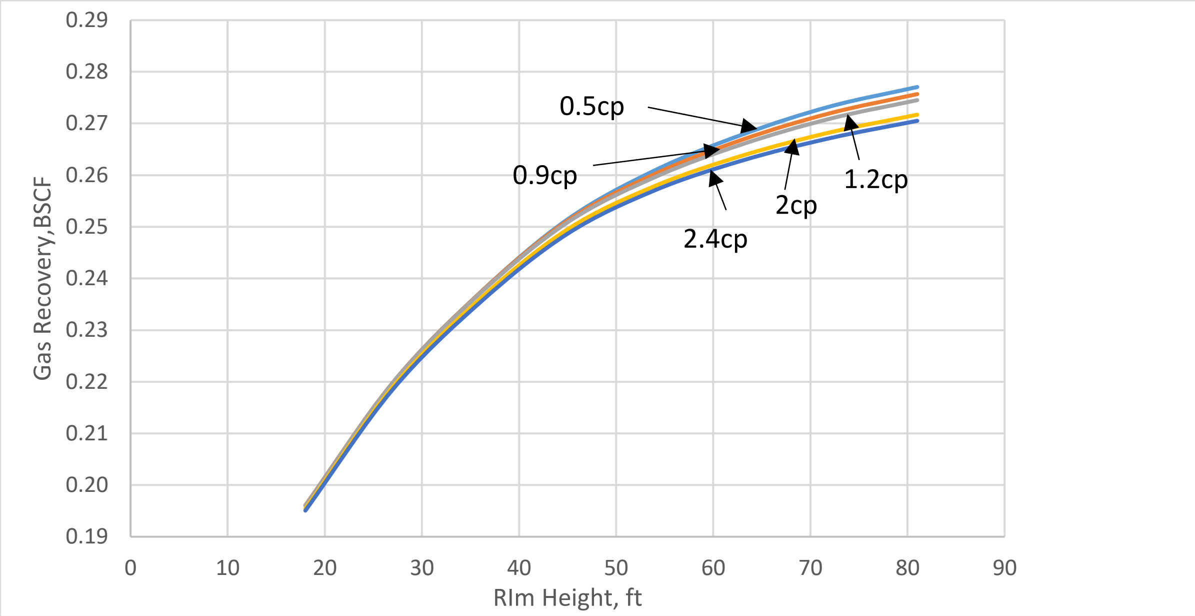

Figure A32 Effect of Viscosity on Gas Recovery at various Oil Rim thickness (Concurrent)

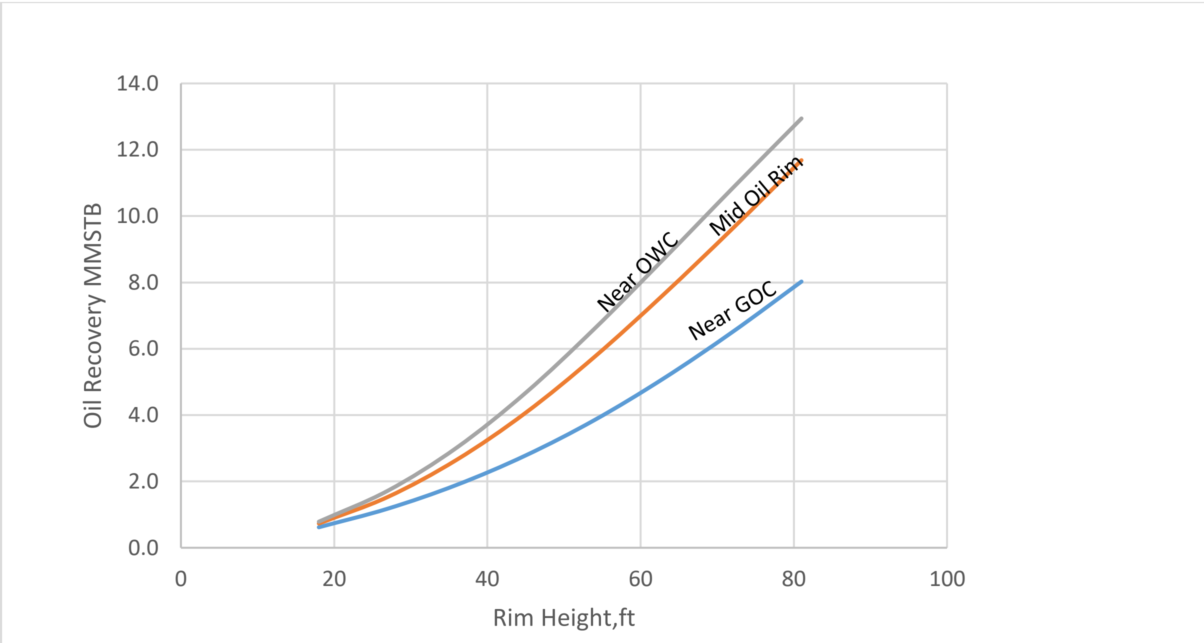

Figure A33 Effect of Horizontal Well Placement on Oil Recovery at various Oil Rim thickness. (Concurrent)

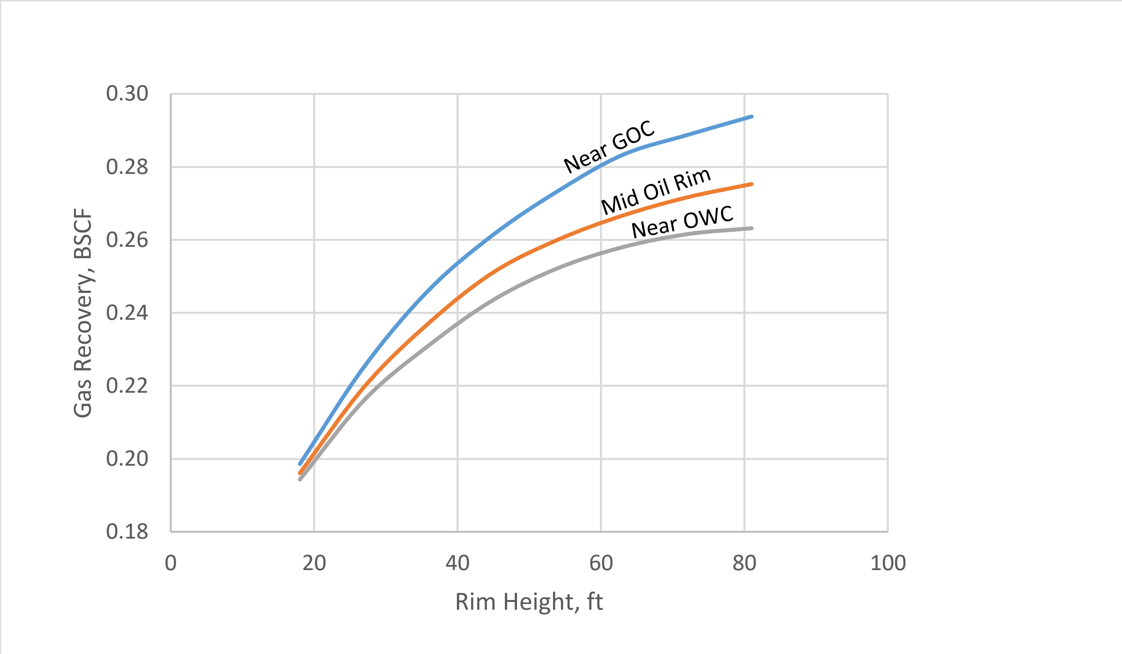

Figure A34 Effect of Horizontal Well Placement on Gas Recovery at various Oil Rim thickness

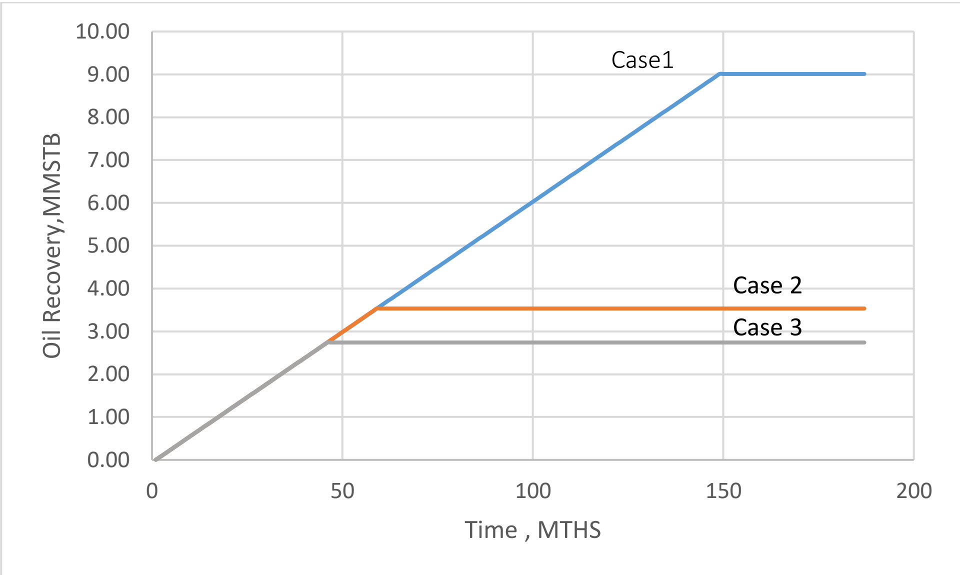

Figure A35 Graph showing the comparison of the 3 different perforation schemes with a perforation density of 20%

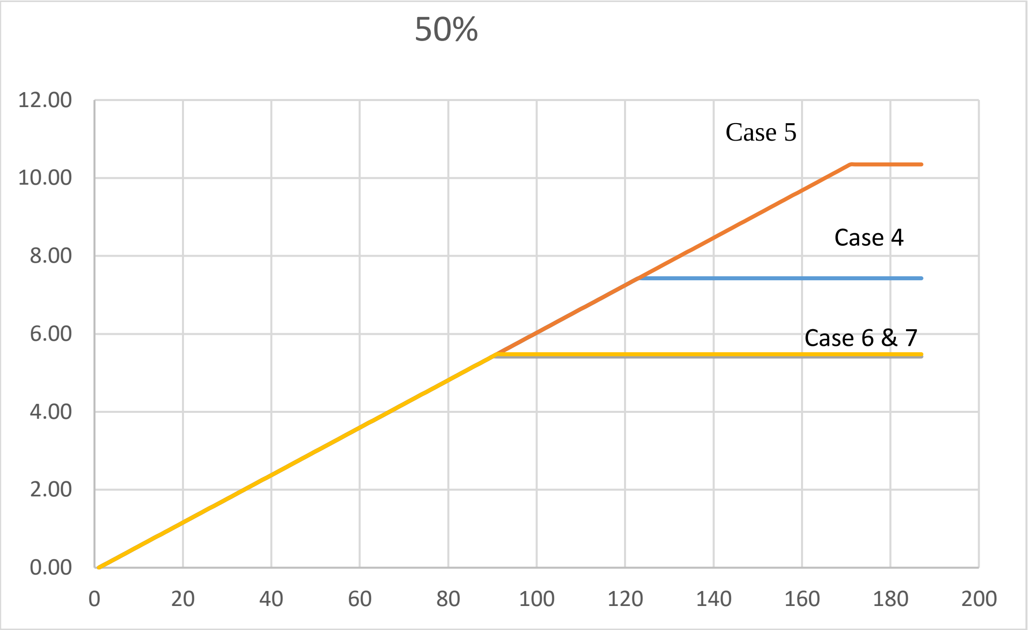

Figure A36: Graph showing the comparism of the 4 different perforation schemes with a perforation density of 50%

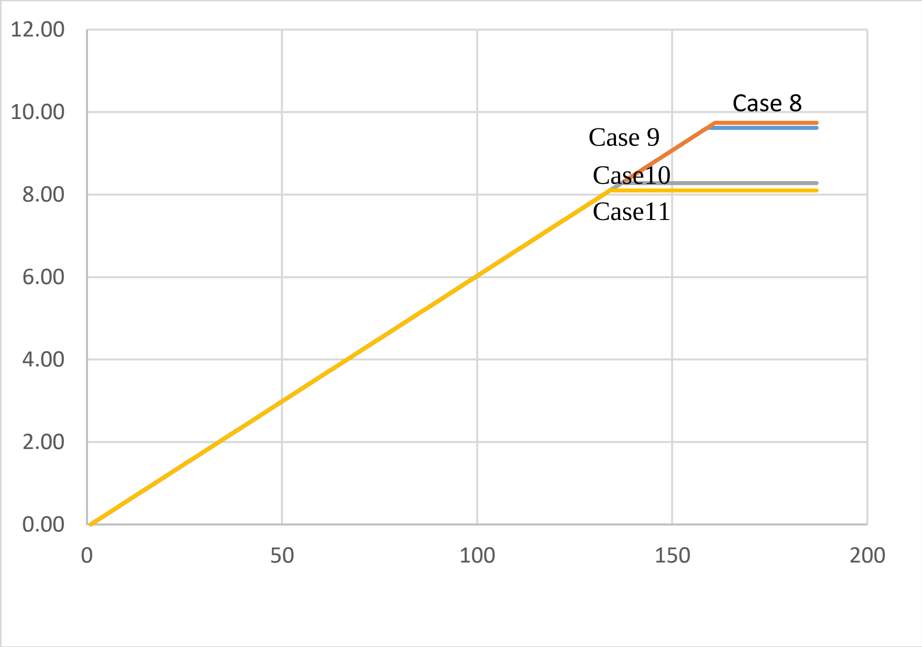

Figure A37: Graph showing the comparism of the 4 different perforation scheme with a perforation density of 80%

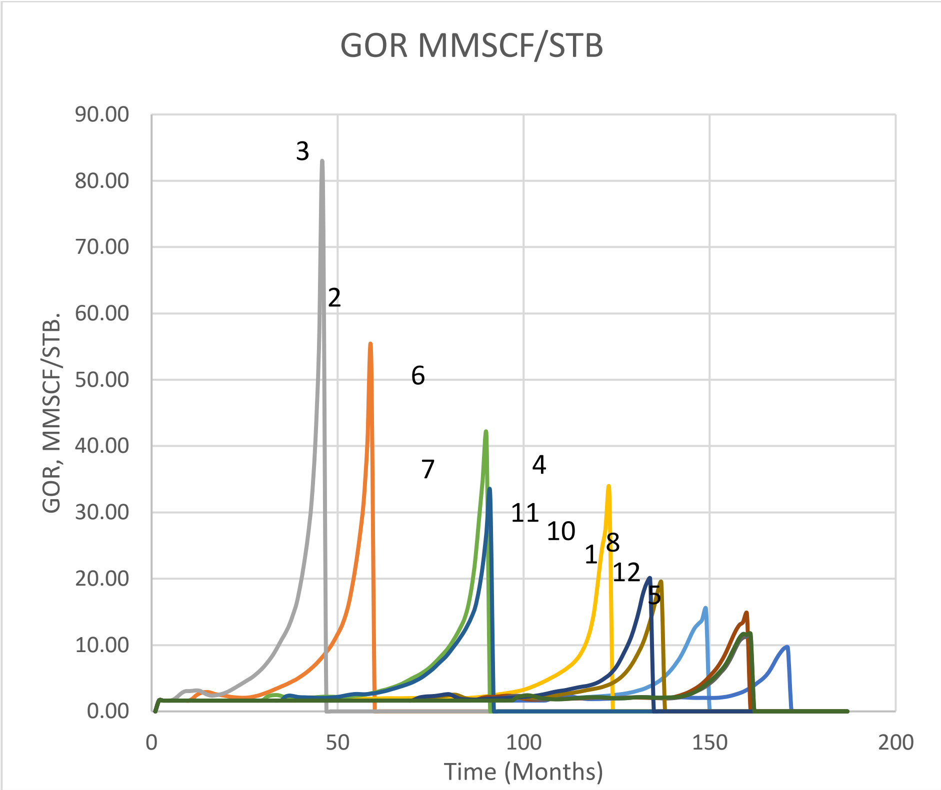

Figure A38: GOR for the different perforation schemes for 192months (16years)