IMPERIAL COLLEGE LONDON

Department of Earth Science and Engineering

Centre for Petroleum Studies

Impact of stratigraphic heterogeneity on hydrocarbon recovery in carbonate reservoirs: effects of the continuity of cemented sequence boundaries

By

Makromallis Konstantinos

A report submitted in partial fulfillment of the requirements for the MSc and/or the DIC

September 2013

Declaration of own work

I declare that this thesis:

Impact of stratigraphic heterogeneity on hydrocarbon recovery in carbonate reservoirs: effects of the continuity of cemented sequence boundaries

is entirely my own work and that where any material could be construed as the work of others, it is fully cited and referenced, and/or with appropriate acknowledgement given.

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Abstract

Carbonate reservoirs host significant hydrocarbon reserves worldwide. Despite their economic importance they typically have a low recovery factor. One reason is that they contain numerous stratigraphic, sedimentological and diagenetic heterogeneities and each of these may have a significant impact on flow during hydrocarbon production. Previous work suggests that cemented hardground surfaces (sequence boundary rock properties) are of key importance to displacements dominated by vertical flow when modeled as laterally continuous surfaces. These “surfaces” are modeled as 10 cm thick layers of decreased porosity and permeability. If they are modeled with transmissibility multiplier of zero across the entire surface there is no pressure communication between the upper and lower part as a result there is little production. If they are modeled without transmissibility multiplier of zero across the entire surface there is pressure communication and therefore significant production.

We use integrated flow simulation and experimental design techniques to investigate the relative impact of stratigraphic heterogeneities on simulated recovery in carbonate reservoirs and especially analyze the effect of circular discontinuous barriers by varying the percentage of the coverage from 0 to 100%, the distribution and the size of these barriers.

The results showed that production is greatly affected by changing the barrier coverage in terms of oil production, recovery factor and water breakthrough time. The change in the percentage also affects the interaction of the other heterogeneities on the production results. Increasing the barriers we generally have reduction in oil production and a more complex result in the breakthrough time. However the impact of the distribution of the barriers takes place and has a great effect in the production data. Moreover reducing the well spacing results to a greater impact of the sequence boundaries, and increasing the diameter of the barriers results in a reduction in sweep efficiency.

Acknowledgements

I would like to express my gratitude to Dr. Peter Fitch for his guidance and insightful knowledge shared to me, especially his patience in guiding me through the project. I extend my gratitude to Prof. Matthew Jackson Dr. Gary Hampson and Dr. Cédric John for their teaching, supervision and kind support. I am grateful for the priceless opportunity which I had to participate in this project.

I thank my family and especially my fiancée Chryso who always believe in the steps I made; for their encouragement, nurture and teaching. Thinking of my family always boosts me to try harder in any situation.

I also wish to thank the Department of Earth Science and Engineering at Imperial College and all Professors for their excellent teaching during the course, for accepting me as a student in the Master program and making my education path possible. To the staffs who have been helping directly or indirectly throughout this research project.

"Our greatest weakness lies in giving up. The most certain way to succeed is always to try just one more time.

Thomas A. Edison

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Imperial College London

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Carbonate reservoirs host significant hydrocarbon reserves worldwide. Despite their economic importance they typically have a low recovery factor. One reason is that they contain numerous stratigraphic, sedimentological and diagenetic heterogeneities and each of these may have a significant impact on flow during hydrocarbon production. Previous work suggests that cemented hardground surfaces (sequence boundary rock properties) are of key importance to displacements dominated by vertical flow when modeled as laterally continuous surfaces. These "surfaces" are modeled as 10 cm thick layers of decreased porosity and permeability. If they are modeled with transmissibility multiplier of zero across the entire surface there is no pressure communication between the upper and lower part as a result there is little production. If they are modeled without transmissibility multiplier of zero across the entire surface there is pressure communication and therefore significant production.

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The results showed that production is greatly affected by changing the barrier coverage in terms of oil production, recovery factor and water breakthrough time. The change in the percentage also affects the interaction of the other heterogeneities on the production results. Increasing the barriers we generally have reduction in oil production and a more complex result in the breakthrough time. However the impact of the distribution of the barriers takes place and has a great effect in the production data. Moreover reducing the well spacing results to a greater impact of the sequence boundaries, and increasing the diameter of the barriers results in a reduction in sweep efficiency.

Introduction

Carbonate reservoirs host approximately 60% of oil and 40% of gas resources globally, but remain a major challenge for development and production. Poor prediction of production behavior in carbonate reservoirs is related to typical hydrocarbon recovery factors below 35%, which is the average recovery factor of reservoirs globally. Carbonate reservoirs have been extensively discussed in the literature within the context of reservoir modeling, however due to their numerous intrinsic complex heterogeneities, carbonate reservoir characterization and modeling remains an important challenge for the petroleum industry. Geological heterogeneities attributed to stratigraphic, sedimentological and diagenetic features exist over a range of length-scales, and control reservoir architecture and the distribution of petrophysical properties of carbonate rocks (Sibley, 1997; Jennings et al. 2000; Lawrence et al. 2002; Pranter et al. 2006; Adams et al. 2011; Hollis et al. 2011). Numerous field development programs have clearly stressed the need for a better understanding of the impact of heterogeneity on flow in carbonate reservoirs, especially for different rock and fluid properties, and for different development strategies (Jennings et al. 2000; Vaughan et al. 2004; Pranter et al. 2006; Agar et al. 2010; Hollis et al. 2011; Meddaugh et al. 2011). Integrated geological characterization and flow modeling studies of carbonate reservoirs have been widely discussed (Bard et al. 1995; O"Hanlon et al. 1996; Abbaszadeh et al. 2000). However, preceding published examples have typically concentrated on the behavior of a subset of geological heterogeneities specific to the carbonate reservoir of interest (Stiles & Magruder, 1992; O"Hanlon et al. 1996; Sibley et al. 1997; Abbaszadeh et al. 2000; Lawrence et al. 2002; Pavlas Jr., 2002; Stenger et al. 2009). Identifying the key heterogeneities for incorporation into reservoir models requires a detailed investigation to understand the impact on flow. This can be achieved by studying carbonate reservoirs and incorporating heterogeneities documented in outcrop and subsurface examples, and combining these with production simulation experiments.

On the basis of a detailed review of available outcrop analogues and subsurface examples, Fitch et al. (in review a) established a hierarchical classification of heterogeneities in carbonate reservoirs. The scheme details the architecture, geometry and spatial distribution of stratigraphic and sedimentological heterogeneities in carbonate ramp reservoirs based on outcrop and subsurface examples. Levels 1 to 3 of the hierarchy (Figure C-1 A-C) record stratigraphic heterogeneities, with a focus on the architecture and spatial distribution of environments of deposition (EOD), at decreasing length-scales. The distribution and arrangement of geobodies and depofacies within EOD belts are documented at level 4 (Figure C-1 D), whilst

level 5 focuses on bed-scale features (Figure C-1 E). Heterogeneity at centimeter-to-micrometer scales (e.g. sedimentary structures, grain shapes, pore networks) are recorded at levels 6 and 7 of the hierarchy.

An initial application of the hierarchy to assess the impact of the stratigraphic and sedimentological heterogeneities (from hierarchy levels 1-3; Figure C-1 A-C) on the flow behavior, and likely hydrocarbon recovery, of carbonate ramp reservoirs was provided by Fitch et al. (in review a, b). A suite of geocellular models was constructed combining six different stratigraphic heterogeneities, and a combination of flow simulation and experimental design techniques was used to quantify the impact of the stratigraphic heterogeneities on recovery for production via waterflooding. Previous work suggested that heterogeneities were of key importance in production results especially laterally continuous cemented surfaces. However, there has been no systematic investigation of the interaction of geological heterogeneity and production mechanism in carbonate reservoirs using the same suite of models. The aim of this paper is to investigate and quantify the impact of laterally discontinuous cemented surfaces on fluid flow in carbonate reservoirs varying their continuity and geometry of the barriers. We are going to analyze 20 years of simulated production data (using Eclipse 100 and Petrel) from the 8 three-dimensional geological models constructed by Fitch et al, (in review a, b). The data we will analyze are oil production, water breakthrough time, recovery factor and we will vary the well spacing. The overarching aim of this paper is to quantify the impact of the cemented surfaces in production and explore the uncertainty of the results. The results will aid reservoir engineers in better predicting the production behavior (in similar reservoirs) and therefore optimize the reservoir operating conditions to achieve the maximum oil recovery. Some examples of carbonate reservoirs suffering from these cemented surfaces are the homoclinal ramps of Spain, Germany and Morocco, the distally steepened ramps of Italy, Menorca, Spain, and the Sultanate of Oman. Also the subsurface carbonate reservoirs, such as the ramps of Abu Dhabi and southwest Iran, and the platforms of Oman. The specific objectives are:

1. Analyze production data in circular shape barriers, different well patterns and quantify the effect of different size of the barriers.
2. By varying the percentage of the coverage on these cemented surfaces to find the threshold of the impact in production between the two extremes (of 100 and 0% barrier coverage).

Methodology

Reservoir Modelling

Geologic heterogeneity in the reservoir and hierarchical approach

A variety of stratigraphic, sedimentological and diagenetic heterogeneities occur across carbonate ramp analogs. These heterogeneities occur across a wide range of length scale, from field to pore scales, and their architecture and distribution depends upon the depositional environment. Using a hierarchy of heterogeneities, based on the length scale of the features within the system, enables to conduct a top down reservoir modeling approach, where it starts with a simple model and then gradually add increasing levels of heterogeneity (Fitch et al. in review a). Such hierarchy is shown in Figure C-1, each of these levels are constituted of different heterogeneities.

Model description

This project was conducted using the suite of reservoir models presented by Fitch et al. (in review a, b), that capture generic styles of gross stratigraphic architecture in carbonate ramp systems. Each model has an aerial extent of 4 x 4 km and a thickness of 66 m. The models are constructed using surfaces that represent stratigraphic surfaces and EOD-belt boundaries, and gridded using corner-point grids, which capture the surface geometries in an accurate and computationally efficient manner (White et al. 2004; Jackson et al. 2005; Sech et al. 2009). Grid cells are 66.6 x 66.6 m in area and vary in thickness up to a maximum of 1 m. Grid layers build up from the underlying surface, and pinch out against overlying surfaces to ensure that the grid conforms to the surface-based geological framework. The number of grid cells that are active for flow simulation ranges from 270,000 to 417,600, depending on the complexity of the stratigraphic framework and EOD-belt geometries in a particular model (60x60 cells laterally and 75 to 116 vertically). Four EOD's are documented in the model; inner ramp, mid ramp, outer ramp and pelagic (indicated in Figure C-2). These models are constructed to represent a range of specified heterogeneities, identified from published examples and constrained to an outcrop analogue and associated forward modelled stratigraphic framework.

This project focuses on stratigraphic heterogeneities. Six key heterogeneities, in different levels, were chosen for examination (Figure 2). On four out of the 8 reservoir models which have the cemented layers (A, C, G, H) (Figure 1) we analyse the impact of the percentage of cemented barriers from 0 up to 100% coverage on water displacement, using a simulation based sensitivity analysis. We also simulate the other 4 models for use in the experimental design.

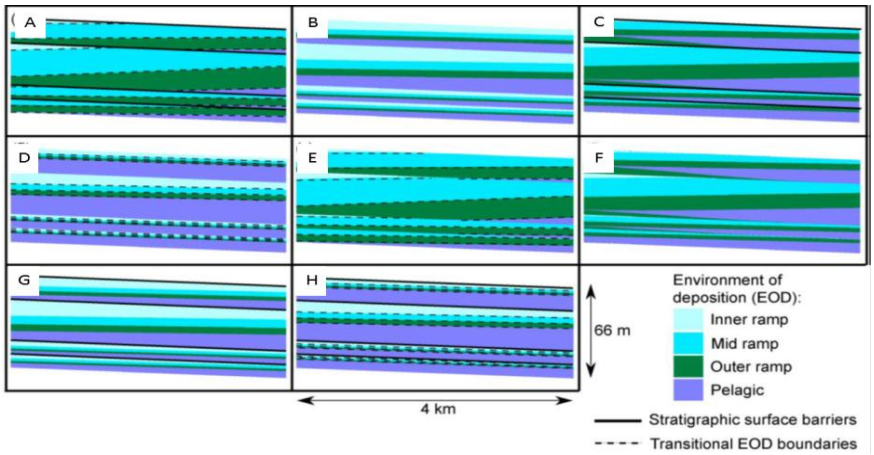

Figure 1: 2D depositional dip sections through the eight geologic models illustrating the geometry and spatial arrangement of EOD belts, character of EOD-belt boundaries, and character of sequence boundaries (Fitch et al. 2011b).

Heterogeneity	End-member settings	
	Setting (i)	Setting (ii)
(1) EOD-belt boundary interfingering	8 km	24 km
(2) EOD-belt geometry	Progradation only	Retrogradation - progradation
(3) EOD-belt rock properties	High (grain-dominated)	Low (mud-dominated)
(4) Anisotropy of EOD-belt permeability	Isotropic Kv/Kh = 1	Anisotropic Kv/Kh = <1 (0.1 - 0.4)
(5) Character of the EOD-belt boundaries	Sharp	Transitional over 300 m
(6) Sequence boundary rock properties	None	Vertical flow barrier

Figure 2: Conceptual models of the modelled heterogeneities. The impact of each heterogeneity on the response was investigated when each factor is varied from setting i to setting ii. EOD – environment of deposition (Fitch et al. 2011b).

Key heterogeneities and settings

The challenge in carbonate reservoirs is to link the heterogeneities measured at well and core scales to the spatial heterogeneities at flow unit and reservoir scales. The inconsistency of the geological interpretation records makes the interpretation and the outcome of the result unreliable. This project is following a hierarchical approach classifying stratigraphic and sedimentological heterogeneities in carbonate ramp reservoirs (Fitch et al. in review a, b) and is consistent with previous work done on the section with this hierarchy. The selected stratigraphic heterogeneities and their origins are described below.

1) *Environment of deposition (EOD) boundary interfingering length (Figure 2)*

In the settings we are focused on two end-member types of the EOD boundary interfingering length, 8 km long and 24 km long (Borgomano et al. 2002; Pierre et al. 2010; Vennin et al. 2003) and is associated with the landward and basinward movement of the EOD belts between two sequence boundaries. The 8km EOD boundary interfingering typically is associated with thicker EOD belts and the 24km EOD boundary interfingering with thinner once.

2) *EOD-belt geometry (Figure 2)*

Two architectures, progradational or retrogradational form the geometry of the EOD's. Progradation occurs when the rate of sediment deposition is greater than the rate of sea-level rise and retrogradation occurs when the rate of sea-level rise is greater than the rate of sediment deposition, causing the EOD-belts to move landward. Setting i has only progradation geometry between sequence boundaries, while setting ii is more complex with both retrogradation and progradation.

3) *Rock properties of EOD belts (Figure 2)*

In the two settings we have to build our geological models we have two different extreme rock properties of the EOD belts. At the Setting i there is more than 50% grain (grain dominated) so high porosity and permeability rock. However Setting ii has less than 20% grain (mud dominated) and possess low porosity and permeability values (indicated in Table C-1in appendix, denoted by High and Low).

4) Permeability anisotropy of EOD-belt (Figure 2)

Anisotropy in permeability may be caused by sedimentary structures such as lamination and cross-beddings (Fitch et al, a) Setting i is isotropic (k_v/k_h =1), while Setting ii is anisotropic where k_v/k_h ratio ranges from 0.1 to 0.45 depending on different EOD-belts (in mid ramp of good reservoir quality, or outer and inner ramp of poorer reservoir quality).

5) Character of the EOD-belt boundaries (Figure 2)

To account for variations in interfingering of depofacies at level 4 of the hierarchy, the character of EOD-belt boundaries is changed from sharp to transitional (setting i and ii, respectively). The transition is modelled as three zones, each of 100 m extent down depositional dip, where the middle zone is centred at the original boundary. The middle zone is assigned rock property values reflecting average porosity and permeability of the neighbouring EOD belts. The outer transition zones are assigned rock properties that reflect 75% and 25% weighting of closest and farthest neighbouring EOD-belt properties, respectively. EOD-belt boundaries are uniform along depositional strike.

6) Sequence boundary rock properties (Figure 2)

In setting (i), the surfaces only provide a constraint for EOD-boundary geometry and spatial distribution. The surface is an architectural feature, and is assigned no characteristic rock properties. However, bioturbation and cementation associated with early diagenesis often decreases the porosity and permeability of sediments directly underlying the sequence boundary. Setting (ii) represents sequence boundaries as thin (10 cm) low permeability zones, in which horizontal and vertical permeability is decreased to 10% of that assigned to the underlying EOD-belt. Additionally, the sequence boundary itself is assigned a transmissibility multiplier of zero, so that no vertical flow can occur across the surface. The sequence boundary barriers are modelled across the whole model, but permeability variations vary along depositional dip according to the underlying EOD-belt. Petrophysical properties are uniform along depositional strike. Moreover in this study we varied setting (ii) from 0 up to 100% coverage of this cemented surfaces.

Reservoir characteristics

The number of grid blocks, size and STOIIP (stock tank oil initially in place) of each model is presented in Figure C-2 in appendix.

The three different well patterns used in the simulations are shown in Figure 3. 4 km line drive, 1 km repeated line drive and 5 spot pattern. Water injection and production rate for each well was controlled by the bottom hole pressure (BHP).

Bottom hole pressure on the wells to meet the pressure drop between the producer and an injector lie within 0.03-0.14 bar/ft (0.5-2 psi/ft). The minimum bottom hole pressure of the producers was set to be 152 bar (2204psi) which is 3 bar (50 psi) above the oil bubble point pressure (ensuring that no gas is evolved from solution). Bottom hole pressure, upper limit, of the injectors was set for the 4 km line drive to be 623 bar (9035 psi), for the RLD (repeated line drive) 270 bar (3916 psi) and for the 5 spot pattern 234 bar (3394 psi). The oil water contact was set to be at a depth of 1429 m. The production wells are producing from an interval of 15 m from the top of the reservoir and the injection wells are perforated 10m below the OWC (oil water contact) Figure 3. The simulations last for 20 years.

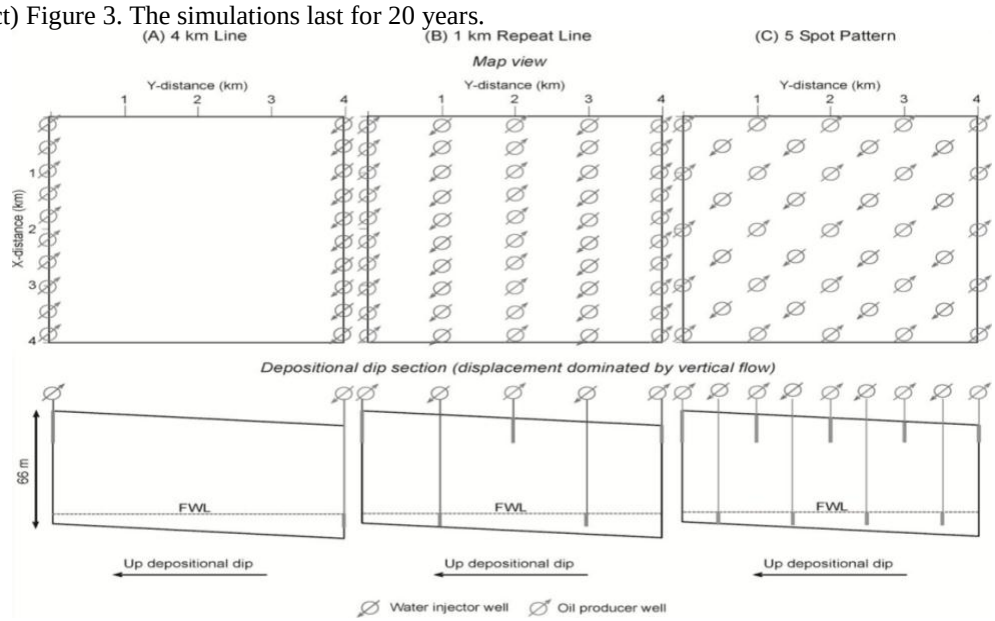

Figure 3: Model dimensions and well placements in the simulation models for three waterflood production schemes: (A) 4 km line drive, (B) 1 km repeat line drive and (C) 500 m five-spot pattern. Well perforation intervals: 15m interval in production wells and 10m interval below water contact in injection wells (Fitch et al. 2011b).

Only one set of Pc (capillary pressure) and k_r (permeability) curves were used for imbibition and drainage for the whole reservoir (Figure C-3, Figure C-4). Variation of Pc/k_r curves has low importance (demonstrated by Fitch at el a, b). Production was simulated assuming incompressible flow and no dissolved gas in the oil, using the fluid and reservoir properties summarized in Table 1 respectively.

Fluid properties		
	Oil	Water
Density (kg/m3)	850	950
Viscosity (cp, centipoise)	0.52	0.36
Bubble point pressure (bar)	152	
Formation volume factor (rm3/sm3)	1	1
Compressibility (1/bar)	1×10^{-4}	3×10^{-5}

Reservoir properties	
Pressure (bar)	206
Temperature (Fahrenheit)	250
Rock compressibility (1/bar)	5×10-6
Wettability	Intermediate oil-wet

Table 1: Left: Fluid properties, Right: Reservoir properties

Experimental Design

A 2^{6-3} fractional factorial experimental design was used to efficiently explore the parameter space defined by the 6 heterogeneities investigated in the suite of reservoir models. This allows the main effects of each heterogeneity to be estimated independently of other heterogeneities, assuming that higher order interactions between heterogeneities are insignificant (Box et al. 1987; Wu & Hamada, 2000; White & Royer, 2003). This experimental design requires two end-member settings to be specified for each of the six stratigraphic and sedimentological heterogeneities under investigation, and establishes a rank order of heterogeneities based on their simulated reservoir performance. A total of eight models were used (Figure 1) combining heterogeneity settings as required by the experimental design (Table 2), and flow simulation of this suite of models was carried out for each production scheme under investigation.

Factor (Heterogeneity)	Geologic Model							
	A	B	C	D	E	F	G	H
Interfingering length of EOD belts	1(i)	1(ii)	1(i)	1(ii)	1(i)	1(i)	1(ii)	1(ii)
Geometry of EOD belts	2(i)	2(i)	2(ii)	2(ii)	2(i)	2(ii)	2(i)	2(ii)
Rock properties of EOD belts	3(i)	3(i)	3(i)	3(i)	3(ii)	3(ii)	3(ii)	3(ii)
Anisotropy of EOD-belt permeability	4(i)	4(ii)	4(ii)	4(i)	4(ii)	4(i)	4(i)	4(ii)
Character of EOD-belt boundaries	5(ii)	5(i)	5(i)	5(ii)	5(ii)	5(i)	5(i)	5(ii)
Petrophysical properties of sequence boundaries	6(ii)	6(i)	6(ii)	6(i)	6(i)	6(i)	6(ii)	6(ii)

Table 2: Heterogeneity setting incorporated into the geologic models, following our experimental design. Factor – heterogeneity, EOD – environment of deposition. Heterogeneity settings (i) and (ii): (1i) short or (1ii) long interfingering length of EOD belts; (2i) prograding or (2ii) retrograding-prograding EOD belt geometry; (3i) grain-dominated or (3ii) mud-dominated EOD belt rock properties; (4i) isotropic or (4ii) anisotropic EOD-belt permeability; (5i) sharp or (5ii) transitional EOD-belt boundaries; and sequence boundaries with (6i) no petrophysical properties or (6ii) barriers to vertical flow.

Geometry of barrier coverage

"Circular" barriers representing patchy, discontinuous cementation of surfaces (Figure 4). This circular barriers act as barriers to vertical flow because of their low properties. Non-cemented areas provide vertical flow paths. Their shape is an ellipse and the size of these barriers (diameter) follows a triangular distribution with minimum 300m mean 500m and maximum 700m (Christ at al. Size of barriers < 1km). There are four layers with these characteristics in each of the 4 models that have the heterogeneity number 6 with the Setting (ii) (Figure 2). For each of the models that have the cemented surfaces (A, C, H, and G) a distribution of 0, 20, 40, 60, 80, 85, 90, 95, and 100% coverage of the circular barriers was created on the surfaces using Petrel.

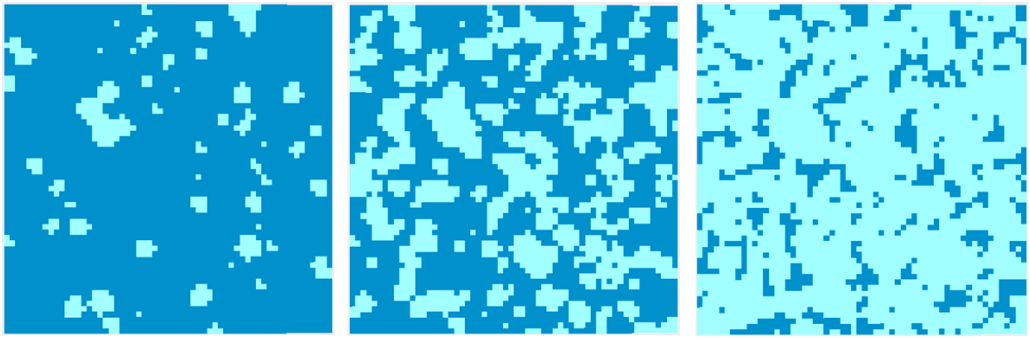

Figure 4: Example of Circular barriers, picturing the cemented and non-cemented areas. At left 10% coverage, middle 40%, right 80%.(Light blue is the barriers)

Reservoir simulation strategy

To investigate the barriers and their effect on production we investigate a range of percentage of coverage. The effects on different development strategies were also investigated (4 km line drive, 1 km repeated line drive, and 500m 5 spot pattern) (Figure 3).

Since these layers are constructed in Petrel and for each seed number, it gives a different distribution of the barriers hence; the same seed number was used for all the constructed layers. Because of the seed number, sensitivity analysis was performed to check the uncertainty if the seed number was varied. The same models were run in different realizations of the seed number (different barrier distribution in the layers). We used 7 different realizations and the sensitivity analysis was contacted on oil production and water breakthrough time.

Results

All models with sequence boundaries (A, C, G and H) were simulated with 0-100% barrier coverage and the results are comparable to Fitch at el (a, b). The simulation results presented here focus on the 4 models A, C, G and H, before all models are included in experimental design interpretation.

Simulation Results

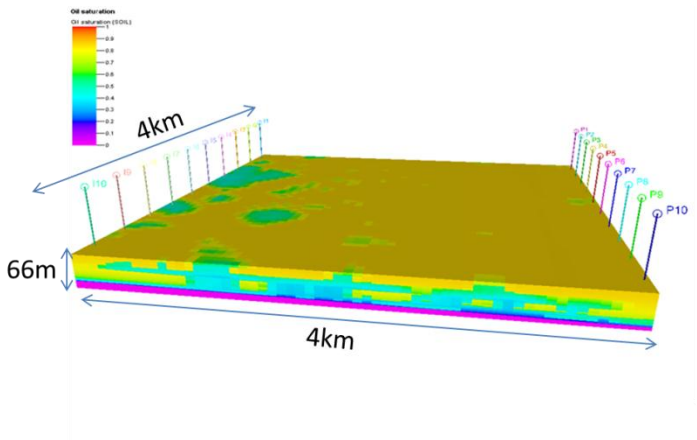

Figure 5: Reservoir image (Model C) after 6 years of production (80% barrier coverage, 4km LD)

Comparison of models A, C, G, H

On Figure 5 the effect of the circular barriers on water flow can be observed.

Simulation result after 20 years production on 4km LD (Line Drive) well pattern show that Recovery Factor (RF) decreases from models A to H regardless of the barrier coverage (Figure 6). Moreover, RF decreases for each model by increasing the percentage of the coverage (Figure 6). The threshold of where the percentage of the barriers starts to have a great impact on RF is decreasing from model A to H. For model A the threshold is around 95% but at model H is around 80% and with a more linear impact on RF.

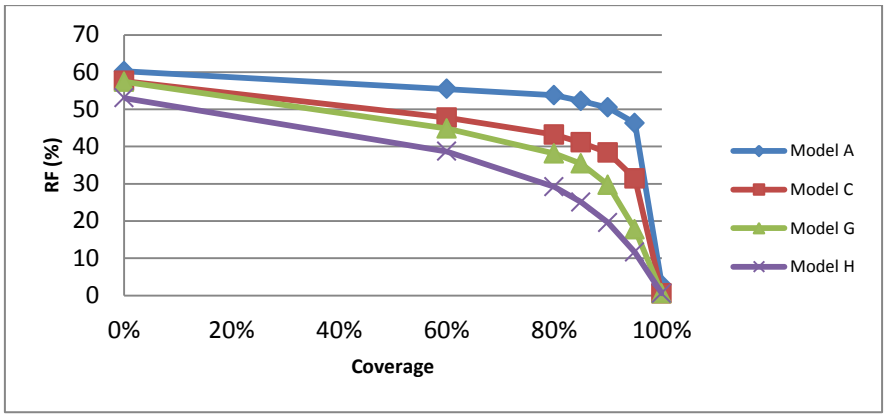

Figure 6: Effect of barrier coverage on RF (20 years, 4 km Line Drive)

Furthermore, Figure 7 shows that the water breakthrough time occurs earlier with increasing percentage of the coverage. Although in the area of the 80% coverage and above it becomes more complex (Figure 7). Model C and H are anisotropic and have later breakthrough time (BKT) than isotropic models A and G (Figure 7).

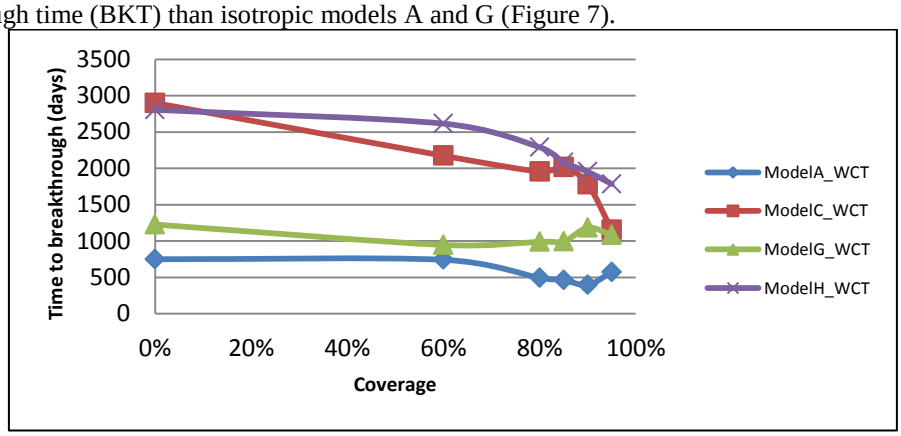

Figure 7: Effect of barrier coverage on BKT (20 years, 4 km Line Drive)

Effect of varying seed number in Model C

The complex results from breakthrough time at the area of 80-95% coverage (Figure 7) further encouraged simulation studies on Model C (4 km LD), by changing the distribution of the barrier coverage varying the seed number (the seed number is a number you define in Petrel to arrange the distribution of the circular barriers in the surfaces). The results suggested that the uncertainty (stochastic variation in seed number) increases with percentage barrier coverage (Figure 8). The variation of the oil produced is not so large maximum 10% for 95% coverage (Figure 8), but the uncertainty introduced to the breakthrough time is large, 80% variation for 95% coverage (the variation is taking as reference the max value of the parameters, if the mean value was used as a reference the uncertainty would be ±half the variation values in Figure 8). Another observation is that the large values of variation starts where the threshold of the barriers coverage occurs. After the threshold the uncertainty is increasing exponentially but below the threshold is decreasing but very little until 0 at 0% coverage.

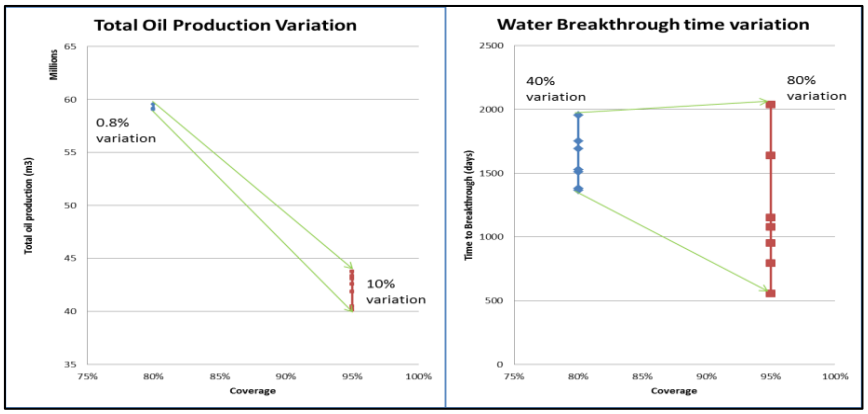

Figure 8: Model C (4km LD) 80%, 95% barrier coverage with different Seed Numbers (The percentage of the uncertainty is with reference the max value of oil production and breakthrough time).

Comparison of well placement

The same investigation was conducted for the other two well patterns, the repeated line drive (RLD) and the 5 spot pattern (Figure D-1, D-2, D-3, D-4). The threshold of the effect of the percentage of coverage on RF for both RLD and 5 spot pattern is decreased and also the uncertainty of the oil produced is increased and breakthrough time is decreased (RLD has the smallest uncertainty of the 3 patterns for BKT) (Table D-1). For the RLD and 5 spot pattern we also have less production of oil, water and less injection of water.

The production results (oil recovery, oil recovery factor, time to breakthrough) of the simulation for each barrier coverage percentage and for the three different well patterns can be seen in Table D-2, D-3, and D-4.

Experimental Design Results

Experimental design allows the relative influence of stratigraphic and sedimentological heterogeneities on production performance criteria to be ranked, based on the impact of changing a given heterogeneity from Setting (i) to Setting (ii) (Figure 2).

Relative impact of different stratigraphic and sedimentological heterogeneities on STOIIP

As described by Fitch et al. (in review a, b), the EOD-belt rock properties (heterogeneity 3 in Figure 2) is the key control on STOIIP (Fig. 14); note that a response >100% means only that the average effect of changing the heterogeneity setting is larger than the average value of the given performance measure over the eight models. Switching from high, grain-dominated porosities to low, mud-dominated porosities for the EOD belts significantly decreases STOIIP and, in order of decreasing impact, the other heterogeneities influencing STOIIP are the EOD-belt interfingering length, EOD-belt geometry (heterogeneities 1 and 2, decreasing STOIIP by 30 and 15 %, respectively), character of the EOD-belt boundaries, and sequence boundary rock properties (heterogeneities 5 and 6 Figure 2, respectively, both of which increase STOIIP by around 5 %). The change in STOIIP for the sequence boundary rock properties is dependable of how many boundary layers we have and there height but switching from setting (i) to (ii) the STOIIP should be decreasing because of the decrease in the properties. We will explain in discussion why the experimental design technic gives a positive response. In our models we have 4 layers and total around 0.4 m out of the 60 m vertically. Anisotropy of EOD-belt permeability (heterogeneity 4 Figure 2) has no impact on STOIIP. Note that the impact of heterogeneity on STOIIP is the same regardless of the well spacing as it has no effect on STOIIP (Fitch et al. in review b); note also that the low ranking of heterogeneity 4 (permeability anisotropy) is expected, as this feature has no effect on rock pore volume. However, it may have a significant effect on flow and, therefore, recovery, as shown in the next section. For all the barrier percentages the effect of each heterogeneity remains the same as the properties of the layer in setting (ii) are unchanged, only the transmissibility multiplier is changed. Moreover the same effects happen in the other two well patterns.

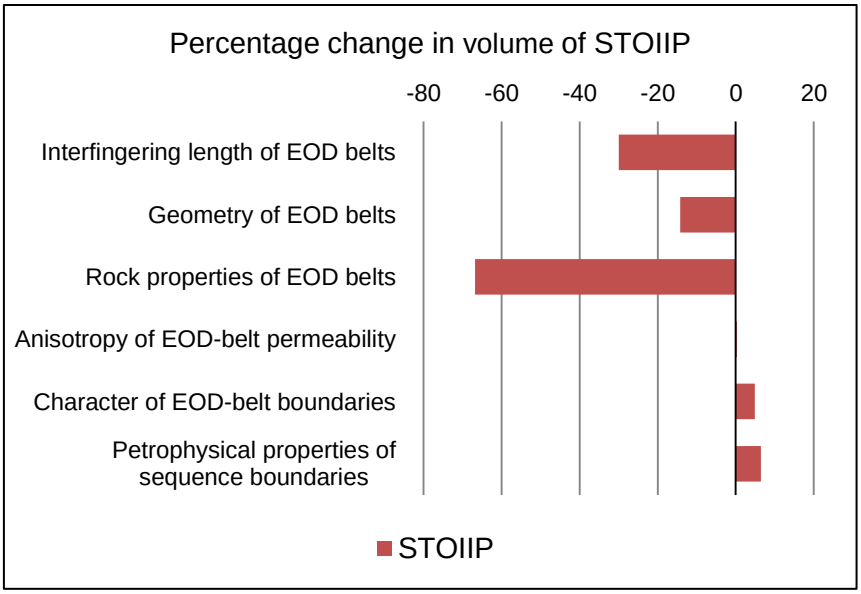

Figure 9: Tornado chart for the oil in place percentage change when we change from setting I to II (as reference is the average OIIP of all models).

Relative impact of different stratigraphic and sedimentological heterogeneities on volume of oil produced, RF and water breakthrough time.

This section presents the results of the 4km LD well spacing and the next presents the results for the other two well patterns.

The tornado charts show the percentage change on oil production, RF and BKT switching from setting (i) to (ii) relative to the average behaviour of the 8 simulation models.

EOD-belt boundary interfingering length

The EOD-belt interfingering length (Figure 2) is the fourth-ranked heterogeneity influencing oil produced, recovery factor and time to water breakthrough; switching from the short to long interfingering length at 100% barrier coverage increases oil recovery and recovery factor (Figures 10, 11), but decreases time to water breakthrough (Figure 12). A short EOD-belt interfingering length yields lower recovery. This result seems counter-intuitive. As for the barrier coverage from 0% to 95%, the switch of the setting affects oil production and RF negatively, which is normal.

EOD-belt geometry

EOD-belt geometry (Figure 2) is the third-ranked heterogeneity for oil produced; incorporating a retrogradational component into the EOD-belt geometry decreases oil recovery, but delays water breakthrough (Figures 10, 11, 12). Increasing the percentage of barrier coverage, an increase to the effect of switching from setting I to II is observed, except at the 100% which decreases.

EOD-belt rock properties

The second-ranked heterogeneity for oil produced, recovery factor and breakthrough time is the EOD-belt rock properties; switching from high, grain-dominated permeabilities and porosities to low, mud-dominated permeabilities and porosities for the EOD belts decreases the volume of oil produced, recovery factor and delays water breakthrough. Furthermore increasing the barrier coverage percentage the negative effect in oil production and RF increases and the positive effect increases in breakthrough time. Only at 100% coverage the effect is decreasing (Figures 10, 11, 12).

Anisotropy of EOD-belt permeability

EOD-belt permeability anisotropy (in Figure 2) is ranked sixth for oil produced and recovery factor but fifth for breakthrough time; permeability anisotropy decreases the volume of oil produced and recovery factor, but increases the time to water breakthrough. Figures 10, 11, 12 shows that increasing the barrier percentage the negative effect increases in oil production and RF but at 100% the effect becomes positive. As for the breakthrough time as the barrier percentage increases the breakthrough time positive effect decreases until 100% coverage were the effect becomes negative.

Character of EOD-belt boundaries

The character of the EOD-belt boundaries is ranked fifth for oil production and recovery factor but sixth for breakthrough time. Switching from sharp to transitional EOD-belt boundaries increases oil recovery factor, and accelerates water breakthrough time. Increasing the barriers percentage the positive effect on oil production and RF is increasing until it reaches 100% coverage were the effect becomes almost 0%.

Sequence boundary rock properties

The heterogeneity with the greatest impact on production is the rock properties assigned to sequence boundaries for 100% barriers at the cemented layers (in Figures 10, 11, 12). Modeling these surfaces as impermeable barriers significantly decreases oil production and recovery factor (Figures 10, 11), and delays water breakthrough (Figure 12).

Figure 10 shows these surfaces if they are modeled with less than 100% barriers coverage they have a smaller impact on oil production than the EOD rock properties. Surprisingly at 0% barrier coverage only the low properties stay on this layers and it gives as a positive response which means that for the 0% barriers going from setting (i) to (ii) it increases the oil production something that was not expected. Increasing the percentage coverage the effect of this heterogeneity increases and becomes larger than EOD rock properties for RF around 80-85% which was expected since the threshold observed on the simulation results were the sequence boundaries play a big role on RF. The rank order of the heterogeneities changes while we increase the percentage of the barriers. The sequence boundary surfaces for the RF they start from fifth and climb up to first place in the ranking at around 80% barrier coverage while the EOD rock properties move to second (Figure 11).

Moreover for the breakthrough time, increasing the percentage of the barrier coverage accelerates the breakthrough time except at 100% coverage, where the water never comes up to the production well, something observed also in simulation results. However, having other realizations of the distribution of the barriers, the result may be different as observed on the sensitivity check done on the previous section; the breakthrough time has big uncertainty.

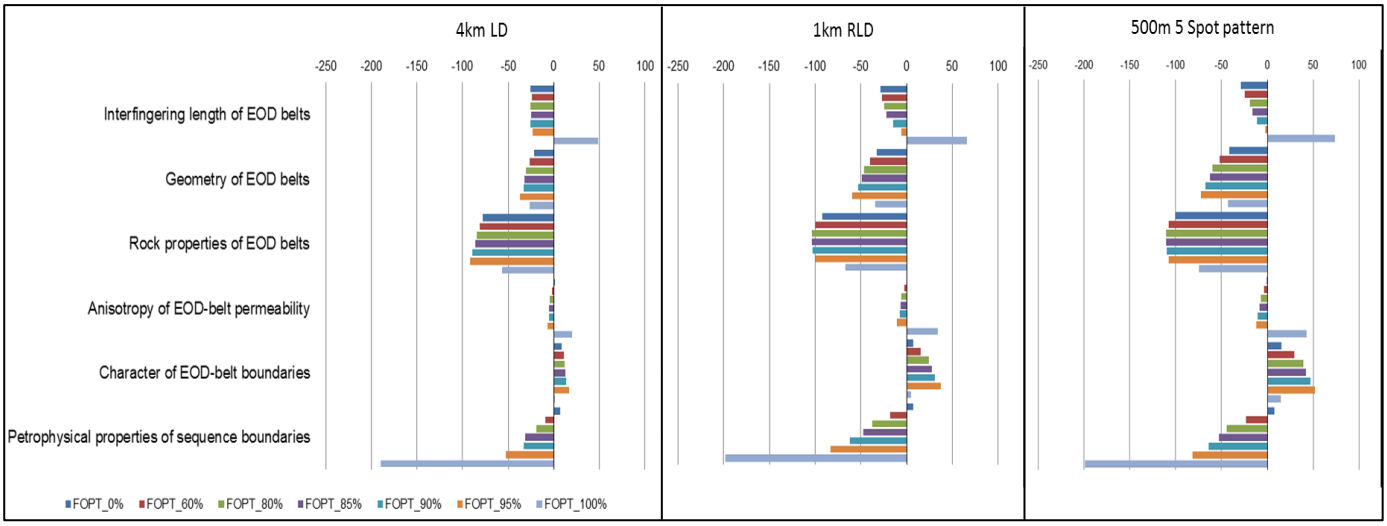

Figure 10: Tornado chart for the percentage change in volume of oil produced after 20 years moving from setting I to II for 0-100% barrier coverage (relative to the average behaviour of all simulated models). For the 4 km line drive, 1km RLD and 500m 5 Spot Pattern.

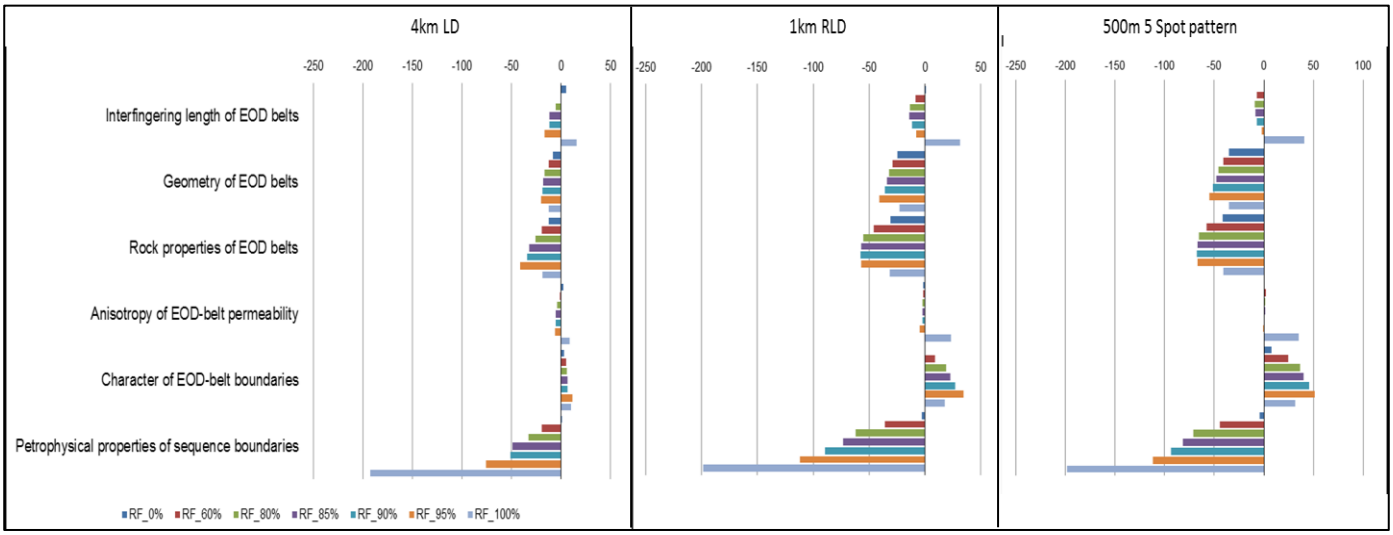

Figure 11: Tornado chart for the percentage change of RF after 20 years moving from setting I to II for 0-100% barrier coverage (relative to the average behaviour of all simulated models). For the 4km LD, 1km RLD and 500m 5 Spot Pattern.

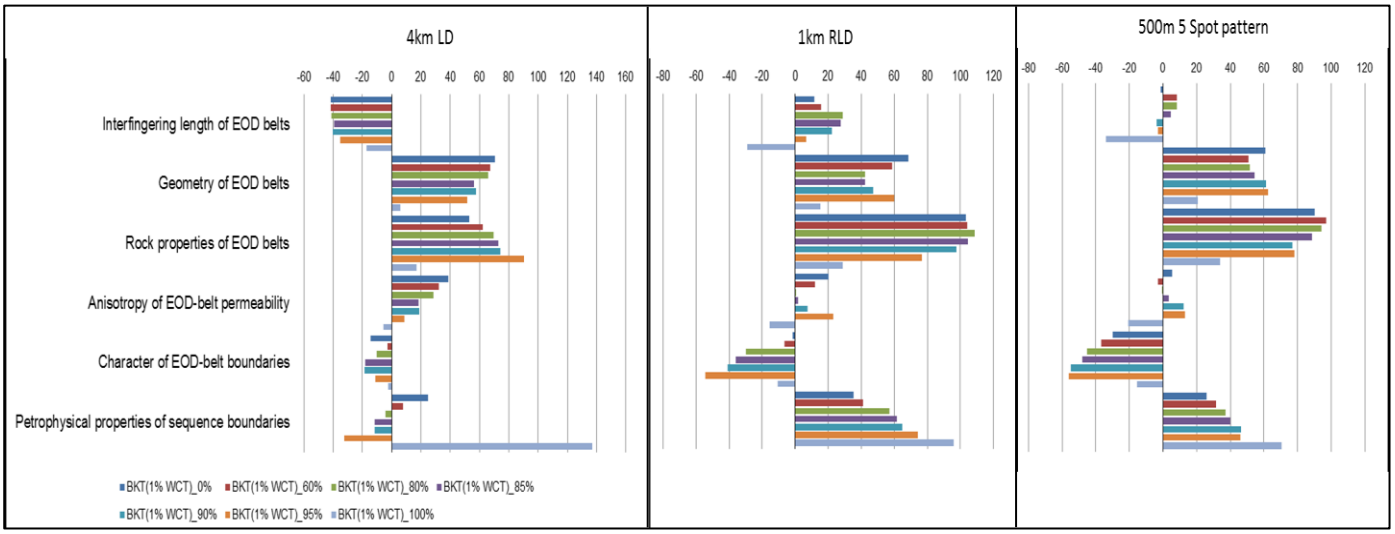

Figure 12: Tornado chart for the percentage change in time to breakthrough moving from setting I to II for 0-100% barrier coverage (relative to the average behaviour of all simulated models). For the 4km LD, 1km RLD and 500m 5 Spot Pattern.

Interaction of well spacing, with the impact of stratigraphic heterogeneities on flow

The highest recoveries are observed for the 4 km line drive well placing for all the models for 0% barrier to flow.
The impact of all heterogeneities on recovery factor and time to water breakthrough increases as well spacing is reduced from 4 km to 0.5 km (Figures 11, 12). In particular, the impacts of EOD-belt interfingering length and rock properties on recovery factor increase significantly at smaller well spacing. These results are comparable to those of Hollis et al. (2011), who found that depofacies-scale heterogeneities had a more significant impact on hydrocarbon production as well spacing decreased.

The character of the EOD-belt boundaries, varying well spacing changes the magnitude and rank order of heterogeneity impacting on recovery factor and breakthrough time.

The interfingering length of EOD-belts effect on breakthrough time, by changing from Setting (i) to (ii), for the 1km and 500 m is opposite than the 4km well spacing for all percentage coverage's.

For the sequence boundaries petrophysical properties at the 4km LD an unexpected behaviour is observed (for the breakthrough time) by increasing the percentage of the barriers at low percentage of coverage it delays the BKT and for higher percentages the BKT is faster. The RLD and 5 Spot pattern show normal results which means increasing the barrier percentage increases the Breakthrough time changing from Setting (i) to (ii).
One important thing we need to mention is the uncertainty found previously, which shows that the results of the experimental design have an uncertainty from the distribution of the barriers (surfaces) especially for the breakthrough time. This uncertainty is reduced for BKT and increased for oil production by reducing the well spacing.

Discussion

Simulation Results Discussion

Increasing the percentage of the coverage the sweep efficiency is reduced because there are fewer flow paths for water to flow and sweep the oil and eventually the RF is decreased (Figure 6).
For the BKT there is a trend, as we increase the % of the coverage (up to 80%) the BKT decreases because the flow of the water has fewer paths to follow upwards and reaches the production well faster. At the area of 80-95% it seems more complex; this observation is caused by another parameter related to the barriers that is affecting the BKT which is the distribution of the barriers (Figure 7). (RF is also a function of the distribution but not that significant, as the sensitivity analysis showed).

Decreasing the well spacing, decreases the oil production and increases the breakthrough time (for all percentages of coverage) because of the BHP control which gives less water injection (rate and cumulative), resulting in lower sweep efficiency (Figure D-1, D-2, D-3, D-4). The uncertainty of BKT is decreased by reducing the well spacing due to the bigger number of wells and their distribution all over the reservoir area. The uncertainty of oil production increases because the cemented barriers affect mostly the vertical flow which dominates in the smaller well spacing patterns (Table D-1).

Experimental Design Results Discussion

First we will discuss about the sequence boundaries and next about the other heterogeneities and their relationship with the percentage of the barrier coverage.

Sequence boundary rock properties results

Increasing the coverage the oil production and RF is decreasing even more, because of the lower sweep efficiency resulted by the distributed paths to flow in the reservoir (Figure 11).

The breakthrough time (Figure 12) at low coverage is increased switching from setting (i) to (ii) and that is because of the low properties of the sequence boundaries that do not allow water to flow fast vertically and reach the production well but after 80% the distribution of the lateral coverage has more effect on breakthrough time than the properties of the sequence boundaries (focussing flow through the smaller and fewer gaps allowing water to flow faster to the production well under same BHP) resulting in earlier BKT. At 100% coverage BKT becomes infinite because the water never comes to the production well. The results for breakthrough time cannot be trusted completely because of the uncertainty that the distribution of the coverage introduces, which is large at high barrier coverage except 100% where the uncertainty is zero.

In the STOIIP tornado chart (Figure 9) we observed a wrong result as we said in the results section, switching from setting (i) of the sequence boundaries to setting (ii) the STOIIP increases. This is a mistake of the experimental design method. The average value of the STOIIP of the models with the sequence boundaries (A,C,G,H) is above the average value of all the models together and also the average of the models that do not have the sequence boundaries (B,D,E,F). The experimental design technic is using as reference the average value of all the models, so switching from a reservoir without the sequence boundary to one with, it is assuming is resulting to an increase in STOIIP because of the average values.

Does the size of the barriers modelled have an impact on the results?

Analysis done on Model C for 80 and 95 % coverage; 400, 500 and 800 m diameter of the barriers and 7 different seed numbers. The results showed that having a large diameter of the barriers (800m) in same percentage of barrier coverage concludes to bigger "gaps" (flow paths) in the boundary layers, compared to smaller diameters (Figure 13).

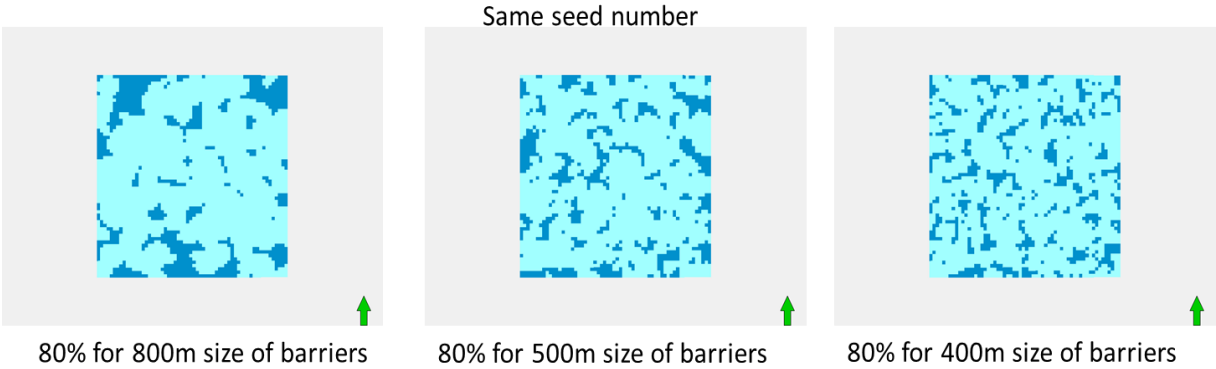

Figure 13: Example of barrier coverage (80%) with different sizes of the barriers, keeping the seed number constant

The production simulation results show that as the size of the barrier increases (keeping fixed the seed number which means the distribution method of the barriers in the layers) the volume of oil produced decreases by an average (we used 7 different distributions also to see if we have the same result keeping fixed other seed numbers) of 1% from 400 to 500m and 2% from 500 to 800m (see example Figure 14). The relationship with water breakthrough is more variable, depending on the distribution of "gaps" between the cemented barriers. Smaller cemented barriers lead to a greater distribution of "gaps" for vertical flow to exploit. Therefore water movement may be considered more "homogeneous", reflecting in a better sweep efficiency.

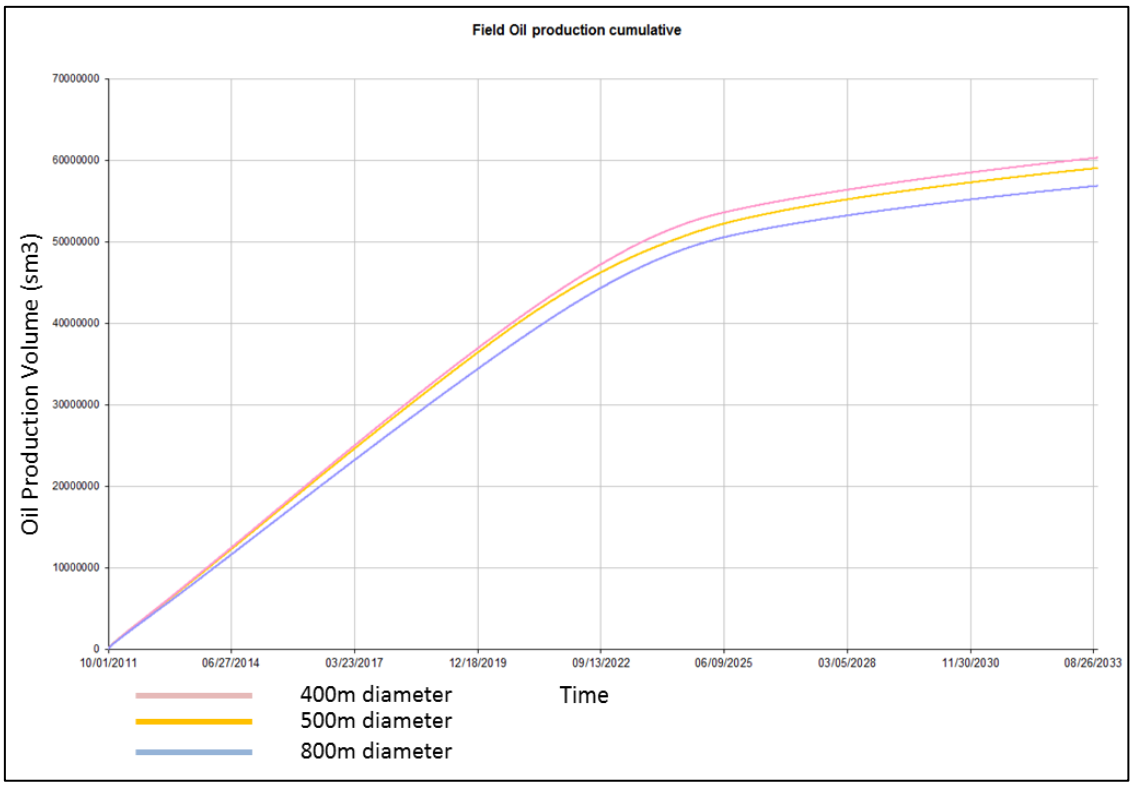

Figure 14: Oil production for a constant seed number but in pink 400m barrier diameter, in yellow 500m and in blue 800m

Increasing the size of the barriers decreases the number of options the modelling software has for positioning them. The uncertainty for 7 realizations for BKT increases and for oil production is variable (Figure 15).

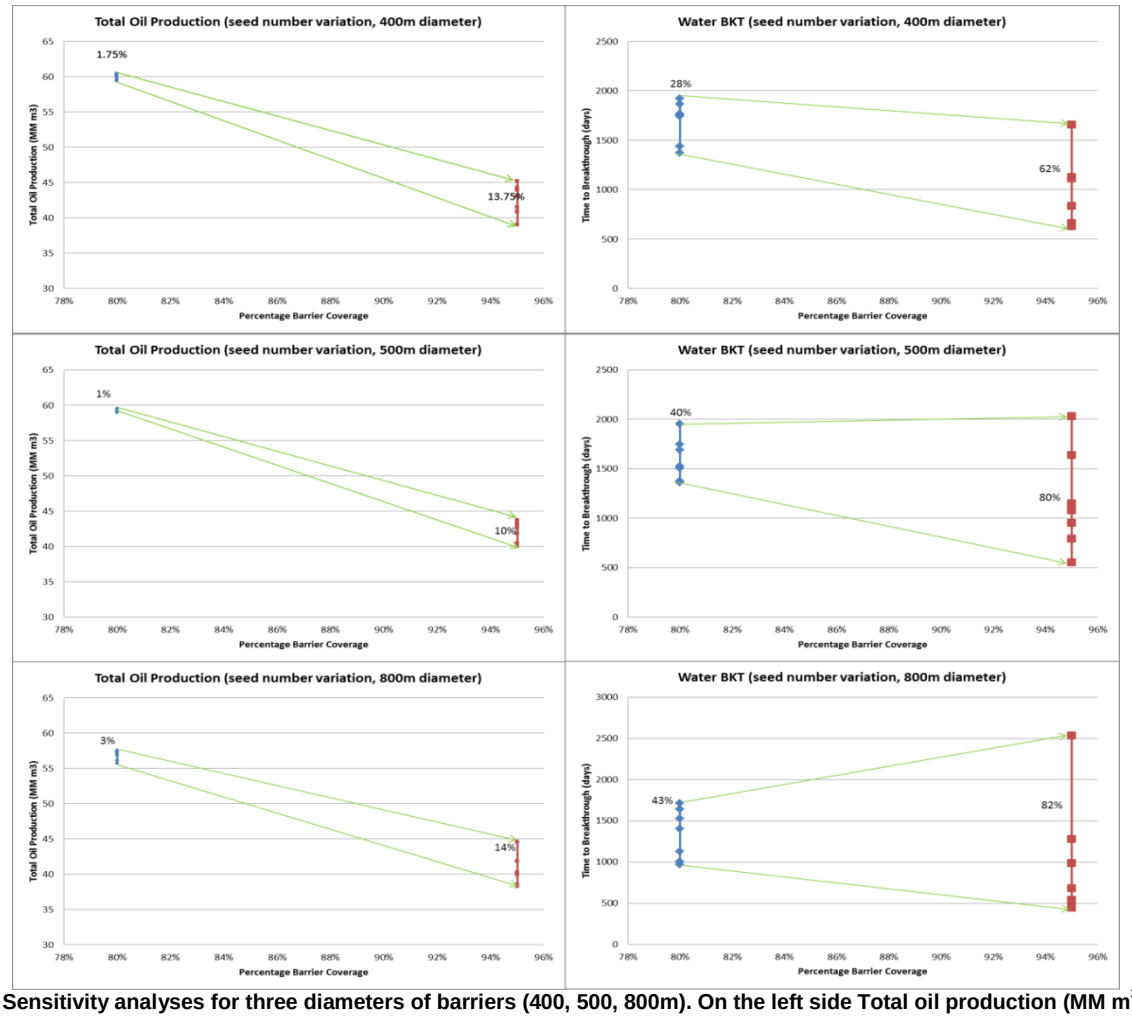

Figure 15: Sensitivity analyses for three diameters of barriers (400, 500, 800m). On the left side Total oil production (MM m^3) variation with reference the highest production on 80% and 95% coverage. On the right water BKT variation (days) with reference the latest BKT on 80% and 95% coverage (different seed number = different barrier distribution).

How heterogeneities and percentage coverage of sequence boundaries effect production results

At 100% coverage for EOD-belt boundary interfingering length, switching from Setting (i) to (ii) the oil recovery increases something that is counter intuitive because a shorter interfingering length might be expected to yield more laterally continuous, low permeability outer-ramp and pelagic EOD belts, yielding less tortuous vertical flow paths and, therefore, higher recovery (Figure 10). The result is an aliasing within the experimental design; of the 4 models without barriers to vertical flow along sequence boundaries, model B and D have the EOD-belt interfingering length in combination with the high EOD-belt rock properties, whereas models E and F have the shorter EOD belt interfingering length with low EOD-belt rock properties. As a result, longer EOD-belt interfingering length is associated with the two models yielding highest oil recovery. If sequence boundaries do not act as continuous barriers to flow, but are still linked with reduced porosity and permeability, production wells in models A, C, E, and F no longer shut-in after 4 years, allowing comparison of the EOD belt interfingering length within the full parameter space of our experimental design. In these models, switching to a longer EOD-belt interfingering length reduces oil recovery. (Same observation in Fitch at el b).

Switching from grain dominated to mud dominated rock properties decreases RF. The reason is that oil production is decreasing more than STOIIP so the impact on RF is negative. Moreover increasing the barrier coverage, the oil production reduces further and the impact is bigger. At 100% barrier coverage the production is only from the top section of the reservoir and in this case the reservoir below the top sequence boundary has no effect on production results, which is why the negative impact is reduced by 30% (Figure 11, 4km LD).

The low ranking of permeability anisotropy on production results (Figure 10, 11, 12) is probably due to the fact that the models have a flat structure where flow is mainly horizontal, if they had a thicker reservoir (more vertical flow) with more layers and/or horizontal wells, one might expect the permeability anisotropy to have a more significant impact on flow.

At 100% barrier coverage switching from setting (i) to (ii), the permeability anisotropy from negative impact it becomes positive. Increasing the barrier coverage it seems to be suppressing the effect of anisotropy (from setting (i) to (ii)) on breakthrough time. But suddenly at 100% it changes (Figure 10, 11, 12) and has a positive effect. Probably this result is not

realistic and is affected by the high values of breakthrough time of models A, C, G, and H which did not occur yet from the simulated results but we used 20 years as the maximum value in the experimental design.
Permeability anisotropy decreases oil production and recovery factor, consistent with previous case studies of carbonate reservoirs (Abbaszadeh et al. 2000; Ates et al. 2005; Hollis et al. 2011). The relatively low ranking of permeability anisotropy is surprising. *Kv/Kh* ratio within EOD belts has a smaller impact on production, even when flow is predominantly vertical, than might be expected (also as found by Hollis et al.2011 and Fitch at el b).

The character of the EOD-belt boundaries is one of the heterogeneity with the least impact on oil produced. More specific it increases the oil production due to the transitional zone which increases the STOIIP (Figure 9) of the reservoir and it allows smoother flow of the water than the sharp change of the EOD belts. Its relatively low impact is due to the small volume of the models occupied by transitional EOD-belt boundaries, as is evident in the small impact of this heterogeneity on STOIIP. Setting (ii) for transitional EOD-belt boundaries was designed 300m transitional zone because is the average value of published outcrop studies (e.g., Castel et al. 2007; Koehrer et al. 2010; Pierre et al. 2010; Elrick, 2011). However, more extreme cases may exist. Increasing the lateral extent of transitional EOD-belt boundaries will increase the proportion of each model impacted by this heterogeneity; this may increase its impact on oil production and recovery factor.
At 100% barrier coverage the only part of the reservoir producing is the top of the reservoir. At the top part of the reservoir there are few transitional zones so it results to a smaller effect of this heterogeneity almost 0%.

Impact of well placement

Reducing the well spacing results in an increase in the effect each heterogeneity has on RF, oil production and breakthrough time (Figure 10, 11, 12). The reason is because the heterogeneities in a smaller well spacing (which increases the potential of vertical flow) are more important than the distribution of the coverage, for the vertical flow of the liquid.

Decreasing well spacing decreases the RF (Figure 11), due to the potential for vertical flow between the deep completions in the injection wells and the shallow completions in the production wells is increased as the well spacing is decreased. Higher recovery is observed for the larger well spacing in models that have low effective vertical permeability, because they have reservoir architectures that are more layercake in geometry, containing laterally continuous, pelagic EOD belts of low permeability, and also anisotropic permeability within EOD belts something that was not expected as theses heterogeneities are introducing properties of low quality reservoirs.

Switching from setting (i) to (ii) of the sequence boundary (Figure 12); the BKT we have 2 parameters affecting the result. The low properties of the barriers that are delaying the BKT and the high % of coverage which allows fluid flow in fewer paths resulting to an earlier BKT. For the 4km LD initially up to 60% coverage the flow paths are enough for water to flow efficiently so the properties affect more the result. However above 80% coverage, except 100%, the effect of the % of barriers is greater resulting to an earlier BKT. Moreover as we decrease the well spacing, BKT is delayed on any percentage of barrier coverage which means the smaller well spacing is affected mostly by the low properties of the sequence boundaries. The uncertainty analysis also showed that decreasing the well spacing the uncertainty that is introduced by the distribution of the barriers in BKT decreases.

Moreover for BKT and Interfingering length (Figure 12), as the well spacing decreases the effect from negative becomes positive. Decreasing spacing increases the potential of vertical flow, which suggests that the vertical flow affects the breakthrough time more than the streak flow that gives a faster BKT for the 4km LD. (Comparable models on this idea are A and B from Figure 1). Setting (ii) introduces worse properties than (i), so in short spacing (and setting (ii)) that vertical flow dominates, water flows slowly vertically. In the 4km LD the water flows firstly vertically but the big streaks make the horizontal flow dominating and with the low properties of setting (ii) (porosity) water moves faster to the area of the production well.

The impact of heterogeneities on oil produced is greater than the variability in dynamic performance exhibited by a single model for different well placements. This suggests that the modeled geology is the most important control on production behavior.

Conclusion

Overall the project provides a generic idea around the effects of cemented barriers on production results. Summarizing, increasing barrier coverage percentage results in a decrease in oil production and for BKT as we observed is more complex because of the distribution of the barriers that affect the result. The threshold of the percentage of the barrier coverage where the RF starts to get affected mostly varies around 80-95% for the 4 models with the sequence boundaries. Decreasing the well spacing the threshold reduces around the range of 75-95%. Furthermore varying the distribution of the barriers and increasing the percentage of the barrier coverage results in an increase in the uncertainty of oil production and BKT and more specifically results in a small variation (uncertainty) in oil production (0-10%) and large in BKT (0-80%). Also increasing the diameter of the circular barriers, results in a decrease in sweep efficiency causing decrease in oil production. Moreover, as the well spacing decreases, the experimental design showed that the effect on production results of all the heterogeneities increases.

The experimental design results show clearly that sequence boundaries and rock properties affect the production results more than the other heterogeneities and has to be the once that need intense investigation. Also some drawbacks were identified in the experimental design interpretation, for example the interfingering and the anisotropy as discussed in previous

sections. But generally the experimental design work was very useful to our interpretation and complemented the simulation results.

Future work:

Even though the experimental design results complement the simulation results, performing the same analysis for a fixed total injection of water can eliminate the factor of amount of water injected which clearly affects the result in production with different well patterns. With fixed water injected we can compare quantitatively the different well patterns and not only by percentages. Having the BHP control at the small well spacing patterns results to less water injected even though there are more wells.

The size of the barriers that is modelled needs to be seen in more detail using all the models and the experimental design interpretation.

Although we identified most of the drawbacks that the uncertainty and the experimental design introduces, in terms of water breakthrough time it needs more detailed investigation, not only to 1% WCT. More detail investigation is required also on the uncertainty that the seed number introduces using all the different models (not only Model C). Regarding the oil production, the uncertainty that the seed number introduces is not large so no additional investigation is required.

Make an analysis if there is a pattern or a mathematical function that represents the deposition of the cemented surfaces so we can reduce the uncertainty of the distribution of the barriers.

Study on the fault style breaks in the cemented surfaces using the same procedure.

This study on the sequence boundaries and in some extent the other heterogeneities is very useful firstly for the reservoir engineers and there simulation studies and forecasts on the oil production in carbonate reservoirs with sequence boundaries (e.g. stylolite). Moreover it gives a general idea to where future studies on this subject must focus and what are “hidden” parameters (distribution of barriers, size of barriers, properties of the sequence boundaries) that must be evaluated. Furthermore in a more detailed study we can derive equations (using Matlab, Mathematica or R) for example between the percentage of coverage versus impact on RF switching from Setting (i) to (ii) of the sequence boundaries (which is a complex logarithmic or fitted in a third order polynomial function $y = 3E\text{-}05x^3 - 0.0138x^2 + 2.076x - 8.5692$) to be used in forecasting.

Nomenclature

SB	Sequence boundary
BKT	Breakthrough Time
bbl	Barrel
Cp	Centipoise
EOD	Environment of deposition
m	Meter
mD	Millidarcy
FOPT	Field oil production total
OWC	Oil water contact
RF	Recovery factor
STOIIP	Stock tank oil initially in Place
LD	Line Drive
RLD	Repeated Line Drive
FWCT	Field water cut
BHP	Bottom Hole Pressure

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Appendix A (Critical literature review)

Paper n°	Year	Title	Authors	Contribution
79676	2003	"Experimental Design as a Framework for Reservoir Studies"	Christopher D. White, SPE, Louisiana State U. and Steve A. Royer, Shell Exploration and Production Co.	Overview how to create an experimental design framework for reservoir simulations. The design approach has been applied to simulate, analyse and optimize a subsea development in the deepwater Gulf of Mexico. This approach reduces analysing time and bypasses the design of expensive reservoir simulations.
93679	2005	"Challenges and Insights in Optimizing Oil Production from Middle East Mega Karst Reservoirs"	R.Trice, C & C Reservoirs Ltd	First pass 'quick look' method has been developed by which carbonate reservoirs can be ranked with the objective of assessing the degree that karst influences are present. The quick look method is intended to identify karst products, or the potential for karst products to be present, from which steps can be undertaken to establish whether a karst drainage system impacts optimum oil productivity.
AAPG Bulletin, 93, 9, p1183-1208	2009	"Three-dimensional modeling of a shoreface-shelf parasequence reservoir analog: Part 2. Geologic controls on fluid flow and hydrocarbon recovery."	Jackson, M.D., Hampson, G.J., and Sech, R.	First to investigate the impact of clinoform controlled, depositional and diagenetic heterogeneitieson fluid flow during hydrocarbon recovery from wave-dominated, shoreface-shelf reservoirs in a 3D model. Flow is simulated using a 3-D model of a single shoreface-shelf parasequence exposed at outcrop, which captures clinoform surfaces and clinoformcontrolled facies architecture.
Sedimentology 59, p. 249-290	2011	"Characterization and interpretation of discontinuity surfaces in a Jurassic ramp setting (High Atlas, Morocco)."	Christ, N., Immenhauser, A., Amour, F., Mutti, M., Tomas, S., Agar, S.M., Always, R., and Kabiri, L.	1. Detailed description and characterization of discontinuity surfaces in a Jurassic ramp system in terms of their stratigraphic time distribution, their lateral extent, facies change across these surfaces, morphology, ichnofauna and thickness of the altered underlying interval. 2. Interpretation of the sedimentary processes that govern the formation or non-formation of the different types of discontinuity surfaces in a carbonate ramp system. 3. Quantitative data on the relevance of discontinuity surfaces in reservoir compartmentalization of Mesozoic carbonate ramp settings.
AAPG (in review)	2012	"A hierarchical approach to classifying stratigraphic and sedimentological heterogeneities in carbonate ramp reservoirs with application to integrated flow simulation studies"	Fitch, P.J.R, Jackson, M.D., Hampson, G.J., and John, C.M.	First to present a length-scale-based hierarchy of heterogeneity for carbonate reservoirs, this orders stratigraphic and sedimentological heterogeneity into a coherent framework and integrates the description of heterogeneity from outcrop and reservoir data types. Moreover apply the hierarchy to understand the impact of stratigraphic heterogeneities on flow in carbonate reservoirs.
Petroleum Geoscience (in review)	2012	"Interaction of stratigraphic and sedimentological heterogeneities with flow in carbonate ramp reservoirs: impact of fluid properties and production strategy"	Fitch, P.J.R, Jackson, M.D., Hampson, G.J., and John, C.M.	First to investigate the impact of fluid properties and production strategy on the hierarchical approach of stratigraphic and sedimentological heterogeneities in carbonate ramp reservoirs (Fitch)

Table A 1: Critical Literature review

Appendix B (Critical literature review Summary)

SPE 93679 (2005)

Title: Challenges and Insights in Optimizing Oil Production from Middle East Mega Karst Reservoirs

Authors: R.Trice, C & C Reservoirs Ltd.

Contribution to the understanding of karst in carbonate reservoirs:

-The paper is a summary of work to establish the impact of karst on optimizing oil production from carbonate reservoirs.

-Understand of what are the karst reservoirs and the importance to identify them in the carbonate reservoir. Moreover assess their impact in oil production.

Objective of the paper:

- Understand the geology of a karst drainage network and how it may form.
- Identify karst drainage networks or potential karst products using 44 Middle East carbonate reservoirs.
- Whether a karst drainage system impacts optimum oil productivity.

Methodology used:

i) Avoiding karst denial, ii) data gathering, iii) conceptualizing megakarst reservoirs and iv) well placement and production scenarios for megakarst reservoirs.

Conclusion reached:

1. It is possible to understand the presence of karst in a reservoir but it needs a specific data gathering approach and implementing it to simulation. (Expensive)

2. If karst processes in the Middle East are primarily associated with porosity and permeability destruction, then further study of productive karst reservoir examples, with the objective of understanding why and how karst drainage systems remain preserved has merit.

SPE 79676 (2003)
Title: Experimental Design as a Framework for Reservoir Studies

Authors: Christopher D. White, SPE, Louisiana State U. and Steve A. Royer, Shell Exploration and Production Co.

Contribution to my project:
Understanding of the experimental design in numerical simulations. Identify the key factors that I will vary and design the optimum approach to get the best result from my calculations.

Objective of the paper: Numerical simulation integrates extensive geoscience and engineering data with complex process models to examine reservoir behavior. Reservoir studies commonly consider many scenario, cases and realizations. However, reservoir simulation can be expensive. Complexity, combinatory, and expense motivate improved reservoir study methods. The experimental design framework selects relevant models, records factor settings for models, creates data files, controls execution, gathers summary data and creates response models. Response surface models facilitate Monte Carlo simulation, uncertainty analysis, optimization, parameter estimation, upscaling and performance forecasting. A predevelopment study of a Gulf of Mexico turbidite reservoir uses this framework to examine the sensitivity of oil production predictions to well location, absolute horizontal permeability, pore compressibility, aquifer size, skin, and vertical permeability.

Methodology used:
Designed simulation studies enumerate influential factors, identify response sensitivities, and yield estimates over the range of all factors.
Factor lists and experimental designs journal the simulation study and automate data element construction, deck assembly, execution, and summary tabulation. Analysis of variance, sensitivity analysis, and response surfaces can be used to analyze designed simulation studies. Response surfaces are efficient proxies for reservoir simulators, and can be used for uncertainty analysis, parameter estimation, forecasting, and optimization.

Conclusion reached:
The designed approach has been applied to simulate, analyze and optimize a subsea development in the deep-water Gulf of Mexico. To be optimized, response models must include quadratic terms for controllable factors and interactions between controllable and other factors. Decisions can be optimized using surface response models. Designed approaches have been used for parameter estimation, upscaling and proxy modeling.

Department of Earth Science and Engineering, Imperial College London, London SW7 2AZ, United Kingdom (Email: p.fitch@imperial.ac.uk) (2012)

Title: A hierarchical approach to classifying stratigraphic and sedimentological heterogeneities in carbonate ramp reservoirs with application to integrated flow simulation studies

Authors: Fitch, P.J.R, Jackson, M.D., Hampson, G.J., and John, C.M.

Contribution to my project:
Understanding of the stratigraphic and sedimentological heterogeneities in carbonate ramp reservoirs. Understand the geological models I will work on and the impact of the heterogeneities changing reservoir parameters in the development plan. Most important is the understanding of the work flow I have to follow using also other papers I already mentioned.

Objective of the paper:
The aims of this paper are therefore twofold. The first is to present a length-scale-based hierarchy of heterogeneity for carbonate reservoirs, which orders stratigraphic and sedimentological heterogeneity into a coherent framework and integrates the description of heterogeneity from outcrop and reservoir data types. The second aim of the paper is to apply the hierarchy to understand the impact of stratigraphic heterogeneities on flow in carbonate reservoirs. This work forms the first step of a larger study, which aims to characterize and quantify the impact of stratigraphic, sedimentological and diagenetic heterogeneities on flow during hydrocarbon recovery in carbonate reservoirs.

Methodology used:
In this study, models are constructed at progressively increasing levels of geologic detail (or decreasing length-scale) identified in the hierarchy, and an analysis of the impact of heterogeneity on flow is undertaken at each stage. This approach avoids the pitfalls associated with very high resolution model construction, in which too much time is devoted to capturing every detail and too little time to applying the model (e.g., Williams et al., 2004). Moreover, as the model predictions change with increasing levels of detail, a picture naturally emerges of the level of interpretational detail required to capture primary fluid flow characteristics, and of which heterogeneities impact on flow. The results here investigate heterogeneities at the largest length-scales of the hierarchy that are relevant to hydrocarbon production, providing a framework for the investigation of smaller-scale heterogeneities, which are the focus of on-going work.
(The hierarchical scheme was applied, in conjunction with reservoir modelling, simulation and experimental design techniques, to quantify the impact of stratigraphic heterogeneities on hydrocarbon recovery from carbonate reservoirs.)

Conclusion reached:
A length-scale based, hierarchical approach to classifying stratigraphic and sedimentologic heterogeneities in carbonate ramp reservoirs has been presented. Levels 1 to 3 of the hierarchy identify and capture the architecture and spatial distribution of stratigraphic heterogeneities (i.e. EOD-belts), at decreasing length-scales. The distribution of depositional facies and geobodies within stratigraphic units are documented at level 4 of the hierarchy. Level 5 describes bed geometries and diagenetic features. Heterogeneity at centimeter-to-micrometer scale (e.g. sedimentary structures, grain shapes, pore networks) are recorded at levels 6 and 7 of the hierarchy.
The hierarchy has been applied to define end-member values for a selection of stratigraphic heterogeneities (levels 1-3 of the hierarchy) and quantify their impact on flow behavior and oil recovery. EOD belt rock properties are consistently found to have the most significant impact on flow. EOD belt geometry and EOD belt interfingering length control the lateral continuity, volumes and spatial distribution of EOD belts and are shown to be the second and third ranked heterogeneities. Heterogeneities impacting vertical flow are of low ranked importance, but this is because vertical flow in the production scenarios we investigate is limited, regardless of heterogeneity. Changing the end-point mobility ratio, well spacing and placement, and the approach to modeling relative permeability and capillary pressure, has no effect on the rank order of the stratigraphic heterogeneities investigated.

Department of Earth Science and Engineering, Imperial College London, London SW7 2AZ, United Kingdom (Email: p.fitch@imperial.ac.uk) (2012)

Title: Interaction of stratigraphic and sedimentological heterogeneities with flow in carbonate ramp reservoirs: impact of fluid properties and production strategy

Authors: Fitch, P.J.R, Jackson, M.D., Hampson, G.J., and John, C.M.

Contribution to my project:
First application of the hierarchy established on the previous paper descripted. From this project I can compare my results and identify any defects of my project and faster understanding on some parts which are similar.

Objective of the paper:
Integrated flow simulation and experimental design techniques are used to investigate the relative impact of stratigraphic heterogeneities on simulated recovery in carbonate reservoirs. Two production strategies are compared, with dominance of either horizontal or vertical flow.

Methodology used:
The suite of reservoir models presented by Fitch et al. (in review) was used, that capture generic styles of gross stratigraphic architecture in carbonate ramp systems. Experimental design was used to efficiently explore the parameter space defined by the heterogeneities investigated in the suite of reservoir models. Specifically, a 2^{6-3} fractional factorial experimental design was used, which allows the main effects of each heterogeneity to be estimated independently of other heterogeneities, assuming that higher order interactions between heterogeneities are insignificant (Box et al. 1987; Wu & Hamada, 2000; White & Royer, 2003). A total of eight models were constructed, combining heterogeneity settings as required by the experimental design, and flow simulation of this suite of models was carried out for each production scheme under investigation.

Conclusion reached:
We find that the modelled geology is more important than the simulated fluid properties and production scenarios. Rock properties and stratigraphic heterogeneities that control reservoir architecture and the spatial distribution of environment-of-deposition (EOD) belts are important controls on recovery regardless of the production strategy. The presence of cemented hardground surfaces becomes the key control on oil recovery in displacements dominated by vertical flow. Permeability anisotropy is of surprisingly low importance for all production strategies. The impacts of the stratigraphic heterogeneities on recovery factor and water breakthrough are more strongly influenced by end-point mobility ratio and well spacing in displacements dominated by vertical flow. These results help to streamline the reservoir modeling process, by identifying key heterogeneities, and optimize production strategies in different carbonate reservoirs.

AAPG Bulletin, 93, 9, p1183-1208 (2009)

Title: Three-dimensional modeling of a shoreface-shelf parasequence reservoir analog: Part 2. Geologic controls on fluid flow and hydrocarbon recovery.

Authors: Jackson, M.D., Hampson, G.J., and Sech, R.

Contribution to my project:

Understand how interfingering affects STOIIP and how waterflood sweep efficiency is affected by barriers to flow along clinoform surfaces. All the conclusions help me understand the results I have in my project and explain them.

Clinoform surfaces control the geometry of facies interfingering within individual parasequences, which strongly affects the permeability architecture because facies types are associated with major permeability contrasts (e.g., Sech et al., 2009, their table 1 and associated references). Clinoform surfaces are also associated with calcite-cemented layers, zones of intense bioturbation, mudstones, siltstones, and concentrations of mica, which further modify the permeability architecture. (Jennette and Riley, 1996; Henk and Ward, 2001;Matthews et al., 2005; Morris et al., 2006; Hampson et al., 2008).

Objective of the paper:

Investigate the impact of clinoform-controlled, depositional and diagenetic heterogeneities on fluid flow during hydrocarbon recovery from wave-dominated, shoreface-shelf reservoirs.

Methodology used:

Flow is simulated using a 3-D model of a single shoreface-shelf parasequence exposed at outcrop, which captures clinoform surfaces and clinoformcontrolled facies architecture (Sech et al., 2009, this issue). The advantage of using a model derived from outcrop data is that clinoformsurfaces and facies architecture can be robustly identified and correlated; moreover, the data set used in this study provides excellent 3-D control on their geometry and spatial distribution.

To investigate the production conditions for which clinoform and associated permeability architecture may impact flow, variation of the injector producer well spacing and waterflood direction with respect to depositional dip is implemented. Production is simulated directly on the geologic models.

Conclusion reached:

Although clinoform surfaces control facies architecture, they have little impact on the waterflood recovery factor unless they are associated with calcite-cemented layers or other barriers to flow. Injected water moves rapidly through the best quality facies at the top of the parasequence, leading to early breakthrough at the producing wells; the better-quality lower shoreface facies are then swept by the gravity driven, downward flow of water.

Sedimentology, 59, p. 249-290 (2011)
Title: Characterization and interpretation of discontinuity surfaces in a Jurassic ramp setting (High Atlas, Morocco).

Authors: Christ, N., Immenhauser, A., Amour, F., Mutti, M., Tomas, S., Agar, S.M., Always, R., and Kabiri, L.

Contribution to my project:
Understanding of the geological features of discontinues surfaces.

Objective of the paper:
This paper has two aims: the first one is the detailed description and characterization of discontinuity surfaces in a Jurassic ramp system in terms of their stratigraphic time distribution, their lateral extent, facies change across these surfaces, morphology, ichnofauna and thickness of the altered underlying interval. The second aim is the tentative discussion of these features in their palaeoenvironmental context. Specific focus is on the interpretation of the sedimentary processes that govern the formation or non-formation of the different types of discontinuity surfaces in a carbonate ramp system. Furthermore, this paper provides quantitative data on the relevance of discontinuity surfaces in reservoir compartmentalization of Mesozoic carbonate ramp settings.

Methodology used:
Field and laboratory study, focussing on the quantitative stratigraphic and lateral characterization of discontinuity surfaces in a Jurassic carbonate ramp setting of the High Atlas Mountains of Morocco is documented and the results are discussed in a process-oriented context.
In order to obtain a statistically relevant data set, discontinuities were physically traced and described laterally over distances ranging from some hundreds of metres to some kilometres.

Conclusion reached:
1) Four factors arguably were dominant in the formation of Assoul Formation discontinuities: firstly, changes in relative sea-level and hence effective fair-weather and storm wave base and wave-induced currents and, linked to this, the hydrodynamic level at the carbonate sea floor; secondly, the type (porosity and permeability) of carbonate facies at the sea floor; thirdly, the sedimentation rate; and fourthly, the physiographic setting of a given locality on the ramp transect (inner, mid or outer ramp).
2) Discontinuity surfaces are clearly assigned to sub-aquatic firmgrounds or hardgrounds and marine omission surfaces and can be classified into three groups: (i) laterally limited surfaces showing incipient lithification; (ii) laterally limited to extended firmgrounds; and (iii) laterally extended to continuous hardgrounds.
3) Amongst the 80 discontinuities identified in the study area, 44 are condensed surfaces, 26 are firmgrounds and 10 are marine hardgrounds.
4) Data shown here are of significance for an improved understanding of discontinuity surfaces in Mesozoic carbonate ramp settings and aid in creating more quantitative reservoir models.

Appendix C (Methodology)

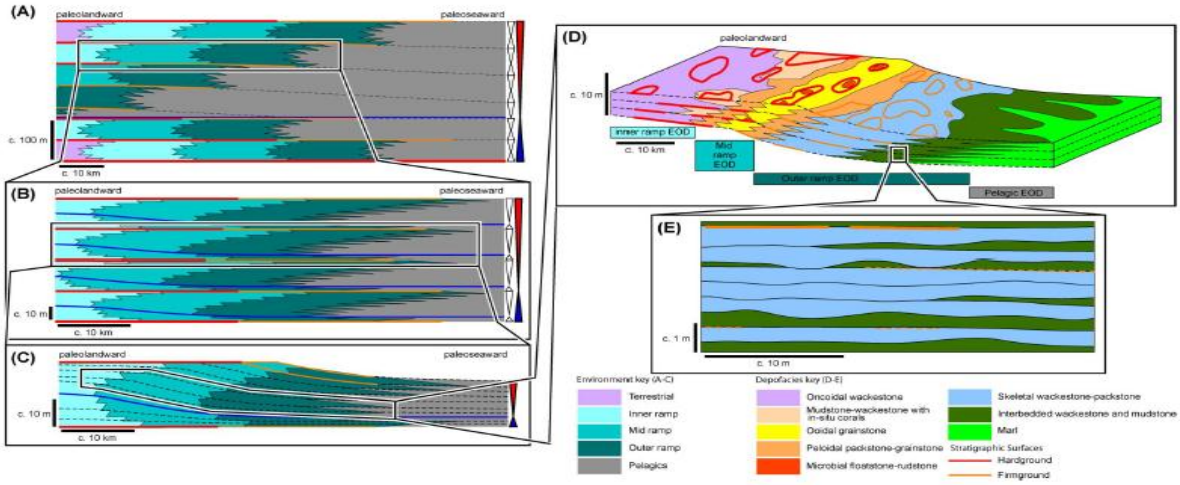

Figure C 1: Heterogeneity hierarchy in carbonate reservoir (Fitch et al. in review a).

Environment of Deposition (EOD)		**Rock properties**					
		High (grain dominated)			**Low (mud dominated)**		
Name	**Lithology and sedimentary structure (after Amour et al. 2011)**	**Ø(pu)**	**kh (mD)**	**kv (mD)**	**Ø(pu)**	**kh (mD)**	**kv (mD)**
Inner Ramp(Semi-restricted ramp)	Bioclastic wackestone, packstone and framestones; low to medium bioturbation intensity; presence of micritization and microencrustation.	0.21	320	47	0.02	170	24
Mid Ramp(High energy ramp)	Packstone, grainstone and floatstone-rudstone; ooids, peloids and bioclastic components; medium to high bioturbation intensity; cross-bedding, encrustation and spary cements dominate.	0.38	4200	2000	0.18	840	390
Outer Ramp(Marly open ramp)	Marl, carbonate mudstone and wackestone; localised boundstone; bioclastic and peloidal grain components; low to medium bioturbation intensity; episodic terrigenous sediment input.	0.17	2.4	0.21	0.001	0.58	0.05
Pelagics	Marl and shale dominated	0.11	0.15	0.02	0.0001	0.01	0.001

Table C 1: Rock properties used in flow simulation models. Ø – porosity , kh – horizontal permeability (and isotropic permeability, kv=kh), and kv – vertical permeability. High and low values of rock properties are used as settings (i) and (ii) of heterogeneity 3. A uniform rock compressibility of microsip is used in all models.

Model	STOIIP (m3)	Number of grid blocks(i,j,k)	Reservoir length, laterally (m)	Reservoir top datum depth(m)	Reservoir bottom datum depth(m)	Reservoir thickness(m)
A	167,581,856	60×60×116		1382	1442	60
B	125,831,144	60×60×77		1382	1442	60
C	136,846,032	60×60×101		1382	1442	60
D	104,963,608	60×60×91		1382	1442	60
E	82,608,192	60×60×113	4km×4km	1382	1442	60
F	74,482,208	60 ×60 ×99		1382	1442	60
G	53,838,432	60×60×80		1382	1442	60
H	55,966,104	60×60×95		1382	1442	60

Table C 2: Models and their characteristics.

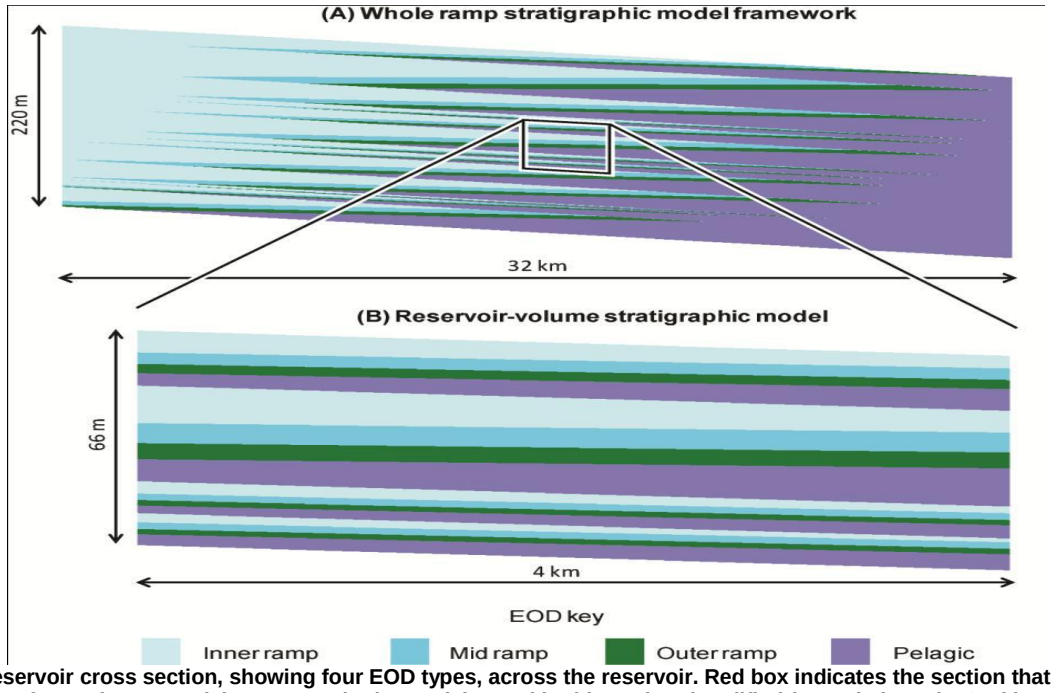

Figure C 2: Reservoir cross section, showing four EOD types, across the reservoir. Red box indicates the section that was extracted from a larger model, to constrain the models used in this project (modified from Fitch et al. 2011b).

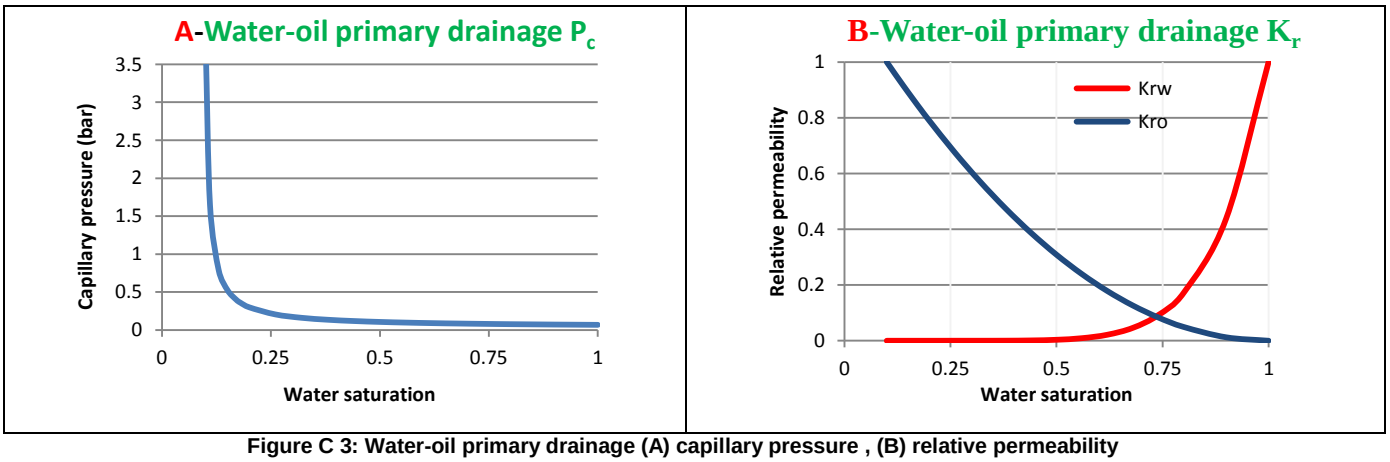

Figure C 3: Water-oil primary drainage (A) capillary pressure , (B) relative permeability

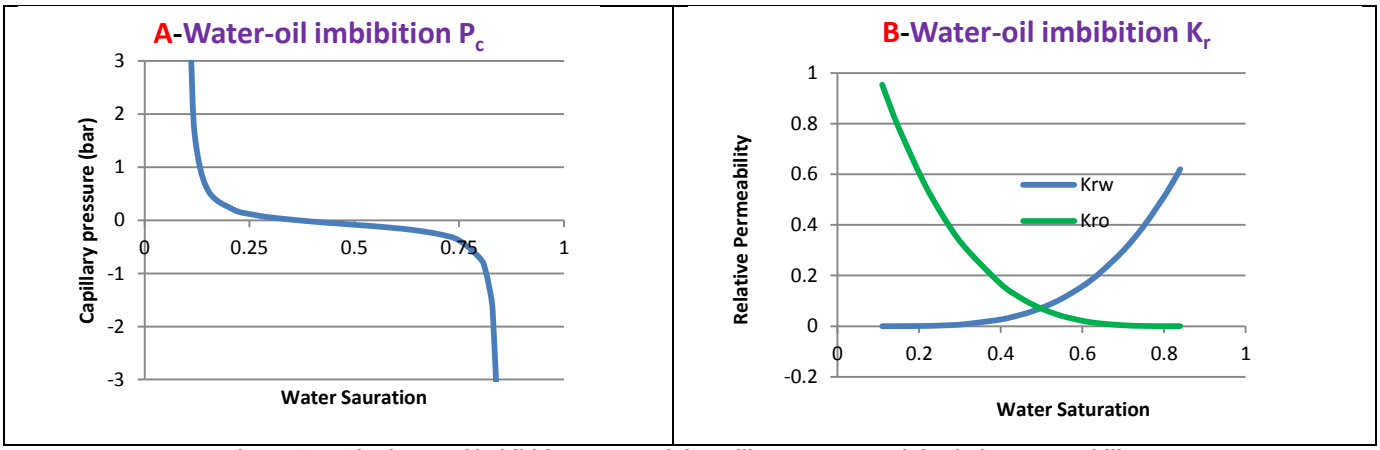

Figure C 4: Single set of imbibition curves (A) capillary pressure , (B) relative permeability

Appendix D (Results)

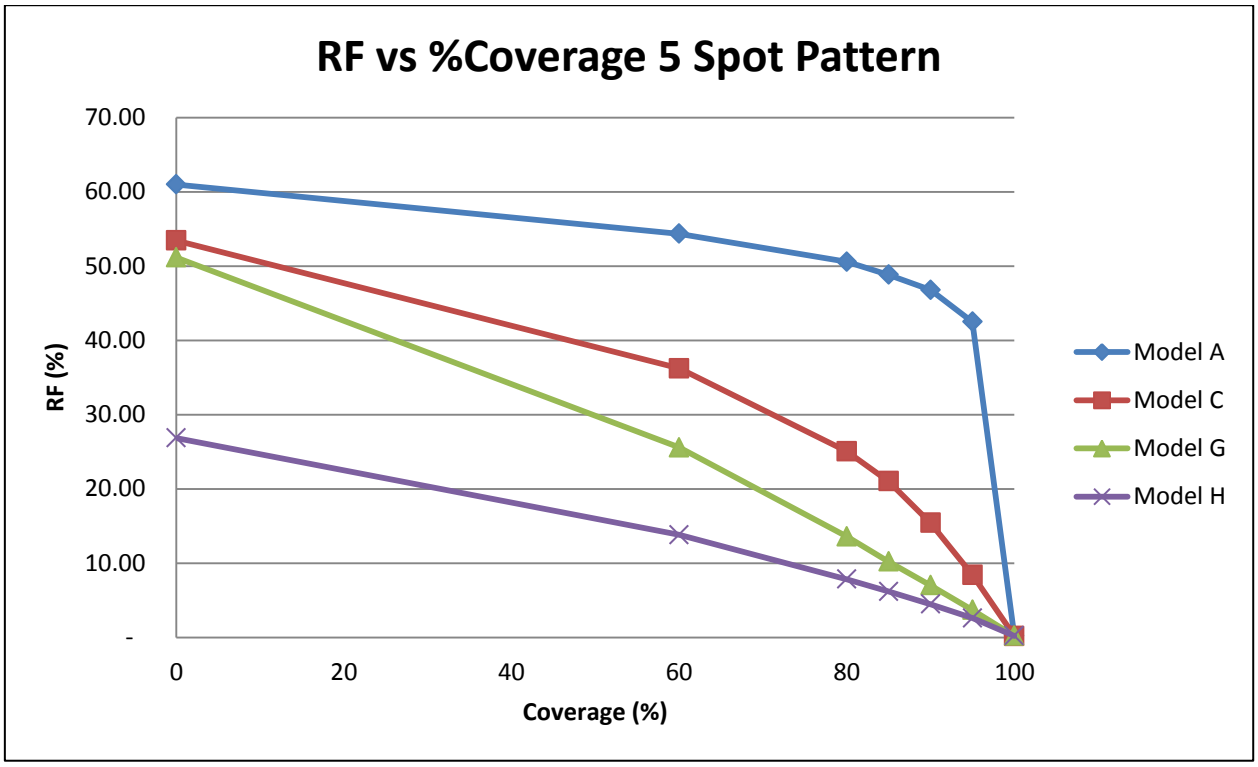

Figure D 1: Recovery factor versus % of coverage (20 years, 5 Spot Pattern)

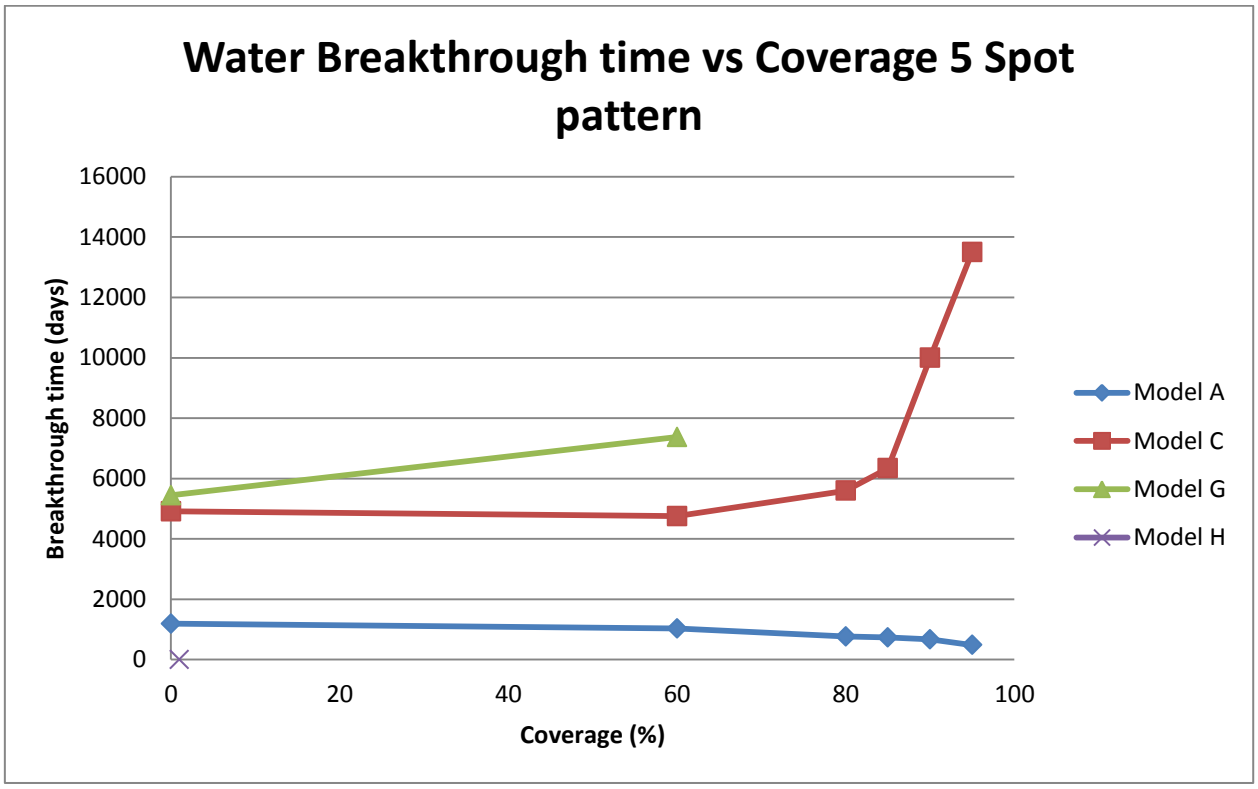

Figure D 2: Water breakthrough time versus % of coverage (20 years, 5 Spot pattern). (The missing data is because the water breakthrough happens after the 22 years (8030 days) of production data). Some of the data I assumed because of the trend of the breakthrough time.

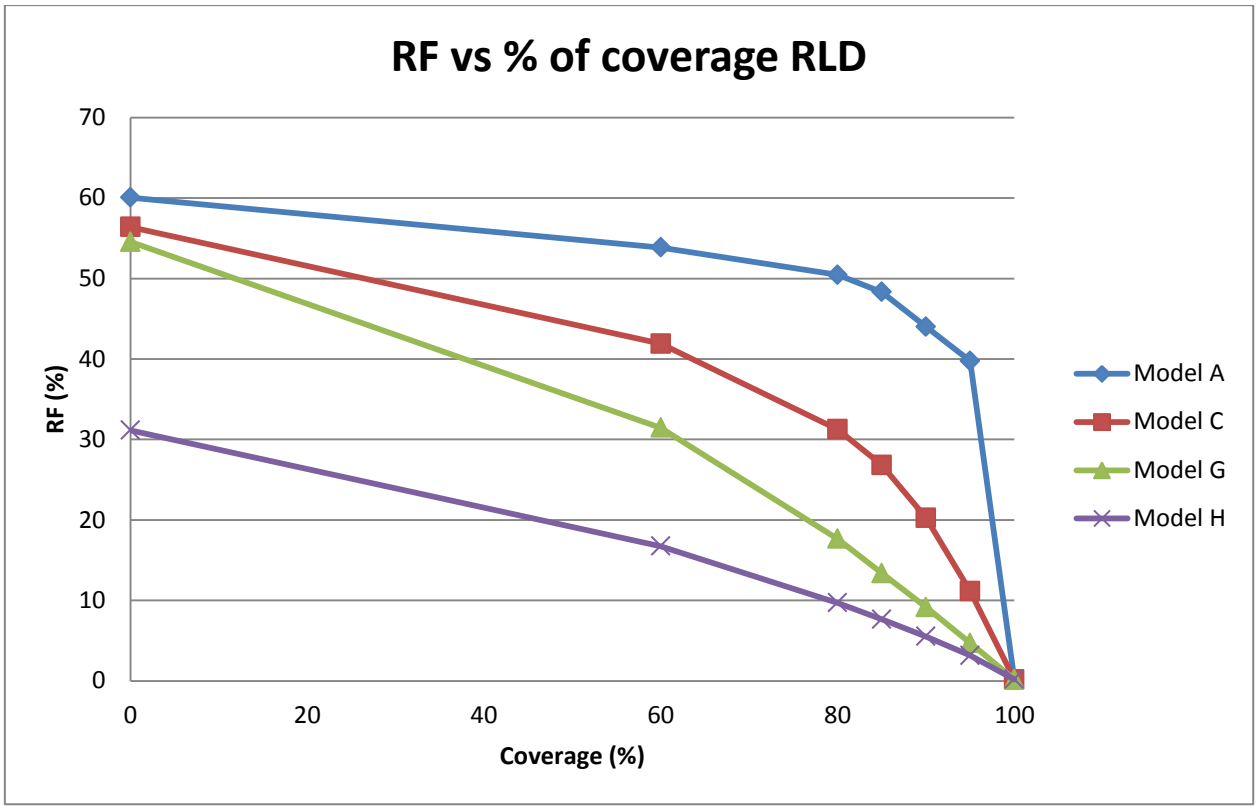

Figure D 3: Recovery factor versus % of coverage (20 years, RLD)

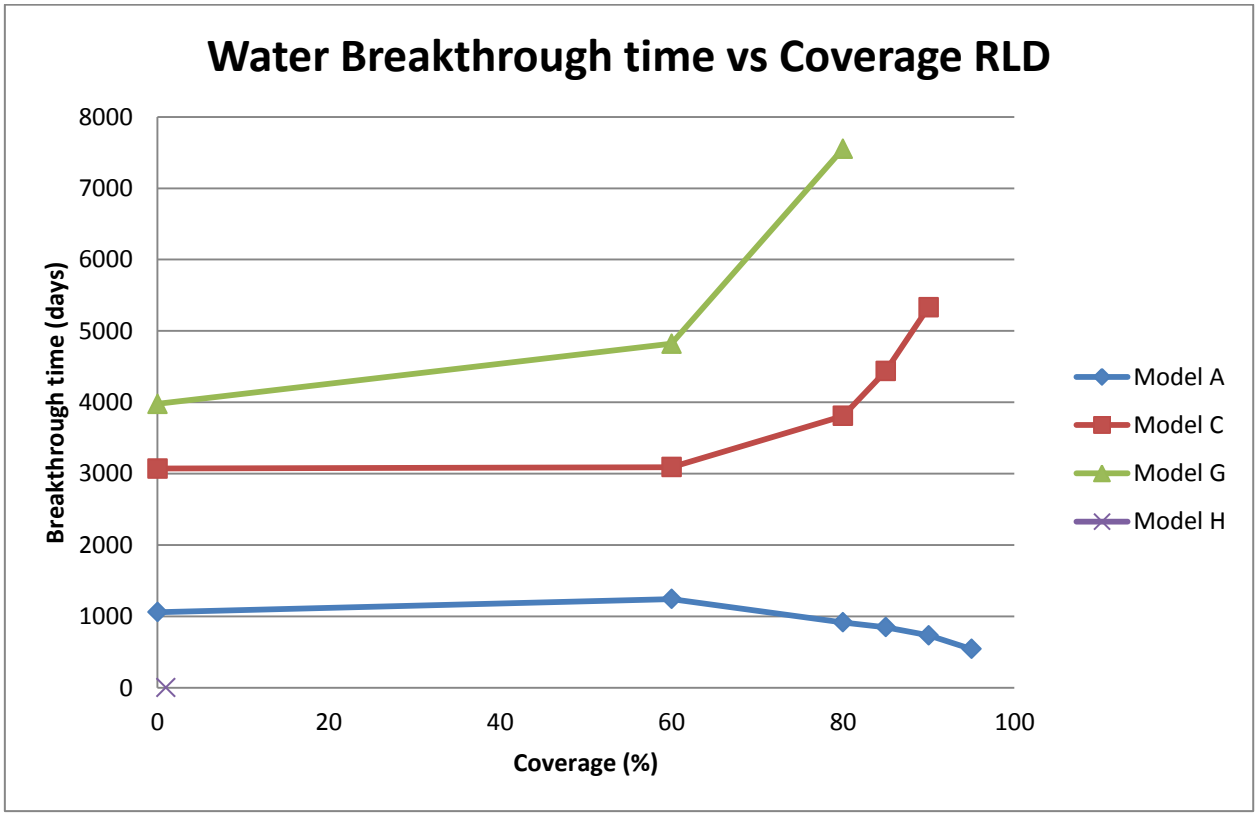

Figure D 4: Water breakthrough time versus % of coverage (20 years, 5 Spot pattern). (The missing data is because the water breakthrough happens after the 22 years (8030 days) of production data).

Variation in the distribution of barriers: (7 Seed numbers)	4km LD (80% coverage)	4km LD (95% coverage)	1km RLD (80% coverage)	1km RLD (95% coverage)	500m 5 Spot (Pattern 80% coverage)	500m 5 Spot (Pattern 95% coverage)
Water BKT variation	40%	80%	12%	57%	17%	Did not reach 1% WCT
Oil production variation	1%	10%	6%	18%	7%	19%

Table D 1: Uncertainty introduced by seed number reducing well spacing (variation has reference the highest value observed in oil production and BKT)

			4km LD		
100%	STOIIP (m3)	FOPT (20 years) (m3)	FWPT (20 years) (m3)	RF (%)	Breakthrough time 1% WCT (days)
A	1.68E+08	4373892	3767.916	2.61	8030
B	1.26E+08	7.73E+07	4.02E+08	61.46	519
C	1.37E+08	704480.13	250.5771	0.51	8030
D	1.05E+08	6.32E+07	2.18E+08	60.24	852.40466
E	8.26E+07	46487872	40559412	56.28	1923
F	7.45E+07	34093256	4853926	45.77	2687
G	5.38E+07	285399.09	137.15077	0.53	8030
H	5.60E+07	294885.31	108.82761	0.53	8030

95%	STOIIP (m3)	FOPT (20 years) (m3)	FWPT (20 years) (m3)	RF (%)	Breakthrough time (days)
A	1.68E+08	74820056	149409950	44.65	296.30344
B	1.26E+08	7.73E+07	4.02E+08	61.46	519
C	1.37E+08	40075396	4836494.5	29.29	1151
D	1.05E+08	6.32E+07	2.18E+08	60.24	852.40466
E	8.26E+07	46487872	40559412	56.28	1923
F	7.45E+07	34093256	4853926	45.77	2687
G	5.38E+07	8820077	946386.88	16.38	1084
H	5.60E+07	5945441.5	365096.41	10.62	1784

90%	STOIIP (m3)	FOPT (20 years) (m3)	FWPT (20 years) (m3)	RF (%)	Breakthrough time (days)
A	1.68E+08	82854464	161590290	49.44	397
B	1.26E+08	7.73E+07	4.02E+08	61.46	519
C	1.37E+08	51124476	12367855	37.36	1780
D	1.05E+08	6.32E+07	2.18E+08	60.24	852.40466
E	8.26E+07	46487872	40559412	56.28	1923
F	7.45E+07	34093256	4853926	45.77	2687
G	5.38E+07	14963361	2876437	27.79	1183
H	5.60E+07	10164513	653074.75	18.16	1953

85%	STOIIP (m3)	FOPT (20 years) (m3)	FWPT (20 years) (m3)	RF (%)	Breakthrough time (days)

A	1.68E+08	86101160	170584560	51.38	463
B	1.26E+08	7.73E+07	4.02E+08	61.46	519
C	1.37E+08	54957180	19730530	40.16	2017
D	1.05E+08	6.32E+07	2.18E+08	60.24	852.40466
E	8.26E+07	46487872	40559412	56.28	1923
F	7.45E+07	34093256	4853926	45.77	2687
G	5.38E+07	18328876	5963519	34.04	994
H	5.60E+07	13205400	1006114	23.6	2081

80%	STOIIP (m3)	FOPT (20 years) (m3)	FWPT (20 years) (m3)	RF (%)	Breakthrough time (days)
A	1.68E+08	88759552	182391570	52.96	493
B	1.26E+08	7.73E+07	4.02E+08	61.46	519
C	1.37E+08	57957208	26927150	42.35	1954.8948
D	1.05E+08	6.32E+07	2.18E+08	60.24	852.40466
E	8.26E+07	46487872	40559412	56.28	1923
F	7.45E+07	34093256	4853926	45.77	2687
G	5.38E+07	19993270	9582390	37.14	990
H	5.60E+07	15582275	1473149	27.84	2290

60%	STOIIP (m3)	FOPT (20 years) (m3)	FWPT (20 years) (m3)	RF (%)	Breakthrough time (days)
A	1.68E+08	91764520	191932420	54.76	742
B	1.26E+08	7.73E+07	4.02E+08	61.46	519
C	1.37E+08	64245012	40672780	46.95	2173
D	1.05E+08	6.32E+07	2.18E+08	60.24	852.40466
E	8.26E+07	46487872	40559412	56.28	1923
F	7.45E+07	34093256	4853926	45.77	2687
G	5.38E+07	23720114	24592296	44.06	946
H	5.60E+07	21120554	4635872.5	37.74	2615

0%	STOIIP (m3)	FOPT (20 years) (m3)	FWPT (20 years) (m3)	RF (%)	Breakthrough time (days)
A	1.68E+08	100058620	246259460	59.71	750
B	1.26E+08	7.73E+07	4.02E+08	61.46	519
C	1.37E+08	78082608	66093648	57.06	2899
D	1.05E+08	6.32E+07	2.18E+08	60.24	852.40466
E	8.26E+07	46487872	40559412	56.28	1923
F	7.45E+07	34093256	4853926	45.77	2687
G	5.38E+07	30557366	47070844	56.76	1227
H	5.60E+07	29364928	11159038	52.47	2805

Table D 2: Production results from 100% to 0% barrier coverage for the 4 km LD, 4km well spacing.

			RLD		
100%	STOIIP (m3)	FOPT (20 years) (m3)	FWPT (20 years) (m3)	RF (%)	Breakthrough time 1% WCT (days)
A	1.68E+08	329518.63	55.773899	0.20	8030
B	1.26E+08	7.73E+07	2.41E+08	61.46	990
C	1.37E+08	248294.47	26.87974	0.18	8030
D	1.05E+08	6.16E+07	8.62E+07	58.72	1518
E	8.26E+07	44881828	17986916	54.33	3006
F	7.45E+07	24615658	131327.84	33.05	5797
G	5.38E+07	109203.64	21.57424	0.20	8030
H	5.60E+07	113979.71	14.350454	0.20	8030

95%	STOIIP (m3)	FOPT (20 years) (m3)	FWPT (20 years) (m3)	RF (%)	Breakthrough time (days)
A	1.68E+08	66628924	61989780	39.76	543
B	1.26E+08	7.73E+07	2.41E+08	61.46	990
C	1.37E+08	15264889	5842.0801	11.15	8030
D	1.05E+08	6.16E+07	8.62E+07	58.72	1518
E	8.26E+07	44881828	17986916	54.33	3006
F	7.45E+07	24615658	131327.84	33.05	5797
G	5.38E+07	2533972.8	497.36218	4.71	8030
H	5.60E+07	1765888.7	230.38922	3.16	8030

90%	STOIIP (m3)	FOPT (20 years) (m3)	FWPT (20 years) (m3)	RF (%)	Breakthrough time (days)
A	1.68E+08	73760848	81487792	44.01	734
B	1.26E+08	7.73E+07	2.41E+08	61.46	990
C	1.37E+08	27721068	218379.59	20.26	5332
D	1.05E+08	6.16E+07	8.62E+07	58.72	1518
E	8.26E+07	44881828	17986916	54.33	3006
F	7.45E+07	24615658	131327.84	33.05	5797
G	5.38E+07	4939710.5	1188.7393	9.18	8030
H	5.60E+07	3099588.2	397.92566	5.54	8030

85%	STOIIP (m3)	FOPT (20 years) (m3)	FWPT (20 years) (m3)	RF (%)	Breakthrough time (days)
A	1.68E+08	80994288	95631976	48.33	848
B	1.26E+08	7.73E+07	2.41E+08	61.46	990
C	1.37E+08	36706836	926337.5	26.82	4438
D	1.05E+08	6.16E+07	8.62E+07	58.72	1518
E	8.26E+07	44881828	17986916	54.33	3006
F	7.45E+07	24615658	131327.84	33.05	5797
G	5.38E+07	7205130	2515.6687	13.38	8030
H	5.60E+07	4285824.5	544.802	7.66	8030

80%	STOIIP (m3)	FOPT (20 years) (m3)	FWPT (20 years) (m3)	RF (%)	Breakthrough time (days)
A	1.68E+08	84536064	107697250	50.44	914
B	1.26E+08	7.73E+07	2.41E+08	61.46	990
C	1.37E+08	42773676	2468419	31.26	3808
D	1.05E+08	6.16E+07	8.62E+07	58.72	1518
E	8.26E+07	44881828	17986916	54.33	3006
F	7.45E+07	24615658	131327.84	33.05	5797
G	5.38E+07	9511005	9237.96	17.67	7552
H	5.60E+07	5427961	695.0072	9.70	8030

60%	STOIIP (m3)	FOPT (20 years) (m3)	FWPT (20 years) (m3)	RF (%)	Breakthrough time (days)
A	1.68E+08	90226696	141608340	53.84	1243
B	1.26E+08	7.73E+07	2.41E+08	61.46	990
C	1.37E+08	57338176	12658811	41.90	3092
D	1.05E+08	6.16E+07	8.62E+07	58.72	1518
E	8.26E+07	44881828	17986916	54.33	3006
F	7.45E+07	24615658	131327.84	33.05	5797
G	5.38E+07	16934870	564546.63	31.45	4821
H	5.60E+07	9367926	1165.6111	16.74	8030

0%	STOIIP (m3)	FOPT (20 years) (m3)	FWPT (20 years) (m3)	RF (%)	Breakthrough time (days)
A	1.68E+08	100651540	204014290	60.06	1058
B	1.26E+08	7.73E+07	2.41E+08	61.46	990
C	1.37E+08	77176056	42235552	56.40	3071.8948
D	1.05E+08	6.16E+07	8.62E+07	58.72	1518
E	8.26E+07	44881828	17986916	54.33	3006
F	7.45E+07	24615658	131327.84	33.05	5797
G	5.38E+07	29365372	7834212	54.54	3978
H	5.60E+07	17429024	2175.3826	31.14	8030

Table D 3: Production results from 100% to 0% barrier coverage for the RLD, 1km well spacing.

			5 Spot pattern		
100%	STOIIP (m3)	FOPT (20 years) (m3)	FWPT (20 years) (m3)	RF (%)	Breakthrough time 1% WCT (days)
A	1.68E+08	329520.56	55.257599	0.2	8030
B	1.26E+08	7.47E+07	1.29E+08	59.26	1520
C	1.37E+08	248207.97	26.32769	0.18	8030
D	1.05E+08	6.06E+07	5.75E+07	57.72	2133
E	8.26E+07	45177832	13700955	54.69	3730
F	7.45E+07	16617132	10206.891	22.3	8030
G	5.38E+07	109204.06	21.381542	0.2	8030
H	5.60E+07	113983.11	13.990121	0.2	8030

95%	STOIIP (m3)	FOPT (20 years) (m3)	FWPT (20 years) (m3)	RF (%)	Breakthrough time (days)
A	1.68E+08	69113304	63920852	41.14	485
B	1.26E+08	7.47E+07	1.29E+08	59.26	1520
C	1.37E+08	10519943	1150.1381	7.68	8030
D	1.05E+08	6.06E+07	5.75E+07	57.72	2133
E	8.26E+07	45177832	13700955	54.69	3730
F	7.45E+07	16617132	10206.891	22.3	8030
G	5.38E+07	1825302	357.98633	3.39	8030
H	5.60E+07	1357732.8	174.11981	2.42	8030

90%	STOIIP (m3)	FOPT (20 years) (m3)	FWPT (20 years) (m3)	RF (%)	Breakthrough time (days)
A	1.68E+08	76666248	91558416	45.63	669
B	1.26E+08	7.47E+07	1.29E+08	59.26	1520
C	1.37E+08	19233404	6177.165	14.04	8030
D	1.05E+08	6.06E+07	5.75E+07	57.72	2133
E	8.26E+07	45177832	13700955	54.69	3730
F	7.45E+07	16617132	10206.891	22.3	8030
G	5.38E+07	3437917.8	673.91663	6.39	8030
H	5.60E+07	2315768.5	290.17484	4.14	8030

85%	STOIIP (m3)	FOPT (20 years) (m3)	FWPT (20 years) (m3)	RF (%)	Breakthrough time (days)
A	1.68E+08	80149688	106094030	47.71	734
B	1.26E+08	7.47E+07	1.29E+08	59.26	1520
C	1.37E+08	26461232	84196.055	19.31	6337
D	1.05E+08	6.06E+07	5.75E+07	57.72	2133
E	8.26E+07	45177832	13700955	54.69	3730
F	7.45E+07	16617132	10206.891	22.3	8030
G	5.38E+07	4979141.5	960.13867	9.25	8030
H	5.60E+07	3175400.5	395.47354	5.67	8030

80%	STOIIP (m3)	FOPT (20 years) (m3)	FWPT (20 years) (m3)	RF (%)	Breakthrough time (days)
A	1.68E+08	83172544	115925900	49.51	764
B	1.26E+08	7.47E+07	1.29E+08	59.26	1520
C	1.37E+08	31785144	272088.56	23.2	5597
D	1.05E+08	6.06E+07	5.75E+07	57.72	2133
E	8.26E+07	45177832	13700955	54.69	3730
F	7.45E+07	16617132	10206.891	22.3	8030
G	5.38E+07	6632754	1307.3433	12.33	8030
H	5.60E+07	4022002.5	503.63425	7.18	8030

60%	STOIIP (m3)	FOPT (20 years) (m3)	FWPT (20 years) (m3)	RF (%)	Breakthrough time (days)
A	1.68E+08	89878168	145093200	53.5	1030
B	1.26E+08	7.47E+07	1.29E+08	59.26	1520
C	1.37E+08	46654288	1619653.1	34.05	4755
D	1.05E+08	6.06E+07	5.75E+07	57.72	2133
E	8.26E+07	45177832	13700955	54.69	3730
F	7.45E+07	16617132	10206.891	22.3	8030
G	5.38E+07	12627558	7972.4102	23.47	7374
H	5.60E+07	7060900.5	859.02698	12.61	8030

0%	STOIIP (m3)	FOPT (20 years) (m3)	FWPT (20 years) (m3)	RF (%)	Breakthrough time (days)
A	1.68E+08	101594910	198436820	60.47	1189
B	1.26E+08	7.47E+07	1.29E+08	59.26	1520
C	1.37E+08	71348792	7112287	52.08	4911
D	1.05E+08	6.06E+07	5.75E+07	57.72	2133
E	8.26E+07	45177832	13700955	54.69	3730
F	7.45E+07	16617132	10206.891	22.3	8030
G	5.38E+07	26177700	478191.38	48.66	5906
H	5.60E+07	13714302	1672.167	24.49	8030

Table D 4: Production results from 100% to 0% barrier coverage for the 5 spot pattern, 500m well spacing.