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Evaluation of uncertainties of thin oil turbidite reservoir using Experimental Design

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Abstract

This thesis concludes the degree of Master in Reservoir Engineering at the NTNU. The thesis was conducted in collaboration with Maersk Oil Company in order to provide to the intern valuable experience by using the reservoir simulator Eclipse and the software Petrel, commonly applied in the oil industry. The report describes an application of different studies performed in a real thin oil rim reservoir. It is oil with gas cap field located in the west of Africa. The reservoir consists of various channels, which divide it into several compartments with different heterogeneity and fluids oil contacts. In order to gain flexibility and ease testing all studies were conducted in a sector model, consisting of the main compartment of the field.

The main goal of this thesis was to evaluate the uncertainties of the reservoir discovery using experimental design. In this study the key uncertain parameters were relative permeability, horizontal permeability and rock compressibility. A secondary objective was relate with coning study, where the main objective was to estimate the critical oil production rate through analytical correlations and numerical simulation, using available reservoir modeling tools. The greatest challenge was obtaining a LGR resolution model with acceptable resolution and CPU time, intending to improve simulation accuracy on the well bore region and to best capture the cone. The process was time consuming and tedious but leaded to satisfactory results. Finally, the report also describes three development schemes with water and gas injection producing under critical oil rate, where the scenario with both gas and water injection shows to be the most favorable scenario with 26% of oil recovered, and a coherent solution to handle gas.

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Nomenclature

Sm^3: Surface Cubic meters

AHM: Assisted History Matching

API: American Petroleum Institute

AVO: Amplitude versus Offset

BHP: Bottom hole pressure

DST: Drill stream test

ED: Experimental Design

EOS: Equation of State

FGOR: Field Gas Oil Ratio

FOPT: Field Oil Production Total

FWCT: Field Water Cut

GIIP: Gas Initially In Place

GOC: Gas Oil Contact

GOR: Gas Oil Ratio

Km: Kilometre

LGR: Local grid refinement

m^2: Square meters

mD: milli Darcy

Multpv: Pore Volume Multiplier

OIIP: Oil Initially In Place

OPT: Oil production total

Permultx: Horizontal Permeability multiplier

Permultz: Vertical Permeability multiplier

PI: Productivity index

REIN: Control mode for gas injection by reinjection of produced gas (fraction or all)

SCAL: Special core analysis

Sorw: Residual oil on water saturation

TUNING: Sets simulator control parameters, Eclipse100 keyword

TUNINGL: Sets simulator control parameters on LGR, Eclipse100 keyword

TVD: True Vertical Depth

VBA: Visual Basic for Applications

VREP: Control mode for water injection by voidage replacement (fraction or all)

WCT: Water cut

WGPR: Well Gas Production Rate

WOC: Water Oil Contact

WOPT: Well Oil Production Total

WTHP: Well tubing head pressure

Ye: Half Drainage area

CHAPTER I – INTRODUCTION

1.1-Problem Description

A strategic development project of an oil field aims as a general rule to accelerate the hydrocarbon production and maximize the recovery at a lowest cost. For thin oil rim reservoir with a large gas cap on top and a strong aquifer on bottom, achieving such goal can be very challenging since recovery of oil shall be maximized. This trend has initiated increasing efforts to improve advanced technologies in order to make less expensive and more profitable the exploitation of thin oil reservoirs. Since, some of them were abandoned in the past, being characterized as non-commercial reserves due the inexistence of adequate technologies. In this context today are notable few reserves around the world, which initially thought to not have any commercial value at first evaluation.

One of the most challenging tasks that such reservoirs present is related to its complicated production mechanism. Due to the very thin oil zone and pressure drawdown around the well bore, during the production process fluid interfaces are not stable during the production process thereby a phenomenon referred as coning or cresting depending on the well completion (Khalili, 2005). While coning is related with the fluid motion towards the perforation of a vertical well, cresting happens when comes to horizontal wells. Therefore, many authors address the problem only as coning. The term cone is nothing more than the tendency of gas and water to push oil towards the well in a cone shaped contour. It occurs when viscous forces exceed gravity forces near the well bore of a producing well. As soon as the cone breaks through the well, gas or water production increases substantially leading a drastic drop in reservoir pressure and consequently affecting the oil production (Kazeem et al, 2010). Surface Constraints are a critical element in the development of oil rim.

In fact, after a certain period of production a reservoir often presents high production level of gas or water, when its respective lines of contact with oil reach the perforation, but this should not be confused with coning phenomena; where the unwanted fluids due the tortuosity of the reservoir find channels to flow and easily reach the perforations. It is important to highlight that cone is more likely to occur when a well is producing at high rates. Coning problem in thin oil reservoirs can occurs even sooner than in conventional reservoirs, affecting seriously the overall recovery efficiency, leaving significant amount of oil behind and consequently increase cost of production operation (Olamigoke et al, 2009).

As this thesis work is focused on a specific thin oil reservoir, which is considered a three fluid phase system the Muskat and Wyckoff method was discarded in this study. In order to portray a similar panoramic of the reservoir under study an especial attention will be given to Work-Bench and Proxi model correlations; which are a three phase, black oil model and suitable for coning.

In general this thesis work addresses the double coning problem of thin oil rim reservoirs with a horizontal well. In order to provide some understanding the mathematical and physical principles behind this process are briefly reviewed.

For the propose of evaluate uncertainty and impact of the various parameters a sensitivity study will be performed, where a number of possible scenarios characterized by different combination of petrophysical and fluid properties was conducted and the obtained results will be displayed and discussed with respect to their simplifying assumptions.

1.2 - Objective

The main objective is to evaluate uncertainty on recovery factor of an oil-rim reservoir using reservoir simulation and Experimental Design.

Others objectives will be also considered such us:

- Understanding the physics behind the cone phenomena.
- Providing an overview of the most relevant parameters that affect water/gas coning by using analytical calculations.
- Improving simulation accuracy on the well bore region in order to best capture the cone by using LGR.
- Accessing uncertainties parameters that most affect the overall oil recovery and how to deal with by using experimental design tool.
- Investigating a development scheme with water and/or gas injection.

CHAPTER II – LITERATURE REVIEW

Attenuate gas or water coning problems during oil production in conventional oil reservoirs is a challenge task but deal with such problem in a thin oil rim reservoir make the process even more complex. Therefore, this chapter outlines concepts behind the coning phenomena and ways to handle it when refers to thin oil accumulations. A few models that can be used to predict critical rate will be mentioned. Procedures used in analytical as well as numerical simulation will be pointed, and its utilities will be discussed.
Then, chapter will give a review of the uncertainties inherent in reservoir with associated impact, and a brief overview of experimental design methodologies as current practice widely used in the industry in quantifying and assessing uncertainties.

2.1- Coning concepts

The term coning is used to describe the mechanism of unwanted fluids trend to flow into the perforation of a production well in a coning shape, due the viscous and gravitational forces in a reservoir. In a system with distinct fluids phase two forces act upon the interface between the oil and the unwanted fluid: viscous forces that result as consequence of fluid production and gravitational forces that arise from the density difference between the two fluids and which tend to counterbalance the viscous forces. If the viscous forces exceed the gravitational forces, then a cone is formed and grows towards the wellbore until the viscous forces at some elevation. If such balance is never achieved, the cone continues to grow and the unwanted fluid breaks into the wellbore (Ozkan et al, 1990). Coning occurs when viscous forces dominate.

The term coning is used because, in a vertical well, the shape of the interface when a well is producing the second fluid resembles an upright or inverted cone. The figure 1 shows a double coning in a vertical well.

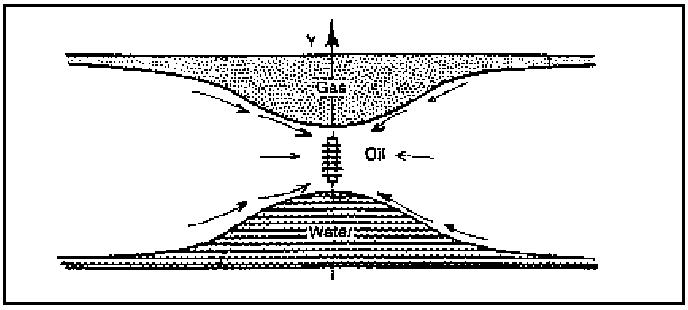

Figure 1 - Double coning in a vertical well

In fact, there are three essential forces playing key role in the coning mechanism. They are capillary, gravity and viscous forces. For simplicity, the process is assumed to be dominated by viscous forces and capillary forces are therefore neglected. Before production, the gravity force, which is a consequence of the density difference between the fluids, is dominant. Once a well is allowed to produce oil, the viscous forces which result from pressure drawdown increase. In order to counterbalance the system, water oil contact (WOC) deforms and moves up until viscous force is balanced by the gravitational force at a certain elevation, that is, at a certain flow rate, there is a point at which a balance can be achieved between the viscous force and the gravity force. If such a balance is never achieved the cone will be dragged up until it will break into the wellbore (Veskimägi, 2013). The shape and the nature of the cone depend on several factors such as production rate, mobility ratio, horizontal and vertical permeability, well penetration and viscous forces.

In a horizontal well, the cone becomes more of a crest (fig. 2), but the phenomenon is still called coning. In the recent years the application of horizontal wells technology has arisen as advantageous solution, for coning problems. Since, the amount of undesired second fluid of a horizontal well is usually less than for a vertical well under equal conditions. In the reality turn out that due the greater wellbore length exposed to the pay zone, more oil would be seeped, besides the pressure drop around the wellbore will be lower, leading to increase the time of the natural production and consequently increasing the overall recovery. This fact has generally motivated the use of horizontal wells, in thin oil columns sandwiched by gas and water (Zakirov et al, 1996).

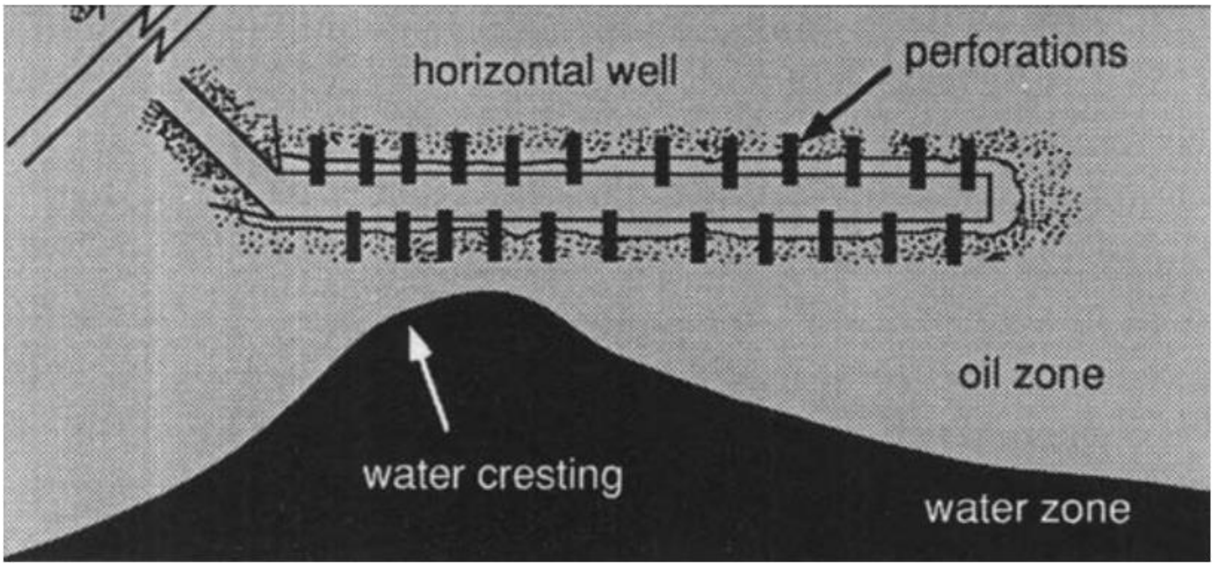

Figure 2 - Coning in a horizontal well

2.1.1 - Impact of coning

Gas and water coning hinder effective oil production as the cone breaks through the oil column, gas or water production increases substantially leading a drastic drop in reservoir pressure and consequently on the well productivity. Coning problems can seriously impact the overall recovery efficiency of an oil reservoir in several manners (shaykhutdinov, 2008).

One of the serious problems lies on fact of deal with huge volumes of gas, (which may or not have a market) and water produced to the surface. If the water contains salts such as sodium chloride, these can corrode production facilities, and the produced fluids must be separated before transporting to the refinery (Onwukwe et al, 2012). Besides, in terms of cost it implies increase operating expenses with some extra surface facilities to separate the produced water from oil and all lead to reduced revenue.

2.1.2 - Cause of coning

Silva et all (2010) claim that the increasing production of unwanted fluids coming from coning problems is generally associated with high producing rates.
The rate above which the pressure gradients in the system cause the cone to break into the well is defined as the critical production rate in the literature. Even when all the assumptions of the critical rate concept hold, technical and economic necessities may enforce production rates above the critical rate (Makinde et al, 2011). It is therefore important to predict the evolution of the cone and the time breakthrough so that future completion and production schemes can be envisaged.

2.1.3 - Handle the coning

Unfortunately, coning formation cannot be avoided in reservoirs with a thin oil-bearing layer, sandwiched between gas cap and bottom or edge water, and in such cases both gas and water coning can occur simultaneously. In consequence, the exploitation of these reservoirs poses a challenge for reservoir development, as early gas and water coning severely hinder maximum oil recovery. Alleviating these challenges by reservoir management involves knowing where the fluid contacts are, optimization of well placement and predict a critical rate that will generate a stable and controlled cone below the perforation.

In general operating a production well at critical rate is usually appointed as the most efficient way to avoid anticipated coning problems. Hamed (2000), defines the critical production rate as the rate above which the flowing pressure gradient at the well causes gas or water to cone breaking into the well. In other words it is the maximum rate of oil production without concurrent production of the displacing phase by coning. However, due to economic necessities, oil companies often produce at a rate higher than critical coning rate. This causes water or gas coning or simultaneous coning of water and gas. Therefore, if the oil flow rate of a well exceeds the critical coning rate calculated for this well the cone becomes unstable and will break into the wellbore after a certain time. At this stage, the well performance becomes important, it merits careful attention and having knowledge of breakthrough time may help to improve well management and extend well life without production of water or free gas (Recham, 2001).

In this context, apart from predict the critical rate, prediction of the breakthrough time is also crucial for oil wells subject to gas/water coning problems as well as to evaluate the well performance after breakthrough. A survey of the literatures shows that several researches have been carrying out around the subject. This ranges from experimental coning studies to analytical and numerical simulation studies aimed at understanding and predicting coning;

which usually imply estimate critical rate, time breakthrough and time after breakthrough in vertical and horizontal wells. However, there is no guarantee of how great the analytical methods are in terms of accuracy (when using to predict coning), because they all contain significant simplifying assumptions (Yang, 1991).

As analytical methods often fail to reliably describe real systems because of their inherent limitations, numerical models are also used in addition to predict cone, since they represent in fact the only viable option for describing any type of fluid flow problem in complex reservoirs problems. Accordingly, the prediction analytical methods are best used for quick approximations, screening, and comparison of alternatives, and will require further reservoir simulations, based on accurate reservoir characterization (Verga et al, 2007).

Moreover cone can also be stimulated or attenuated in numerical models by a setting of constraints on the production well. The well is assumed to produce under specified conditions, where the target of gas and liquid allowed to be produced can be specified, in order to maximize oil production, while honor the sets well constraints. In other words while implementing surface constraints it will limit coning effects by prevent high production of gas and water.

2.2- Analytical correlations to predict coning

Most of the published works that address conning problem have developed correlations assuming that only oil and gas or oil and water are present at reservoir conditions (two phase systems). However, when refers to reservoirs with thin oil zones sandwiched between gas cap and bottom water this scenario changes. Since, it will deal with three phase fluid system and for these cases is believed that those correlations will not work out the same way. It would probably require adjustments in order to preserve the real reservoir conditions. Based on the most used analytical methods to predict the critical rate for horizontal wells, in the following sections are presented four correlations, where two of them were developed to describe the cone behave of a two phase system and the other two were specially developed to portray the cone behave in thin oil reservoirs. The idea was to evaluate whether those developed for two phase system would provide similar results as the one destined to three phase systems.

2.2.1 - Giger & Karcher correlation

Giger (1989) presented an analytical 2-D mathematical model of water cresting before breakthrough for horizontal wells. He used the free surface boundary condition and assumed that the free surface is at a large distance from the well, as the oil height in the model may be difficult to choose. The author suggested that these solutions should not be used for small values of the drainage radius, since he modified the mathematical solution based on the comparison with experimental data (Verga et al, 2007).

Equation 1 shows the respective developed correlation to estimate the critical rate in two phase system. The density difference term ($\Delta\rho$) to be used in the equation is ($\rho_o - \rho_g$) for a single gas cone and ($\rho_w - \rho_o$) for a single water cone.

$$\mathbf{q_o} = 4.888 \times 10^{-4} \times \left[\frac{K_h}{\mu_o B_o}\right]\left[\frac{\Delta\rho\, h^2}{2Y_e}\right]\left[1 - (1/6)\left(\frac{h}{2Y_e}\right)^2\right] \times L \quad (\text{stb/d}) \qquad (1)$$

2.2.2 - Joshi correlation

Joshi (1988, 1991) studied the productivity of slanted and horizontal wells using the potential fluid theory. The mathematical solution of his theory was simplified by subdividing the three-dimensional fluid flow problem into two bi-dimensional problems, namely oil flow into a horizontal well in a horizontal plane and in a vertical plane. He also compared horizontal wells to vertical wells in terms of critical rate and gas and water coning occurrence, providing an equation for the calculation of critical rates for gas coning (Eq. 2) and water coning (Eq. 3) systems (Gawish, 2007).

$$\mathbf{Q_{OC}} = 0.0246 \times 10^{-3} \times \frac{(\rho_o - \rho_g)K_h[h^2 - (h - D_t)^2]}{\mu_o B_o \ln(r_{eh}/r_w')} \qquad (\text{stb/d}) \qquad (2)$$

$$\mathbf{Q_{OC}} = 0.0246 \times 10^{-3} \times \frac{(\rho_w - \rho_o)K_h[h^2 - (h - D_b)^2]}{\mu_o B_o \ln(r_{eh}/r_w')} \qquad (\text{stb/d}) \qquad (3)$$

Where:

$$r_w' = \frac{r_{eh}\left[\frac{L}{2a}\right]}{\left[1 + \sqrt{1 - [L/(2a)]^2}\right][h/2r_w]^{h/L}}$$

$$r_{eh} = \sqrt{\frac{43{,}560A}{\pi}} \quad ; \qquad a = (L/2)\left[0.5 + \sqrt{0.25 + (2r_{eh}/L)^4}\right]^{0.5}$$

2.2.3 – Work-Bench correlation

The Work-Bench is a standard numerical model, three phase, and black oil model with finite difference formulation with simultaneous and direct solution and therefore suitable for coning studies. Its validity has been extensively tested over the last years (Recham, 2001). This approach was specially developed to deal with three phase fluid system and aim to predict, optimum oil rate, water breakthrough time and gas breakthrough time for both vertical and horizontal wells. The following equations are the correlations to estimate the critical rate and the breakthrough time for both gas and water in horizontal wells.

$$\mathbf{Q_{sc,h}} = 2.8248 * 10^{-11} \times (X_D)^{2.332} \times (\mu_o)^{-0.182} \times \left(\frac{\rho_w - \rho_o}{\rho_o - \rho_g}\right)^{0.158} \times (h_o)^{4.753} \times \left(\frac{K_v}{K_h}\right)^{-1.234} \times (K_h)^{0.2396} \times (L)^{0.211} \times \left(1 - \frac{h_{ap}}{h_o}\right)^{0.036} \times \left(1 - \frac{h_{bp}}{h_o}\right)^{-0.211} \quad \text{(stb/d)} \qquad (4)$$

Where:

$$X_D = \frac{X_a}{h_o} \times \sqrt{\frac{K_v}{K_h}}$$

Gas breakthrough time for horizontal wells:

$$\mathbf{t_{BT_{g,h}}} = 6.0587 \times \left(\frac{1}{q_{D_{w,h}}}\right)^{0.892} \times \left(\frac{1}{X_D}\right)^{0.179} \times \left(\frac{1}{M_{g/o}}\right)^{-0.514} \times \left(\frac{h_o^2}{L}\right)^{1.121} \times \left(\frac{K_v}{K_h}\right)^{0.779} \times \left[1 - \left(\frac{h_{ap}}{h_o}\right)^2\right]^{0.796} \times \left[1 - \left(\frac{h_{bp}}{h_o}\right)^2\right]^{3.347} \times \left(\frac{h_o}{LK_h}\right)^{0.5397} \quad \text{(days)} \qquad (5)$$

Where:

$$q_{D_{g,h}} = \frac{325.86\mu_o q_o B_o}{Lh_o(\rho_o - \rho_g)\sqrt{K_v \times K_h}} \quad ; \quad M_{g/o} = \frac{\mu_g K_{ro}}{\mu_o K_{rg}}$$

Water breakthrough time for horizontal wells:

$$\mathbf{t_{BT_{w,h}}} = 5.13 \times 10^5 \times \left(\frac{1}{q_{D_{w,h}}}\right)^{0.88} \times \left(\frac{1}{X_D}\right)^{1.094} \times \left(\frac{1}{M_{O/W}}\right)^{-0.253} \times \left(1 - \frac{h_{ap}}{h_o}\right)^{4.675} \times \left(1 - \frac{h_{bp}}{h_o}\right)^{0.929} \times \left(\frac{h_o}{LK_h}\right)^{0.5397} \quad \text{(days)} \qquad (6)$$

Where:

$$q_{D_{w,h}} = \frac{325.86\mu_o q_o B_o}{Lh_o(\rho_w - \rho_o)\sqrt{K_v \times K_h}} \quad ; \quad M_{o/w} = \frac{\mu_o K_{rw}}{\mu_w K_{ro}}$$

2.2.4 – Proxi model correlation

The Proxi model was developed based on Joshi (1991) correlations to estimate the critical rate using horizontal well for gas-oil systems and oil-water systems respectively. This model was generated through a semi-analytical analysis of applying the principle of Nodal analysis to graphically combine gas-oil system and oil-water reservoir system. As result a single equation was generated to estimate critical rate and optimum horizontal well placement, with a view to controlling gas and water conning phenomena in gas-oil-water reservoir system. The model is simple for fast calculation for reservoir with thin oil zones sandwiched between gas cap and bottom water. It can be used as a tool to make the first pass assessment in the development of oil rim reservoirs anticipated to experience water and or gas conning during production (Recham, 2001). May allow for the simulation of various oil rim reservoir scenarios and allows comparison with field and simulation data.

$$q_{oc} = 6.7 \times 10^{-4} \frac{k_h^{0.69} h_o^{1.47} L^{0.68} r_w^{0.21}}{\mu_o^{0.98} B_o^{1.21} A^{0.21} (\rho_o - \rho_g)^{0.1} (\rho_w - \rho_o)^{0.4}} \quad (\text{stb/d}) \qquad (7)$$

$$h_{opt} = 28 \times 10^{-1} \frac{h_o^{0.998} B_o^{0.013} L^{0.007} r_w^{0.008} (\rho_w - \rho_o)^{0.098}}{k_h^{0.001} \mu_o^{0.003} A^{0.002} (\rho_o - \rho_g)^{0.436}} \quad (\text{stb/d}) \qquad (8)$$

2.3 - Uncertainties

Olea (1991) defines uncertainty as lack of assurance about the truth of a statement or about the exact magnitude of an unknown measurement or number, The uncertainty of a parameter may result from difficulty in directly and accurately measuring the quantity and its degree may vary from one variable to another (Olea, 1991).

Scales of reservoir uncertainties are important because different uncertainties have a different impact on reservoir performance and oil recovery. Proper identification and knowledge of reservoir uncertainties on various scales will establish a better understanding on capturing reservoir characterization to optimize production performance and maximize the hydrocarbon reserves from oil and gas reservoirs. In turn in the reservoir simulation models, would help conceive the proper field development plan (Friedmann et al, 2003).

To progress from the discovery of a hydrocarbon reserve to an economically viable project means to assess and reduce reservoir uncertainties. This could be achieved firstly by making efforts to guarantee that the data are acquired following best practice procedures in the measurement and secondly access the associated uncertainty impact on development schemes, improve the reservoirs appraisals, and manage their developments more efficiently (Riegert et al, 2007).

Accordingly, a large number of uncertainties can be identified and classified into different groups. Table 1 shows the diversity of uncertainties inherent of different sources. These sources combine several types of data, including geological, seismic, petrophysical, and well data (Walstrom et al, 1967).

Table 1 - The diversity of uncertainties inherent of different sources

Type of uncertainty	Difficult accuracy	Impact
Uncertainty in geophysical data	Uncertainties and errors in picking	Affects reservoir envelope and its fault system
	diference between several interpretations	
	Uncertainties and errors in depth conversion	
	Uncertainties in the seismic	
	Uncertainties in pre-processing and migration	
	Uncertainties in the top map reservoir	
Uncertainty Geological data	Uncertainties in gross rock volume	
	Uncertainties in the extension and orientation of sedimentary bodies	Results in uncertainties on reservoir sedimentary and petrophysics-that influence the hydrocarbons volume in place and the dynamic of fluids
	Uncertainties in the distribution, shape and limits of reservoir rock types	
	Uncertainties in the porosity values and their distribution	
	Uncertainties in horizontal permeability values and their distribution	
	Uncertainties in the layers Net to gross ratio	
	Uncertainties in the reservoir fluids contacts	
Uncertainty in dynamic reservoir data	Horizontal permeability	Have impact on the determination of reserves and production profiles
	permeability anisotropy	
	Vertical to horizontal permeability	
	relative permeability parameters	
	capillary pressure ccurves	
	Aquifer behaviour	
	Fault sealing transmissibility	
	Extension of horizontal and vertical barriers	
	well productivity index and infectivity index	
	well skin	
Uncertainty of reservoir fluids data	Lack of representative reservoir fluid samples	impact the on the optimization of the processing capacities of oil and gas
	Uncertainty in reservoir samples from different reservoir zones	
	Uncertainty in the compositional analyses	
	Uncertainty in the PVT laboratory measurements	
	Uncertainty in the reservoir interfacial tension	

2.3.1 - Management of reservoir uncertainties

In undeveloped reservoirs, there are always many uncertain parameters affecting management and decision making in a development plan stage. The diversity of inherent uncertainties and how they impact the predicted hydrocarbon accumulation and recovery in the reservoir require carefully analyze and therefore, the proper and unbiased decisions for oil reservoir development can be made.

Management of uncertainty, would require identify uncertainties, both of the reservoir's static geometry and of its dynamic behavior (Friedmann et al 2003). For this purpose statistic approaches provide a means of estimating the probability of outcomes from the uncertainty variables. A rigorous approach of all possible realizations would imply a very large number of simulations run making the process complicated and time consuming. Therefore, encouraging solutions can be achieved.

2.3.2 - Assessment of reservoir uncertainties

To access the effect of uncertainties a systematic and efficient approach based in statistics methods called Experimental Design has been widely used; where a set of reservoirs parameters are chosen from their specific ranges in such a manner that the uncertainty in the system is captured with the least number of simulations runs. Experimental Designs is often used in diverse workflows to quantify uncertainties and to investigate the propagation of parameter uncertainties by using Monte Carlo and Proxy sampling techniques (Begg 2001). In other words it consists in performing an uncertainty workflow to generate many realizations of the model. Each of the uncertainties is allowed to vary within prescribed ranges. It is a useful tool firstly for saving simulation time and secondly for assessing a large number of uncertainty parameters and selecting the ones that have more impact.

2.3.2.1 – Experimental Design

Experimental design is a structured methodology used to determine the relationship between the different factors affecting a process and the output of that process. The methodology offers not only an efficient way of assessing uncertainties by providing inference with minimum number of simulations, but also can identify the key parameters governing uncertainty in economic and production forecast (Yeten et al, 2005). Attempts to generate a mathematical model that describes the process there are many experimental design methods, the selection of which often depends on the objective of the exercise (Itotoi et al, 2010). The following sections will focus on different techniques of experimental design based on probabilistic method process with emphasis to fractional factorial design which is the method used in this study.

2.3.2.1.1 - Full factorial designs in two levels

A design in which every setting of every factor appears with every setting of very other factor is a full factorial design. A common experimental design is one with all input factors set at two levels each. These levels are called *high* and *low* or +1 and -1, respectively. A design with all possible high/low combinations of all the input factors is called a full factorial design in two levels. If there are k factors, each at two levels, a full factorial design has 2^k runs (Itotoi et al, 2010).

2.3.2.1.2 - Fractional factorial designs

Fractional factorial design is defined as a factorial experiment in which only an adequately chosen fraction of the treatment combinations required for the complete factorial experiment is selected to be run (ASQC, 1983).

The design is mainly used for screening objective where the primary purpose of the experiment is to select or screen out the few important main effects from the many less important ones. Called also as *screening design* it usually requires a less rigorous resolution (Itotoi et al, 2010). It is denoted by the expression N_R^{k-p} where N is the number of levels for each factor, k specifies the number of factors (or variables), p is the confounding pattern, and R is the resolution level. Designs resolutions seeks to screen out the few important main effects from the many less important others. Higher resolution designs have less severe confounding, but require more runs (NIST, 2014).

The solution of the current method uses only a fraction of the runs specified by the full factorial design. The subject of interest of the method is to select which runs to make and which to leave out. In general, it picks a fraction such as ½, ¼, etc. of the runs called for by the full factorial using various strategies that ensure an appropriate choice of runs (NIST, 2014).

2.3.2.1.3 - Plackett-Burman designs

Plackett-Burman designs are very efficient screening designs when only main effects are of interest, in general, heavily confounded with two-factor interactions. The Plackett-Burman design in 12 runs, for example, may be used for an experiment containing up to 11 factors. These designs do not have a defining relation since interactions are not identically equal to main effects. However, these designs are very useful for economically detecting large main effects, assuming all interactions are negligible when compared with the few important main effects (NIST, 2014).

2.3.2.1.4 - Central Composite Designs (CCD)

A Box-Wilson Central Composite Design, commonly called as *'central composite design*,' contains an imbedded factorial or fractional factorial design with center points that is augmented with a group of star points that allow estimation of curvature. If the distance from the center of the design space to a factorial point is ±1 unit for each factor, the distance from the center of the design space to a star point is ± α with $|\alpha| > 1$. The precise value of α depends on certain properties desired for the design and on the number of factors involved. Similarly, the number of center point runs the design is to contain also depends on certain properties required for the design (Itotoi et al, 2010).

2.3.2.1.5 - D Optimal design

From a set of points (e.g. a full factorial set), an initial sub set is selected according to the number of combinations desired. The methodology then iteratively exchanges design points for candidate points in an attempt to reduce the variance of the coefficients that would be estimated using this design. The order of the underlying regression model is quadratic, which means the design matrix returned by the optimization algorithm will include linear, interaction and squared terms (Itotoi et al, 2010).

CHAPTER III - THE ALPHA FIELD

This chapter makes reference to one thin oil discovery in deep-water in wet of Africa, which initially was thought not have enough volume of oil to allow a development plan viable. A detailed description of the field in reference will be given based on regional study information. Its potentialities will be pointed and strategies to allow a plan of development will be discussed.

3.1 - Field description

Alpha is a gas field with a thin oil column located approximately 45 km off the Omega field, (which is the main nearby discovery field) on the West of the cost of Africa. It was first discovered in 1994, in the following four years the discovery was subsequently appraised and considered non-commercial in 1999.

In 2005, new evaluations noted that Alpha could contain a sufficient volume of recoverable oil to allow an economically viable development (Alpha, 2011). The Field, which has not been developed yet, consists of three main sands named as *"90"*, *"100"* and *"110"*. The new evaluation found a 7 m thick gas cap overlying a 28 meter thick column of 20° API biodegraded oil in the 110 sand (fig. 3). In this context different strategies have been studied in other to best develop the field.

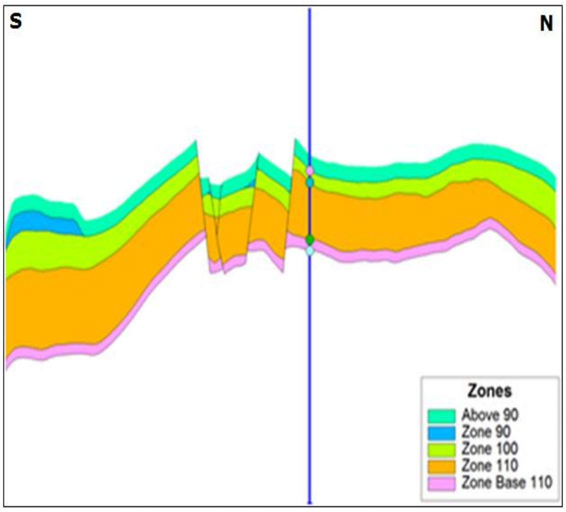

Figure 3 - Structural cross sections through Petrel model

The field remains complicated structurally and stratigraphically and the total oil in-place volume estimate in the *"90"*, *"100"* and *"110"* reservoirs remains modest. Oil and gas in place for the deterministic case, are 165 MMStb and 319 Bcf (278 bcf in gas cap and 41 Bcf associated gas in oil), respectively.

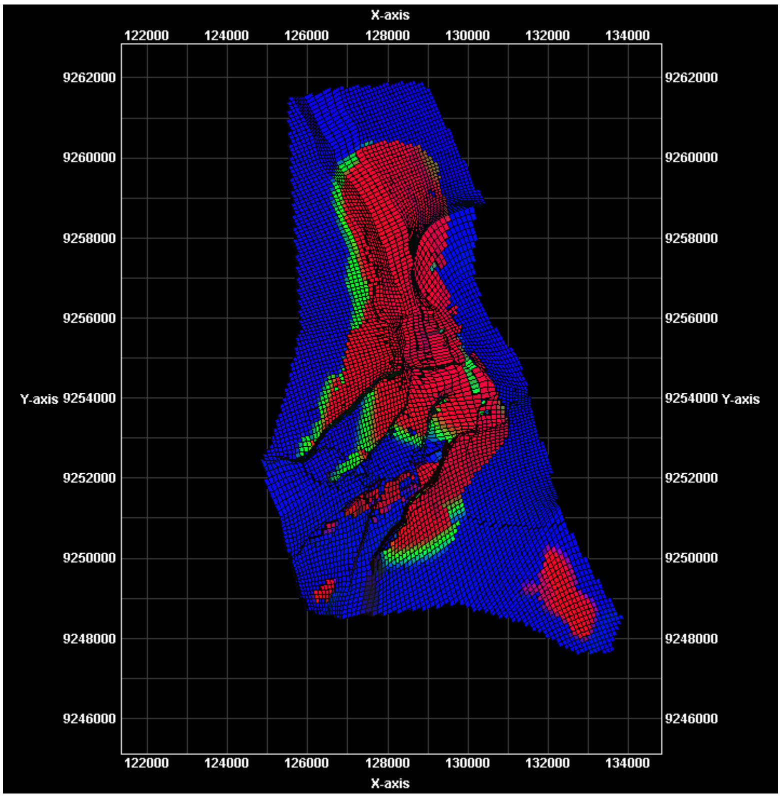

Figure 4 - Petrel illustration of full field model

Alpha Field presents an approximated area of 32 Km^2 with several compartments. The water depth is about 550 meters and the depth of the different sands varies between 1400 and 1500 m TVDss. The main faults are founded in the south part of the reservoir, as result the fluids contact depth varies over the reservoir.

3.2 - Seismic acquisition

The existing 3D dataset was first acquired in 1993 and covers some 231 Km^2 were initially used for studies. In 1995 and 2006/2007 the survey was reprocessed with output near and far stacks. The main objectives of the reprocessing included multiple removal, preservation of amplitude response beneath a significant gas layer above the main reservoir, and enhanced migration to increase the fault definition within the target reservoir systems.

The seismic gather tracks to the right highlight the AVO response based on the actual log data assuming a thin gas cap; a slightly thicker gas cap as initially predicted by the petrophysicist and finally a model assuming in situ fluid (oil/gas) with a thin gas cap, respectively. The signal to noise in the seismic data decreases below the gas cap and both horizons are difficult to pick in this area. The amplitudes are not structurally conformable and are possibly associated with the nearby faulting (Alpha, 2011).

3.3 - Evaluation of depositional environment and burial history

The depositional model for the Alpha reservoir is defined as a fully marine intra-slope or base of slope environment, characterized by turbiditic sand flows originating from the shelf. Both confined and unconfined channel systems have been observed, showing that the reservoir is compartmentalized with different sands along with sheet-like facies indicating considerable complexity. The natural local deposition was during the Upper and Middle Miocene, which resulted in to present renewed sub-regional subsidence and raft grounding and initiation of extreme downdip raft tectonics and continued halokinesis.

The ultimate seal to the alpha hydrocarbon accumulations is the Upper Miocene package above the *"90"* and *"100"* sands. This package, was grey, soft, plastic, homogeneous claystones with very minor streaks of dolomite, and represents a deep marine depositional environment (Alpha, 2011).

Figure 5 below shows an illustration of the stratigraphic subdivision concerning the Alpha field and consists of four main formations.

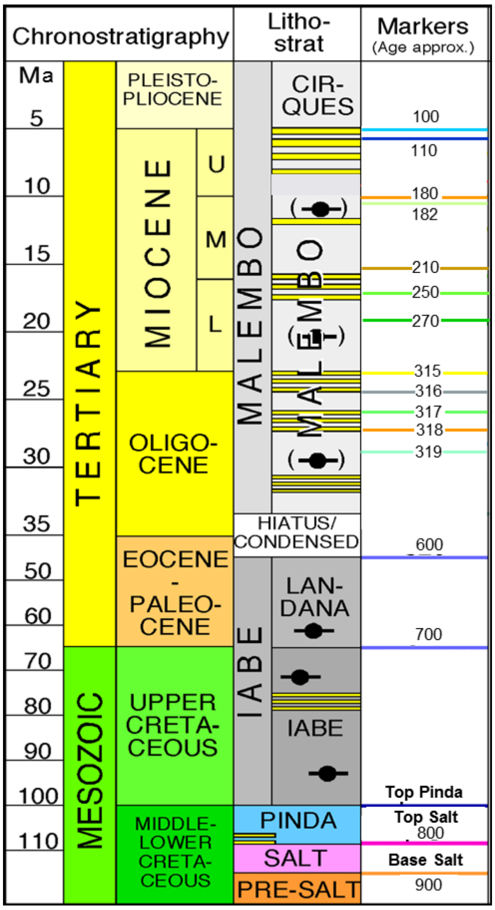

Figure 5 - Post-Salt Stratigraphy and Structural Events of the Alpha field

Malembo Formation: Closure of the Tethys and the incipient collision of the Indian and Asian continents in the Middle Oligocene triggered a significant global tectonic event. The West African margin was uplifted and eroded, shedding a large quantity of clastics into the basin. Consequently the basin was gradually filled with a progradational sequence of fluvial, deltaic to prodeltaic sediments. In the offshore area, a thick pile of deep marine shales and sandy turbidites was deposited from the Late Oligocene into the Miocene (Alpha, 2011).

Iabe and Landana Formations: Deep marine black shales and bituminous lime mudstones rich in organic matter were the predominant sediments deposited over the broad slope and deeper shelf environment (Alpha, 2011).

Pinda formation: Separation of the African and South American continents accelerated toward the end of the Aptian, leading to a eustatic sea level rise. Normal sea water broke through the Walvis Ridge and flooded the entire inland basin. Albian carbonates or mixed carbonates and clastics were accumulated on the shelf initially, but sediment-starved conditions quickly took over under the rapid marine transgression from the late Cretaceous to the early Tertiary (Alpha, 2011).

Salt and pre-salt formations: pre-salt and post-salt mega-sequences, separated by the Aptian salt layer (fig. 5). Some minor early vertical salt movement is believed to have started in the Albian and Cenomanian locally. Such deformation was closely associated with the reactivation of the syn-rift faults, and it caused significant local thickness and lithology variations of the Pinda Formation (Alpha, 2011).

3.3.1 - Geological interpretation

The geological interpretation of the Alpha reservoir systems was based upon seismic sequence analysis, seismic amplitude, seismic waveform classification and core and log analysis from the explorations wells (alpha-1 and alpha-2 wells).

Cores samples collected in *"110"*, *"180"* and in the *"105/110"* sands by alpha-1 reveals that the reservoir sands in all of the cores were fine grained, rich in quartz without clay, fine-medium grained, and moderate to well sorted. They were mostly massive at alpha-1. At alpha-2 there were fining up cycles to silty and shaley sandstone. Environments of deposition were interpreted as channels or sheets at alpha-1 and channel abandonment at alpha-2. The numerous faults at Alpha opened the possibility that there could be fault compartmentalization, especially in consideration of the fact that alpha-1 and alpha-2 encountered different fluid contacts. In addition, in the southeast and southwest parts of the field there were some isolated *"90"* sand reservoirs which had deeper contacts. From the seismic response, these appear to contain gas only (Alpha, 2011). The fluids contacts of the wells were encountered at different depth.

Alpha accumulation contains a free gas cap in the *"90"*, *"100"* and *"110"* intervals (as penetrated by alpha-1 and alpha-2), it is also clear that the post *"90"* and *"100"* seal is effective, despite clear evidence of faulting through the known reservoirs, through the seal package, and into the shallower sand units above. In addition, shallow gas anomalies associated with the crest of the Alpha structure indicate some leakage from the hydrocarbon column (Alpha, 2011).

3.3.2 - Sedimentological reservoir model

Seismic analysis of the *"100"* and *"110"* intervals suggests that the reservoir systems are related, with the *"90"* interval being the last pulse of coarser clastics from the shelf system before the onset of deeper water and the dominance of the claystone which forms the present-day hydrocarbon seal.

Coherency and amplitude extractions indicate that the core of the Alpha field is dominated by strong, westward oriented, linear, confined turbidities channel systems, which appear to reach a break in slope outboard of the field and become largely unconfined and more distributary in nature.

The west of the field is dominated by two large turbidities fan systems, the greater of which originates in the center of the field and coincides with an observed down-cutting canyon system that partially erodes the *"100"* and *"110"* levels. The large fan system was observed due to a switching confined to unconfined close to the observed oil water contact (OWC). Above the OWC it would appear that the system is predominantly confined and hence limits reservoir connectivity in the north-south direction. Below the OWC the reservoirs become much more like amalgamated channelized sheets with a greater degree of connectivity and avulsion events (Alpha, 2011).

3.4 - Strategy and developing plan

Different studies have been carrying out to evaluate how would be an optimal strategy for a developing plan. It was already mentioned that Alpha field is located around 45 km away from a main field (Omega field) and was initially thought to not have any commercial value. Therefore, it is important to emphasize that as a thin oil reservoir in deep water, a standalone would be a commercial challenge. The interest of developing such field is related in adopt advanced technologies as smart or intelligent wells as well as integrated operations, and thus extend the life time of the reservoir. As start point engineers have been focused in developing the field along with the Omega field. In other words both reservoirs (Omega and Alpha) would be sharing common surface infrastructure and production facilities, which strongly interlinks its operations. This way some of the costs would be reduced. A tieback development scenario relies mostly on flow assurance and pipelines issues.

3.5 - Uncertainties in the Alpha reservoir data

Given that the Alpha field is in appraisal stage the data gathering process still in progress. The process is been lengthy, due the limited volume of hydrocarbons encountered in different compartments around the field. The progress of the process is compounded because it is located in deep water conditions, where the data collection is a challenge beyond to be costly. In addition the reservoir itself is stratigraphically complex with multiple reservoir layers compartments, resulting in drastic changes along the reservoir,(in terms of type of sand grains, net to gross ratio, permeability heterogeneity, fluids contacts, oil saturation), which may lead to different scales of uncertainties.

As result some measurements as SCAL, rock compressibility, wettability are not available and some others are uncertain as permeability. In cases were no SCAL data is available, important measurements analysis as relative permeability become unknown leading to the use of information based on generic data and some extent regional knowledge (as verified in the present work) corresponding to a certain degree of uncertainty. Relative permeability curves define the reservoir mechanics, and hence, they are vital for describing the depletion method of any field discovery.

So, it becomes essential to have a consistent and efficient way of incorporating the effect of uncertain parameters on the behavior of a reservoir and to forecast the probabilistic production of the reservoir. In this study a screening experimental design is implemented in order to portray how robust the oil production is to variations in some of the key engineer parameters, and also highlight which of the inputs parameters is more sensitive to. Ranking the uncertainties can greatly help to prioritize where resources should be directed to get the most cost effective investigation.

CHAPTER IV – THE SIMULATION MODEL

This chapter gives a more technical description based on availability of data. In the following are presented some of the key input data of the full model with emphasis on the sector model.

4.1 - Available data

The progress of the entire work was based on a set of existing data provided. The following data were given:

- Regional seismic information
- Log analysis
- Pressure data
- PVT lab measurement
- DST
- Static and dynamic models

4.2 - Reservoir simulation model

As the reservoir is still in the initial stage of appraisal then many parameters are uncertain. Therefore, a simulation model was generated based on various deterministic scenarios from previous studies.
The initial simulation model is actually a Cartesian 3D, black oil simulator ECLIPSE 100 was developed from the geological model calibrated to seismic data along with some generic data where data were absent. The simulation model is discretized into 77 by 159 by 51 cells, making a total of 624,393 grid cells, among them 296,859 are active.

The reservoir formation is upper Miocene with different sands quality and high permeability. Table 1 gives some of the reservoir property ranges as well as fluids properties, provided by studies performed during the appraisal phase of the field (Alpha, 2011).

Table 2 - Reservoir and fluids properties

Reservoir properties	
Initial pressure, psi	2100
Initial temperature, °C	55 - 60
Reservoir depth, m TVDss	1400
Rock wettability	unknown
Formation	Upper Miocene
Water Depth, m	500 - 600

Crude	Heavy oil biodegradaded
Porosity, %	22 - 38
Permeability (best estimate), mD	2000
Thickness, m	28
Bubble point pressure, psi	2075
Fluids distribution	Gas cap, thin oil, significant aquifer
Reservoir fluids properties	
Oil density, g/cm^3	0.8709
Specific gravity (air =1)	0.611
Oil viscosity, cp	4 - 5
Solution GOR, scf/stb	240
Formation volume factor, rb/stb	1.11
Oil gravity (API)	20

A three-dimensional view of the entire model with the respective area of interest modeled in the sector model (area in blue) can be seen in fig. 6. The simulation period started from the first of January 2016 up to the first of December 2041.

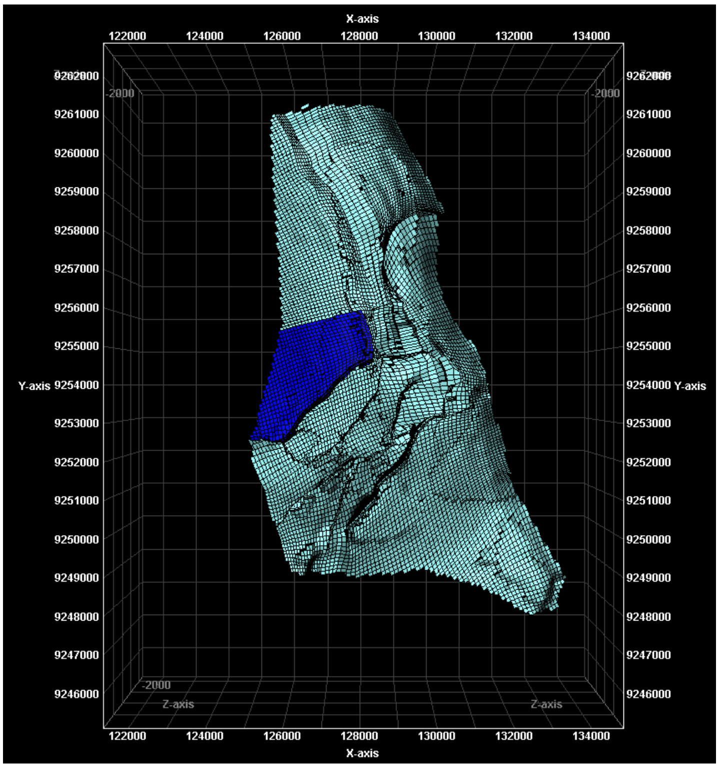

Figure 6 - Alpha field showing the area of Sector Model in blue dark

The regional seismic information indicates that the Alpha accumulation contains a free gas cap in the main sands intervals (*90*, *100* and *110*). In addition the several channels encountered in south part of reservoir indicate clearly that the reservoir contains several sealing faults, which divide the reservoir into different compartments. In the simulation model those compartments were designated as region with no way of communication with nearby regions. The simulation model comprises a total of seventeen regions but only one has been selected. The so-called sector model will receive a special attention in the following sections.

4.2.1 – Sector model

It is well known that a single reservoir simulation could require several hours or even days of computation time, depending on the size of the reservoir, the numbers of the wells involved, and the complexity of the physical model to be considered. In this context the sector model was selected for phenomenological and CPU time studies, where different tests were performed involving critical rate prediction, impact of grid resolution, sensitivity analyses and IOR. Since, the present work deals with a thin oil accumulation sandwiched by a gas cap and bottom water, these studies were quite interesting to investigate the coning progression over the time as well as to achieve a suitable plan that would lead to a realistic range of outcomes.
As previously mentioned the sector model is basically one of the field compartments, it is located in the Southwest part of the Alpha field and has a total area of around $6km^2$. The initial gas in place is about 15% (43 bcf) of the total gas in place and 24% (38MMstb) of total amount of oil present in the entire field. Its simulation model comprises a total of 31,350 coarse grids blocks with 100x100x3 m in dimensions. A single producer horizontal well was placed and named P1.

In this work the sector model was considered to be the numerical model reference case scenario, represented by thin heavy oil column, homogeneous and isotropic reservoir, for simulating gas and water coning tendency, where P1 was producing for twenty six years as a horizontal well.

The entire work was performed taking into account P1 well path in the sector model as reference case. Knowing where the fluid contacts were in the model, the optimization of well placement was achieved by varying the well's vertical position within the oil column as function of the oil recovery. A reasonable well placement was found at height closest WOC.

4.2.2- Model Input Data

Due to large amount of data on the full field model, only a few of the essential parameters are presented in this report. In the following are presented some of the key input fluid and reservoir data like formation volume factor oil and gas viscosity, porosity and net to gross ratio. It is important to emphasize that permeability in the sector model was considered to be homogeneous as little variation was observed within net sand package in the two wells in the structure.

4.2.2.1 - Fluid data

The fluid properties characterization of the Alpha reservoir was based in a number of laboratory experiments. To construct a representative fluid data to be used as input to the dynamic model, a fluid characterization study was generated using the EOS modeling and it was conducted accordingly with respect to pressure in the simulation input data.

Figures 7 to 10 depict plots of fluid data which are oil formation volume factor (Bo), oil viscosity (cp), solution, gas formation volume factor (Bg), and gas viscosity data (cp), respectively.

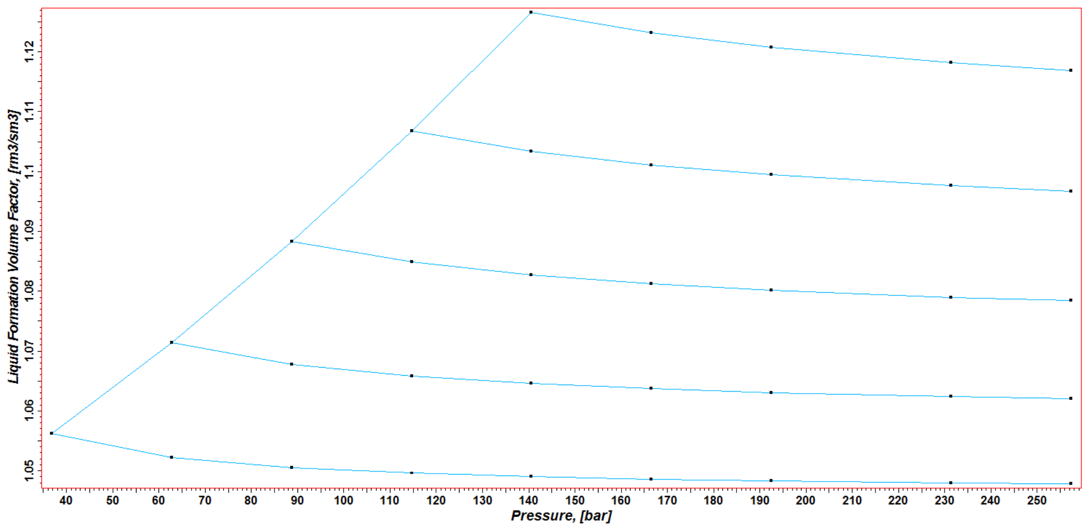

Figure 7 - Liquid formation volume factor vs. pressure captured from petrel

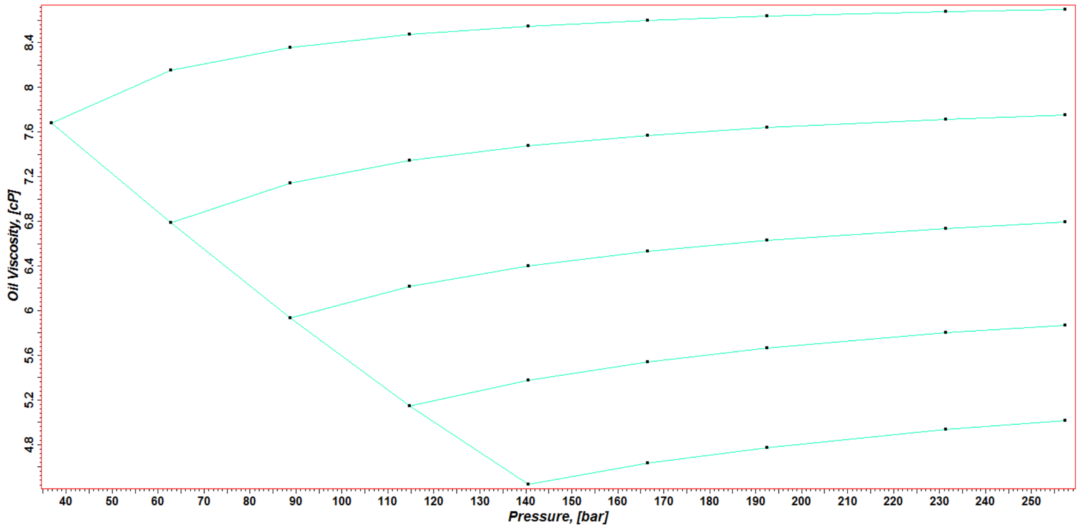

Figure 8 - Oil viscosity vs. pressure captured from petrel

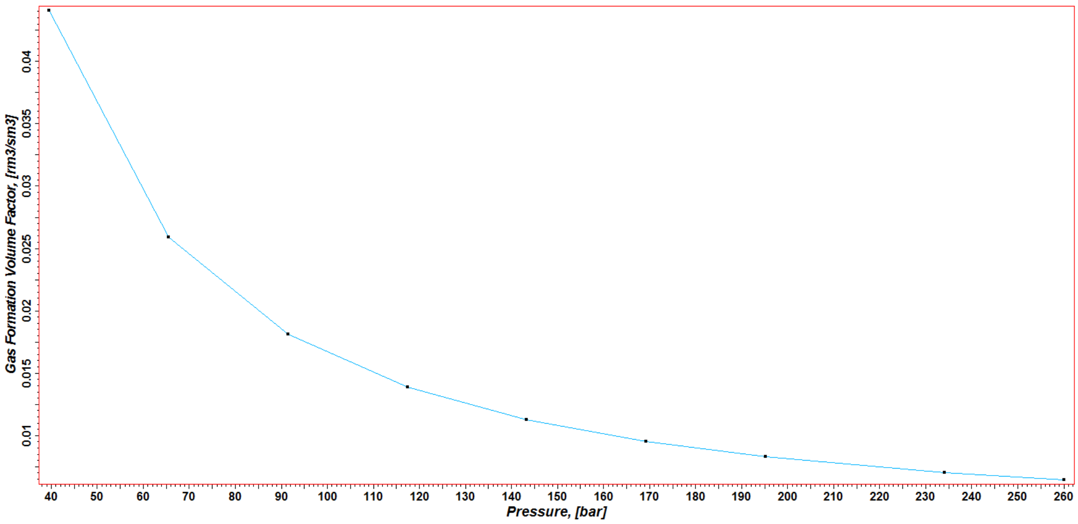

Figure 9 - Gas formation volume factor vs. pressure captured from petrel

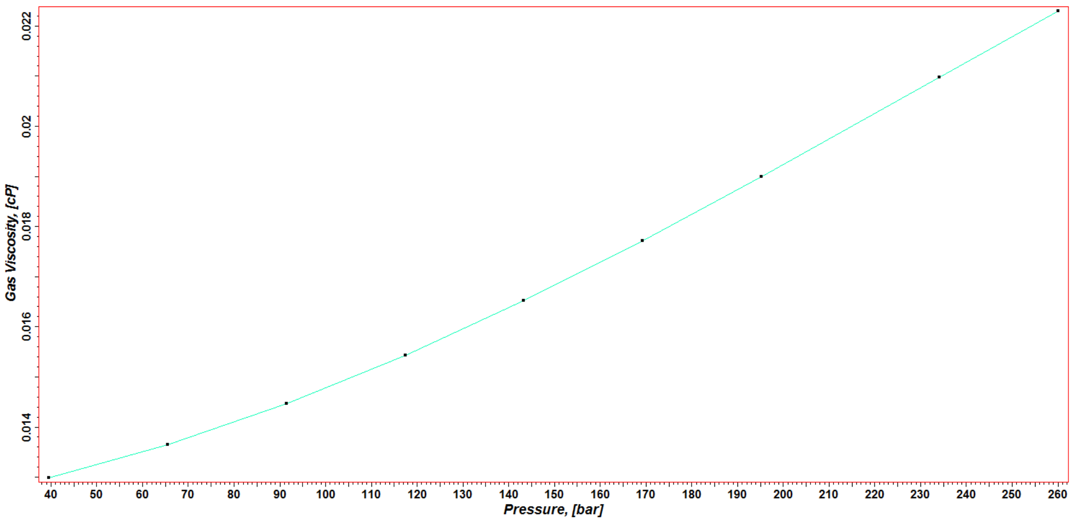

Figure 10 - Gas viscosity vs. pressure captured from petrel

4.2.2.2- Porosity

The porosity in the sector model is high, attaining values between 28 and 32%, and its distribution was found to have a very little variability. Each global grid block within the sector model was assigned to one porosity value. The histogram in fig. 11 shows the percentage of grid blocks with a certain porosity value. The majority of grids blocks have porosity between 27.8 and 28.4 % and the mean is around 31%.

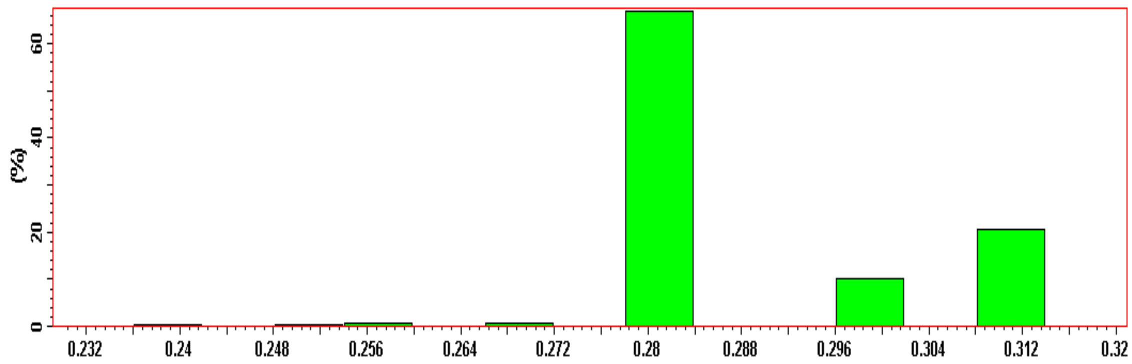

Figure 11 - Porosity distribution in the model

4.2.2.3-Net to Gross ratio

The Net-to-Gross ratio reveals the quality the height of producible sand relative to the total thickness; it is usually linked to the accessible length of the appropriated sand in the reservoir, required to convert from gross to net thickness. The good sands were grouped between 0.95 and 1 and accounted for more than 18 % of the grid blocks. About half of total grid blocks are found around 0.05 and 0.5. Figure 12 shows the distribution.

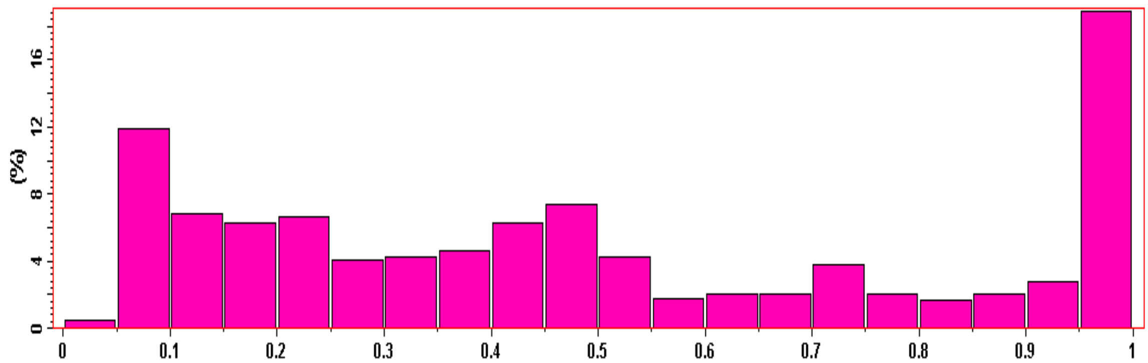

Figure 12 - Net-to-Gross ratio distribution in the model

CHAPTER V - DEVELOPING OF THE THESIS WORK

This chapter will detail the main steps of the practical solutions to handle gas cone and investigate the key uncertainty parameters of a thin oil reservoir. In this part of the work the Schlumberger Simulation Launcher (Eclipse 100) and Petrel software played an important role in achieving the objectives.

The following figure 13 gives a schematic overview of the main scenarios performed in this chapter.

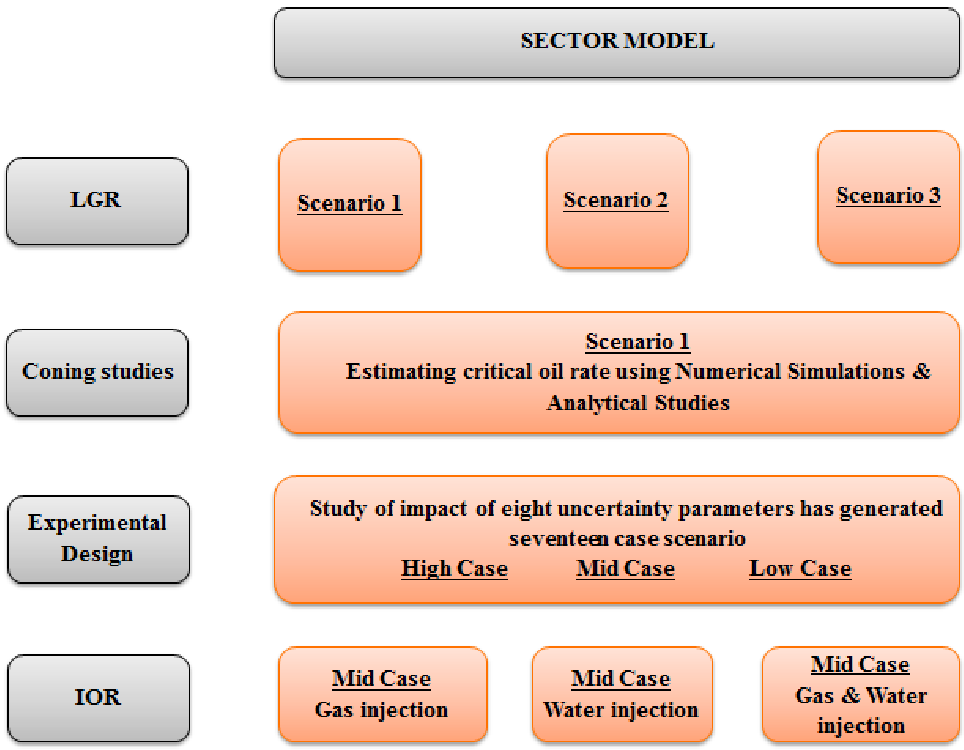

Figure 13 - Schematic overview of the main scenarios performed in this thesis

5.1 – Impact of gridding (LGR)

Given that by increasing the model´s resolution would on one hand side imply better representation of physics but on the other hand it would entail a greater computational time, the impact of gridding was tested in the sector model in order to reach a best compromise between computational time and accuracy of results. For this study three different resolution scenarios were applied to the sector model. Basically, a local grid refinement was considered around the oil zone while maintaining a coarser scale grid away from the thin oil zone. For this, a polygon around the thin oil zone was defined. Then, each coarse grid inside the polygon was divided into 3x3x3, 5x5x5 and 7x7x7 resolution. In this study Petrel software played an important role since, it allows rapid construction of LGR, which made this project suitable for the limited time available. The scenarios are addressed more in detail in the following sections.

5.1.1-LGR on an irregular volume

The refinement polygon area was specified in Petrel then exported to Eclipse 100. Therefore, to perform LGR in ECLIPSE 100 on a volume that is not a regular box the AMALGAM keyword has been used. By amalgamation smaller refinements could be made along the wellbore in a zigzag pattern instead of having one single, large LGR box. This way the amount of local cells and, consequently, simulation time would be reduced. Moreover, this tool has provided a means of completing a well in more than one local grid. Thus the grid would be refined more efficiently around a deviated well by employing a number of smaller refinements.

5.1.2 -Time steps

In general, refined grids often require shorter time steps than coarse grids. Local time stepping allows each amalgamation to be solved at individual time steps. Two types of time stepping are available when simulating LGR; namely *LGR using local time steps* and *LGR in-place*. The LGR using local time steps have been used in this study. It is basically an implicit solution scheme (IMPES method) that Eclipse uses by default, which permits larger time steps. It is important to take into account that problems related with stability may occur due the semi-implicit of the method. Despite of the LGR in-place method lead to fully implicit solution, where the solution of a nonlinear system is required at each time step it may reduce efficiency of the process.

5.1.3 - Convergence control

Dealing with LGR tool, convergence problems may occur more than usual. Since the number of cells in the sector model was increased, it also increases the odds that a cell will cause non-convergence problem. The convergence tolerances are eased slightly at each non-linear iteration, to make convergence easier as the number of iterations increases. Therefore, to avoid several convergence problems, during the simulations runs the keyword TUNINGL were applied along with TUNING. In order to avoid a time-step chop on study of coning the maximum length of next time step for both global grid and refined grid was set to 0.01 days. Adjustments on the LITMAX item in both TUNING and TUNINGL keywords were also considered to improve the performance of the simulator.

5.1.4 -The production well

The horizontal production well here presented measures 2000 meters therefore, the use of a well with such length in current practice still being investigated. It was considered open hole completed with a production hole of 8,5 inches diameter. A skin value was assumed to be equal to zero. The well is mainly controlled by bottom hole pressure and rates, which was set to 100 bars. In order to induce surface constraints, limits target on gas and water was set to control the volume those fluids to be produced. A favorable vertical placement in the oil column was considered at 1/3 above OWC. Figure 14 shows the completion and trajectory of the production well along the layer nine used in all simulations runs.

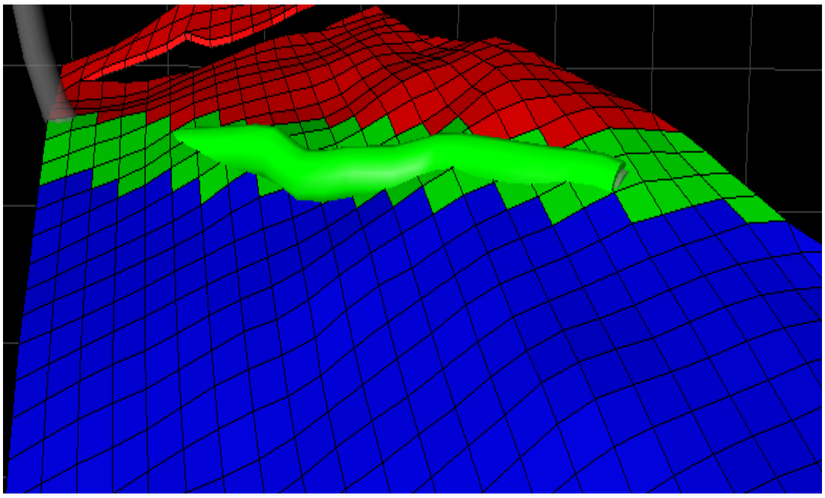

Figure 14 - Production well trajectory

5.1.5 - Scenario1

Scenario 1 was a case study for a 3x3x3 setting of resolution. It contains 16 amalgamated local grids, and the maximum number of cells in LGR is 38556. This means that each global grid was divided into three on the x, y and z directions. In other words Nx=Ny=Nz=3. Figure 15 illustrates a two dimension of the LGR resolutions inside the polygon.

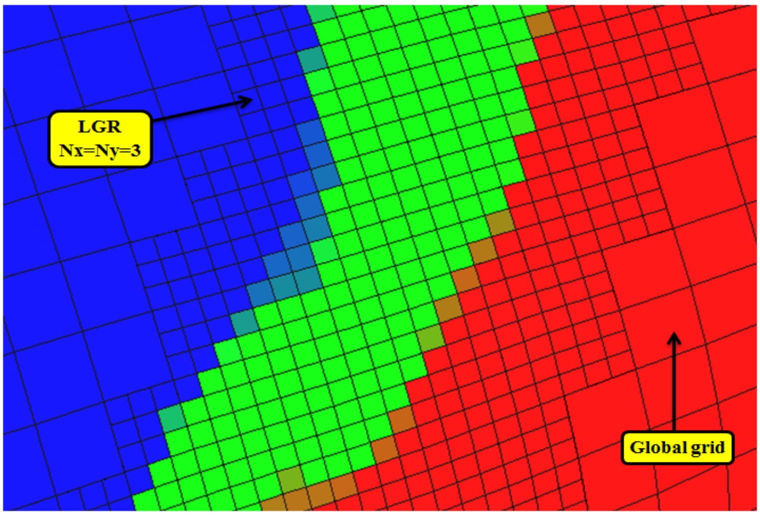

Figure 15 - Illustration of LGR 3x3x3 resolutions inside the polygon used in the model

5.1.6 - Scenario 2

In order to promote high resolution the scenario 2 was the case of study for Nx=Ny=Nz=5 setting. As the previous case scenario it also contains 16 local grids but higher total number of cells which is 178500. Figure 16 illustrates the LGR resolutions inside the polygon.

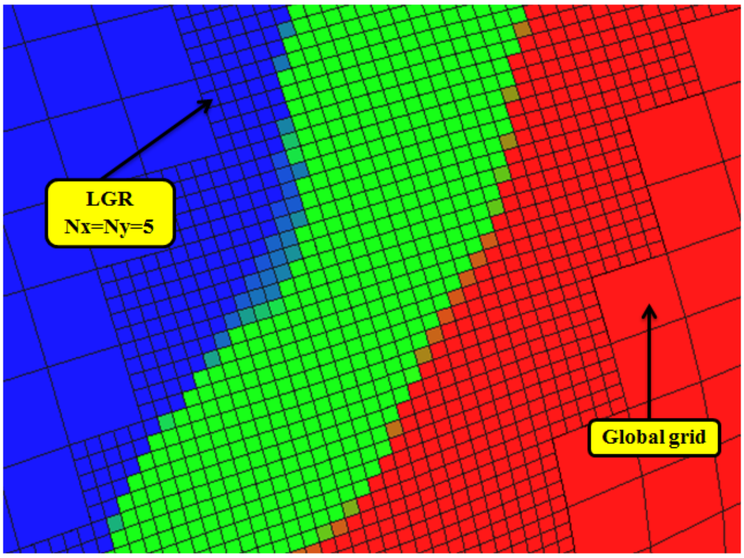

Figure 16 - Illustration of LGR 5x5x5 resolutions inside the polygon used in the model

5.1.7 - Scenario 3

Scenario 3 was the case of study of highest resolution. As the polygon considered in all case scenarios have been the same it also comprise 16 local grids amalgamations, and the maximum number of cells in LGR is even higher making a total of 624393 grid cells. Figure 17 illustrates the LGR resolutions inside the polygon with refinement along the three direction was set to be seven (Nx=Ny=Nz=7).

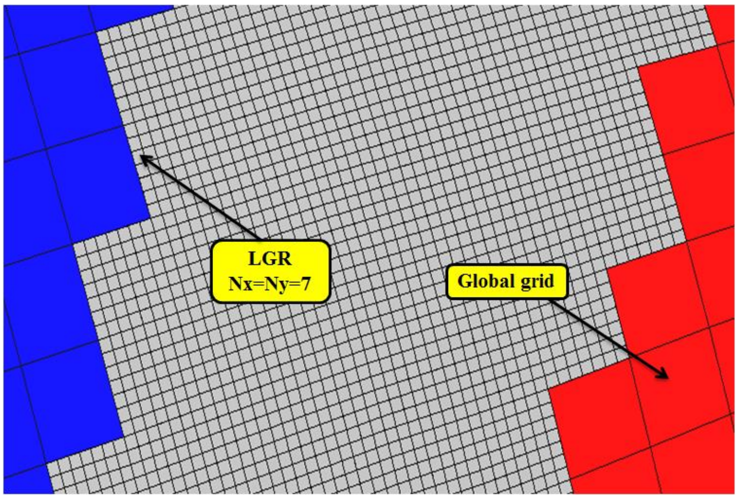

Figure 17 - Illustration of LGR 7x7x7 resolutions inside the polygon used in the model

Table 3 gives the different refinements used in each direction and the respective number of cells generated for the different scenarios.

Table 3 - Refinements in the different directions

Case	Nx	Ny	Nz	Number of cells
Scenario 1	3	3	3	38556
Scenario 2	5	5	5	178500
Scenario 3	7	7	7	624393

Having defined the scenarios simulations runs were performed and as expected the scenario 3 resolution shows the lowest performance in terms of computing time. This scenario took several weeks of simulations and for this reason, it was not possible come up with a computing time in this study hence it was neglected. The others two cases presented similar results both in terms of resolution and production profiles, but with large differences in terms of computing time. Therefore, the case scenario 1 was the case selected to describe both gas and water coning tendency and used for further investigations. The quality of the grid definition as well as the CPU time compromise of this study will be displayed in results section.

5.2 - Estimating critical oil rate on analytical study

Based on the most used analytical methods for predicting the critical oil rate were selected, namely the models proposed by Joshi, Giger and Karcher, Work-Bench and Proxi model for horizontal wells. Joshi and Giger & Karcher correlations were developed for two phase system, but Work-Bench and Proxi model were designed for a three phase system suitable for this study. Each method was analyzed paying attention to the main assumptions and the validity range of some of its solutions.

5.2.1- Sensitivity analyses on estimated critical cone

Different scenarios involving parameter's variations, within their associated range were considered. The idea was to anticipate and compare the results provided by the analytical methods against the results obtained by numerical simulations.

The fluid properties were preliminary tested in order to assess which ones most affect critical rate. Visual basic tool form Excel spreadsheet played an important role in this part of the study. Due the extension of some correlation, the equations were entered in the Visual Basic Editor. This procedure has eliminated time consuming and errors when typing the large correlations and has facilitated handling the sensitivity study as well. Table 4 provides the values of the model parameters assigned to the reference case scenario and the range within which they were varied during the study. Each parameter was varied independently while keep others constant.

Table 4 - Reference case scenario and ranges of variation

Prameter	Reference value	Range of variation	Unit
ρ_o	934.3	800.9 – 961.1	Kg/cm3
ρ_w	1023.1	961.1 – 1281.4	Kg/cm3
ρ_g	0.74738	0.4806 - 0.9611	Kg/cm3
μ_o	4,29	4 - 5	cP
B_o	1.11	1-1.2	rb/stb
K_h	2000	1000-2100	mD
K_V	200	100-210	mD
L	2000	5000-7500	m
r	0.35	0.25-0.50	m
Y_e	470	200 - 600	acre

To evaluate the impact of the distinct parameters on the critical rate by using correlations for two phase system two rates were calculated (for gas-oil system and for oil-water system) using the same correlation and the minimal rate obtained from both system was selected for a final comparisons.
While relative permeability curves, water viscosity and well bore radius had negligible effects on coning phenomena, parameters such as absolute permeability, viscosity, formation volume factor, oil density, total reservoir thickness, well placement, and anisotropy ratio affected the formation of gas and water coning. These preliminary simulations were acquired only at the correlation level since it was quiet hard to identify with good accuracy the cone behavior as the parameters were altered at numerical model. For instance, it was difficult to choose an optimal well placement in the model, since in the mathematical model assumes that lateral distance to fluid contacts are fixed whereas in the model it varies according to geometry.

5.3 -Estimating critical oil rate on numerical simulation study

The investigation of critical oil rate on numerical model was conducted taking as reference case the one which presented best compromise in terms of computing time and accuracy of results. The technique adopted to estimate it in the numerical model was based on the adjustment of the oil production rate while observing the variation of the gas oil ratio and water cut. Some cross section view adjacent the well trajectory was also considered in ways to best control the cone progress over the time.

Different constant oil production rates at producer were imposed in each scenario to define when the gas and water cones are initiated. Notional surface constraints in the amount of gas and liquid to be produced were also considered. This procedure allowed to rapidly narrowing down a possible range for the critical rate.

5.4 - Uncertainty parameters study

For the uncertainties studies was chose as start point a case that integrated good resolution, satisfactory computational time and a well producing at estimated critical oil rate (200m^3/d). Experimental Design technique was applied, but limited to screening phase.
The impact of the chosen uncertainty parameters was evaluated by the variation of each parameter from its minimum to its maximum values. For this, Petrel software offers a powerful tool considered of extreme importance in this study; *uncertainty and optimization,* tool has several available options to assist the creation of random models. This tool has permitted select a subset of the combinations of the parameters that provide unambiguous estimates by run a minimum number of simulations and extract the same information that could be obtained if every single combination would be considered.

The notional experimental design workflow used in the present work is as followed:

- Selecting the uncertainty parameters;
- Generate the matrix design table using factorial fractional design method;
- Create the ED realizations depending on matrix design;
- Perform simulations for all realizations in the ED table;
- Import the results to an excel spreadsheet and generate the Pareto plot;
- Screen the key parameters from the Pareto plot.

5.4.1 - Selecting the uncertainty parameters

The reason to choose the parameters for this study was based on inexistence of information. In other words some of data was not available for the Alpha field; therefore generic rock curves and parameters based on experience and some regional knowledge were used. In the following are presented the main parameters considered uncertain in this study.

5.4.1.1- Relative permeability

In the absence of actual SCAL for the rock-flow curves, assess the influence of the relative permeability with an emphasis on the degree of the rock wettability was based considering different wettabilities.

Three sets of generic relative permeability data were considered representing three different wettabilities. The oil-wet, weak water-wet and strong water-wet were represented by the low, mid and high case data sets, respectively. Figure 14 shows the relative permeability curves for different wettabilities used in this study for water oil system.

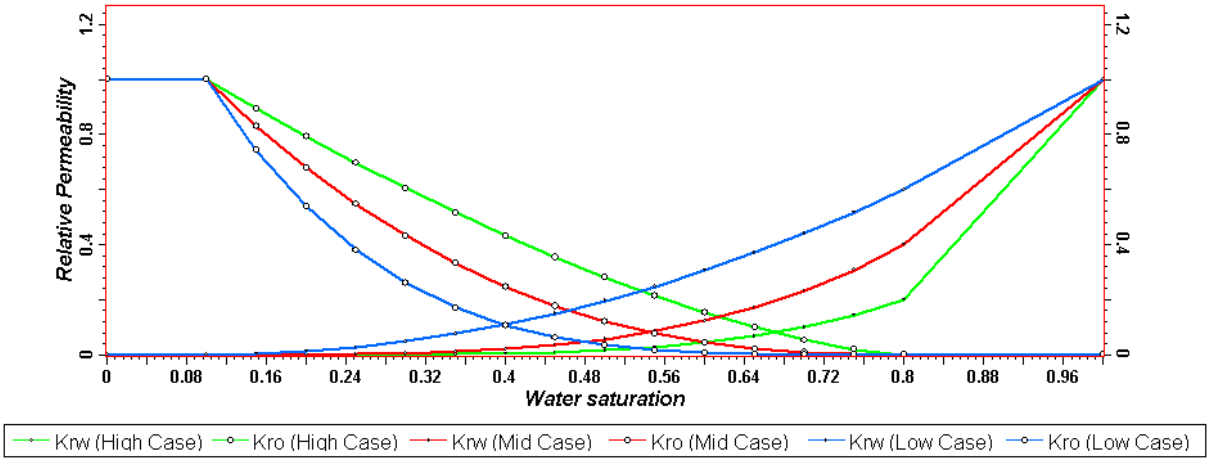

Figure 18 - Relative Permeability Curves (water-oil system)

5.4.1.2- Horizontal permeability

Both horizontal and vertical permeability were also selected for this study. The permeability used on previous studies was set to be constant on the intire sector and a reasonabel value to promote coning prblems. Although a DST was run on a 110 sand interval in the Alpha-1 well (sector model zone) there is no BHP or WTHP information for the test. BHP or WTHP data is often used to calibrate permeability and, if run for a sufficient time, can also be used to detect boundaries and or faults. Since no pressure data was available, the dynamic model used the horizontal permeability without any calibration. Permeabilities multipliers values rnging from 0,5 to 1,25 were used for this study.

5.4.1.3 - Vertical permeability

A generic vertical permeability of 0.275 for the Permultx mnemonic was used in the mid case model. Since the core data is very limited and does not suggest a representative degree of permeability, the influence of anisotropy for this value was investigated. While a low value was used to incorporate the impact of more shale baffles appearing in the reservoir a high value was simulated to capture the possibility of a low degree of reservoir anisotropy or the possibility of holes in shales which would act as vertical conduits to flow.

5.4.1.4 - Aquifer connectivity

It is well perceived that pressure support to the production of reservoir's hydrocarbons is critical to the reservoir performance. The efficiency of production wells has the aquifer as a source of pressure support.

To quantify its effectiveness the connectivity between the aquifer and reservoir was selected as uncertain parameter to represent both the reasonably low and high sides. The impact of aquifer on oil production was analyzed by allowing the permeability of certain grid blocks situated in or near water-oil contacts to vary. This was modeled by applying, to these grid blocks, a pore volume multiplier (MULTPV) of 1, 8 and 15 for the low mid and high cases respectively.

5.4.1.5 - Rock Compressibility

Being the absence of information the main reason for selecting the uncertain parameters, the rock mechanics data of the Alpha field were also not available; therefore assumptions were made to represent the rock compressibility. A typical rock compressibility value of unconsolidated rock of 0.000217 bar^{-1} (at approximately 141 bars) was used in the mid case model. A range of rock compressibility was assigned 0.0000725 bar^{-1} and 0.000435 bar^{-1} for the low and high sides respectively.

5.4.1.6 - Well productivity index

Well productivity index reflects the improvement of connectivity between well bore and formation in terms of degree of damage created during drilling and/or completion of the well. In order to evaluate the degree of uncertainty for this parameter the permeability in a near-wellbore area was altered. Multipliers ranging from 0.1 to 10 were used to represent the possible range of productivity impairment or improvement in the near wellbore area.

5.4.1.7 - Residual oil-to-water saturation

Residual oil saturation is considered as the stranded oil which is capillary trapped in the rock. The accurate measurement of residual oil saturation is one of the most difficult parameters to attain in SCAL experiments. In this context a residual oil saturation ranging from 0.1 to 0.25 was used to evaluate its influence on oil production.

5.4.2 - Generating the matrix design table using factorial fractional design method

The case scenario 1 developed in section 5.1.5 (LGR 3x3x3) was set as reference case scenario and the variables were actually altered based on correspondent Eclipse keyword. In the context of this study the method was selected with aim of a screening design.

First the variables were defined in Petrel software in order to access the design matrix, where eight uncertainty parameters have been chosen with low, middle and high values. Table 5 summarizes the ranges in which the parameters have been stretched for this study.

Table 5 - Uncertainty parameters and its ranges

Variable		Values		
		Low	**Middle**	**High**
1	Permultx	0.5	0.875	1.25
2	Permultz	0.05	0.275	0.5
3	Multpv	1	8	15
4	Relative permeability	Oil wet	Weak water wet	Strong water wet
5	PI	0.1	5	10
6	Sorw	0.1	0.175	0.25
7	Rock compressibility (1/bar)	0.0000725	0.000217	0.000435
8	Water viscosity (cP)	0.2	0.45	0.7

To control and to create realizations that cover all the possible combinations of the parameter values the validation method used was the *fractional factorial sampler* with resolution four; which is a deterministic sampling algorithm suitable for Proxy models. It yielded to seventeen experimental design realizations with the base case included. Figure 19 shows the matrix design generated from Petrel.

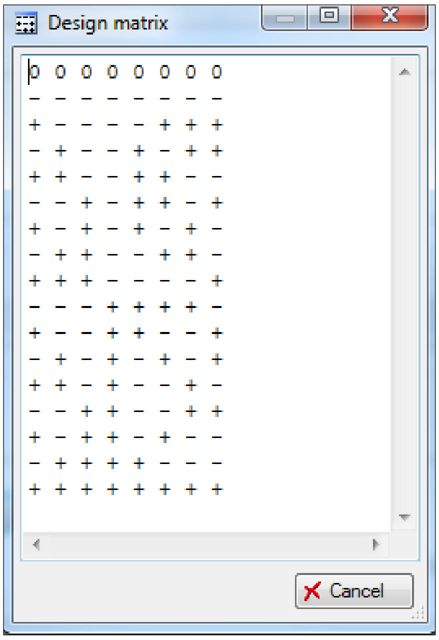

Figure 19 - Matrix design generated from Petrel

5.4.3 - Create the ED realizations depending on matrix design

Seventeen cases of the correspondent design matrix have being generated. Table 6 gives the experimental design realizations depending on matrix design generated from Petrel. The specific value for each parameter for the seventeen experimental design realizations is presented in Appendix section.

Table 6 - ED realizations depending on matrix design generated from Petrel

Exp. Design cases	PERMULTX	PERMULTZ	MULTPV	Relative permeailty	PI	S_{orw}	Rock	Water viscosity
1	0	0	0	0	0	0	0	0
2	-1	-1	-1	-1	-1	-1	-1	-1
3	+1	-1	-1	-1	-1	+1	+1	+1
4	-1	+1	-1	-1	+1	-1	+1	+1
5	+1	+1	-1	-1	+1	+1	-1	-1
6	-1	-1	+1	-1	+1	+1	-1	+1
7	+1	-1	+1	-1	+1	-1	+1	-1
8	-1	+1	+1	-1	-1	+1	+1	-1
9	+1	+1	+1	-1	-1	-1	-1	+1
10	-1	-1	-1	+1	+1	+1	+1	-1
11	+1	-1	-1	+1	+1	-1	-1	+1
12	-1	+1	-1	+1	-1	+1	-1	+1
13	+1	+1	-1	+1	-1	-1	+1	-1
14	-1	-1	+1	+1	-1	-1	+1	+1
15	+1	-1	+1	+1	-1	+1	-1	-1
16	-1	+1	+1	+1	+1	-1	-1	-1
17	+1	+1	+1	+1	+1	+1	+1	+1

5.4.4 - Perform simulations for all realizations of the ED table

After generated the seventeen cases resulting of the correspondent design matrix, they were submitted to the ECLIPSE 100 simulator. The respective results and its interpretations will be displayed and discussed in the results section.

5.4.5 - Import the results to an excel spreadsheet and generate the Pareto plot

The goal here was to obtain a representative screening distribution of the input uncertain parameters, when they assume the maximum or minimum value of its associated range over the time. For this the vector of interest (FOPT) data from Eclipse 100 of the seventeen cases were imported to the Excel spreadsheet to compute the Pareto plot according with a sequence program stated in VBA Macro. The program sequence was based on fractional factorial design method with resolution four (see fig. 66 in appendices). The purpose was to rank the impact of the each single parameter on the cumulative oil production in terms of absolute value. The required input parameters to build a Pareto Plot were the number of variables, combination of the matrix design provided by Petrel, the number of simulations runs and the output vector of interest.

5.4.6 - Screening the key parameters from the Pareto plot

A representative screening distribution to assess the impact of the each of the chosen variables on oil production was achieved. The respective outcome of the screening study is displayed on the Pareto plot addressed on the results section with respective interpretations.

5.5 - Impact of plateau length by producing above critical rate

In order to access the impact on the plateau length by producing above critical oil rate, the three main scenarios generated from uncertainty study were considered as low, mid and high scenarios. The aim of this analysis was to provide an overall view in terms of gains and losses of reserves when oil companies for economic reasons produce oil as fast as possible. The results referring to this case will be presented and discussed in the results chapter.

5.6 - Impact of surface constraints on production profiles

Given that specific recovery factor is only valid for a given development concept, in this particular section the base case generated from experimental design study was simulated under different gas and water constraints in order to test how the recovery could be affected. In reality it is linked to the investment proposal on surface capacity. In this context different scenarios were tested, where only the target limit of unwanted fluids were duplicated and divided by a factor two. Another case neglecting constraints on the amount of gas and water allowed to be produced was also considered. On the results section for this study the scenarios named as high, low and no constraints cases will be presented by Case_Mult, Case_Divid and Case_No_limit constraints respectively.

5.7 - Improving oil recovery in the sector model

Minimizing the amount of oil recovered in a conventional reservoir is already a challenging process. It becomes even more complex when it comes to thin oil reservoir with heavy oil between gas cap and bottom water. As in any reservoir during production it will sooner or later require pressure maintenance in order to recover as much oil as possible. This study was conducted under conditions of the mid case generated from experimental design study; where different scenarios were tested involving gas and water injection wells, placed in different zones of the sector model in order to support the pressure and thus improve the oil recovery. Variations on injection rate and test the performance of the injectors at different control mode were also considered. Therefore, only one case from the each different scenario studied that yield good results in terms of oil recovery will be presented and compared with the base case.

5.7.1- Gas injection scenario

Taking in into account that the sector model is producing a considerable amount of gas, a source of gas supply would not represent an issue. The main idea was to re-inject the produced gas to support the pressure ensuring that it could have an effective contribution to the oil recovery. In an offshore context, solution to handle produced gas might be challenging as flaring is not a sustainable solution and not allowed in many countries, and no access to gas network and plants may exist. In this context gas reinjection would represent a coherent framework solution.

The gas injection well was placed at top of sector model into the gas zone. In order to achieve constant pressure maintenance and ensure total reinjection the control mode REIN was considered. This control type allowed handling all produced gas and eliminating the need for an external source of gas supply.

5.7.2 - Water injection scenario

Water flood has showed to be the most efficient secondary method to maintain pressure and increase recovery at low cost. In this context a water injection well scenario was considered with same purpose. To define the injection well location oil and water saturation changes and the fluids flow through the reservoir during the entire production period was taken into account. To ensure constant pressure maintenance the injection well was set to inject 1000 Sm^3/d using voidage replacement (VREP) as control mode.

5.7.3 - Gas and water injection Scenario

These scenarios evaluate the combination of the two cases scenarios above outlined. Figure 21 shows the set of the wells in the sector model.

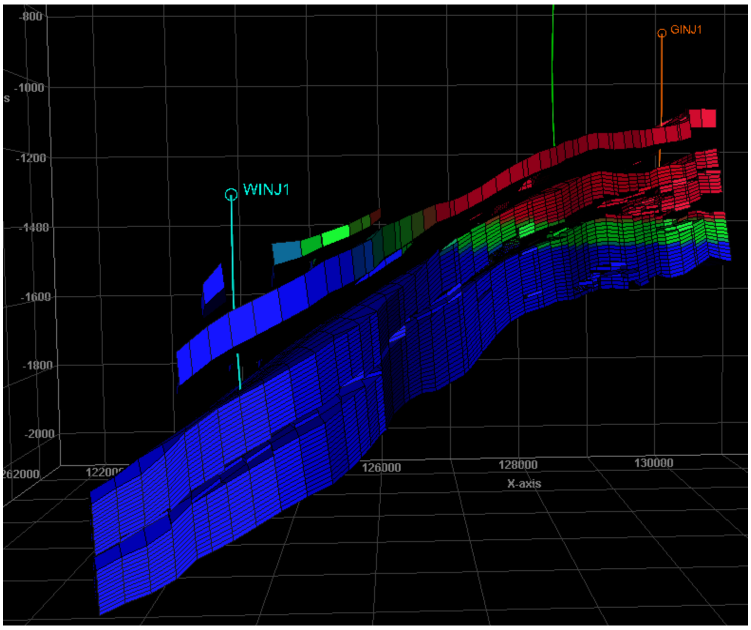

Figure 20 - Sector model showing the set of injection wells

CHAPTER VI – RESULTS AND DISCUSSION

This chapter will provide and discuss the results from all scenarios conducted in the different studies performed in the sector model. For each scenario and cases the respective outcome is addressed, followed by interpretations.

6.1 - LGR results

The refinement of the grid allowed reaching the best compromise between computational time and accuracy of results. A refinement around the thin oil zone ensured good solution quality in the grid model. Figure 22 show a cross sectional view of the well with different resolutions.

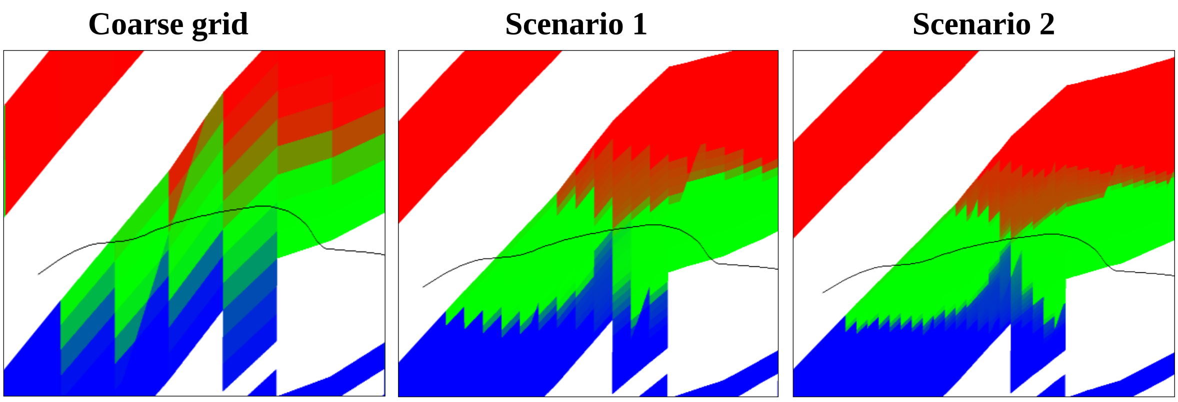

Figure 21 - cross sectional view of the well with different resolutions

The results clearly indicate that to represent regions with rapidly changes of fluids saturations with good accuracy it requires finer grid. It is also visible that scenario 1 and scenario 2 give similar results in terms of resolution hence scenario 1 was adopted as reference case for coning study; first to give a good resolution of the cone shape and second to provide satisfactory computing time. No cone was observed on coarse grid, indicating not to be appropriated for cone studies. Figure 23 presents the CPU time for the different resolutions.

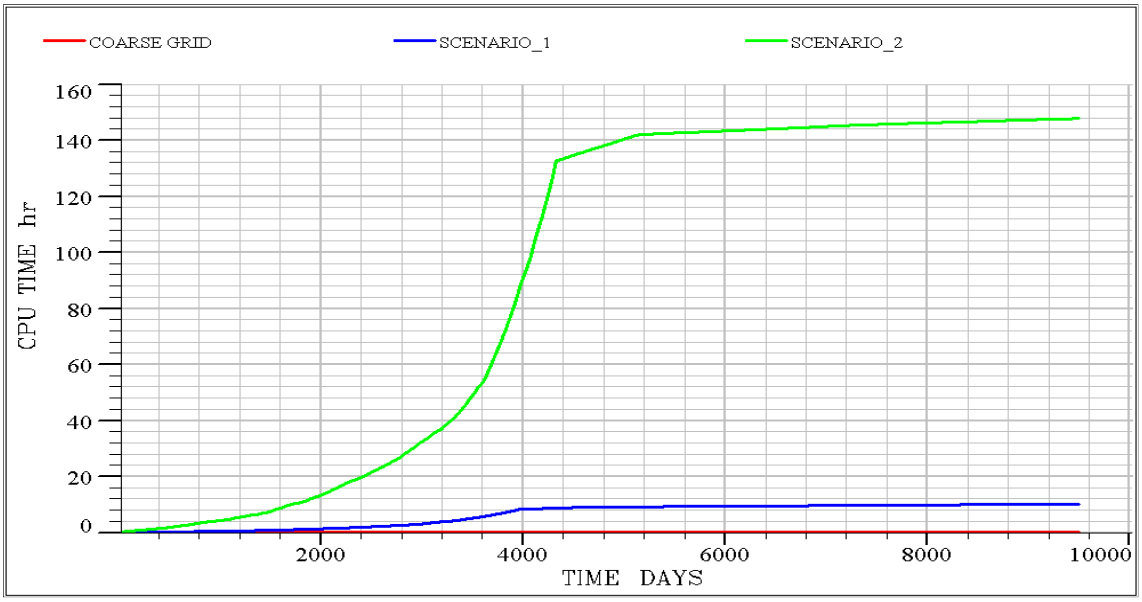

Figure 22 - CPU time for the different resolutions

CPU time curves for different LGR show considerable variation in time. Clearly indicating that the finer the model more cells will be generated and subsequently the longer runtime will be.

In the following fig. 24 through 27 the different profiles are evidenced and how the results were affected when using different resolution.

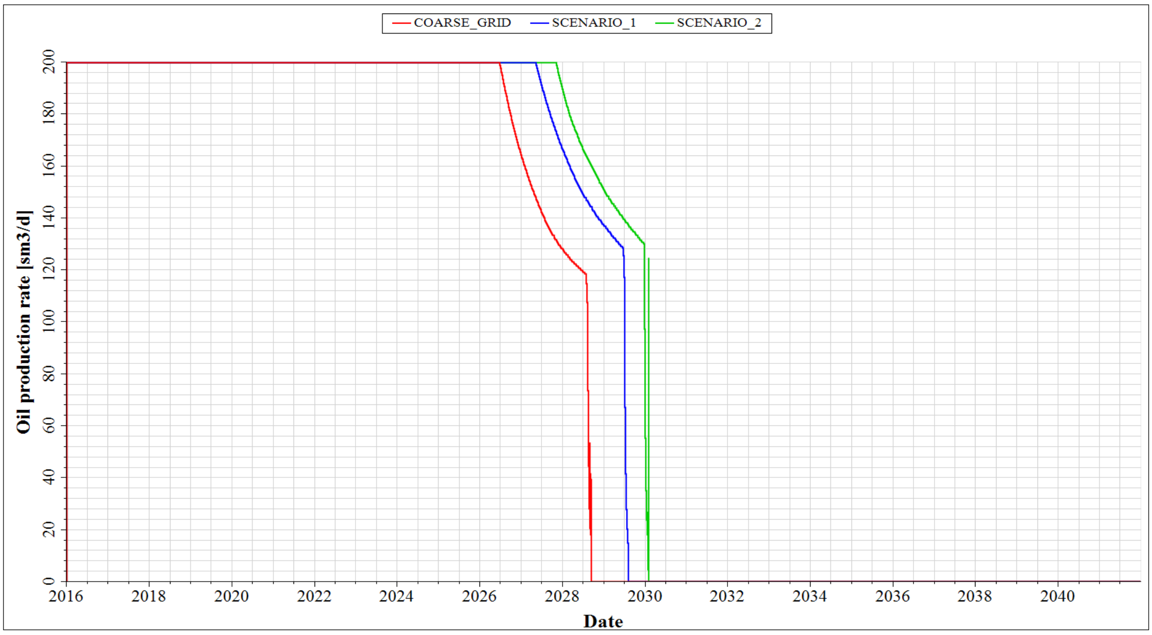

Figure 23 - Oil production rate for different resolutions

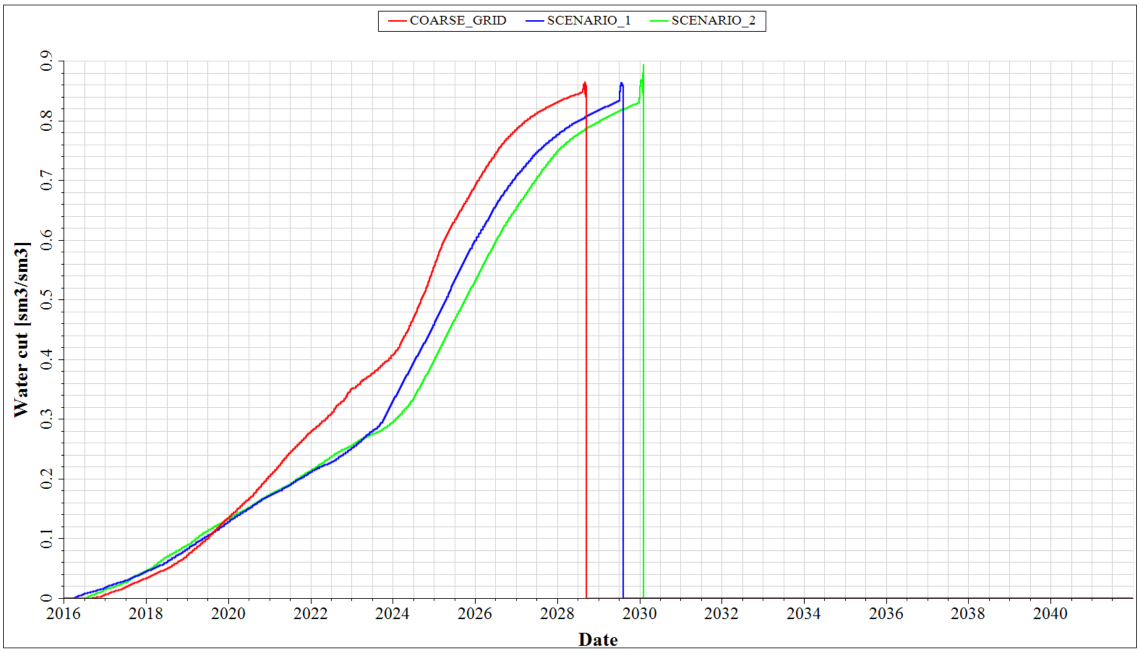

Figure 24 - Field water cut for different resolutions

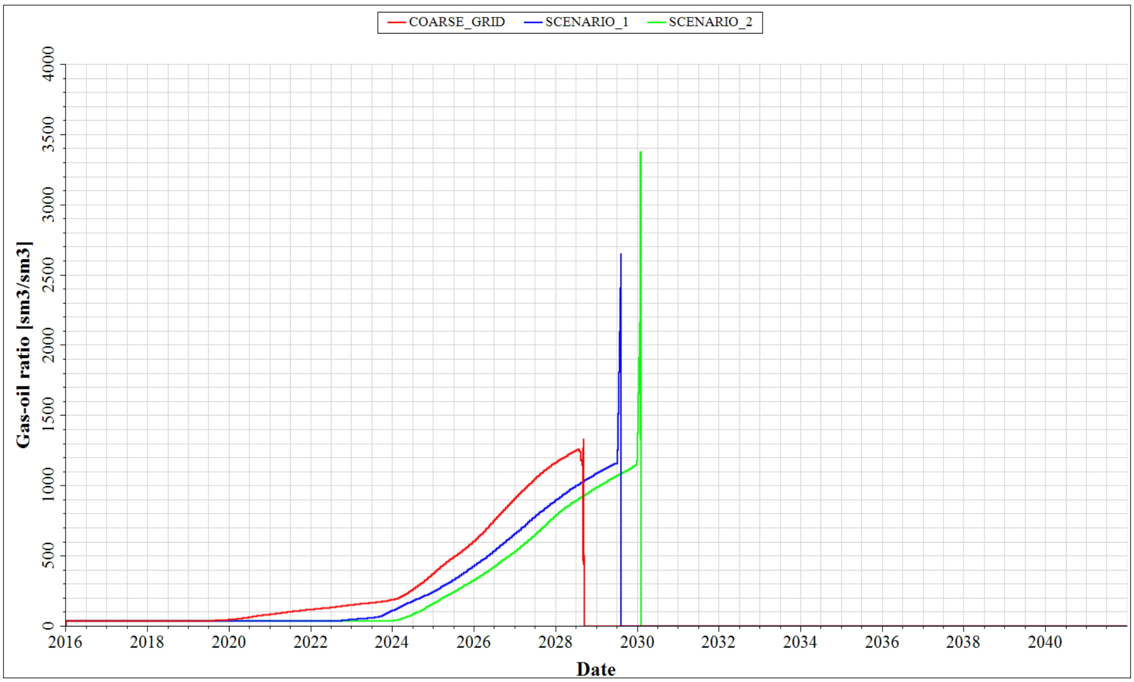

Figure 25 - Gas oil ratio for different resolution

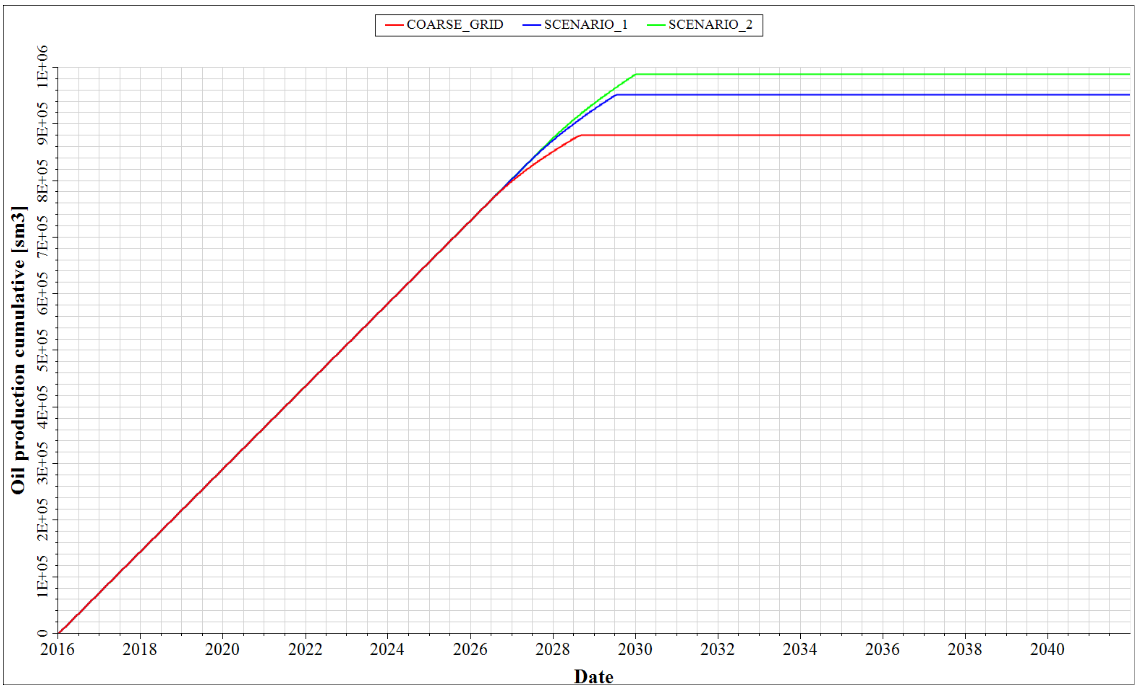

Figure 26 - field oil production total at different resolution

Based on presented results for this study it is clearly visible that Scenario1 has yielded to the best compromise between computational time and accuracy of results. Table 7 shows the recovered volume in barrels and its respective recovery factor for the study above outlined.

Table 7 - Recovery factor for study of resolution

Case of study	Recovered volume (MMbbl)	Recovery Factor (%)
Coarse Grid	5,5	16,2
Scenario_1	6,0	17,5
Scenario_2	6,2	18,2

The cross sections are useful for capturing the cone shape and control its progress over time. Figure 28 represents the west to east cross section view, how the coning progress over the time.

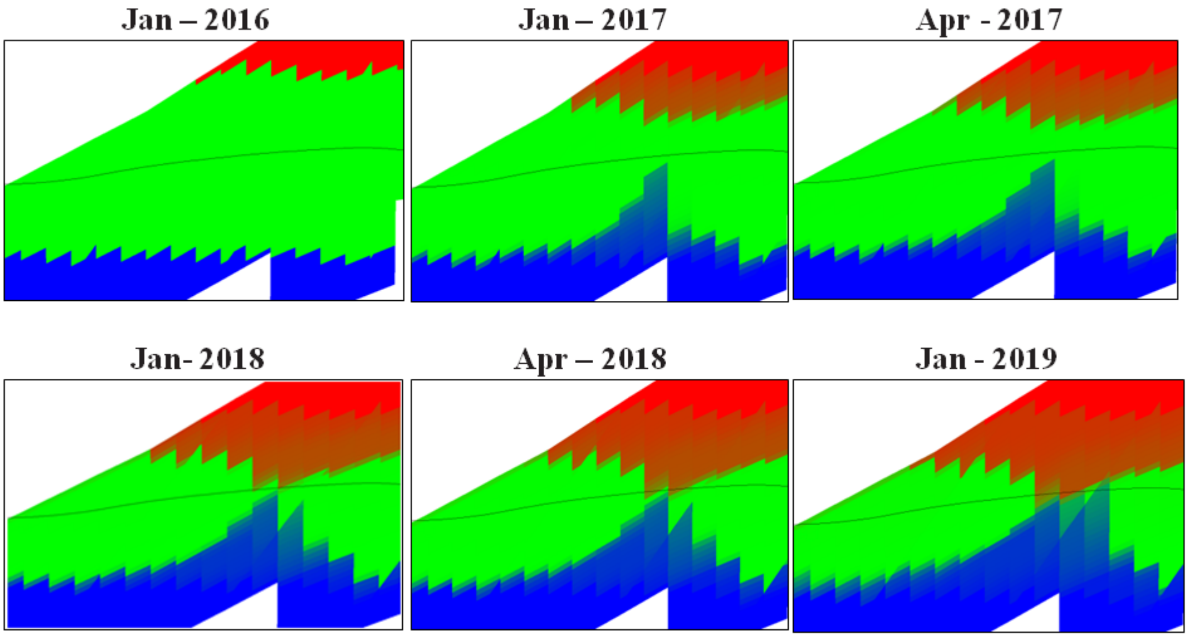

Figure 27- Cross section view of the coning progress over the time

This study has allowed verifying that gridding effects, leaded to a satisfactory saturations disposition and a better resolution of the fluids variation at the model level.
A conclusion that can be taken from this study is that increasing grid resolution improves the coning interpretation and provides good accuracy on results but the process can be very time consuming. Therefore, a good compromise between computational time accuracy of results was achieved.

6.2 - Analytical study results

6.2.1- Critical rate

The analytical and numerical models were used to estimate the critical oil rates based on the real reservoir characteristics. The ranges of estimated critical rate obtained for correlations where encountered when varying the parameters evaluated in the sensitivity study. The response of the numerical model was taken as a reference, so the results obtained with the

analytical simulation were evaluated with respect to the numerical simulation results. In the simulation model, a critical oil rate between 200 sm^3 and 300 sm^3 was found.
According with results obtained from the selected methods it has resulted in different critical oil rates for each correlation. This fact is mainly associated with assumptions made to develop the theoretical correlations. Figure 29 shows the analytical results of the estimated critical rate for the different models at equal reservoir conditions.

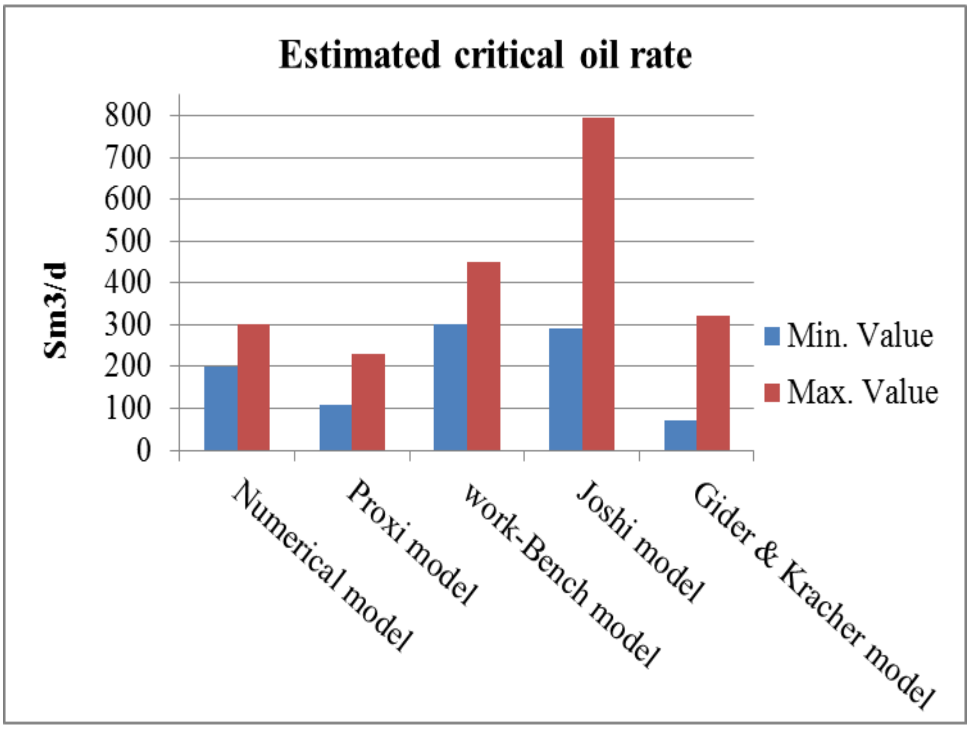

Figure 28 - Estimated critical oil rate by different correlations

Proxi model provided the range of critical oil rate that appears to be in good agreement with the numerical model.

Giger & Karcher model gives the lowest range of critical rate when compared to numerical model. The reason for it may be related by the fact that their correlation does not consider the effect of a simultaneous cone. In other words the method here presented, calculate the critical rate as two separated cases and assume the smaller one as the critical production rate of a system of gas oil and water. Another reason would be associated to the validity of the correlation, which suggests that its solution should not be used for small values of the drainage radius; therefore, a more accurate solution would be obtained by considering an effect of range of drainage radius on critical rate.

It was noted that Joshi´s model has provided the highest range of critical oil rate and far of the range of numerical model. Therefore, such higher range was already expected since, his correlation usually differ from several other theories including Giger & Kracher by a factor of up to 20 (Guo, 1992). Another reason may be related with the fact that this correlation does not consider the presence of a third fluid in the reservoir.

Although Work-Bench model gives a range slightly out of the estimated range it remains worthy of some confidence. This model has been generated to a specific thin oil reservoir, and the delivered equation has involved several regression analyses. Regardless of the result a coherent solution would require further delineation to substantiate the impact of the reservoir characteristics.

6.2.2 - Breakthrough time

Only Work-Bench method gives an analytical correlation to estimate the time breakthrough of simultaneous gas and water coning in a horizontal well. The results obtained indicated that the water breakthrough time can greatly vary depending on oil production rate and the well placement. Figure 30 shows the breakthrough time for both gas and water.

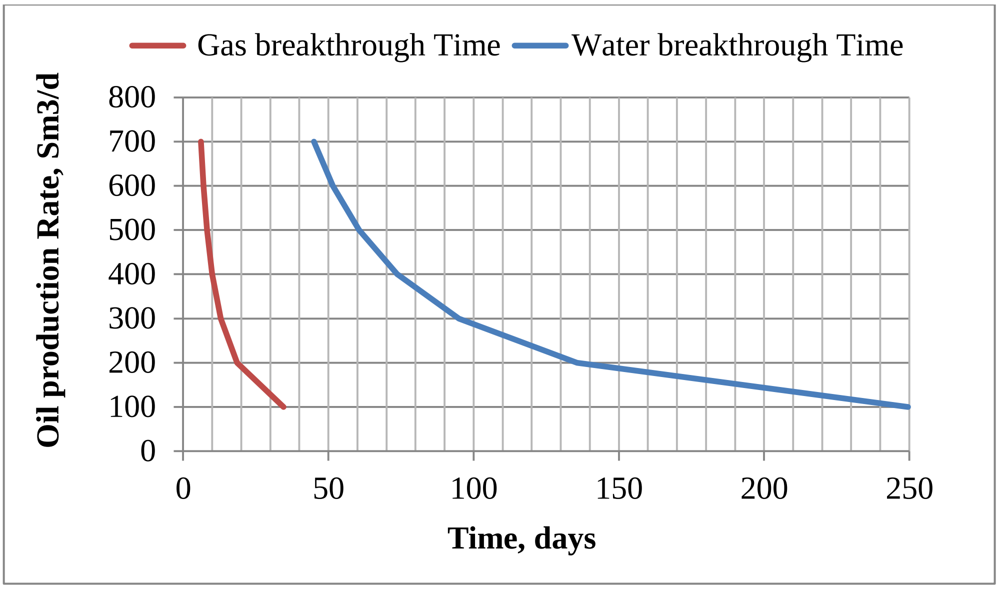

Figure 29 - Breakthrough time

Given the low viscosity of the gas compared with others fluids present in the reservoir this study has served to confirm that gas breakthrough happens sooner than water breakthrough and the optimum location should be chosen in order to prevent gas breakthrough rather than water. Therefore, it is important to keep in mind that due the simplicity of analytical correlations they are mainly used for quick interpretations and they do not eliminate completely the possibility of producing water or gas before the estimated time.

6.2.3 - Sensitivity analyses

A sensitivity study was conducted to analyze the effect of the most relevant parameters on the critical rate. The results of the sensitivity analysis are presented in the following figures (31 through 33) to show how the critical rate is affected by horizontal permeability, well length and oil viscosity for the different correlations.

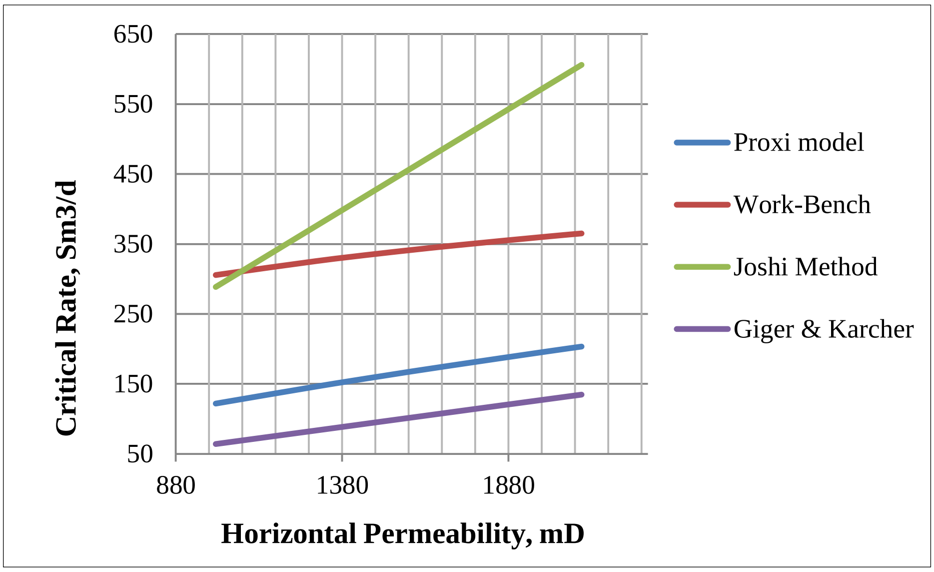

Figure 30 - Critical oil rate as a function of horizontal permeability

As it can be seen all methods have similar trend for critical rate. They increase slightly as horizontal permeability and well length increases, and almost constant as oil viscosity decreases. With exception of the Joshi method that shows an abrupt and different variation in all cases.

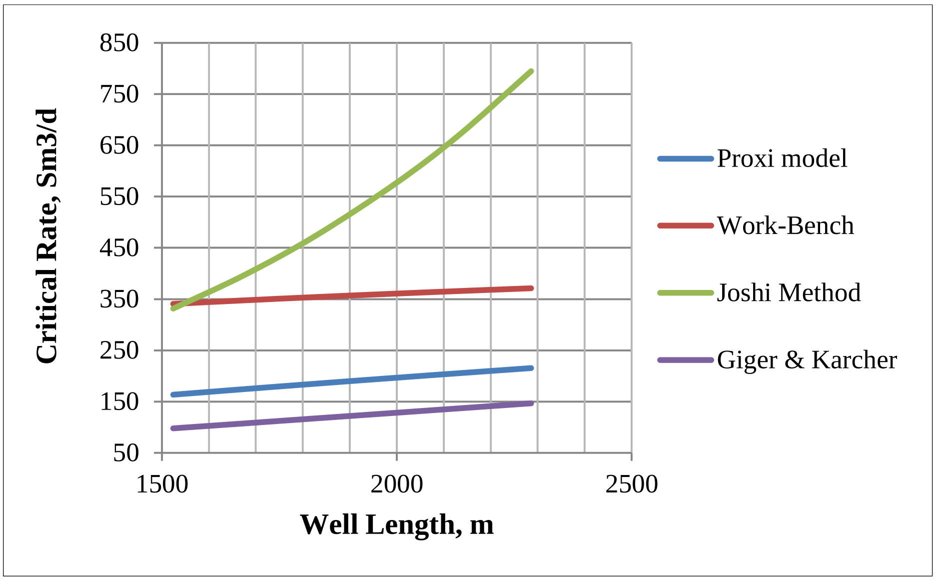

Figure 31- Critical oil rates calculated as a function of the well length

Work-Bench correlation shows not to be too sensitive for the chosen intervals for both well length and oil viscosity parameters since it yielded to a variation almost constant on sensitive study.

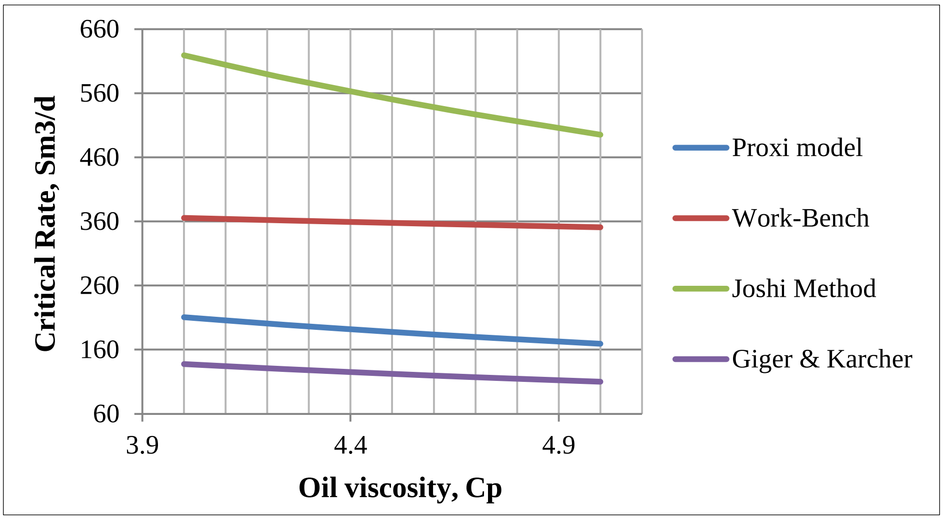

Figure 32 - Critical oil rate as a function of oil viscosity

Regarding the sensitivity study it has served to notice that critical rate is more sensitive to horizontal permeability. Since, all correlations show a great variation for this parameter.

6.2.4 - Comparison between the methods

Based on the obtained results, the general conclusion can be drawn that analytical models are useful tools for predicting critical oil rates, but should be considered with care. Critical oil rate ranges estimated from Proxi model are in very good agreement with ranges obtained from Alpha numerical model. This trend may be associated to the fact that this correlation was developed specifically to thin oil rim reservoirs. It is true that some inconsistencies may be associated due to the reservoir condition variations but still keep the main principle of mechanism of thin oil column. It is also important to keep in mind that some errors related to well placement, may affect results, since numerical model are more exacts in several aspects, while the analytical models do not take into account several reservoir geometry and complexity.

6.3 - Results of the uncertainty parameters by using experimental design

The combinations of the chosen uncertain parameters in the probabilistic model have generated significant number of cases, which permitted to achieve a practical approach to assess their impact on oil production. The study has served to identify the key uncertainties and rank theirs impact in absolute value on oil recovery.

6.3.1 - Pareto plot interpretation

No variation is noticed at the earlier stages of production and after fifteen years of production the influence became constant. The reason for this is linked to the fact that all the generated case maintains the plateau length for 4 years and after that it starts to decline. After around fifteen years of production, influence became almost stable in most of the cases as the well stopped producing. Indeed BHP has reached its limit so just few of them still producing for this reason the variation at the last years of production on Pareto plot is slightly constant. Figure 34 shows the impact of uncertainties on oil recovery on a Pareto plot.

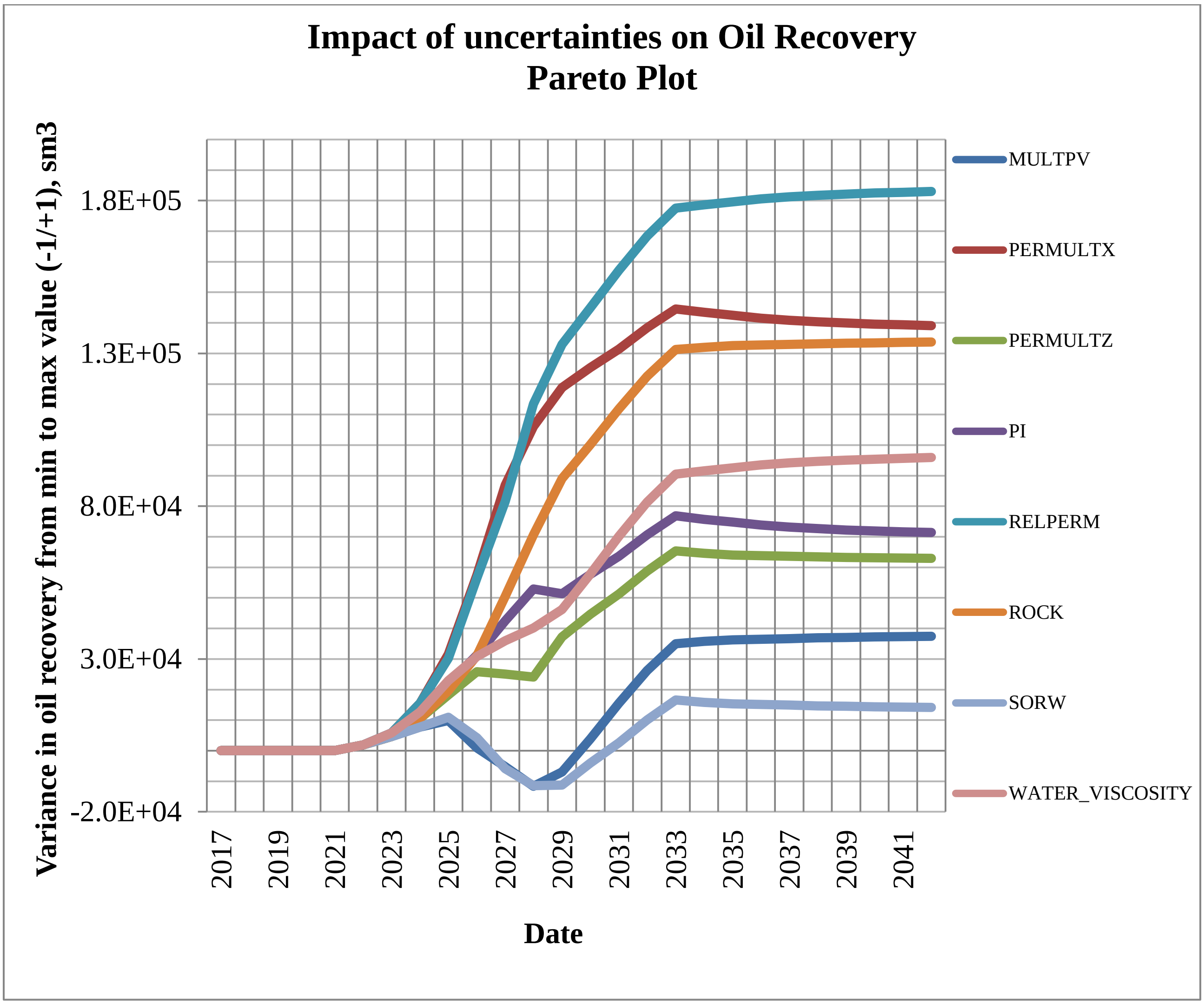

Figure 33 - Impact of uncertainties on oil recovery on Pareto plot

MULTPV and residual oil on water saturation parameters present a different tend between the years 2025 and 2028, indicating that at this stage of production these parameters do not affect significantly the oil production.

Figures 34, 35 and 36 show oil production rate, gas oil ratio and oil production cumulative over the years of the seventeen ED realizations.

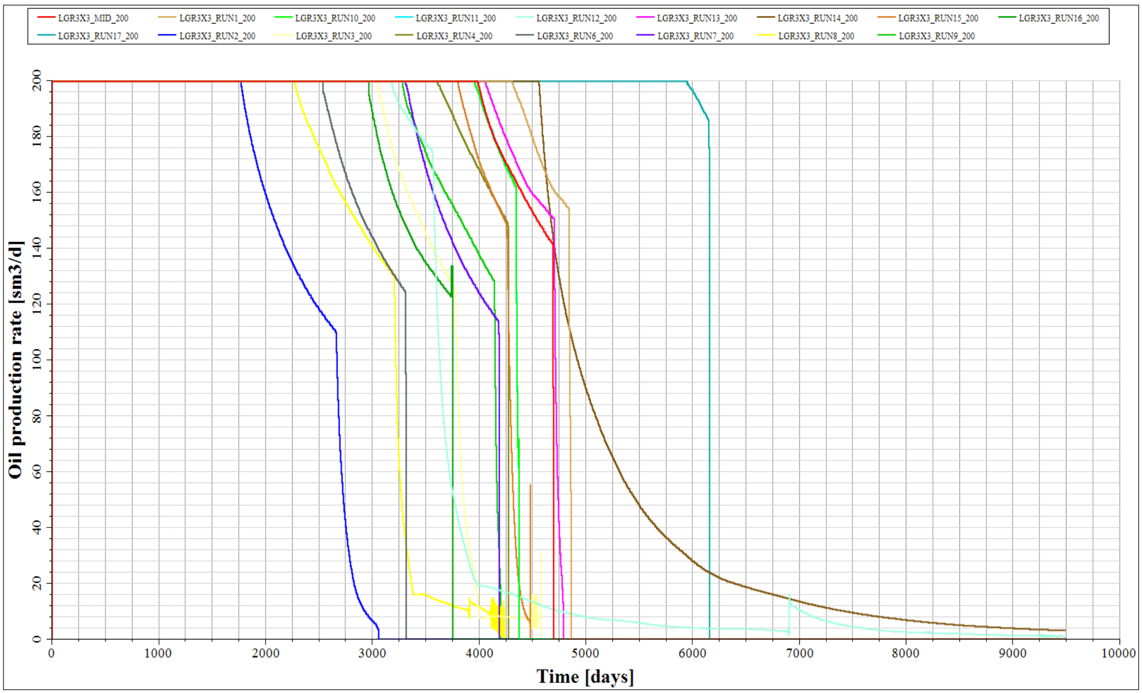

Figure 34 - Oil production rate vs. time of the experimental design study

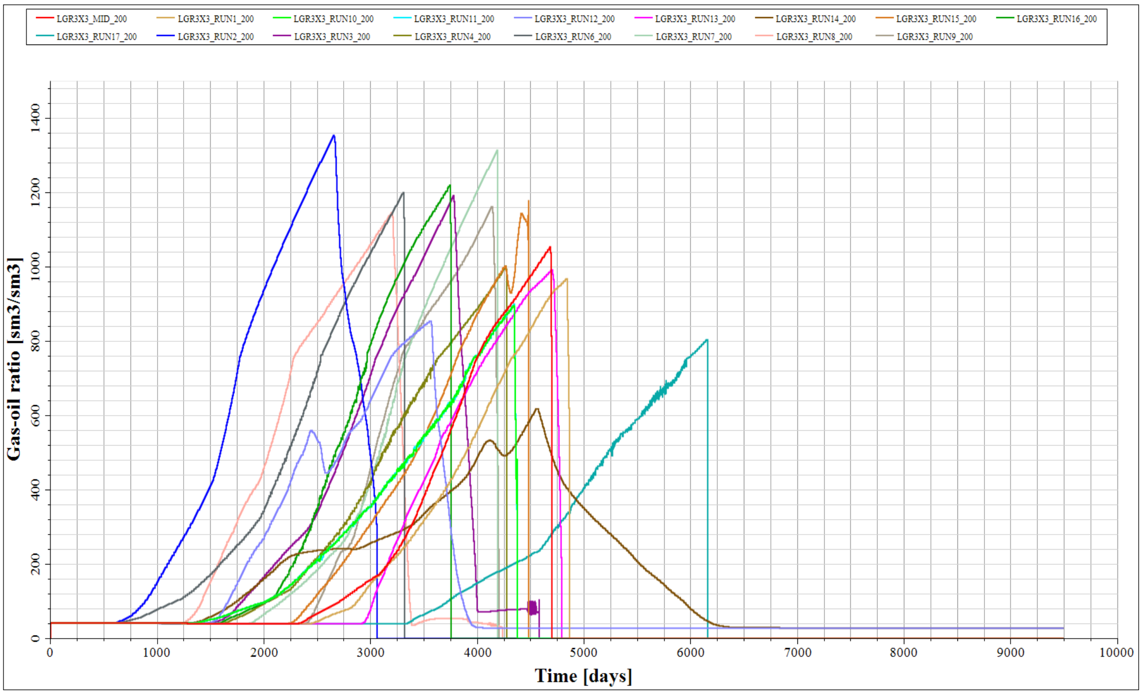

Figure 35 - Gas oil ratio vs. time of the experimental design study

As showed in the above figures it is obvious that the different cases present distinct trends. Others plots as water cut, reservoir pressure and more for the current study are displayed in the appendice.

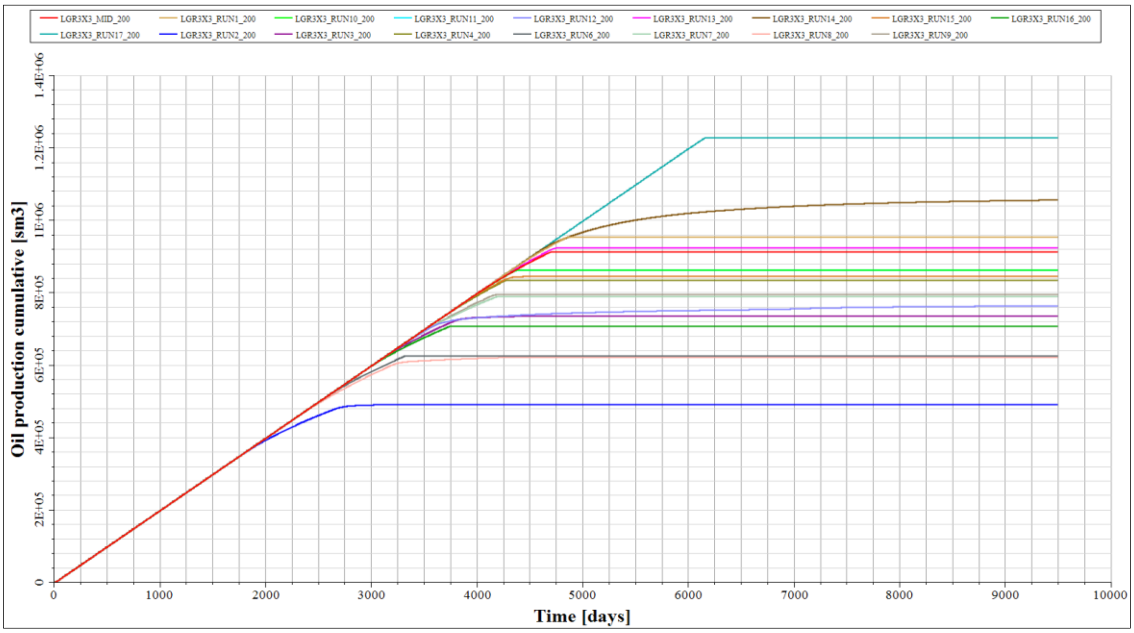

Figure 36 - Oil production cumulative vs. time of the experimental design study

6.3.2 - Uncertainty parameters discussion

This study has revealed relative permeability, horizontal permeability and rock compressibility as the key uncertainty parameters; having leaded to more than 1MMbbl of influence in absolute value on oil recovery for the relative permeability parameter. Clearly indicating that uncertainties related with this parameter can lead to a different oil recovery profile and predict a development plan without properly consider its impact would entail unrealistic results, which seriously affect a decision making. It is became important to obtain SCAL and wettability measurements of the field to ensure a better understanding of the fluids mechanism and injection cases would also be well planned.

Although Alpha reservoir presents good sand quality in terms of permeability at level of the sector zone, calibrations on this parameter should also be considered in order to provide more confidence result in terms of oil produced when dealing with heavy oil. Horizontal permeability has resulted in one of the parameters with highest impact on oil recovery. The study has showed that uncertainties around this parameter can have a quite similar impact as relative permeability for the six first years of variation.

Rock compressibility has also showed as the one of the parameters with considerable impact. It is important emphasize that no measurements were taken for this parameter and the base value considered for this study was assumed based on analogs for a unconsolidated rock (at reference pressure of the Alpha reservoir), with a wide range of variation. Since, the compressibility of a rock does not present large variations as the hydrocarbon in the reservoir the explanation of this parameter appear as one with such degree of impact is related with chosen interval.

In a gradual descending order water viscosity, productivity index and vertical permeability represent the parameters with moderate impact on oil recovery. Water viscosity shows an accentuated increasing variation on the first years followed by a more abrupt after the year 2026 due high level on water production for most of the cases.

Residual oil on water saturation and the parameter related with aquifer size (PERMULTPV) have revealed to be the parameters with least impact on oil recovery.

6.3.3 - Result of the three main cases generated from uncertainty study

As mentioned before the study of uncertainty has generated seventeen probabilistic cases. In this section will be presented only the high, mid and low cases. This study has served to evaluate a possible range of recovery factor and how they impact on gas oil ratio as well as water cut. In fact the mid case obtained in this study was considered the base case scenario for further studies.

Figures 37 and 38 shows GOR and water cut versus time of the main cases generated from experimental design. The cases High, Low and Mid represent the cases when the uncertainties parameters assume maximum, minimum and middle values respectively. According with results they indicate that when the uncertainty parameters assume its minimum value it tends to increase the possibility of produce gas and water.

Figure 37 - Gas oil rate vs. time for the three main case of experimental design

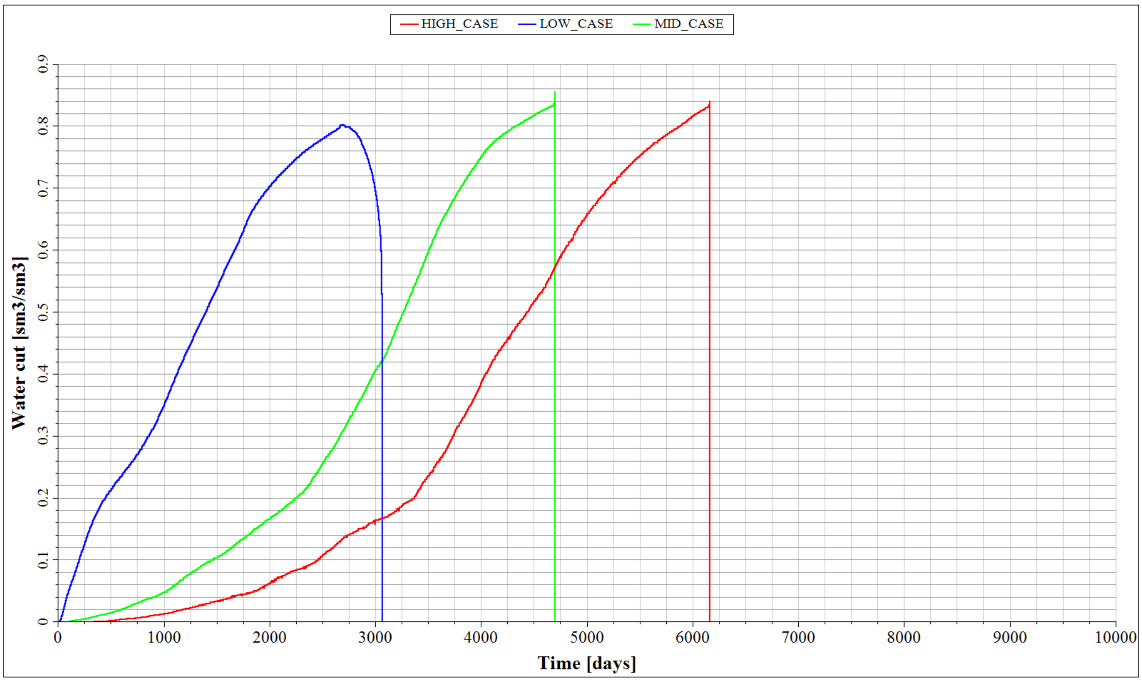

Figure 38 - Water cut vs. time for the three main case of experimental design

In other words it indicates that due the mobility difference of the fluids present in the reservoir the conditions assumed for the low case parameters show to be more favorable to the production of the less viscous fluids.

For the high case the production of those fluids it is also visible but it delayed indicating good oil production in the first times; while for the low case the oil production is hindered by gas and water at early stages of production. As result figure 39 shows the production oil profiles in terms of oil cumulative and oil rate of the three cases above mentioned.

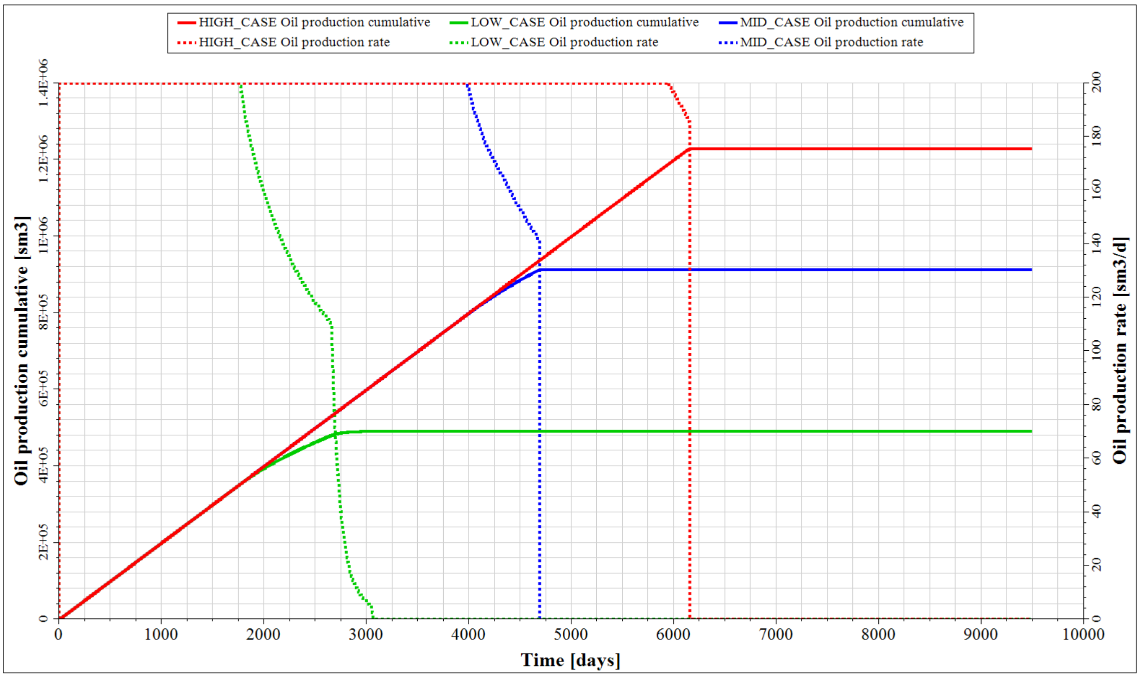

Figure 39 - Field oil production total vs. time for the three main case of experimental design

The three cases yielded to 9%, 17% and 23% of recovery factor for the low, mid and high case respectively. Table 8 shows the recovered volume in barrels and its respective recovery factor.

Table 8 - Recovered volume in barrels and recovery factor

Case of study	Recovered volume (MMbbl)	Recovery Factor (%)
Low Case	3.1	9
Mid Case (Base case)	5.8	17
High Case	7.7	23

6.3.4 - Results of impact on plateau length by producing above critical rate

The study of the impact of plateau has served to evaluate the plateau length and an interval of recovery when producing above critical rate. Figures 40 and 41 show the possible plateau length and the respective oil recovery of the three main cases generated from experimental design study, when they produce above critical oil rate (1000 sm^3/d).

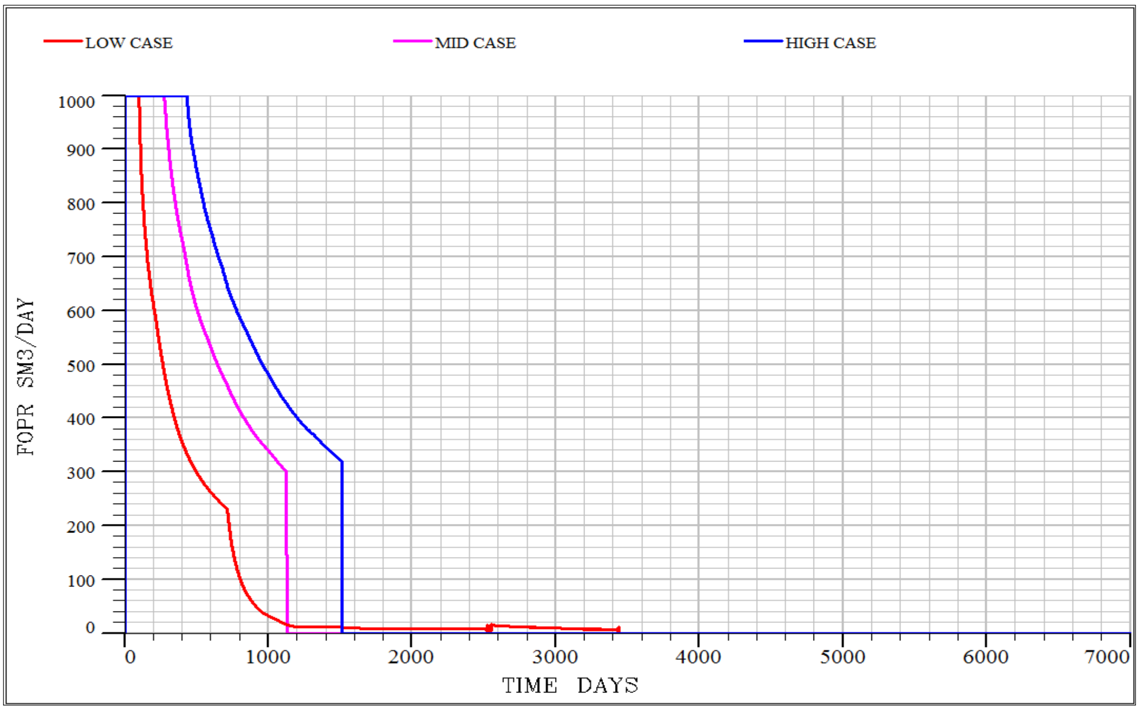

Figure 40 - Field oil production rate vs. time for the three main case of experimental design

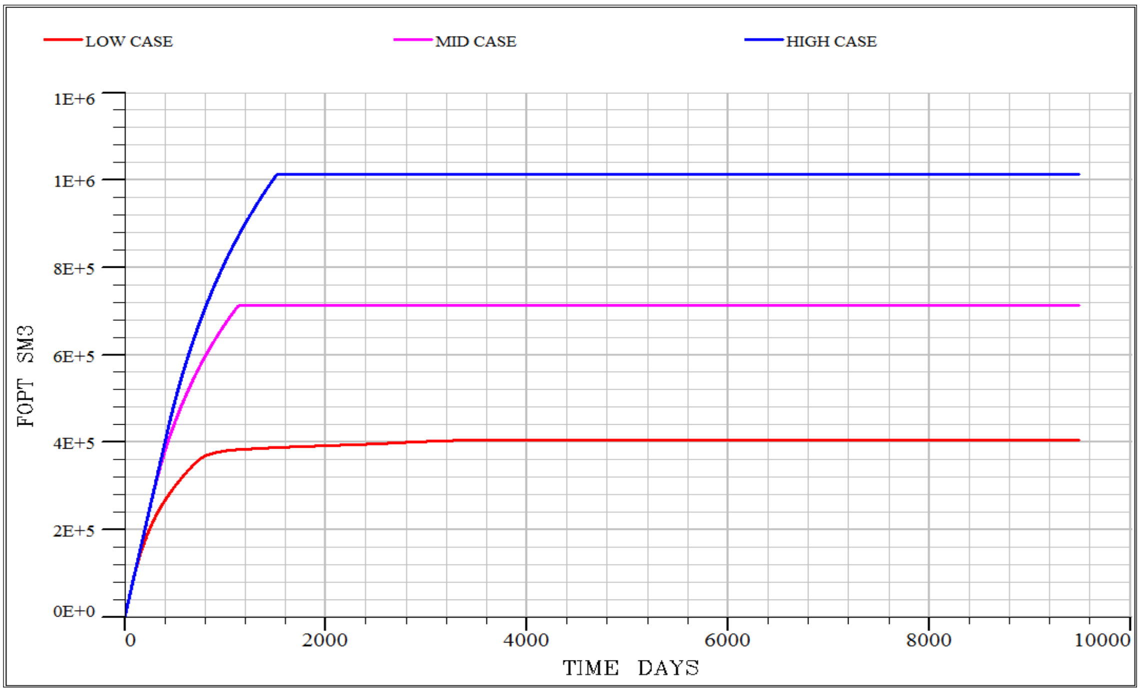

Figure 41 - Field oil production total vs. time for the three main case of experimental design

According to the results it is notable that producing at critical oil rate yielded to 5.8 MMbbls in almost 12 years, whereas producing above critical rate, a recovered oil volume of 4.5 MMbbls was achieved after only 3 years. Table 9 shows the recovered volume in barrels and its respective recovery factor when producing above critical rate compared with base case, which was produced at critical rate.

Table 9 - Recovery factor by produce above critical rate

Case of study	Recovered volume (MMbbl)	Recovery Factor (%)
Base case	5.8	17
Low Case	2.5	7
Mid Case	4.5	13
High Case	6.4	19

Indeed produce above critical rate can represent a good solution in terms of oil recovered at reduced time; therefore, consider such scheme of production would imply the drill of smart wells adapted with ICD´s and debottleneck plan involving increase capacity for gas and water treatment.

6.3.5 - Impact of surface constraints on profiles

The effect of surface constraints on results is well noticed in terms GOR, OPR and water cut. This indicates that as decrease the limits of gas and water production it leads to a reduction on plateau length, since the gas constraint is reached earlier. Despite of it the production last for longer indicating that the reservoir is not being rapidly depleted as the production of unwanted fluids is lowered. Figures 42 through 45 shows the production profiles of the different cases.

Figure 42 - Gas oil ratio vs. time for the test of fluid constraints

Figure 43 - Field Water cut vs. time for the test of fluid constraints

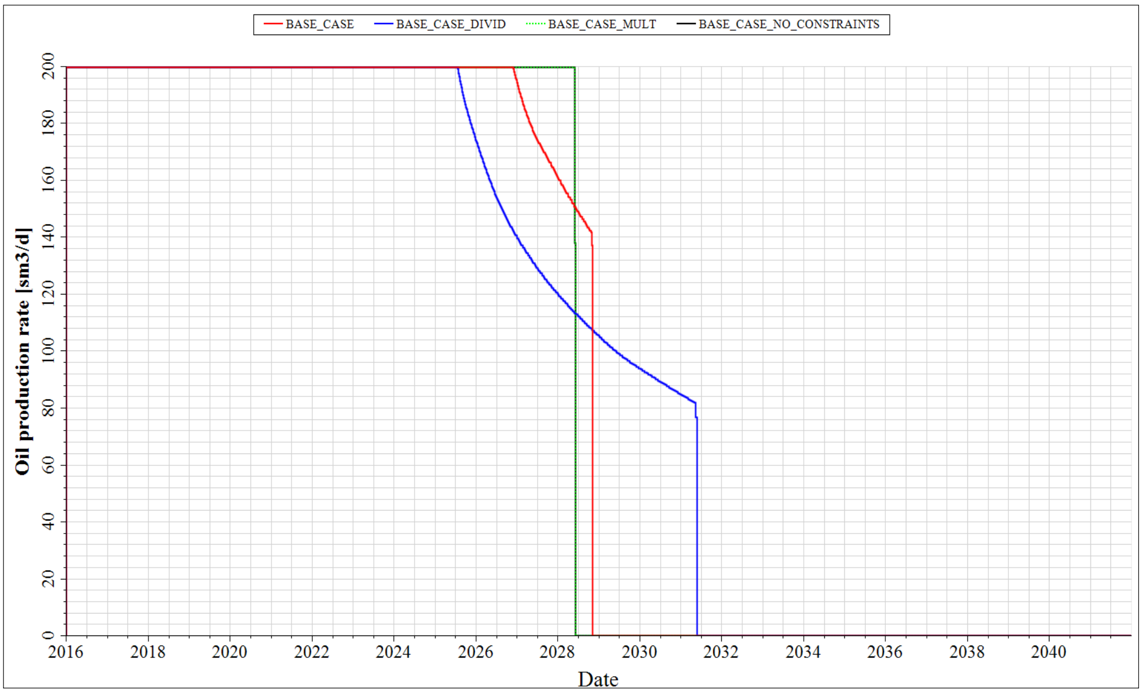

Figure 44 - Oil production rate vs. time for the test of fluid constraints

It is observed that no differences were noticed when operating at higher surface constraints or without surface constraints, since both cases show equal profiles. For this case the plateau length is not affected by the gas production since its limit of production is high enough. The following figure shows the oil production cumulative versus time for the different cases.

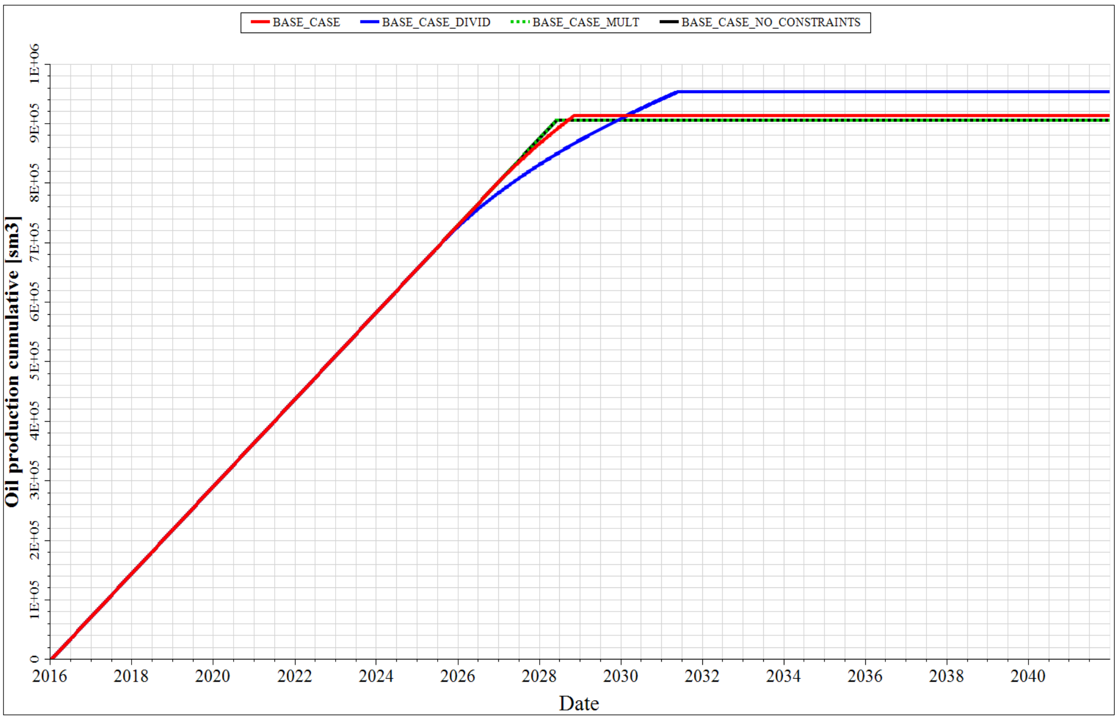

Figure 45 - Oil production Cumulative vs. time for study of the test constraints

According with results decreasing surface constraints leaded to an increasing on oil recovery of 18%. Table 10 shows the recovered volume in barrels and its respective recovery factor when surface constraints are altered.

Table 10 - Recovery factor by varying surface constraints

Case of study	Recovered volume (MMbbl)	Recovery Factor (%)
Base Case	5.8	17
Base Case_ No limit constraints	5.7	16.7
Case_Low surface constraints	6.0	18
Case_High surface constraints	5.7	16.7

6.4 - Results of IOR

6.4.1 - Gas injection scenario

The conditions implemented on injection well for this scenario yielded satisfactory results. In fact the control mode stated, has positively contributed achieving the expected results. Figures 46 through 51 are presented the different profiles obtained in this study compared with the reference case.

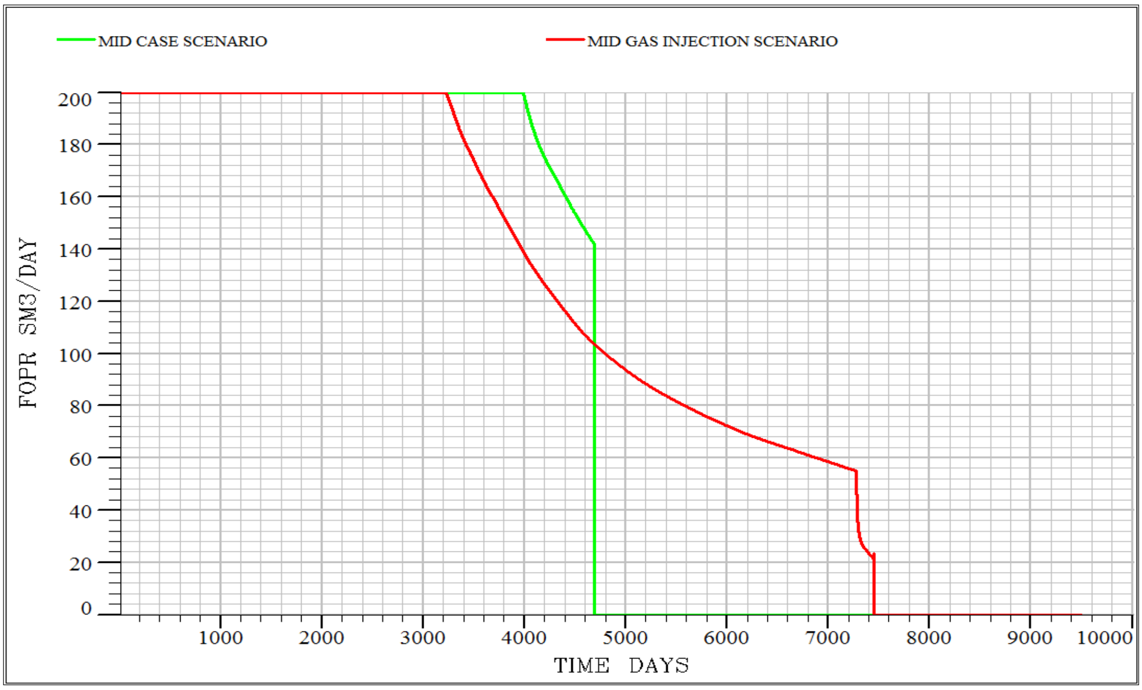

Figure 46 - field oil production rate vs. time for gas injection scenario

Although the plateau last less than Mid case scenario (Base case) it produces for longer time as expecting confirming the pressure maintenance of gas injection as showed in figure 49. For Base case it stops due the low BHP verified on production well when pressure maintenance was not implemented. The reason why the plateau length is shorter than base case scenario it is due to gas constraints. In other words for the injection case it was expected to produce more gas and consequently the constraint for the produced gas was reached earlier affecting the oil rate production.

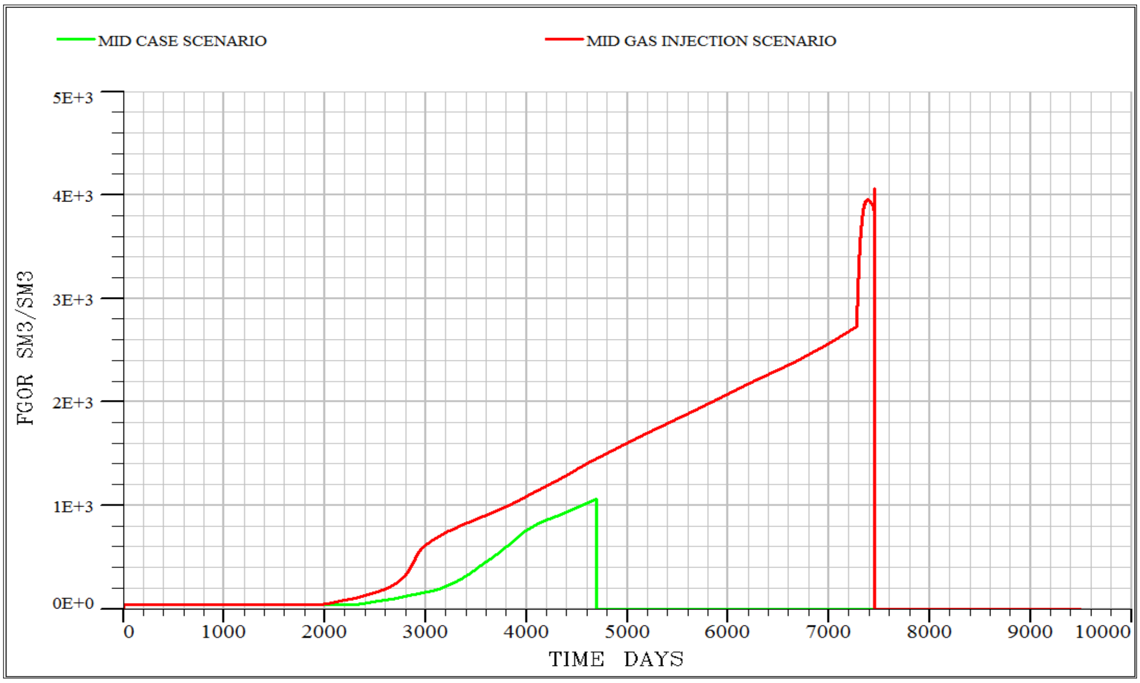

Figure 47 - Figure field gas oil ratio vs. time for gas injection scenario

As gas is being injected more gas is produced, consequently gas oil ratio is higher than base case as shown in figure 47. Figure 48 shows a stable water production for the first eight year followed by an abrupt production of water, which may indicate a possible water breakthrough.

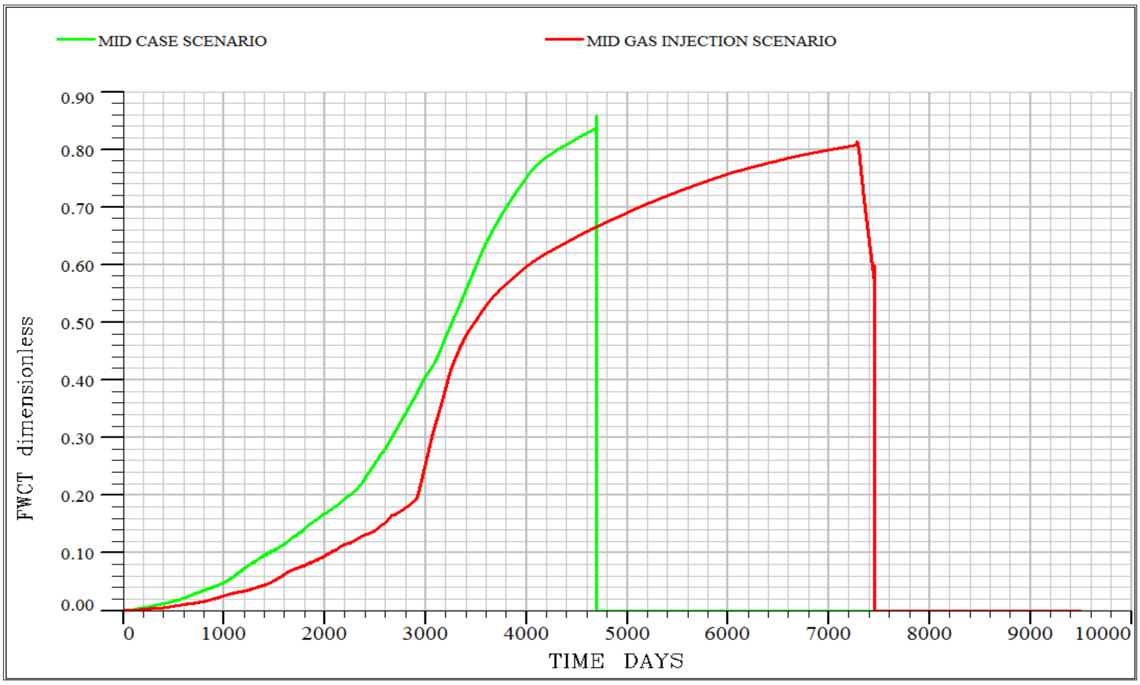

Figure 48 - Figure field water cut vs. time for gas injection scenario

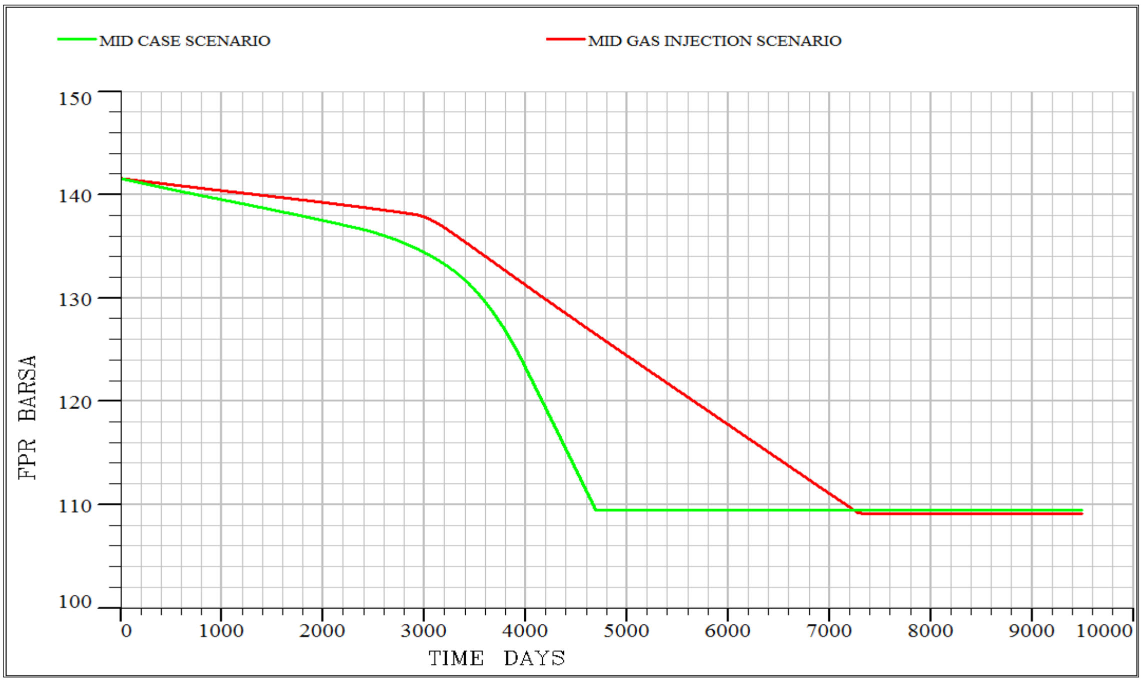

Figure 49 - Field pressure vs. time for gas injection scenario

Figure 49 reveals that good pressure maintenance is not achieved by gas injection due its compressibility. The following figure shows the difference between what have been produced and what have been injected for current case scenario.

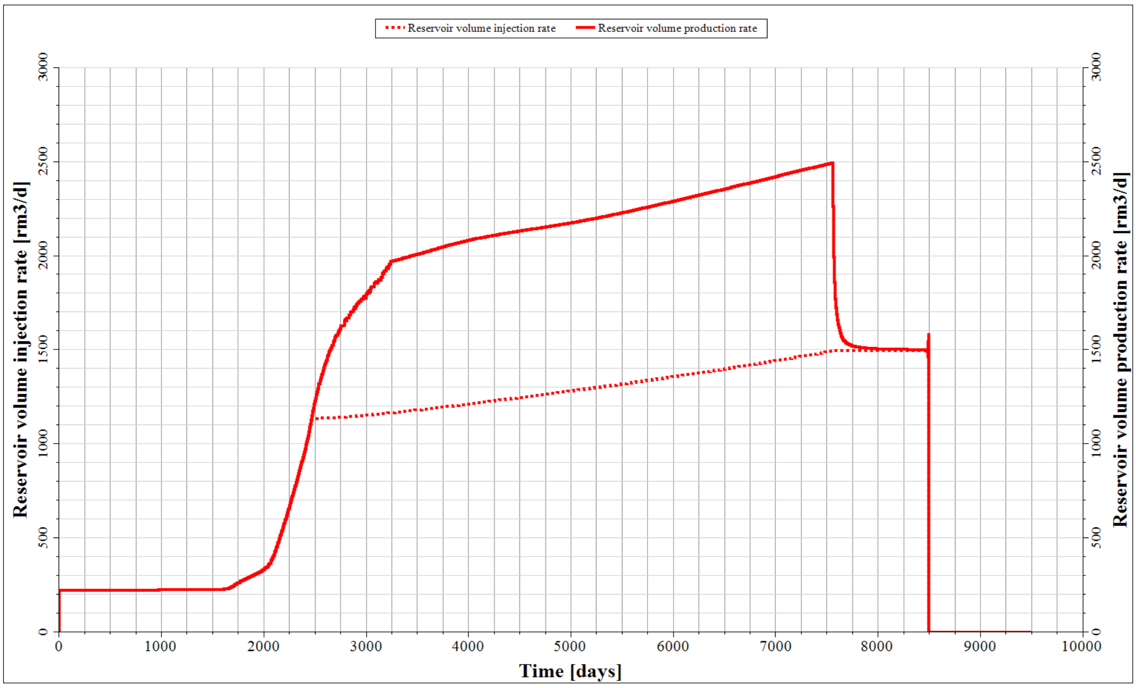

Figure 50 - Reservoir volume production and injection rate vs. time for gas injection scenario

Figure 51 presents the recovered oil over the years. Gas injection scenario clearly leads to an increase on oil recovery from 17 to 19%.

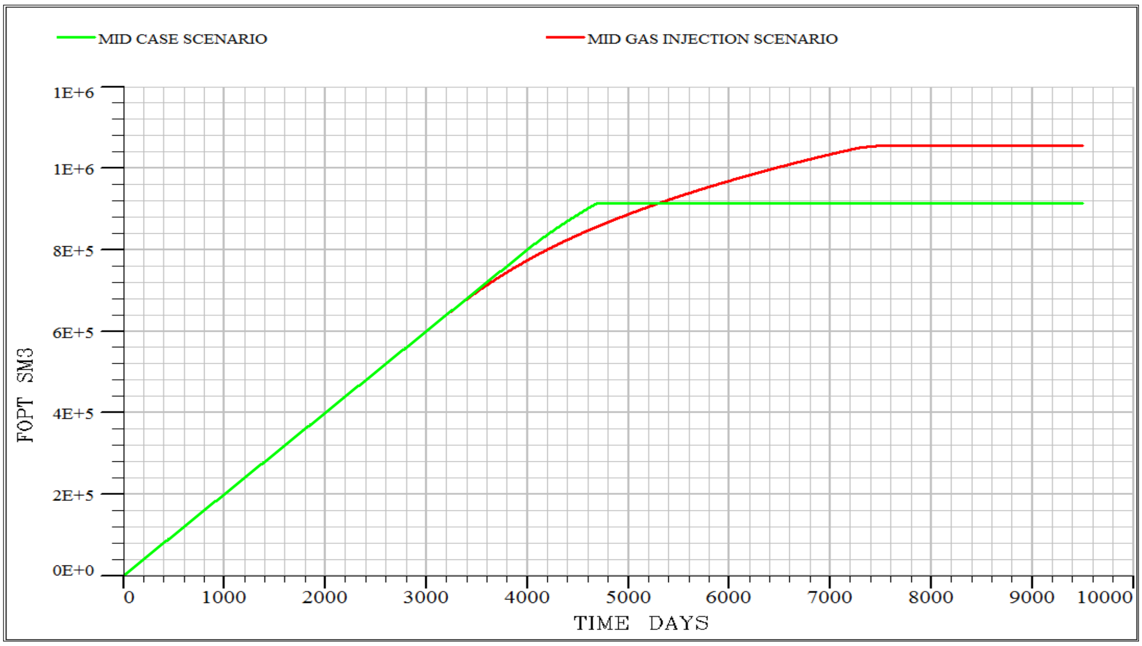

Figure 51 - Field oil production total vs. time for gas injection scenario

6.4.2 - Results of Water injection scenario

Water injection scenario is clearly the case that better delay the production of gas, since it permits a stable production of gas for longer, while keeps almost constant the reservoir pressure above saturation pressure. Figures 52 through 56 shows the production profiles for the water injection case.

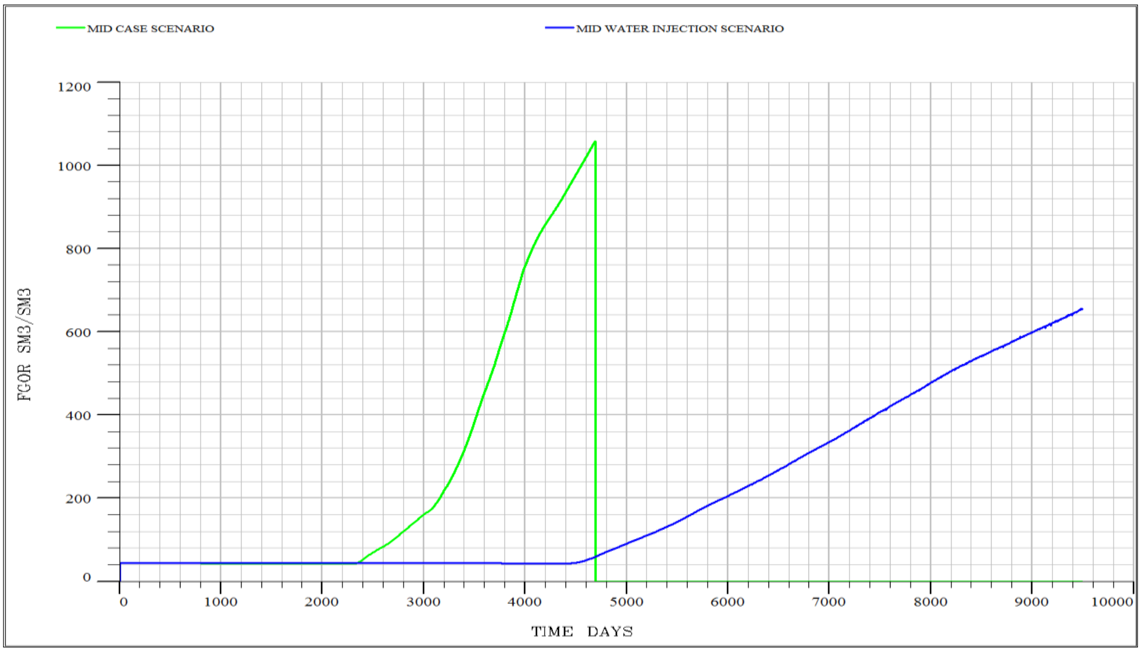

Figure 52 - Field gas oil ratio vs. time for water injection scenario

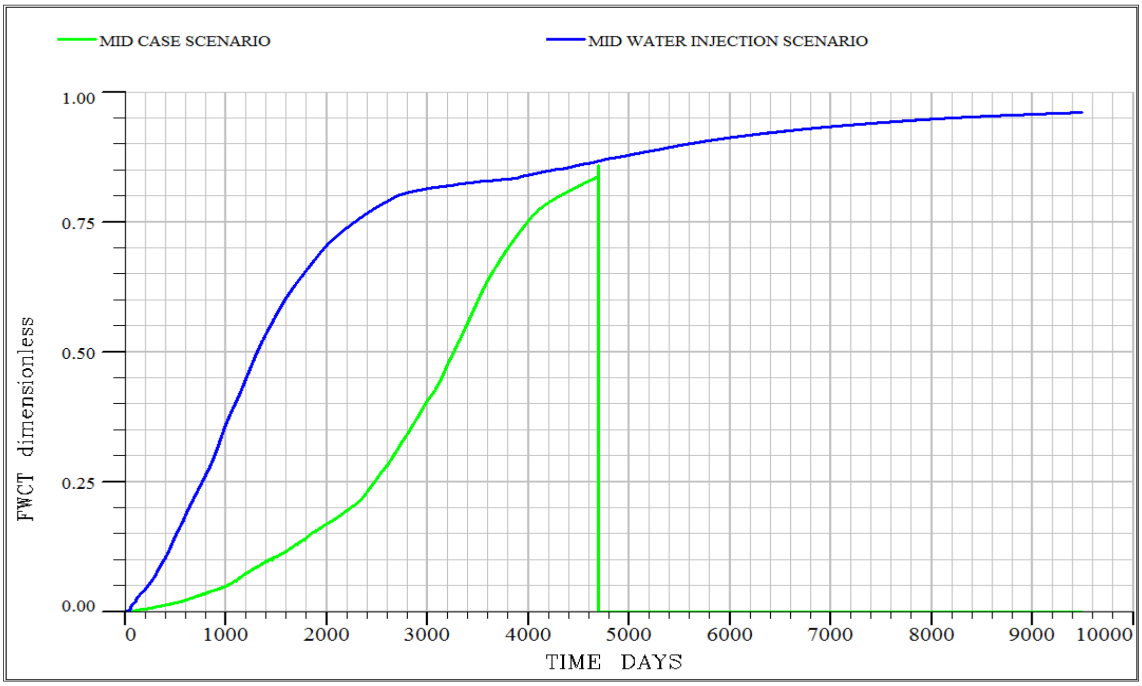

Figure 53 - Field water cut vs. time for water injection scenario

As observed on fig. 54 it is well seen how the pressure in being maintained at early stages of production as stated on control mode. It is verified that the desired pressure maintenance as stated on control mode was not achieved so, an increase on water injection rate could be considered.

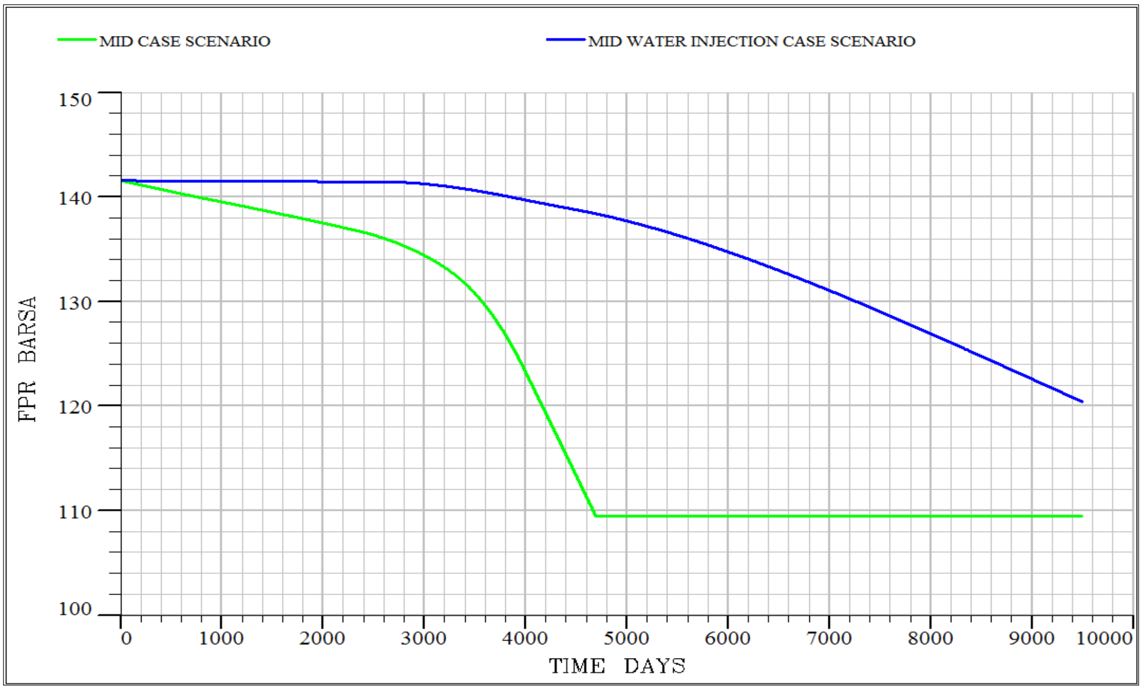

Figure 54 - Field pressure vs. time for water injection scenario

Figure 53 shows the difference in terms of volumes injected and produced. The reason why the water injection line is showing a constant line at 1000 sm^3/d is because it has reached the water limit of constraints.

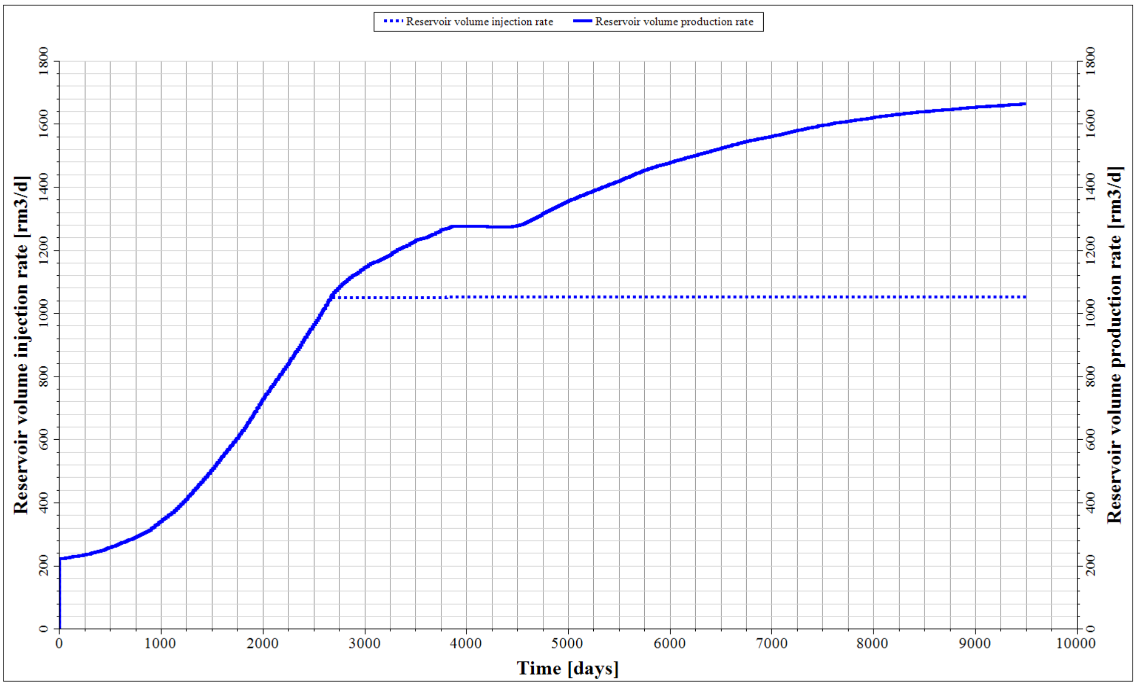

Figure 53 - Reservoir volume production and injection rate vs. time for water injection scenario

Figure 54 shows the field oil production total versus time. A quite good increase on oil recovery was noticed for the current scenario having reached 25.1% of recovery factor.

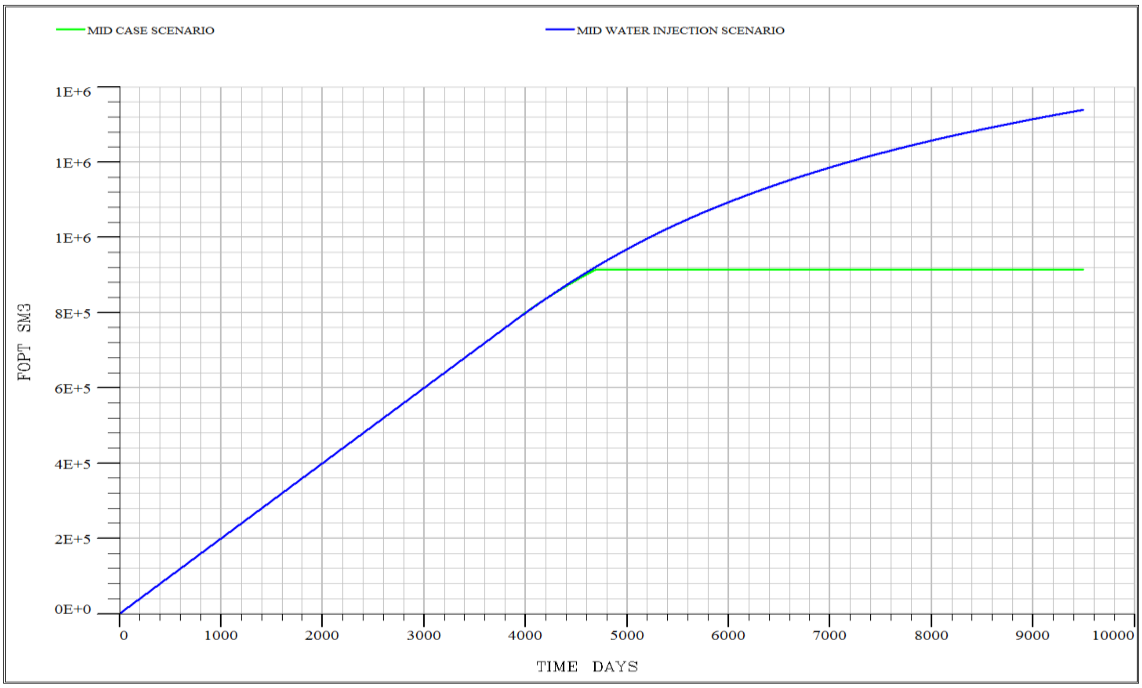

Figure 54 - Field oil production total vs. time for water injection scenario

6.4.4 - Results of both gas & water injection scenario

Figure 55 shows the gas oil ratio versus time for both gas and water injection scenario. As result a constant production of gas is verified in the first ten years followed by an abrupt variation.

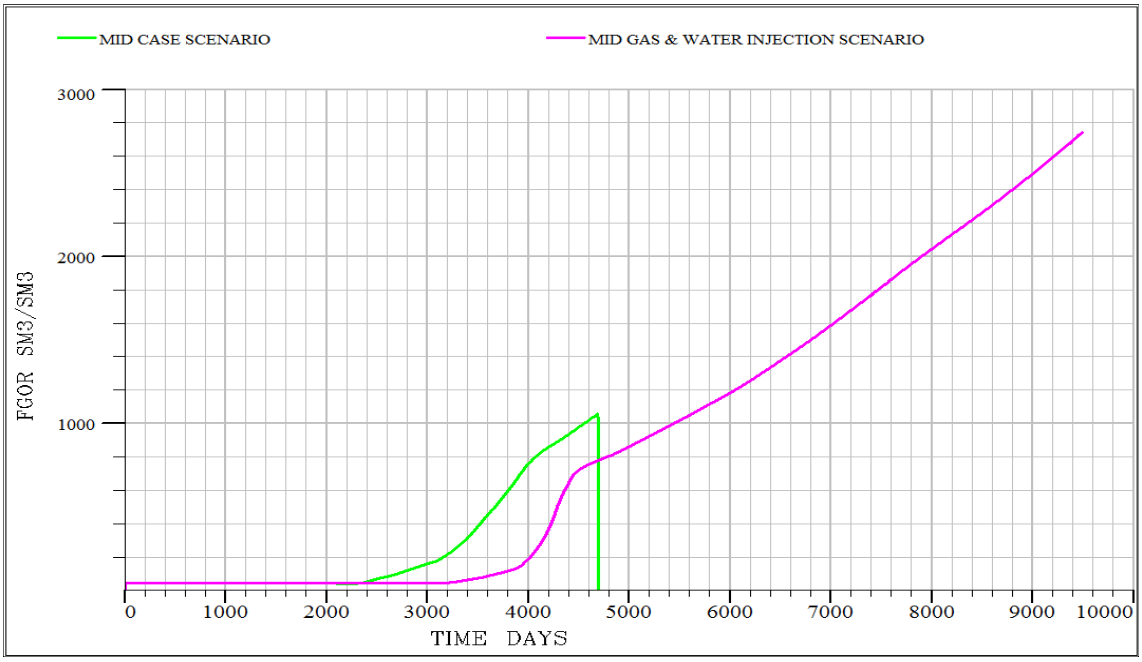

Figure 55 - Field gas oil ratio vs. time for gas & water injection scenario

Figure 56 shows the difference in terms of volumes produced and injected for the gas and water injection scenario.

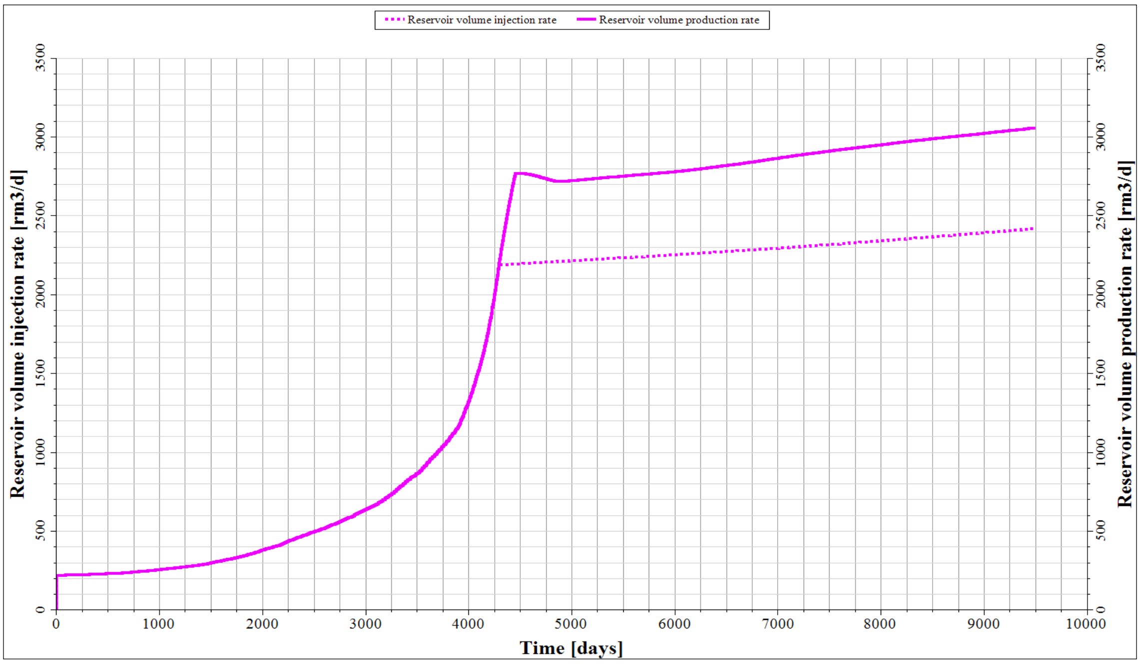

Figure 56 - Reservoir volume production and injection rate vs. time for gas & water injection scenario

Figure 57 shows the field pressure versus time for both gas and water injection. It is obvious that this scenario lead to more efficient pressure maintenance.

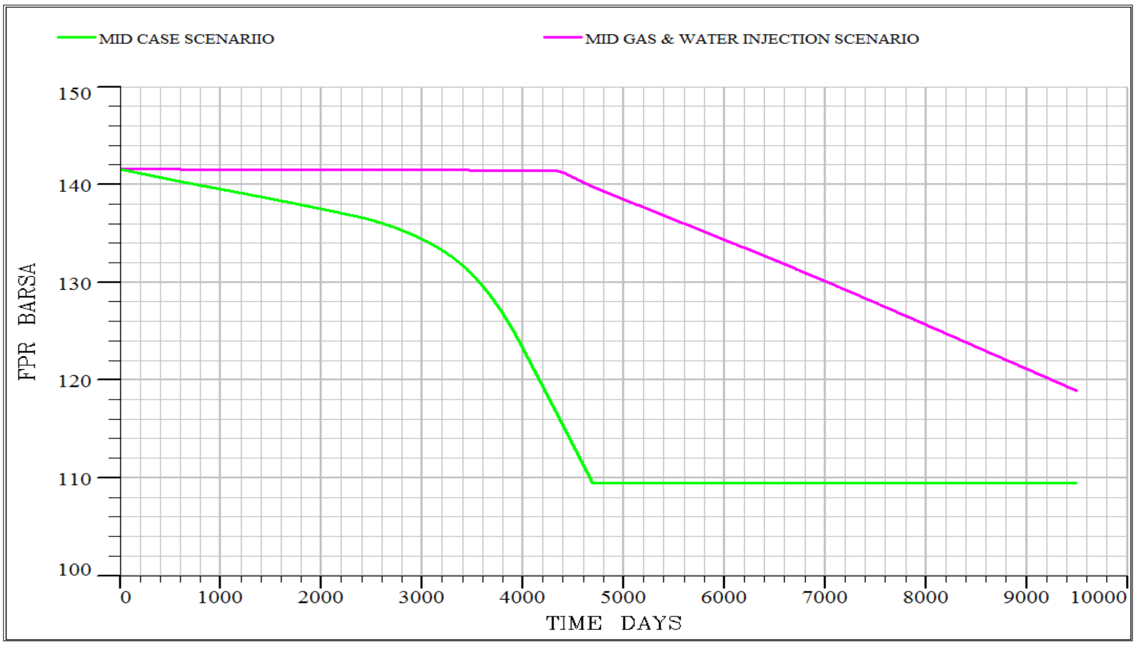

Figure 57 - Field pressure vs. time for gas & water injection scenario

A constant pressure is achieved on the first years of production for gas and water injection scenario then it starts to decline sharply. The reason for this is due high production of gas from this period verified on fig. 55. The reservoir is being rapid depleted due the high production of gas greatly affecting the overall pressure.

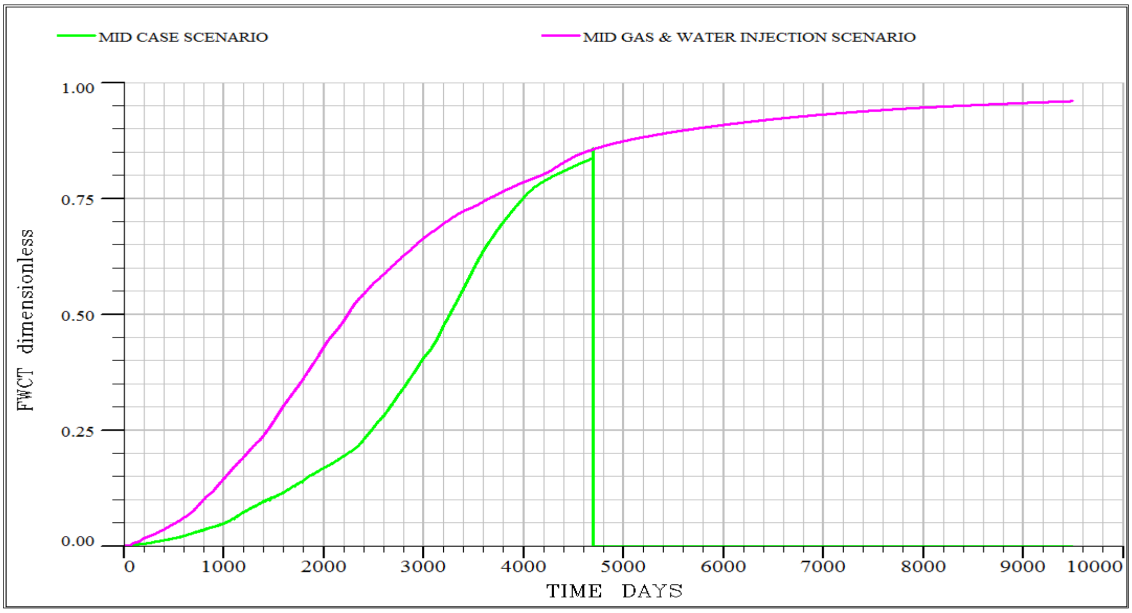

Figure 58 - field water cut vs. time for gas & water injection scenario

6.4.5 - Comparison of three case scenarios results

Both horizontal and vertical well injectors were considered for this study, but the use of horizontal injector was neglected, since both wells completions presented quite similar performance. On figures 59 through 62 is presented a comparison among the profiles for the different scenarios.

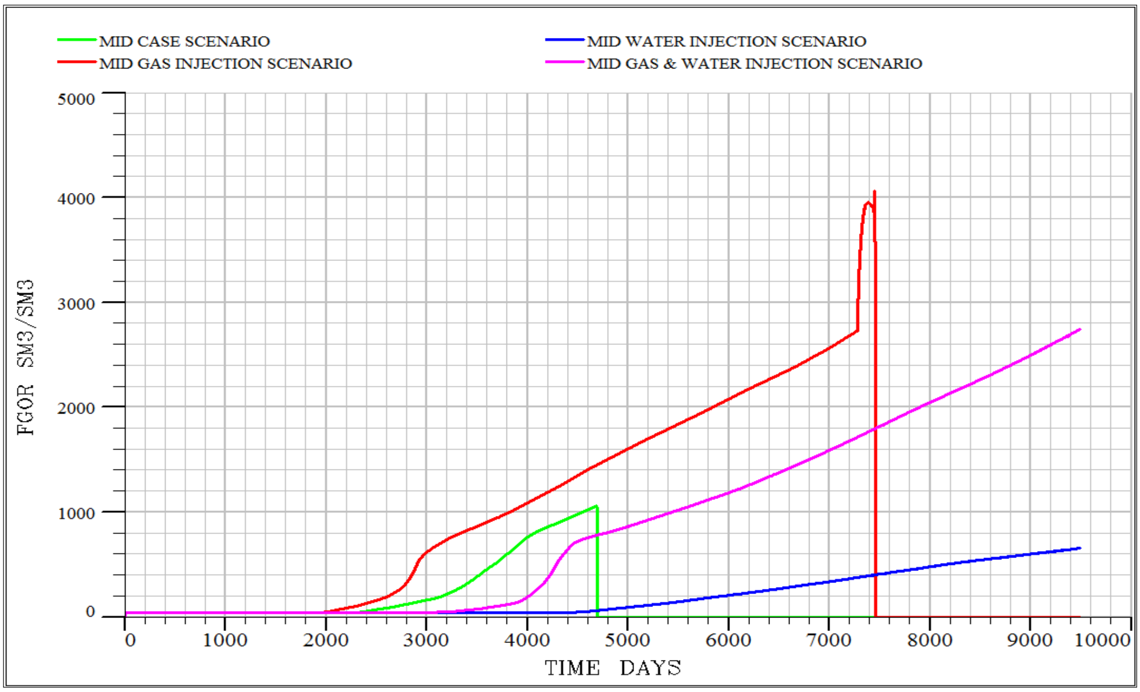

Figure 59 - field gas oil ratio for injection cases

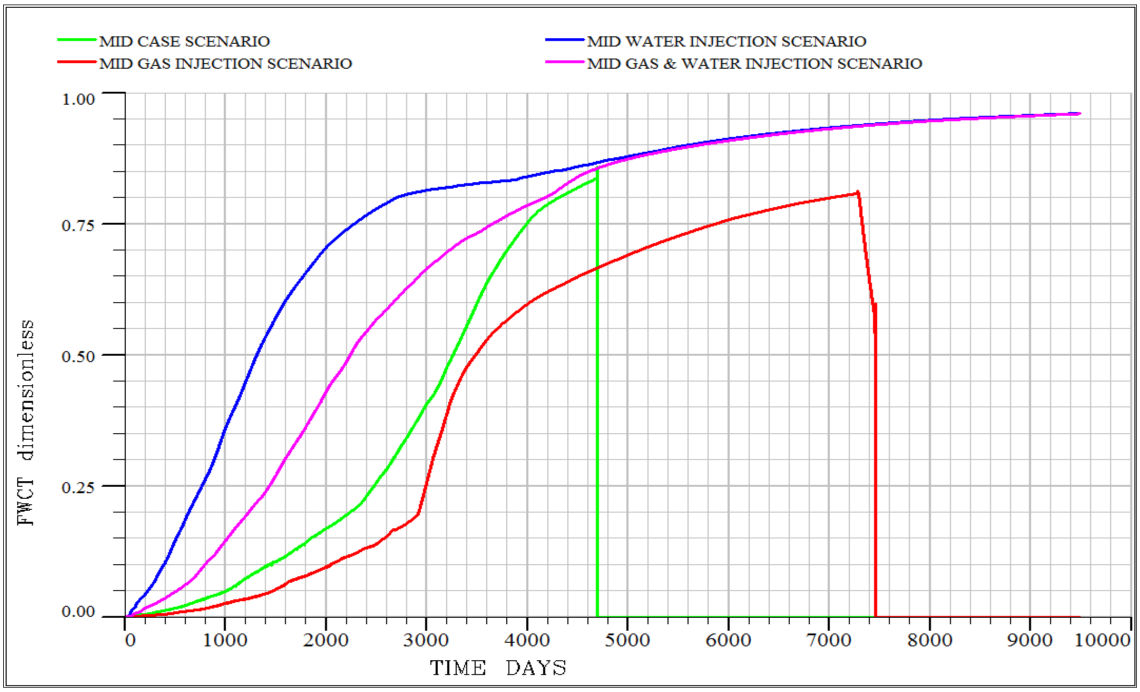

Figure 60 - Field water cut field for injection cases

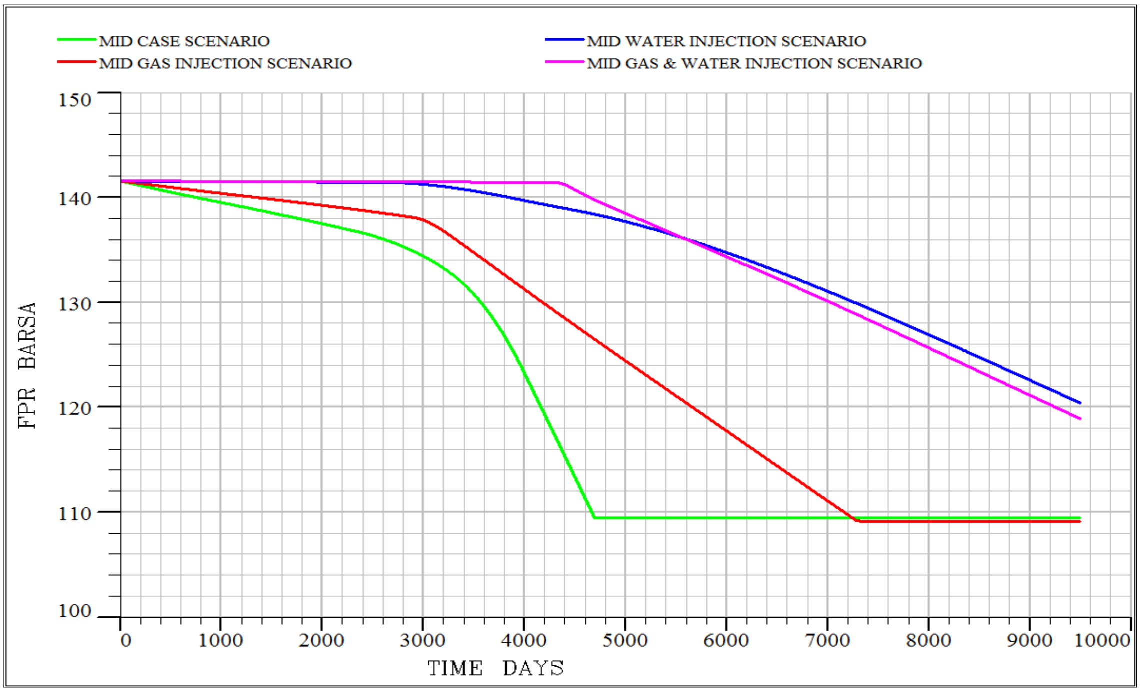

Figure 61 - Field pressure vs. time for injection cases

The scenario with a both gas and water injection shows to be the most favorable scenario to increase oil recovery. Although gas & water scenario has presented a rise of only 1% on the recovery factor compared with water injection scenario, it is still a coherent solution to handle gas.

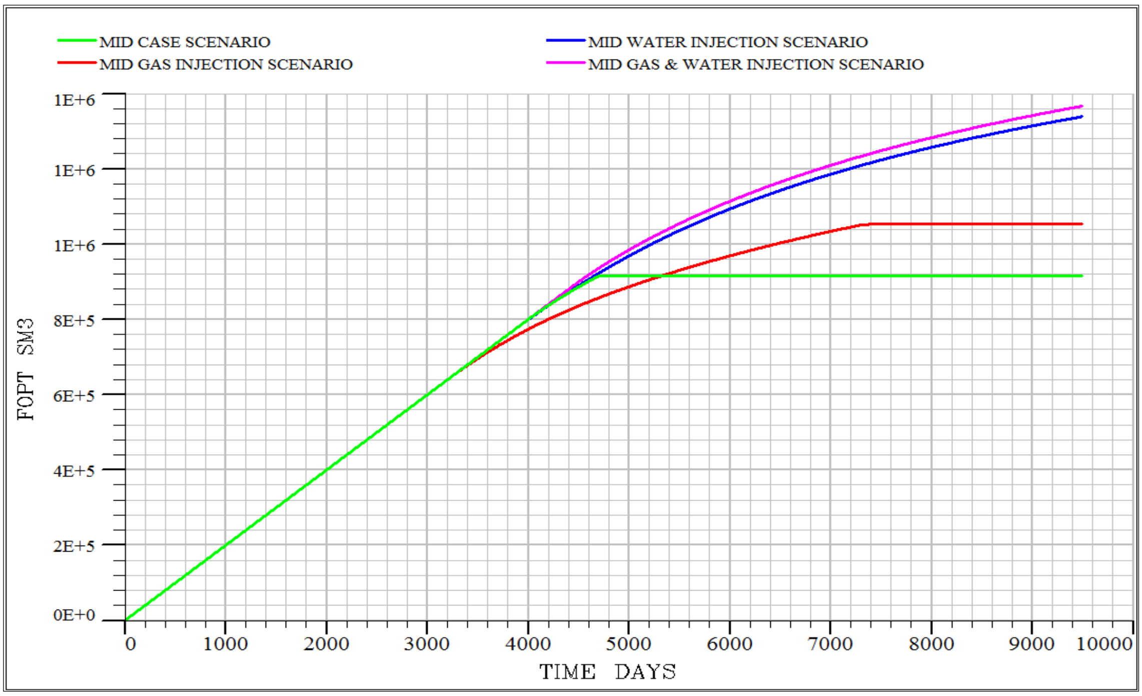

Figure 62 - field oil production total vs. time for injection cases

The different cases lead to 26 %, 25% and 19% for the gas injection, water injection and gas & water injection scenario respectively**.** Table 11 shows a comparison of the Recovery factor for the different scenarios.

Table 11 - Recovery factor for the injection case scenarios

Scenarios	Recovered volume (MMbbl)	Recovery Factor (%)
Base case	5.8	17
Gas Injection	6.6	19
Water injection	8.4	25
Gas & Water injection	8.8	26

The different cases lead to distinct results it is however, important emphasize that due to limited volume in place and high well cost environment, no injection scenario was investigated before. Taking into account that Alpha field is a compartmentalized reservoir, in order to achieve to the probabilistic recoverable oil per compartment, it would imply a water injector pair in each compartment, which would be economically difficult to justify.

6.4.6 - Analog recovery factors

A number of worldwide and regional fields were examined to derive analog recovery factors which were compared with the recovery factors obtained from this work. Seven field analogs outside offshore West Africa shown in fig. 51 indicate an average recovery factor of 28% which is 2 percent higher than the recovery factor based on the result of the mid simulation case with two injection wells (Alpha Sector).

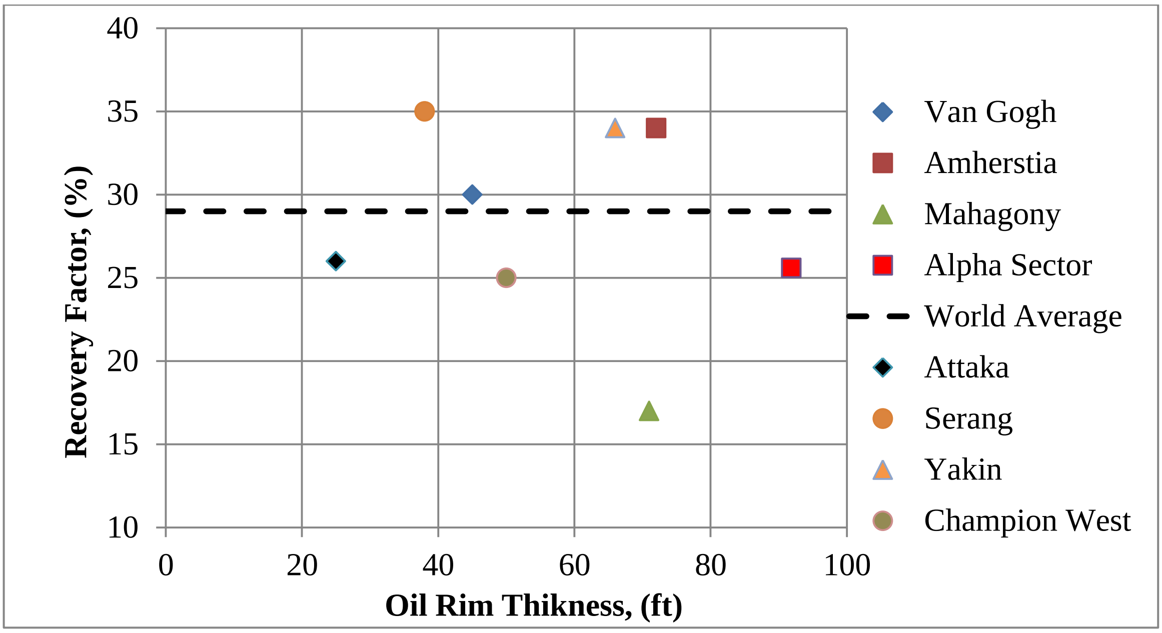

Figure 63 - Analog Recovery Factors for Oil Rim with Gas Cap, Offshore Fields outside Africa

CHAPTER VII – CONCLUSION

The main goal of this thesis was to evaluate the uncertainties of a thin oil reservoir discovery using experimental design. The reservoir consists of various channels, which divide it into several compartments with different heterogeneity and fluids oil contacts. A secondary objective was relate with coning study, where the main objective was to estimate the critical oil production rate through analytical correlations and numerical simulation, using available reservoir modeling tools. A development scheme with water and gas injection was also investigated. Based on the results the following general conclusions were achieved.

Increasing grid resolution improves the coning interpretation and provides good accuracy on results but the process can be very time consuming. Therefore, a good compromise between computational time and accuracy of results was achieved.

Due to the conflicting results of analytical correlations they should be carefully used when implemented in a specific field data and further investigations (i.e. model simulations) should be considered in order to support the results.

The adopted screening design shows relative permeability, horizontal permeability and Rock compressibility as the key uncertainties parameters. The study clearly suggests that SCAL data are required. Indicating that the data availability to be really important in provide confident results and therefore a more realistic plan would be achieved.

Pressure maintenance is required to maximize oil recovery. The development scheme scenario with a both gas and water injection shows to be the most favorable scenario with 26% of oil recovered. Although gas and water scenario has presented a slightly rise on the recovery factor compared with water injection scenario, it is still a coherent solution to handle gas.

RECOMMENDATIONS FOR FURTHER WORK

- Well modelization (Inflow/outflow, to understand the regime of fluid transportation inside the tubing).
- Impact on three phase relative permeability (to get more accurate knowledge of fluid movement in the analyses).
- Integration with surface engineering
  Development concept and facility capacity constraints
  Flow assurance
- Sensitivity on injection wells (varying distances between the wells should be investigated to determine any effect on well spacing)

REFERENCE

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APPENDICES

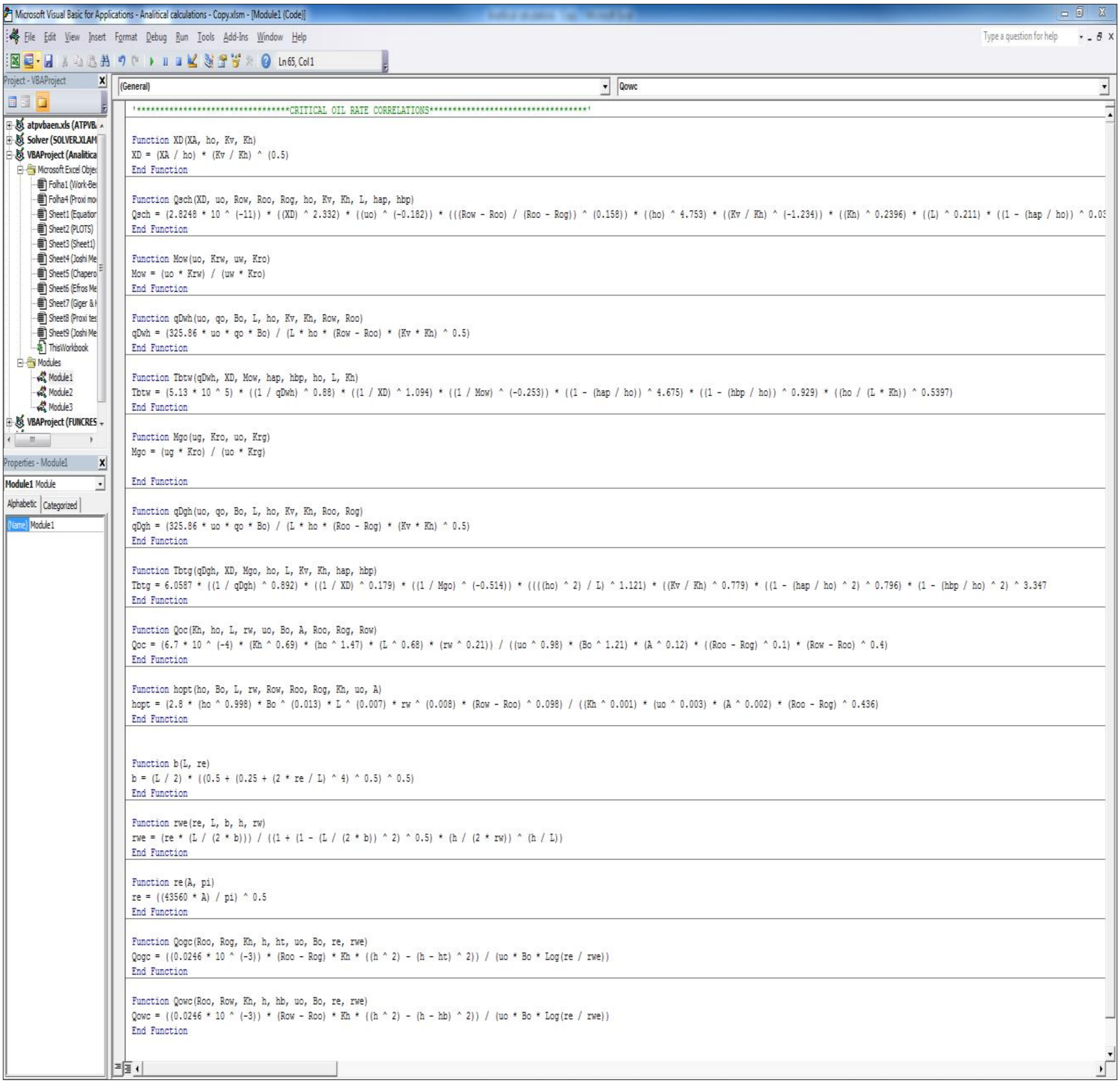

Figure 64 - critical oil correlation on VBA

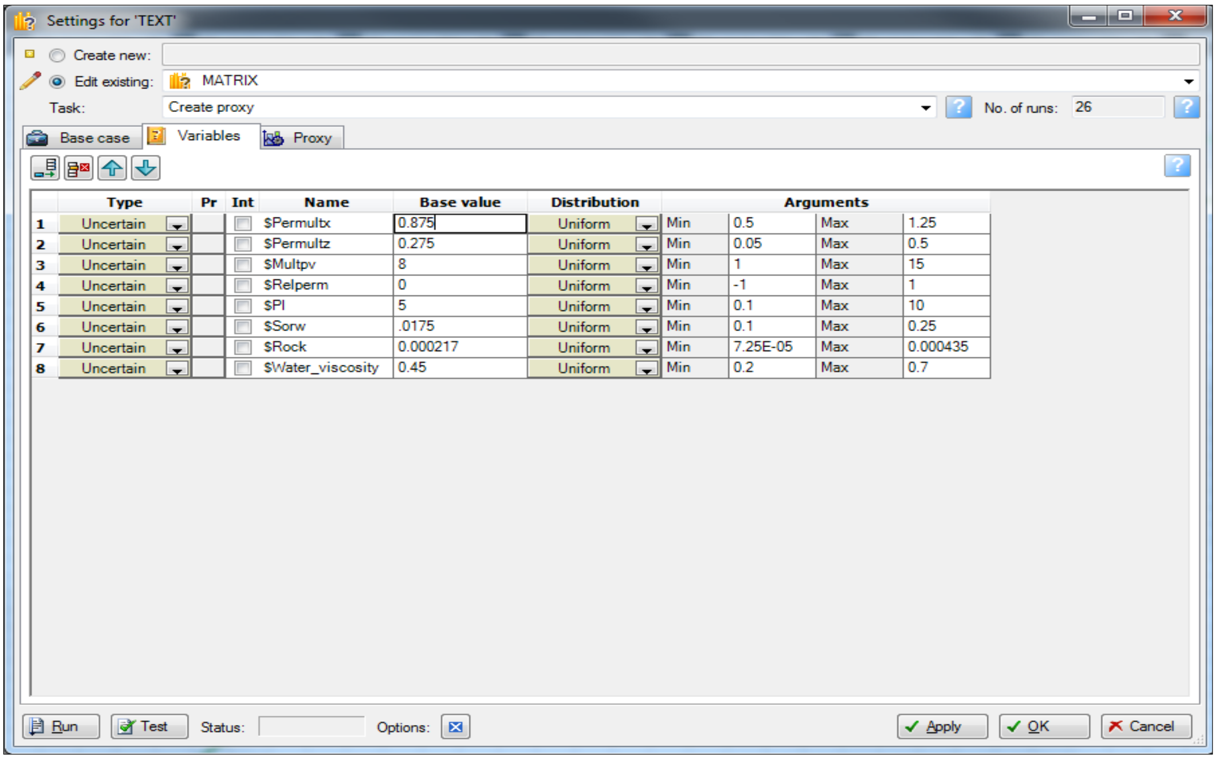

Figure 65 - Defining variables to generate the design matrix on Petrel

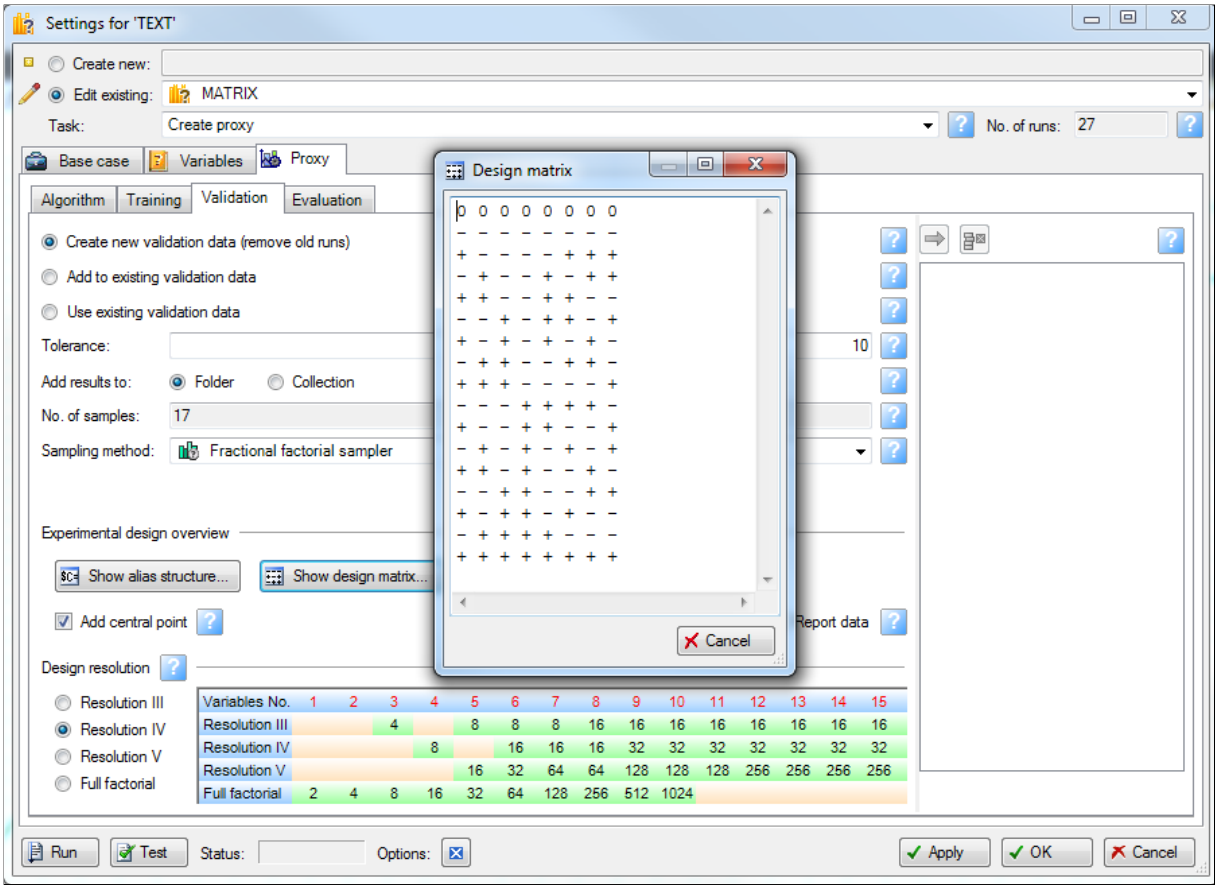

Figure 66 - Selecting method and and generating matrix design

Table 12 - Generated cases of experimental design study

Run	Permx	Permz	Multpv	Relative permeabilty	PI	Swcr	Rock (1/bar)	Water viscosity (cP)
1	1	0.1	6	Weak water wet	1	0.2	0.000217	0.5
2	0.5	0.05	1	Oil wet	0.1	0.1	0.0000725	0.2
3	1.25	0.05	1	Oil wet	0.1	0.25	0.000435	0.7
4	0.5	0.5	1	Oil wet	10	0.1	0.000435	0.7
5	1.25	0.5	1	Oil wet	10	0.25	0.0000725	0.2
6	0.5	0.05	15	Oil wet	10	0.25	0.0000725	0.7
7	1.25	0.05	15	Oil wet	10	0.1	0.000435	0.2
8	0.5	0.5	15	Oil wet	0.1	0.25	0.000435	0.2
9	1.25	0.5	15	Oil wet	0.1	0.1	0.0000725	0.7
10	0.5	0.05	1	Strong water wet	10	0.25	0.000435	0.2
11	1.25	0.05	1	Strong water wet	10	0.1	0.0000725	0.7
12	0.5	0.5	1	Strong water wet	0.1	0.25	0.0000725	0.7
13	1.25	0.5	1	Strong water wet	0.1	0.1	0.000435	0.2
14	0.5	0.05	15	Strong water wet	0.1	0.1	0.000435	0.7
15	1.25	0.05	15	Strong water wet	0.1	0.25	0.0000725	0.2
16	0.5	0.5	15	Strong water wet	10	0.1	0.0000725	0.2
17	1.25	0.5	15	Strong water wet	10	0.25	0.000435	0.7

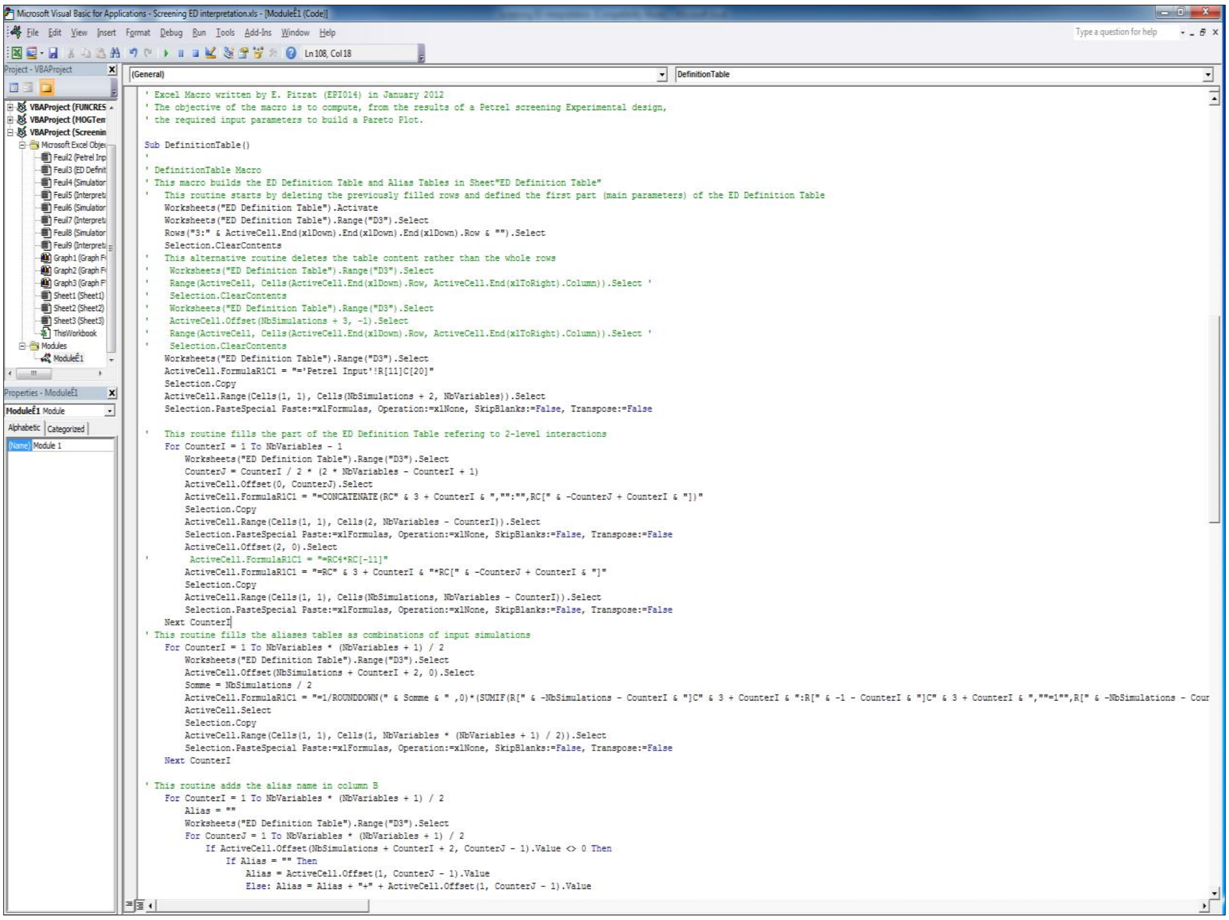

Figure 67 - Program sequence to generate Pareto plot (a)

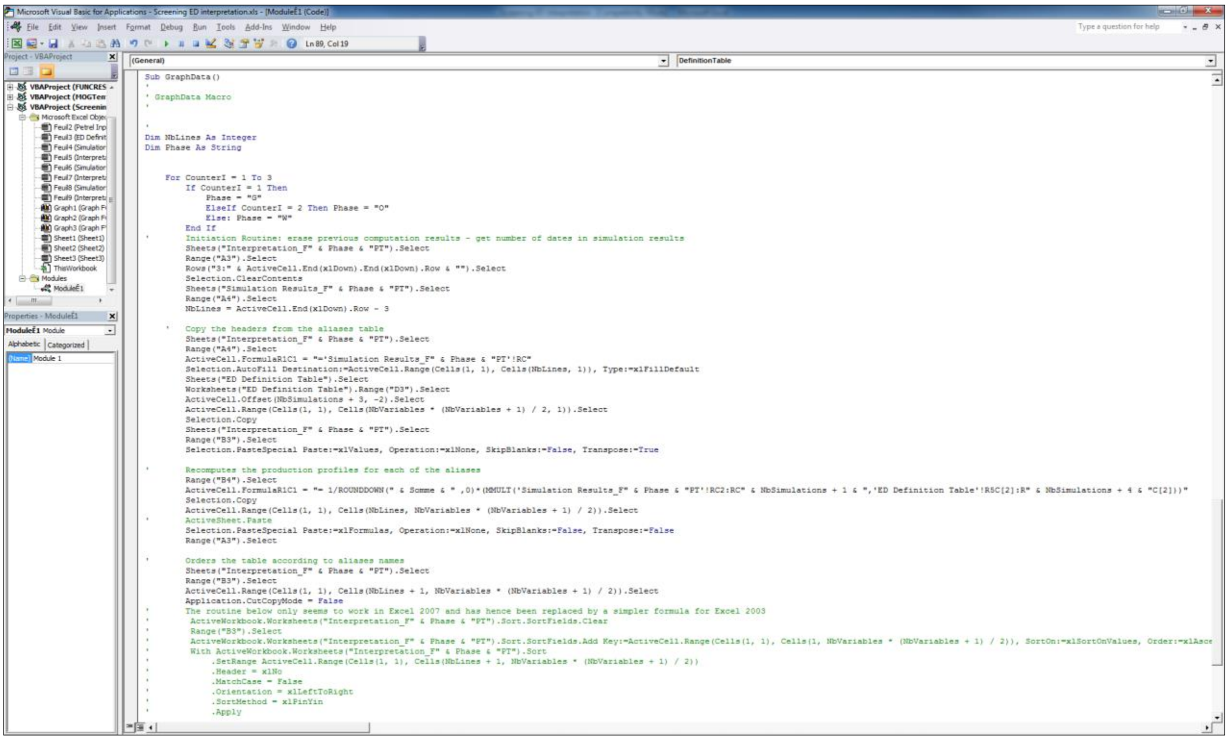

Figure 68 - Program sequence to generate Pareto plot (b)

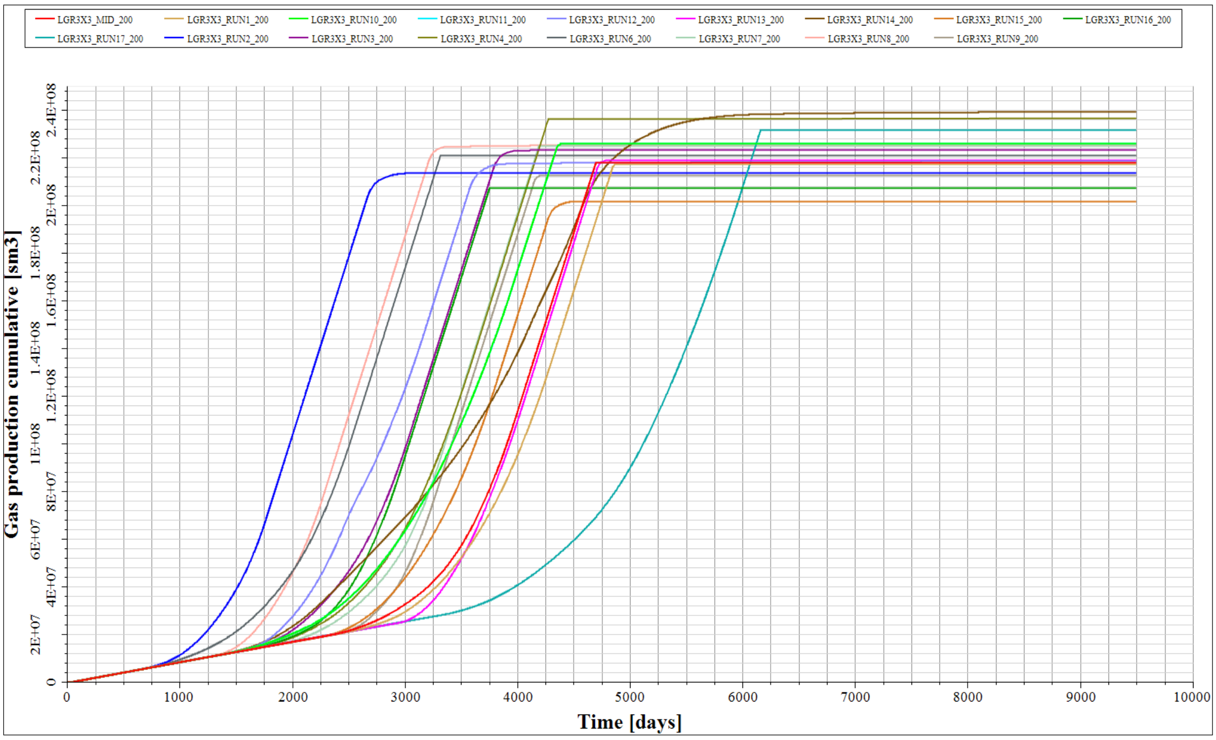

Figure 6969 - Gas production cumulative vs. time of the ED cases

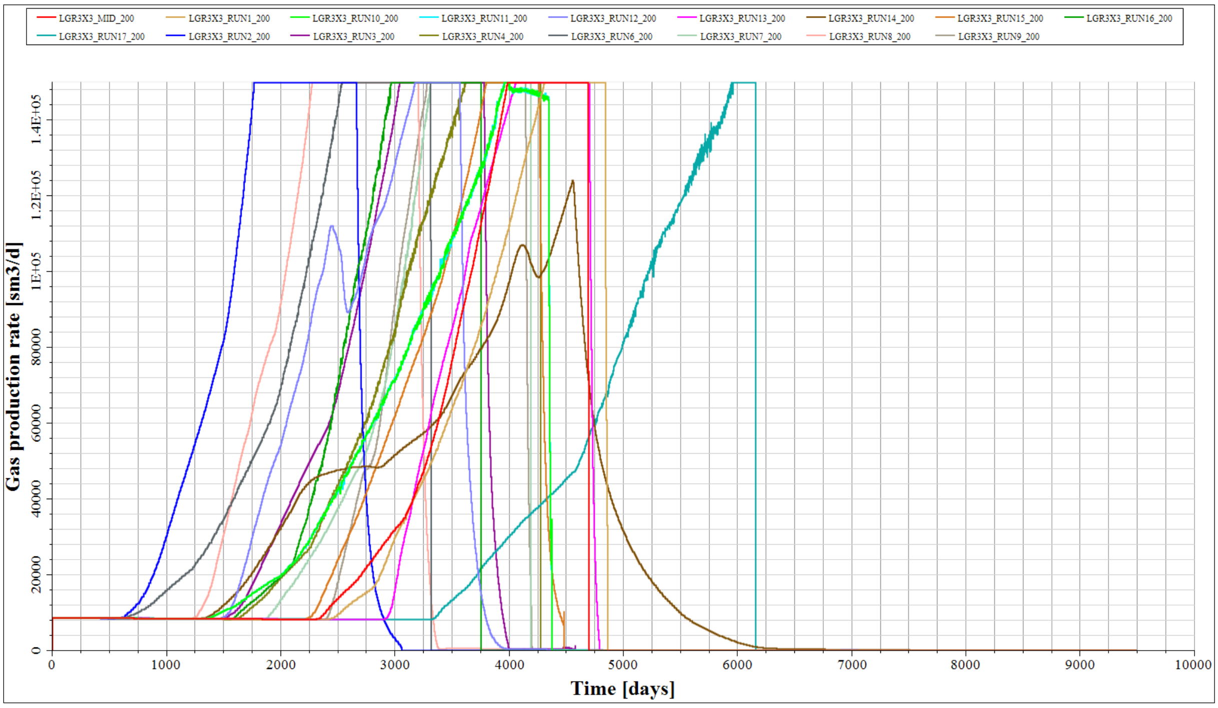

Figure 70 - Gas production rate vs. time of the ED cases

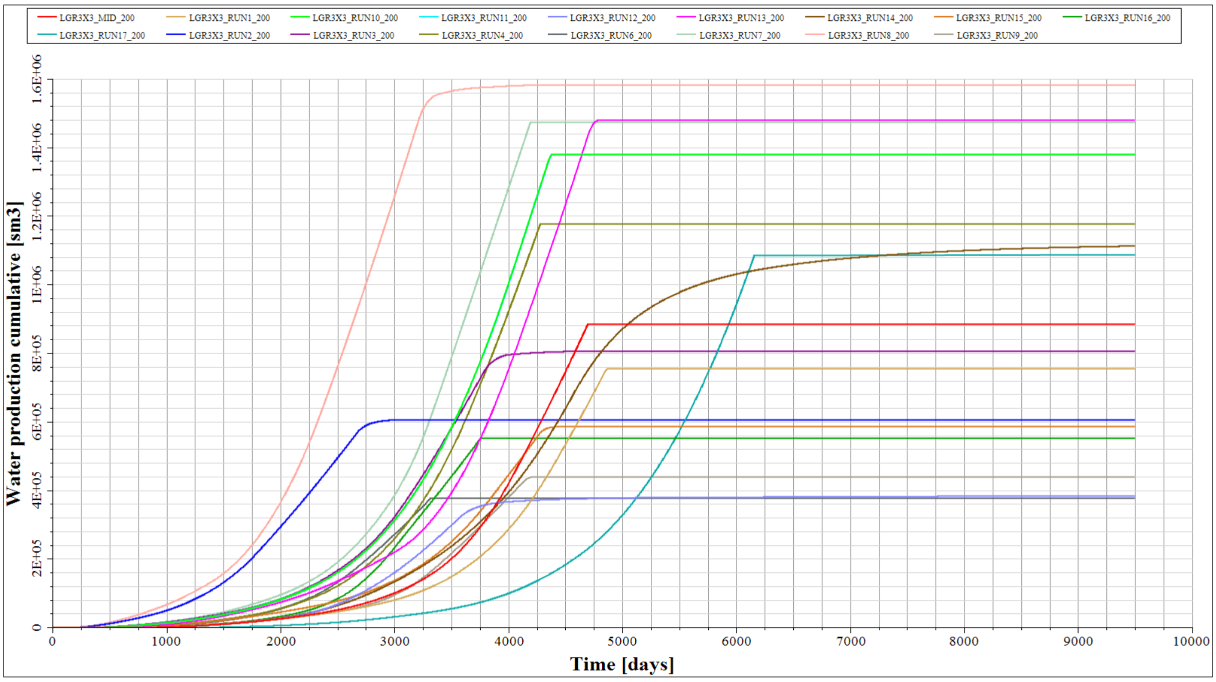

Figure 71 - Water production cumulative vs. time of the ED cases

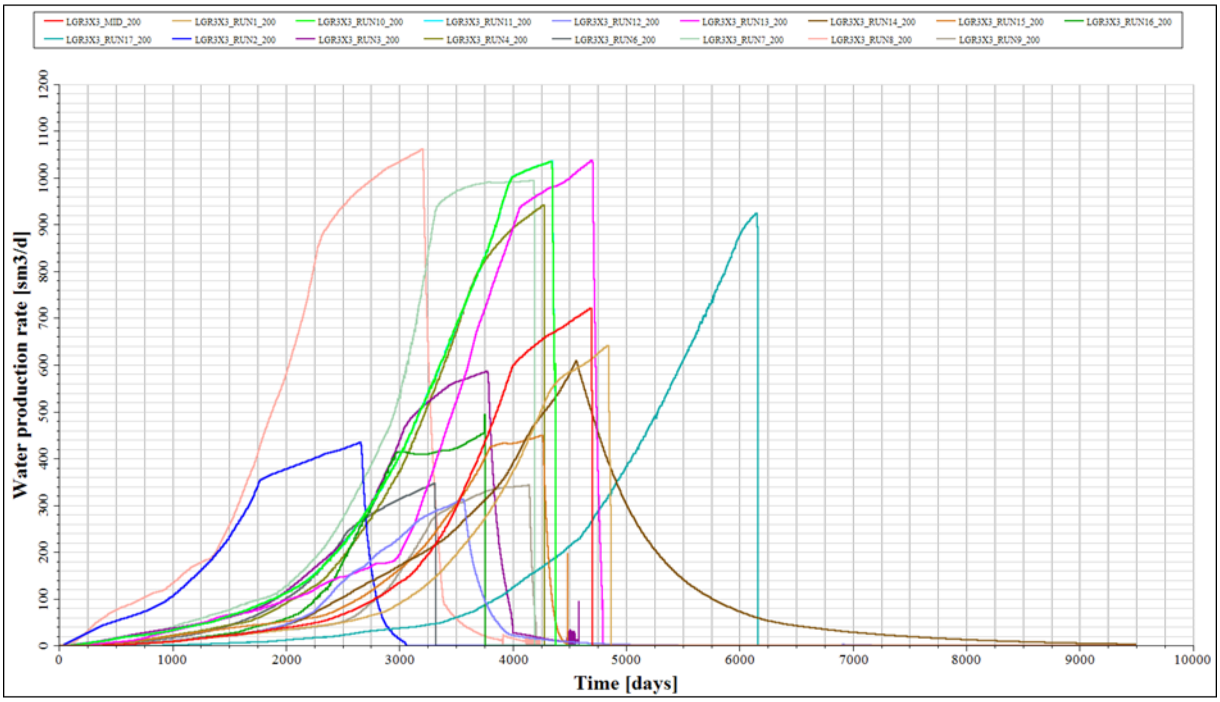

Figure 70 - Water production rate vs. time of the ED cases

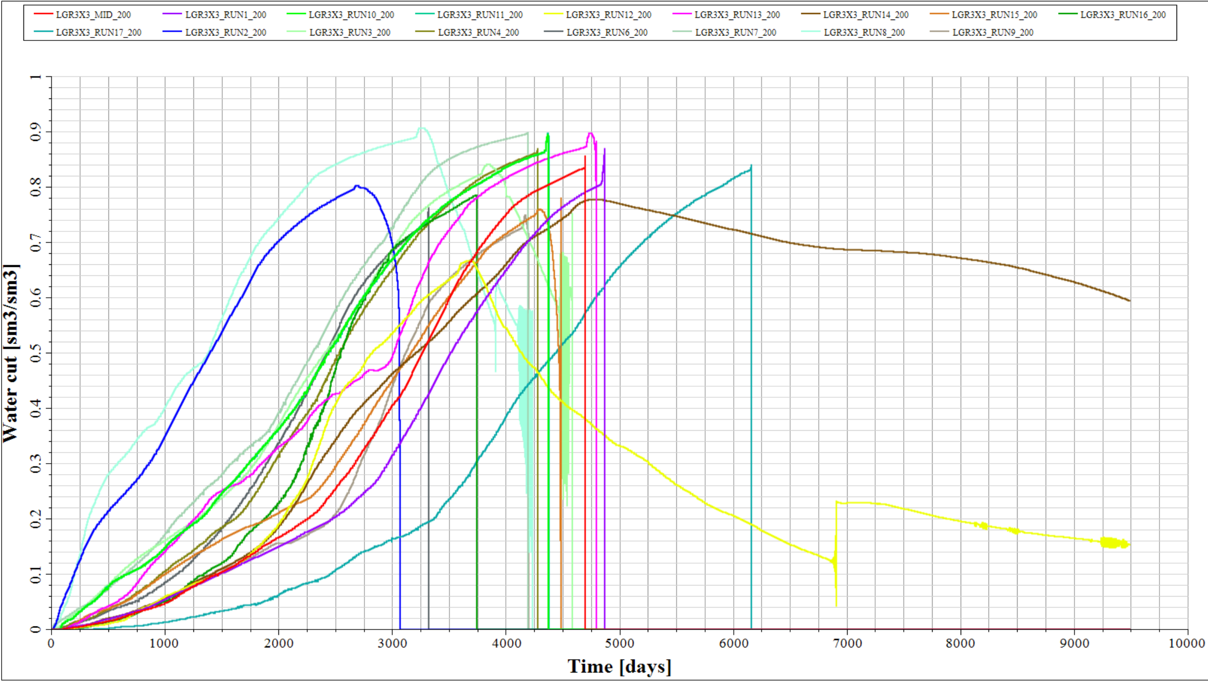

Figure 71 - Water cut vs. time of the ED cases

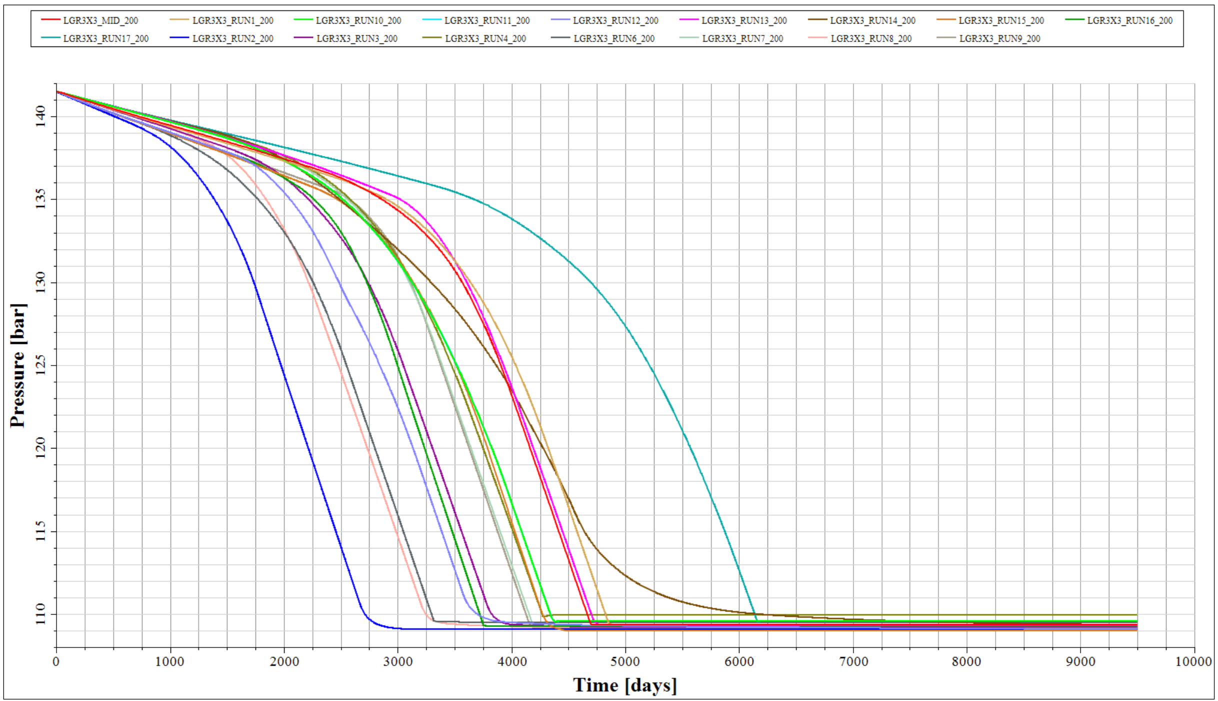

Figure 72 - Pressure vs. time of the ED cases

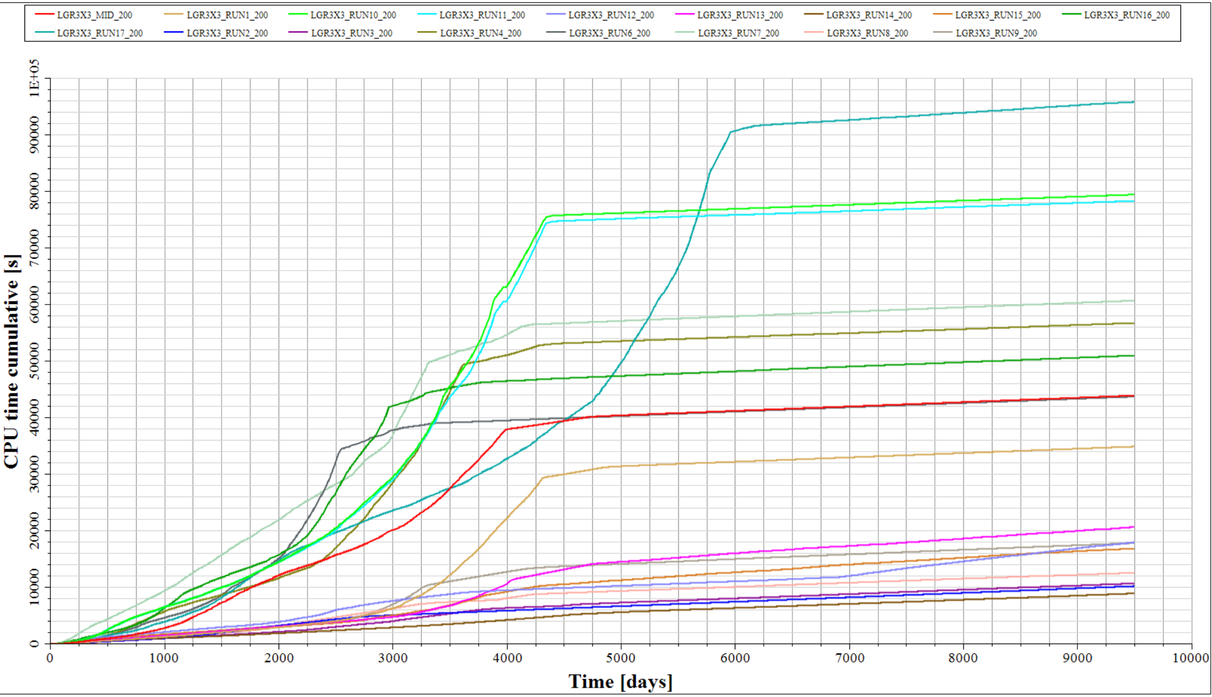

Figure 73 - CPU time vs. time of the ED cases

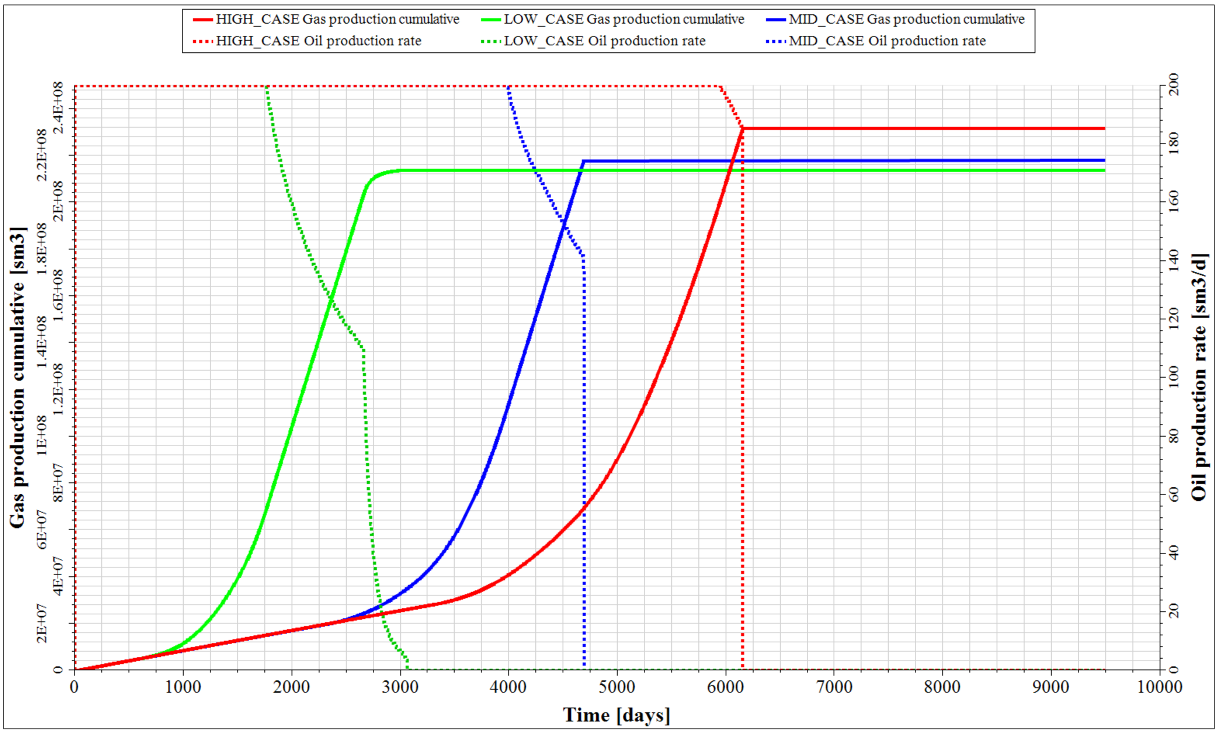

Figure 74 - Gas production cumulative and oil production rate vs. time of the three main ED cases

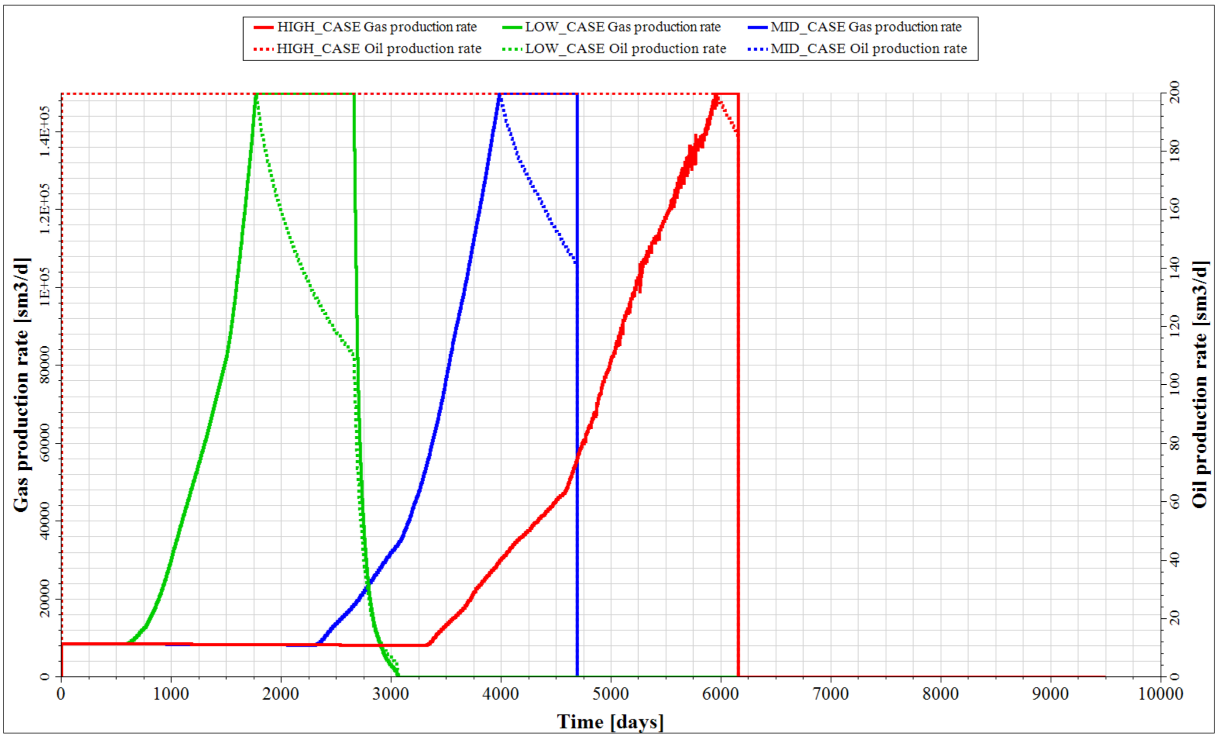

Figure 75 - gas and oil production rate vs. time of the three main ED cases

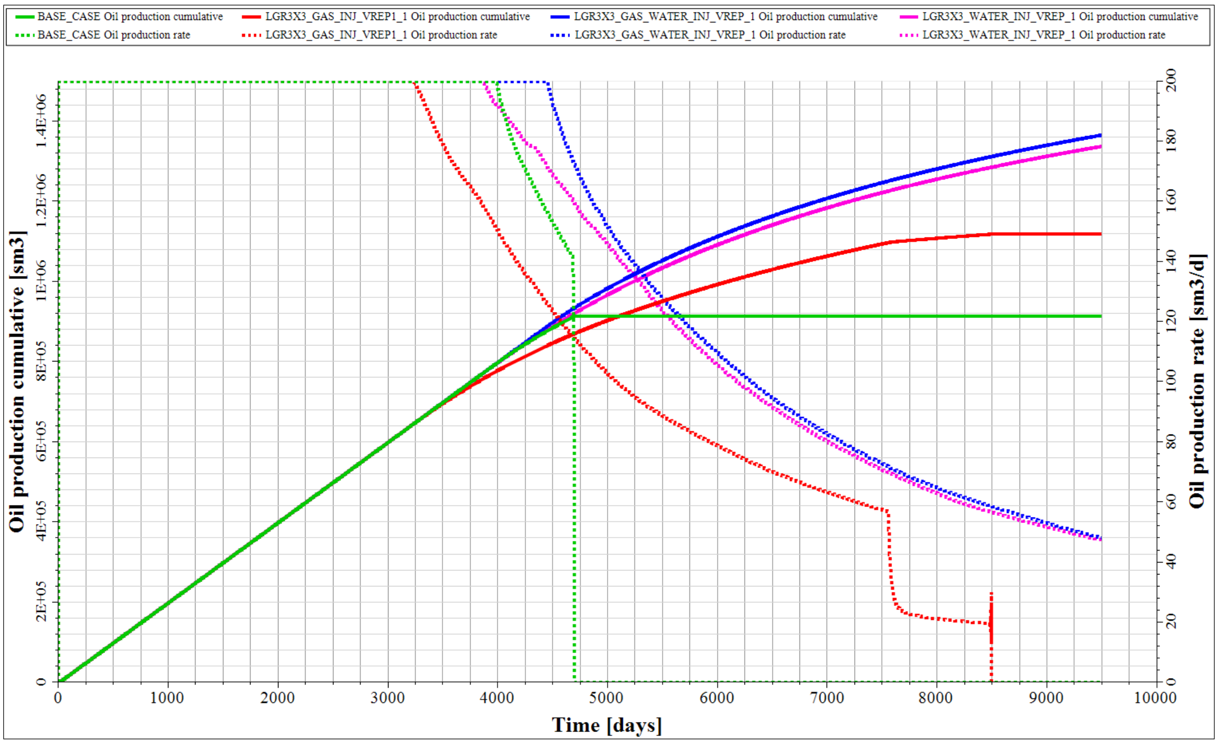

Figure 76 - Oil production cumulative and oil production rate of the three scenarios of the IOR study