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Impact of stratigraphic heterogeneity on hydrocarbon recovery in carbonate reservoirs: Effect of fluid properties and development strategy

By

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DECLARATION OF OWN WORK

I declare that this thesis

"**Impact of stratigraphic heterogeneity on hydrocarbon recovery in carbonate reservoirs: Effect of fluid properties and development strategy**"

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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Impact of stratigraphic heterogeneity on hydrocarbon recovery in carbonate reservoirs: Effect of fluid properties and development strategy

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Abstract

Carbonate reservoirs have been widely recognized to have economic importance and to present some of the largest oil field around the world, mainly in the Middle East. However, the complex heterogeneities control the productivity of carbonate reservoirs, explaining the average recovery factor obtained (Montaron, 2008). By evaluating the importance of the stratigraphic heterogeneities on productivity of carbonate reservoirs, according data acquisition and reservoir modeling program can be proposed to effectively focus into the most significant heterogeneities affecting future reservoir performance.

This study investigates the production performance sensitivity to stratigraphic heterogeneities in carbonate ramp reservoirs, using geologic models from an on-going project. The stratigraphic heterogeneities analyzed include the heterogeneities which represent the spatial distribution of rock units and the associated rock properties in carbonate reservoirs. A suite of geological models integrating the stratigraphic heterogeneities were developed and their impact on fluid flow under horizontal flow profile was assessed (Fitch et al., 2012). This study is extended from the work of Fitch et al. (2012) and focuses on a different production strategy which improves vertical flow profile. The impact of the geological heterogeneities on recovery factor and oil production of each model was quantified; and the factor affecting the heterogeneity impact on reservoir performance such as different rock, fluid properties and well placement were considered.

The results of this work indicate the barriers along sequence boundary and rock properties of the environment of deposition (EOD) are the most important factors controlling fluid flow. EOD-belt interfingering length and EOD-belt geometry are identified as the intermediate parameters affecting flow. It also shows that the mobility ratio, relative permeability and capillary pressure model and well spacing affect oil recovery but do not affect the heterogeneity ranking on fluid flow. The quantification of the stratigraphic heterogeneity effect on fluid flow highlights the main factors to be focused on in reservoir characterization plan and analysis.

Introduction

Carbonate reservoirs host significant hydrocarbon resources worldwide, containing 60% of the world's oil and 40% of the world's gas reserves; they are especially significant in the Middle-East Gulf region (Montaron, 2008). Despite their economic importance, carbonate reservoirs present a complex architecture in all scales, from pore networks and various scales of petrophysical heterogeneity associated with stratigraphic cyclicity, facies distribution and diagenesis (Pranter et al., 2006). Because of the complexity in predicting these heterogeneities, carbonate reservoirs remain a major challenge today for reservoir developing projects.

Recent field development programs for carbonate reservoirs have clearly heightened the need for a better understanding of the impact of the heterogeneities existing in carbonate reservoirs on flow, especially over different rock, fluid properties and development strategies. A number of studies for the siliciclastic counterpart have investigated the degree to which stratigraphic architecture influences recovery efficiency, including connectivity and continuity, permeability heterogeneity, permeability anisotropy and fluid types (Larue & Friedmann, 2005). In carbonate reservoirs, a large number of past studies have focused on the heterogeneities which are specific to the carbonate reservoirs of interest. For example, Hollis et al. (2011) assessed the impact of combined subsurface parameters such as porosity and permeability, permeability anisotropy, fracture distribution, relative permeability and imbibition capillary pressure curves on future reservoir production, specific to a carbonate field in Oman. The integrated characterization and flow modeling of carbonate reservoirs have also been widely discussed, as applied to the investigated carbonate fields (Bard et al., 1995; O'Hanlon et al., 1996; Abbaszadeh et al., 2010). An integrated study to capture all types and scales of heterogeneities present in carbonate reservoirs and apply in flow modeling is therefore lacking.

In the attempt to bridge the gap in integrating a full length-scale based hierarchy of heterogeneity in carbonate ramp reservoirs, Fitch et al. (2012) established a hierarchy framework to identify and classify geologic heterogeneities from a large number of published outcrop examples. It details the architecture, geometry and spatial distribution of stratigraphic, sedimentological and diagenetic heterogeneities from carbonate ramp outcrops around the world (Fitch et al., 2012). The work not only provides a guideline to the architecture, geometry and distribution of different heterogeneities, the hierarchy was also applied to assess the impact of these heterogeneities on reservoir performance and likely recovery of carbonate ramps. To understand the impact of stratigraphic heterogeneities on fluid flow at hierarchy levels 1-3 (Fitch et al., 2012), a suite of models were constructed combining six different stratigraphic heterogeneities at two end-member settings (Fitch et al., 2012). Flow simulation and experimental design technique were used to quantify the impacts of these stratigraphic heterogeneities on fluid flow for waterflood displacement between vertical wells. Different fluids, rock properties and development strategies were examined for the variation in the heterogeneity impacts. Fitch et al. (2012) demonstrated that under the studied level of hierarchy, rock properties of EOD-belts and the stratigraphic architecture / geometry heterogeneities were the most important factors controlling production in carbonate reservoir.

This work builds on this investigation of Fitch et al. (2012) and aims to examine the impact of stratigraphic heterogeneities on fluid flow in carbonate reservoirs, using the same suite of simulation models constructed in Fitch et al. (2012) under different production profile. Fitch et al. (2012) focused on horizontal flow profile water flooding, in which the wells are completed over the whole reservoir intervals. The horizontal profile less accounts for the heterogeneity parameters such as the laterally carbonate-cemented layers and the permeability anisotropy was found to be of low influence on flow. By incorporating an aquifer into the simulation models, vertical flow profile can be established with injection wells are completed down into the water zone. A parallel heterogeneity ranking with Fitch et al. (2012) under vertical flow profile can be analysed with similar reservoir parameters and development options. Such study allows the comparison of heterogeneity impacts on flow under different production settings.

Thus the objectives of this project are: (1) to investigate and quantify the impacts of different stratigraphic heterogeneities on fluid flow in carbonate reservoirs using production strategies which enhance the potential for vertical flow, (2) to investigate and quantify the effects of different fluid, rock properties and well placement on the ranking of stratigraphic heterogeneities and (3) to compare and contrast the ranking of stratigraphic heterogeneities on flow under different production settings.

Literature review

This section introduces the key stratigraphic heterogeneities examined in this study, the constructed geologic models and the methodology to quantify the effects of stratigraphic heterogeneities on flow by Fitch et al. (2012).

Stratigraphic heterogeneities

The six stratigraphic heterogeneities detailed below were chosen to investigate as key controls on geometry, architecture and spatial arrangement of the environment of deposition belts (EOD-belts) in carbonate ramp reservoirs (Fitch et al., 2012). Two end-members (i.e. setting A and setting B) were chosen to represent the ranges of values for each heterogeneity, and are summarized in Table 1. The stratigraphic heterogeneities were studied and constrained from a large number of published literatures from carbonate ramp outcrops around the world.

Interfingering length of EOD-belts: Interfingering length of EOD-belts describes basinward movements of the environments of deposition between two sequence boundaries (Fitch et al., 2012). If the rate of sediment production is greater than the rate of sea-level rise, then the belts migrate into the basin with time (progradation). As the rate of sediment increases, the belts migrate further. The two settings for EOD-belt interfingering length used in the geologic models are 8km (short interfingering length) and 24km (long interfingering length). The shorter interfingering length is typically associated with increased lateral thickness variation, of thicker EOD-belts.

Geometry of EOD-belts: Geometry of EOD-belts exhibits a progradational or retrogradational architecture, related to the rate of sea-level rise cycles and the rate of sediment deposition. As described, progradation occurs when the rate of sediment deposition is greater than the rate of sea-level rise. 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 A represents only progradation between sequence boundaries, while setting B represents the complex geometry where both retrogradation and progradation are present.

Rock properties of EOD-belts: Rock properties of EOD-belts account for the types of lithology and sediment deposition within EOD-belts. Rock properties were obtained from a proprietary dataset and are applied to the individual EOD-belts (Fitch et al., 2012). Rock properties of individual EOD-belt are uniform throughout the geologic models. Setting A for EOD-belt rock properties represents a grain-dominated ramp system, with high porosity and permeability values, while setting B represents a mud-dominated ramp, with low porosity and permeability values.

Anisotropy of EOD-belt permeability: Anisotropy of EOD-belt permeability examines the variation of permeability with direction. Setting A corresponds to isotropic reservoir where vertical permeability and horizontal permeability are equal (k_v/k_h=1). In setting B, the k_v/k_h ratio ranges from 0.1 to 0.45 depending on different EOD-belts (i.e. in mid ramp of good reservoir quality, or outer and inner ramp of poorer reservoir quality). This permeability anisotropy accounts for the intercalation of thin, laterally continuous bodies of mud- and grain-dominated depofacies (Fitch et al., 2012).

Interfingering of EOD-belt boundaries: Interfingering of EOD-belt boundaries represents the transition between two individual EOD-belts. In setting A, the boundary is sharp, representing a distinct change between EODs. For setting B, the boundary is characterised as three transitional zones where rock properties are averaged values from neighbouring EOD-belts

(Fitch et al., 2012). Setting B reflects smaller scale heterogeneities, e.g., the interfingering of depofacies units within EOD-belts, or uncertainty in the location of the boundary.

Petrophysical properties of sequence boundaries: Sequence boundaries can either act as simple framework features within the geologic model, with no associated petrophysical properties (setting A), or may act as barriers to vertical flow (setting B). This sequence boundary barrier is laterally extensive (Fitch et al., 2012). A decrease in the porosity and permeability at sequence boundaries can result from bioturbation and cementation process (e.g., formation of a hard- or firmground, Christ et al., 2012). Setting B is characterised by a 10-cm-thick zone with decreased porosity and permeability which extends laterally the whole model, representing 10% the properties of the underlying EOD-belt. Additionally, transmissibility multipliers of zero are assigned for the sequence boundary so that no vertical flow can occur across the boundary.

Table 1: Summary of stratigraphic heterogeneities investigated (After Fitch et al., 2012)

	Heterogeneity	Setting A (Low case)	Setting B (High case)
1	Interfingering length of EOD-belts	8 km	24km
2	Geometry of EOD-belts	Progradation only	Retrogradation-progradation
3	Rock properties of EOD-belts	High (grain-dominated)	Low (mud-dominated)
4	Anisotropy of EOD-belt permeability	Isotropic ($k_v/k_h = 1$)	Anisotropic ($k_v/k_h < 1$)
5	Petrophysical properties of sequence boundaries	None	Vertical flow barrier
6	Interfingering of EOD-belt boundaries	Sharp	Transitional over 300 m

Geologic models

Different combinations of the above stratigraphic heterogeneities with low and high settings were incorporated into eight geologic models. Fitch et al. (2012) used a fractionation factorial experimental design (White and Royer, 2003) to determine the number of models and their combinations of heterogeneities, allowing a practical number of models to be investigated. A two-level full factorial design includes all possible combinations of the factors and would be robust; however it entails 2^6 models to be constructed, which is excessive for the study. The combinations of different stratigraphic heterogeneities presented in eight geologic models are illustrated in Fig. 1 and the heterogeneity settings of eight geologic models, defined by experimental design are further shown in Table 2.

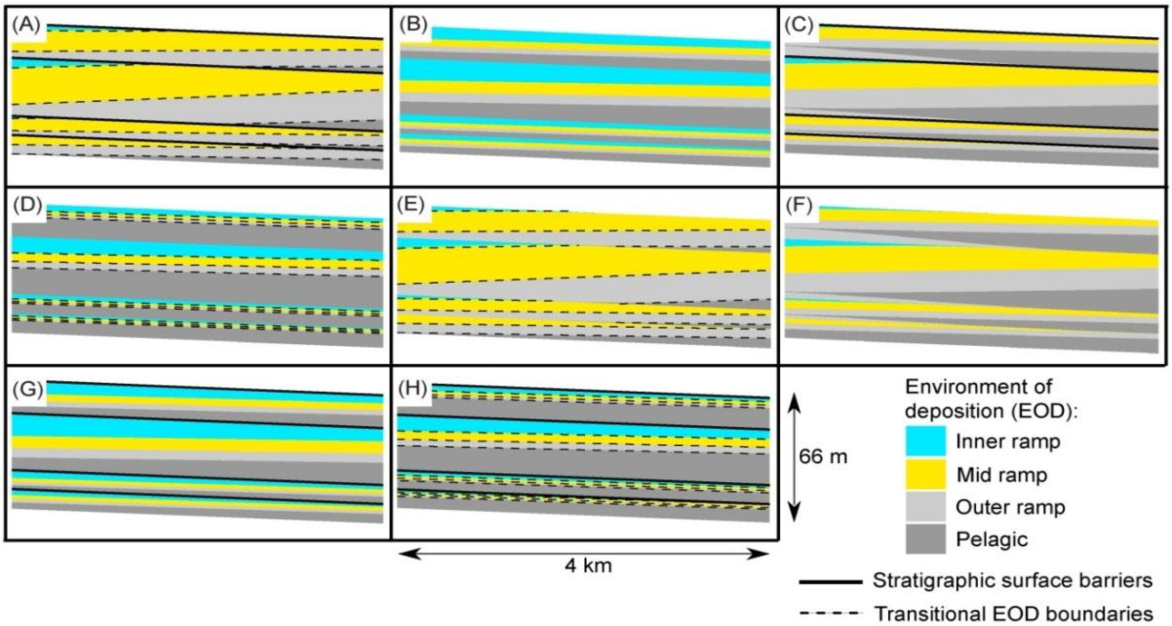

Fig. 1: 2- D cross-sections showing the combinations of six stratigraphic heterogeneities incorporated into eight models (A–H) (Fitch et al., 2012)

Different features of stratigraphic heterogeneities can be observed in Fig. 1. Models A, C, E and F with short interfingering length (setting A of heterogeneity 1, Table 1) show a greater variation in thickness between EOD-belts while models B, D, G and H with long interfingering length (setting B of heterogeneity 1, Table 1) show a more layer-cake geometry with limited thickness variation between EOD-belts. A greater portion of mid ramp with high quality rock properties can be noticed dominating models A, C, E, and F with short interfingering length while a smaller portion of mid ramp are identified in models B, D, G and H. Retrogradation-progradation of EOD-belt geometry (Heterogeneity 2, Table 1) is only obvious in models E and F (Fig. 1), however this also occurs to models D and H (Table 2). Transitional EOD-belt boundaries

(Heterogeneity 6, Table 1) can be observed in models A, D, E, H while flow barriers along sequence boundary (Heterogeneity 5, Table 1) which separate mid and inner ramp of good reservoir quality from the poorer quality EOD-belts are observed in models A, C, G and H. The full description of the characteristics of each model is referred to the work of Fitch et al. (2012).

Table 2: Heterogeneity settings incorporated into the geologic models (After Fitch et al., 2012)

		Model runs							
	Factors	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**
1	Interfingering length of EOD-belts	A	B	A	B	A	A	B	B
2	Geometry of EOD-belts	A	A	B	B	A	B	A	B
3	Rock properties of EOD-belts	A	A	A	A	B	B	B	B
4	Anisotropy of EOD-belt permeability	A	B	B	A	B	A	A	B
5	Petrophysical properties of sequence boundaries	B	A	B	A	A	A	B	B
6	Interfingering of EOD-belt boundaries	B	A	A	B	B	A	A	B

The main effects of the six heterogeneities on fluid flow and their ranking were analyzed. The reservoir performance criteria (i.e. responses in experimental design) used in the analysis are total oil and water production, recovery factor, water cut total at 20 years and time to water breakthrough (defined as 1% water cut in the study). Experimental design quantifies the effects of each heterogeneity on reservoir performance.

Flow simulation methodology

This section presents the flow simulation part of the project, including the flow simulation model, rock and fluid properties and development strategies adopted from Fitch et al. (2012), together with the completion design used in the work.

Flow simulation models

3D models were constructed to demonstrate the combinations of the above mentioned stratigraphic heterogeneities (Fig. 2). The total model size is uniform 4km x 4km laterally and 66 meters vertically. The reservoir simulation model consists of 98-129 active layers depending on the models. The increasing number of layers corresponds to models containing EOD-belt boundaries with retrogradational-progradational geometries (setting B of heterogeneity 2, Table 1) and barriers along sequence boundaries (setting B of heterogeneity 5, Table 1). The number of grid cells varies from 352,800 to 464,400 and each grid cell has dimensions of 67m x 67m x 0.5-0.67m. Flow simulations were performed using the ECLIPSE 100 blackoil simulator.

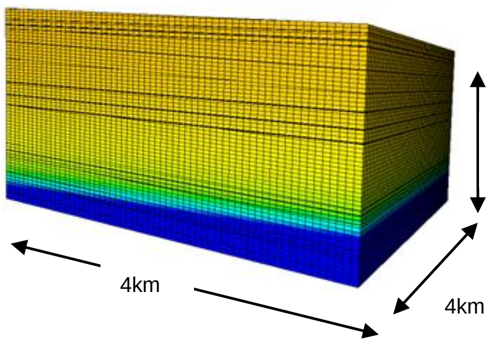

Fig. 2: Flow simulation model

Rock and fluid properties

Two relative permeability and capillary pressure models were investigated: (1) single curve set of relative permeability (k_r) and capillary pressure (P_c) is applied for the whole model; and (2) multiple sets of relative permeability and capillary pressure are applied for different rock types. The variability of wettability in carbonate reservoirs suggests that using a single curve set of k_r and P_c is not suitable (Masalmeh et al., 2005). Moreover, the choice of relative permeability and capillary pressure data used in production simulations has been shown to have significant impact on performance results (Hollis et al., 2011). Multiple sets of k_r and P_c facilitate more accurate performance predictions of the reservoir by capturing the distribution of rock types. In the study, multiple sets of k_r and P_c measurements were assigned to individual rock types (of <10 mD, 10-100mD, and >100mD) (Fitch et al., 2012). Fig. 3 shows the relative permeability and capillary pressure curves used for the two rock models (i.e. using one drainage curve and one single imbibition curve or using one drainage curve and multiple imbibition curve sets). Different approaches of modeling relative permeability and capillary pressure allow the investigation of the impact of the rock models on the ranking of the stratigraphic heterogeneities on fluid flow.

Two mobility ratios were examined: (1) mobility ratio of 0.92 (which shows a favourable condition - oil viscosity of 0.52 c.p.) and (2) mobility ratio of 7.22 (which shows a more unfavourable condition - oil viscosity of 4.0 c.p). The end-point mobility ratio of the displacing phase (water) to displaced phase (oil) was shown to have a significant impact on hydrocarbon recovery during waterflood (Larue & Friedman, 2005). The favourable and unfavourable mobility ratios allow the investigation of how end-point mobility ratio affects the impact of stratigraphic heterogeneities on fluid flow in carbonate reservoirs (Fitch et al., 2012).

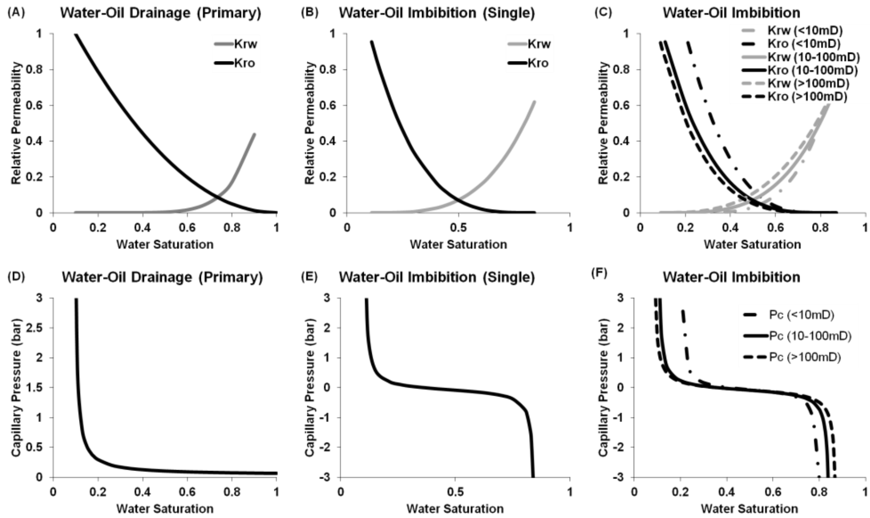

Fig. 3: Relative permeability (A-C) and capillary pressure curves (D-F) used in simulation experiments: primary water-oil drainage curves (A, D); single set of water-oil imbibition curves (B, E); and multiple water-oil imbibition curves (C, F) (Fitch et al., 2012)

Well spacing and well placement

Well spacing of 4km, 1km and 500m were investigated respectively to examine the impact of well spacing and well placement types on the stratigraphic heterogeneity ranking on waterflood performance. Fig. 4 shows the plan view of the well placement investigated, including 4km line drive, 1km repeat line drive and 500m five-spot pattern. The numbers of vertical wells and the ratios of producers to injectors were varied; however a constant pressure gradient between producers and injectors was maintained across the three different well placement schemes (Fitch et al., 2012). The bottom hole pressure (BHP) of injection and production wells were controlled to maintain a pressure gradient of 0.11 bars/m (favourable condition) - 0.45 bars/m (unfavourable condition). Table 3 summarizes the BHP constraints for the three well placement schemes. It should be noted that the large 4km well spacing is impractical in reality and the resulted BHP of the injector with unfavourable mobility ratio to maintain the specified pressure gradient is unrealistically high. However, this field development option was considered in our study to examine the impact of heterogeneities on fluid flow using different rock and fluid properties.

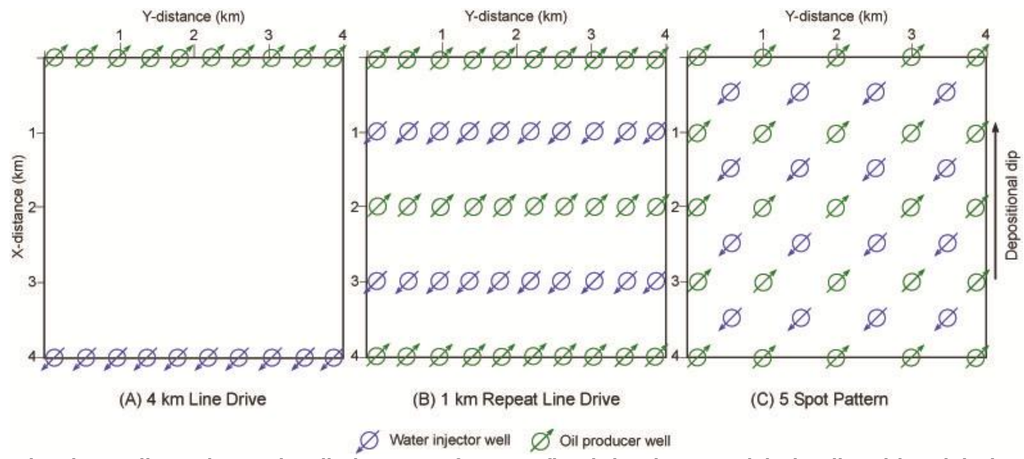

Fig. 4: Plan view showing well spacing and well placement for waterflood development (A) 4km line drive, (B) 1km repeat line drive and (C) 500m five-spot pattern (Fitch et al., 2012)

Table 3: Well spacing and bottom hole pressure limits for the simulated production scenarios, using two end-point mobility ratios. (After Fitch et al., 2012)

	Well spacing (m)	Injector BHP (bars)		Producer BHP (bars)
		Favourable	Unfavourable	
(A) Line drive	4000	623	1963	152
(B) Repeat line drive	1000	270	605	152
(C) Five-spot pattern	500	235	468	152

Well completion

The effects of stratigraphic heterogeneities on carbonate reservoir performance using horizontal flow profile have been assessed in the work of Fitch et al. (2012). In their work, the OWC was established below the simulation models and the injection and production wells were completed across the whole model thickness. The perforated open area to fluid flow across the whole model created a horizontal water-oil sweeping profile from the injector to producer, as shown in Fig. 5a. In practice, this completion design is not always applied in many developing options. In this study, we concentrate on accounting for vertical flow profile of water flooding and comparing the heterogeneity ranking on fluid flow using the same suite of simulation models by Fitch et al. (2012). The vertical flow profile was established for the simulation models by: (1) integrating an aquifer as part of the models (2) partially completing the production wells from top of the oil zone and the injection wells from top of the oil-water contact (OWC). The open section of fluid entry from the injection well to the production well creates a vertical water-oil sweeping profile (Fig. 5b).

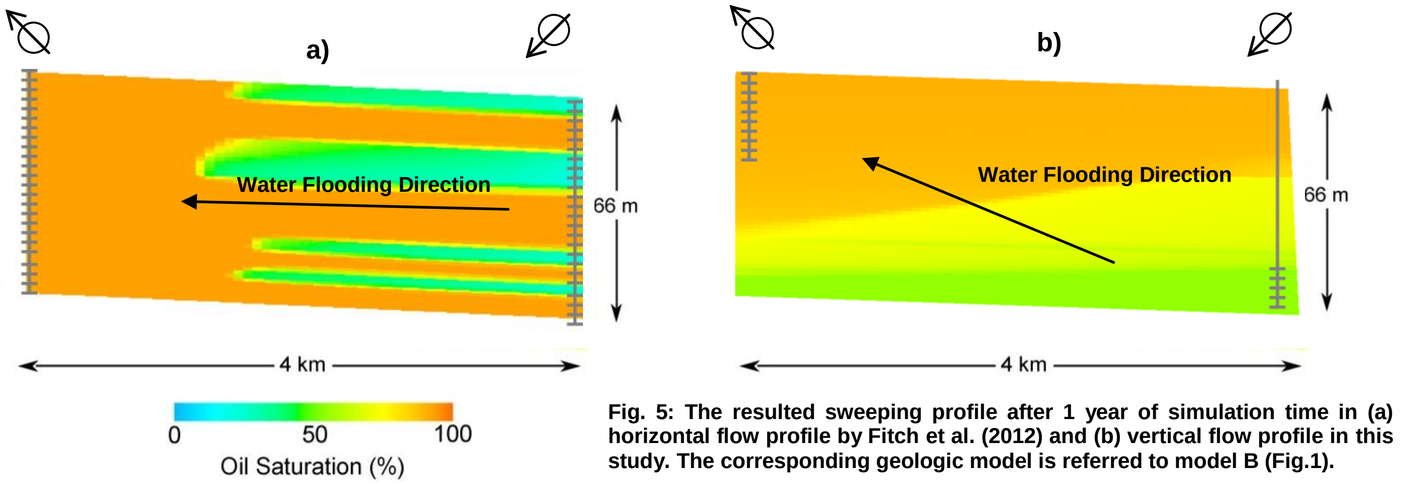

Fig. 5: The resulted sweeping profile after 1 year of simulation time in (a) horizontal flow profile by Fitch et al. (2012) and (b) vertical flow profile in this study. The corresponding geologic model is referred to model B (Fig.1).

An aquifer was firstly integrated into the simulation model and its thickness would be justified after choosing the oil zone completion. Simulation was set up with water injection into the aquifer (Fig. 6). Simulation was then run for the model with different completion thickness from top of the oil zone, applying to different well placement such as 4km line drive, 1km repeat line drive and 500m five-spot pattern, thus a range of production rates and cumulative oil and water volumes over the simulation time were derived. Fig. 7 presents the simulated oil and water production when varying the completion thickness of the producing zone. It shows that the production results for three well placement types are not sensitive to the thickness of producing intervals from 10m to 16m thick. Increasing production depth from 10m to 16m results in a very slight change in the oil production and water production (with less than 0.1% difference), applied to all well placements of 4km line drive, 1km repeat line drive and 500m five-spot pattern. The completion thickness of 16m from top of the oil zone was chosen where field oil production total at 20 years starts to reduce and field water production total at 20 years starts to rise when increasing the completion thickness. Additionally, the 16m perforation intervals target the good quality EOD-belts which are present in the top half of the geologic models (Fig. 1).

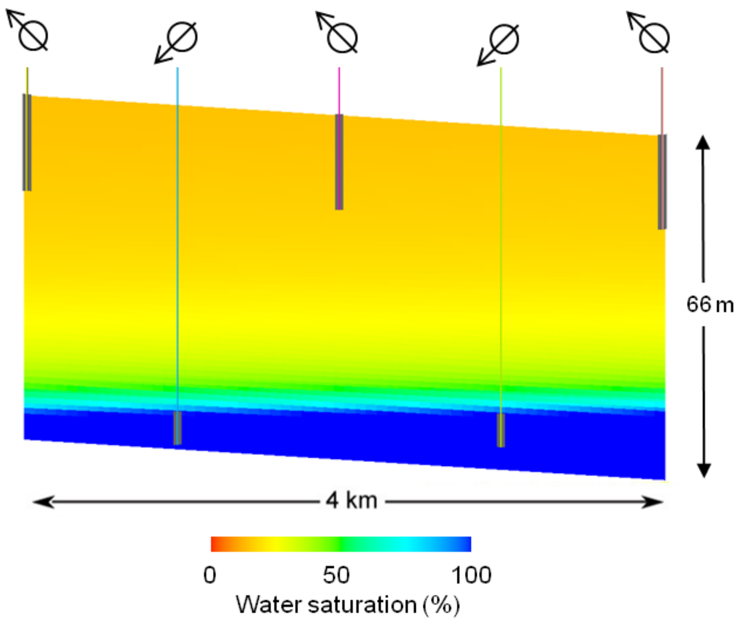

Fig. 6: 2D depositional dip section through the center of a representative simulation model, showing water saturation at the start of simulation. OWC is established. Production perforation is from top of the model and injection perforation is from OWC down to the aquifer.

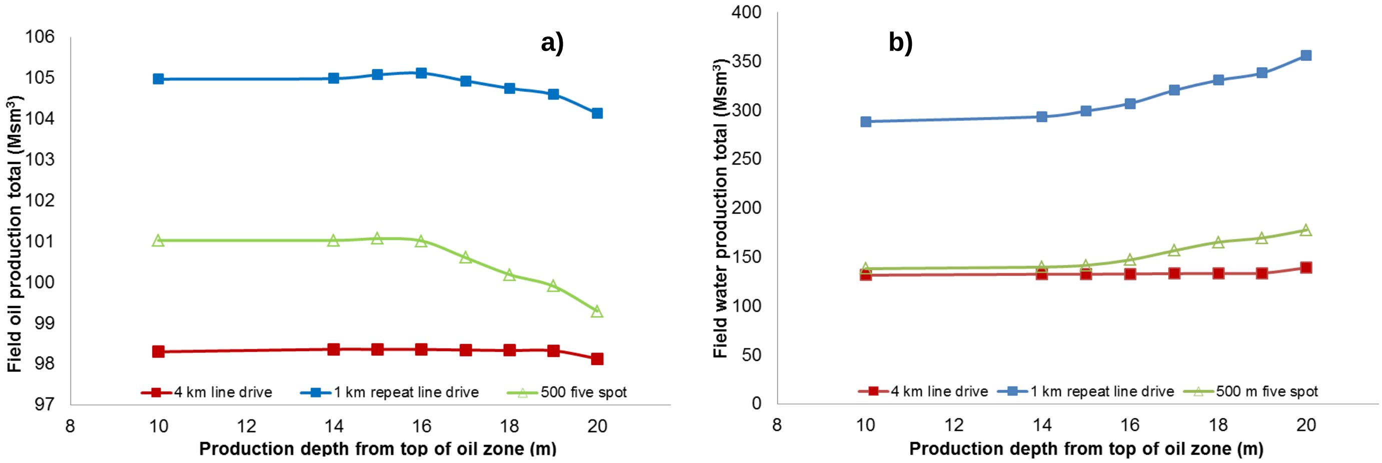

Fig. 7: Sensitivity of production zone to Field oil production total after 20 years (a) and Field water production total after 20 years (b)

The next step was to determine an aquifer thickness to apply to all flow simulation models. Sensitivity runs were carried out with the selected 16m completion of producing zone and three cases of 5-, 7- and 10-m aquifer thickness were examined to study the sensitivity of injection thickness to field production. All of the models could maintain the required BHP and the required pressure gradient. Fig. 8 further shows the resulted oil production and water production at 20 years with different aquifer thickness. It can be noticed that oil production at 20 years increases and water production at 20 years decreases with a reduced injection interval (Fig. 8). Water production with 10m injection interval is nearly doubled compared to 5m injection interval; therefore 5m injection interval from OWC was chosen to apply in our simulation models.

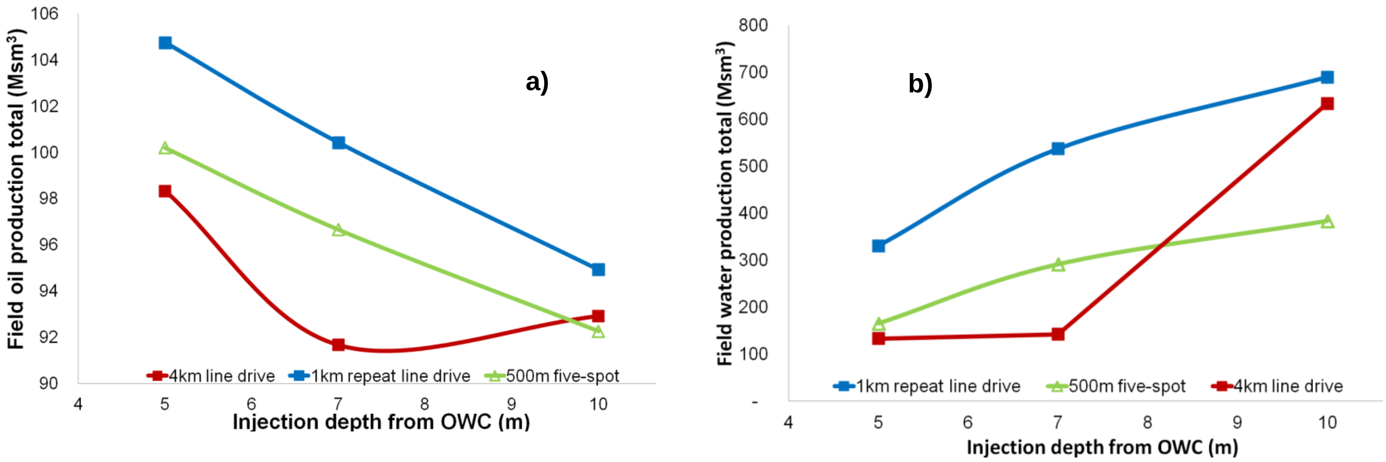

Fig. 8: Sensitivity of injection zone to Field oil production total after 20 years (a) and Field water production total after 20 years (b). All of the production perforations are 16-meter thick.

Hence all of the models were flow simulated with a uniform completion setting. Vertical water flooding was yielded, therefore allowing us to conduct a similar investigation with Fitch et al. (2012) to quantify the effects of heterogeneities on flow under various scenarios: (1) Different relative permeability and capillary pressure models are used; (2) Different fluid mobility ratios are used; and (3) Different well spacing and well placement types are used.

Results

Fig. 9 shows the simulation results for the case in which reservoir rock properties are represented by one set of relative permeability and capillary pressure curves; with a favourable mobility condition and 4km line drive. Throughout the work, the performance criteria such as field oil production total (FOPT), recovery factor (RF), field water production total (FWPT) and field water cut total (FWCT) are referred to the simulated results at 20 years. The variation in production results, as can be seen in Fig. 9, demonstrates that stratigraphic heterogeneities impact on oil production. Furthermore, it is also apparent that there are two extremes in production which relates to the presence of the barriers along sequence boundary (Heterogeneity 5, Table 1). The sequence boundary barrier impacts strongly on oil production such that it divides the reservoir models into two groups: the first group of models which are characterized by the sequence boundary barriers to flow (models A, C, G and H – Table 1), and the second group of models without a sequence boundary barrier (models B, D, E and F – Table 1). In the former group, the oil recovery after 20 years is at low extreme because of early shut-in. The thin sequence boundary barrier acts as a barrier to vertical flow thus reservoir pressure was insufficient to produce at the required BHPs. Only the top most of the reservoir open to perforation was produced until all wells are shut (e.g., after 10 years for model A and the earliest shut-in is after 2.5 years for model H). Hence, cumulative oil recovered after 20 years for these models are less than 0.87 Msm^3 and the recovery factors are less than 0.51%. The water breakthrough had not occurred for these cases and the FOPT, FWPT, RF and FWCT at 20 years were obtained at the date of shut in. In the latter group, the reservoir models have no barrier to flow and could deliver a total oil volume of 17 - 74 Msm^3 and a RF of 42-58% at 20 years. The oil in place ranges from 18Msm^3 (Model H) to 172 Msm^3 (Model A). The variation in oil in place is characterized by a combination of different rock properties and stratigraphic architecture of EOD-belts, i.e. interfingering length and geometry. For example, the oil in place for the group of models A-D is greater than the group of models E-H, associated with the high petrophysical properties assigned to these models (Fitch et al., 2012). A long interfingering length of 24km and a retrogradation-progradation EOD-belt geometry decrease the proportion of the high rock quality mid-ramp EOD-belts in the models by 35-40% respectively (Fitch et al., 2012) and thus decrease the total pore volume and oil in place. As a result, within a group of models with barriers along sequence boundary, production decreases from model A to H as increasing in heterogeneity and complexity, for example oil production in model A is higher than model C, than model F and the lowest is model H. A similar trend can be identified within the group of models without flow barrier along the sequence boundary.

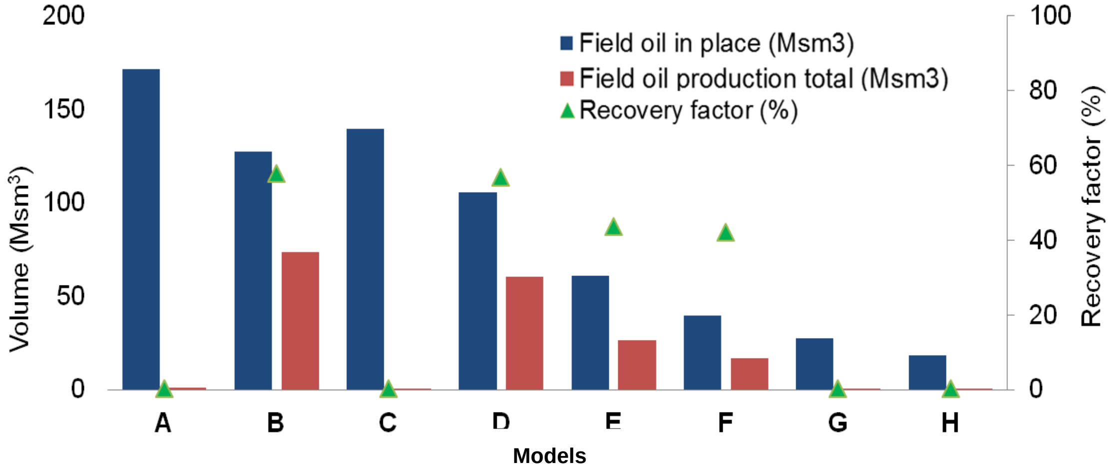

Fig. 9: Production results for all simulation models. The results are shown for field oil in place, field oil production total and recovery factor after 20 years.

Heterogeneity ranking

Sensitivity analysis examines the impact of each heterogeneity factor on the reservoir performance criteria (i.e. responses). Fig. 10 presents the sensitivity analysis carried out for the case in which reservoir rock properties are represented by one set of relative permeability and capillary pressure curve; with a favourable mobility ratio and a 4km line drive water flooding. The bar charts depict a negative or positive percentage change in a response compared to the averaged response of the suite of models when a heterogeneity factor varies from setting A to setting B. From the quantification of these effects, a ranking order of heterogeneity effects on each performance criteria is generated.

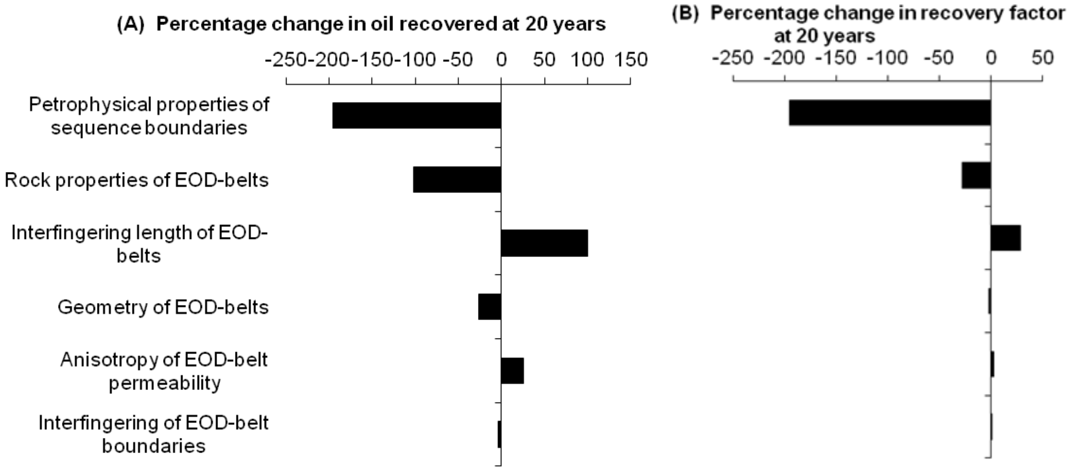

Fig. 10: Impact of six heterogeneities on A) oil recovered at 20 years, B) recovery factor at 20 years. Simulations with single imbibition curve set, favourable mobility ratio and 4km line drive.

As can be seen in Fig. 10, the ranking orders of heterogeneities which affect on cumulative oil production and recovery factor at 20 years are similar. It clearly shows that the most significant heterogeneity on all performance criteria is the petrophysical properties of sequence boundaries (Heterogeneity 5, Table 1), whereas the least important factor is the interfingering of EOD-belt boundaries (Heterogeneity 6, Table 1). Petrophysical properties of sequence boundaries has nearly the same effects on both oil recovered and recovery factor, which affects approximately 200% reduction in oil recovered and recovery factor compared to the average production results when this heterogeneity is changed from setting A (with no sequence boundary barrier) to setting B (with barrier along the sequence boundary). The 200% decrease in oil production is possible since this depicts the maximum percentage change in oil recovered compared to the average volume of oil recovered from all simulation models when sequence boundary barrier is switched from extreme setting A to extreme setting B. For example, in our study the high oil production result is predicted more than 200% of the averaged oil production, which makes it possible to reduce oil production by 200% compared to the averaged value. As can be noticed from the direction of the bars towards positive or negative side, a heterogeneity factor which reduces the oil recovered and recovery factor at 20 years also reduces the water production at 20 years and vice versa (except from EOD-belt boundary nature).

The second most important heterogeneity is the rock properties of EOD-belt (Heterogeneity 3, Table 1). Changing EOD-belt rock properties from setting A (high rock properties) to setting B (low rock properties) reduces the volume of cumulative oil produced at 20 years by approximately 100% and reduces the recovery factor by 28% respectively. Varying EOD-belt rock properties from setting A to setting B results in different percentage change in the oil recovered and percentage change in the recovery factor. Lower EOD-belt rock properties also reduce water production (by 160%).

The next most important heterogeneity on oil production and recovery factor are the interfingering length of EOD-belts (Heterogeneity 1, Table 1) and the geometry of EOD-belts (Heterogeneity 2, Table 1). Changing interfingering length from setting A (short) to setting B (long) has a positive effect on oil production and recovery factor at 20 years, increasing oil production by 100% and recovery factor by 28% respectively, whereas changing geometry of EOD-belts from setting A (progradation) to setting B (retrogradation-progradation) decreases the oil recovered by 26% and the recovery factor by 2%. Although permeability anisotropy (Heterogeneity 4, Table 1) is the second lowest impact on fluid flow among six heterogeneities, its effect to increase oil produced at 20 years by 25% is considered of high impacts. Transitional EOD-belt boundary (Heterogeneity 6, Table 1) is the least influential factor.

Impact of mobility ratio

Unfavourable mobility ratio decreases the oil recovery at 20 years (by 0.3-25%) and breakthrough time (by 10- 86%) in all the simulation models, as shown in Fig. 11 for a representative model. This reflects a decreased flow rate in the reservoir and a delayed water breakthrough time corresponding to a higher oil viscosity. As can be noticed, however, the heterogeneity ranking on flow is consistent when changing from favourable to unfavourable mobility ratio (Fig. 12). Unfavourable mobility ratio also decreases the effects of EOD-belt rock properties (Heterogeneity 3, Table 1), interfingering length (Heterogeneity 1, Table 1) while increases the effects of geometry of EOD-belts (Heterogeneity 2, Table 1) and permeability anisotropy (Heterogeneity 4, Table 1) on oil production, recovery factor and water production at 20 years. The oil recovered, recovery factor and water produced at 20 years are reduced by approximately 200% when a sequence boundary barrier (Heterogeneity 5, Table 1) is present in the models, i.e. there is almost no change in the impacts of sequence boundary barrier on oil recovery and water production (less than 1% difference in the effects).

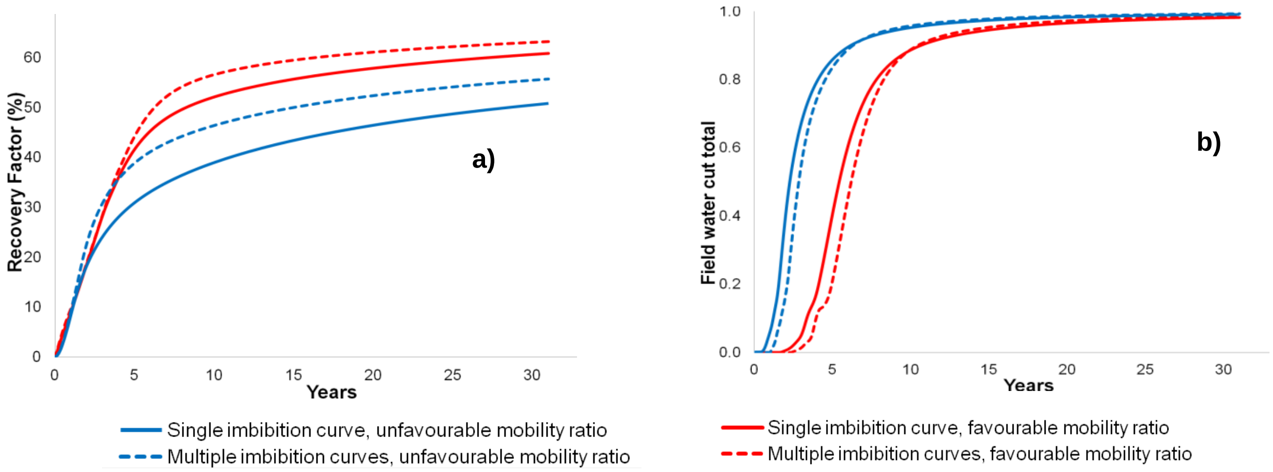

Fig. 11: Recovery factor (a) and field water cut total (b) for representative model B. The results are shown for single imbibition curve set (continuous lines) and multiple imbibition curve sets (dashed lines). The red lines represent favourable mobility ratio and blue lines represent unfavourable mobility ratio. Simulations with 4km line drive.

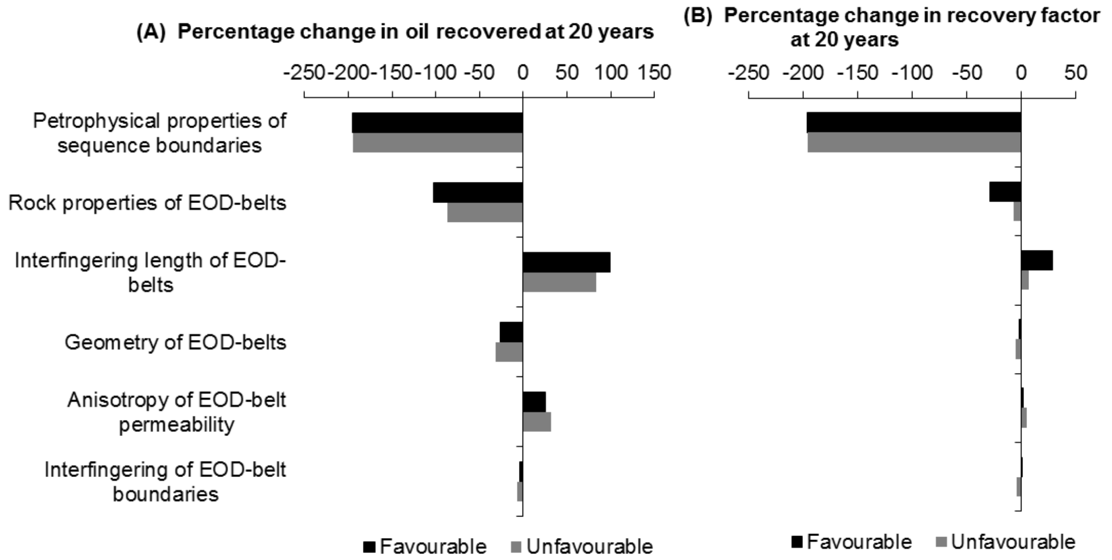

Fig. 12: Impact of six heterogeneities on A) oil recovered at 20 years, B) recovery factor at 20 years. The results are shown for favourable and unfavourable mobility ratio. Simulations with single imbibition curve set and 4km line drive.

Impact of multiple relative permeability and capillary pressure curves

When multiple relative permeability and capillary pressure curve sets are used, the simulation models predict more oil but less water production, as shown in Fig. 11 for a representative model. This is because the multiple imbibition curve sets account for the high rock properties (>100 mD) which give a lower residual oil saturation (0.13) and low water saturation endpoint (0.09) than the average rock type (Fig. 3). One curve set gives a higher Sor (0.16) and a higher Swi (0.11). Hence when multiple imbibition curves sets are used, the oil production and recovery factor at 20 years are increased (by 0.3-34%) and cumulative water production at 20 years is decreased (by 9-31%) with a delayed breakthrough time (by 57-145%).

Fig. 13 illustrates the impacts of six heterogeneities on oil recovered and recovery factor at 20 years using different relative permeability and capillary pressure models and different fluid mobility ratios. The heterogeneity with higher impact on flow corresponds to a higher percentage change in oil recovery and recovery factor, in which its data-point is further away from the origin (Fig.13). The ranking orders of heterogeneities which impact on oil produced at 20 years are similar using two approaches of modeling relative permeability and capillary pressure, applicable to both unfavourable and favourable displacements (Fig. 13A). However the rank changes for the heterogeneities that impact on recovery factor when multiple curves sets are applied (Fig. 13B). EOD-belt rock properties (Heterogeneity 3, Table 1) and interfingering length (Heterogeneity 1, Table 1) become less important for recovery factor at 20 years. Instead, permeability anisotropy (Heterogeneity 4, Table 1) and EOD-belt geometry (Heterogeneity 2, Table 1) become more important and mark the second and third most important factors that impact on recovery factor.

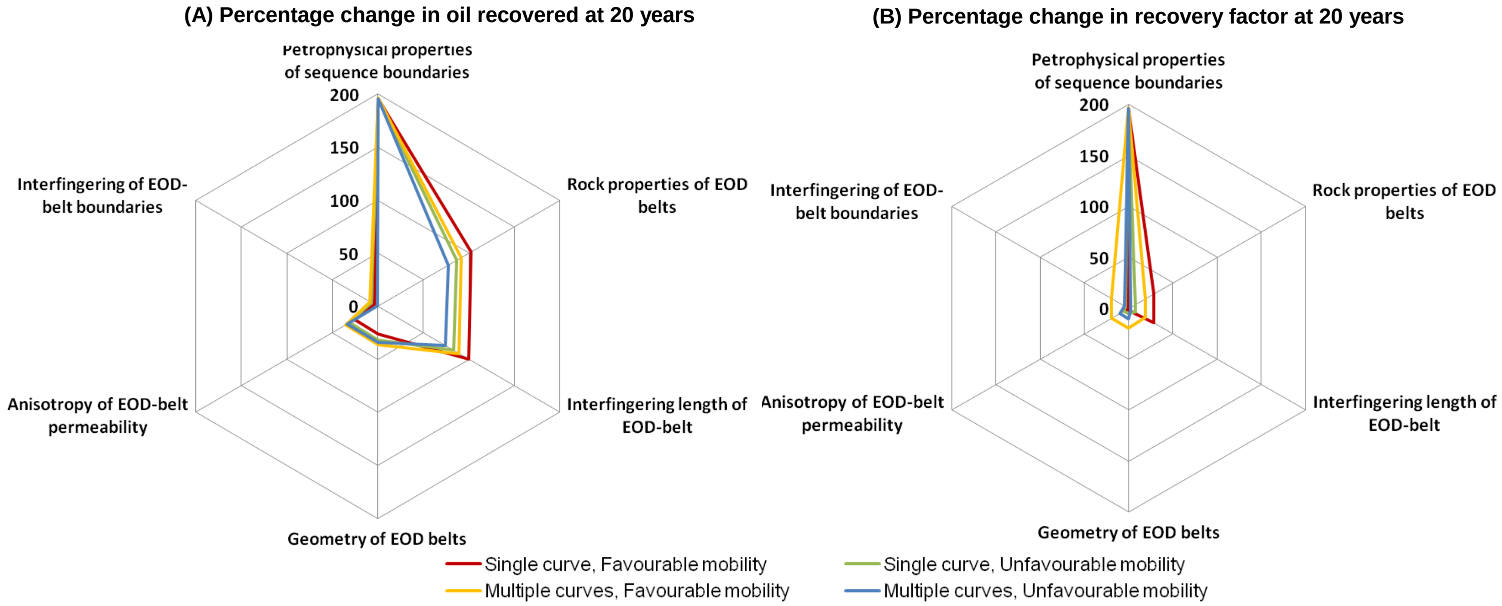

Fig. 13: Impact of six heterogeneities on (A) oil recovered and (B) recovery factor using different relative permeability and capillary pressure models and different fluid mobility ratios. Results are shown for simulations with 4km line drive.

Impact of well spacing and well placement

Fig. 14 shows that the heterogeneity ranking which impacts cumulative oil production is consistent for different well spacing and well placement types in this study, although the ranking orders is changed for the impacts on recovery factor at 20 years. Interfingering of EOD-belt boundaries has an enhanced impact when well spacing is decreased (in 1km repeat line drive and 500m five-spot pattern) and becomes the second most important parameter which impact on recovery factor at 20 years. Reduced well spacing generally decreases the effect of EOD-belt rock properties and interfingering length but increases the effect of EOD- belt geometry, permeability anisotropy and boundary nature on both oil production and recovery factor.

The rank of permeability anisotropy affecting total oil production is still low compared to the remaining heterogeneities but its effect on recovery factor is increased significantly when a patterned well placement is introduced. While permeability anisotropy is insignificant for recovery factor in 4km line drive (causing less than 5% change), it appears causing 26-27% change with 500m five-spot and 1km repeat line drive respectively.

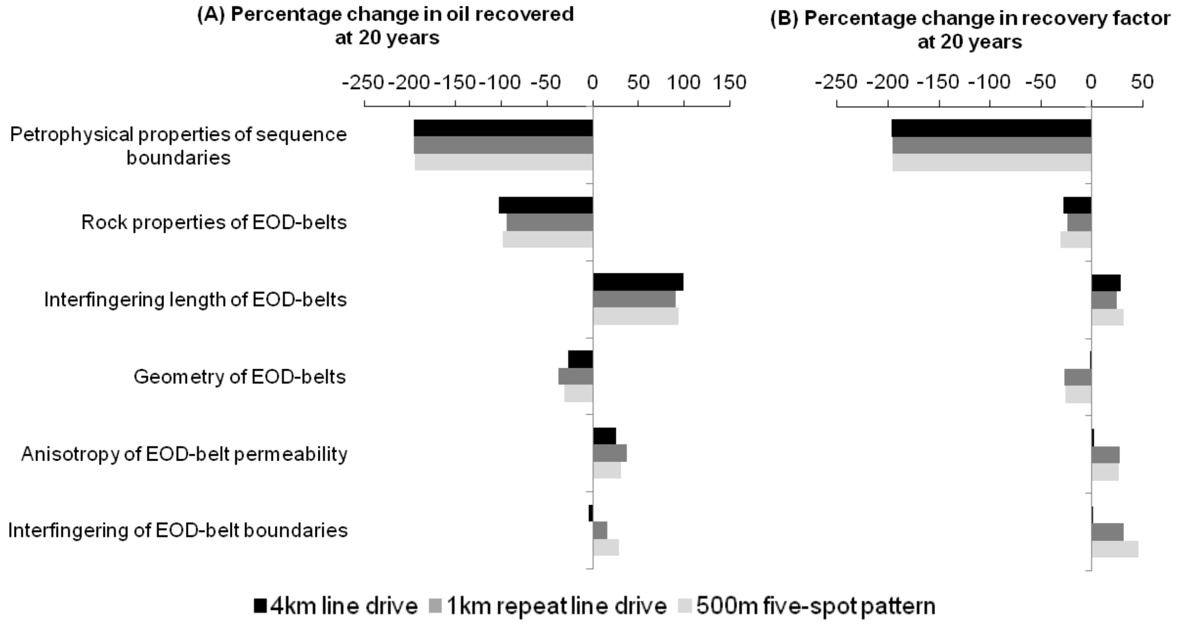

Fig. 14: Impact of well spacing on heterogeneities ranking for (A) oil recovered, (B) recovery factor. Simulations with favourable mobility ratio and single set of imbibition curve.

The predicted oil recovery factor at 20 years for each model varies with different well placement, and can be compared in Fig. 15 for all of the simulation models investigated. For models A, C, E, G and H, production using 4km line drive is lower than 1km repeat line drive and 500m five-spot pattern respectively. This shows that more vertical wells with 1km repeat line drive and 500m five-spot pattern can recover more oil from the reservoir. However, for three models B, D and F, highest oil recovery is obtained in 4km line drive, followed by 1km line drive and 500m five-spot pattern. The reason for the highest recovery factor achieved with 4km line drive is explained by early water breakthrough in 4km line drive (after 3-6 years) compared to five-spot pattern (after 8-14 years) and repeat line drive (after 6-9 years) in these models.

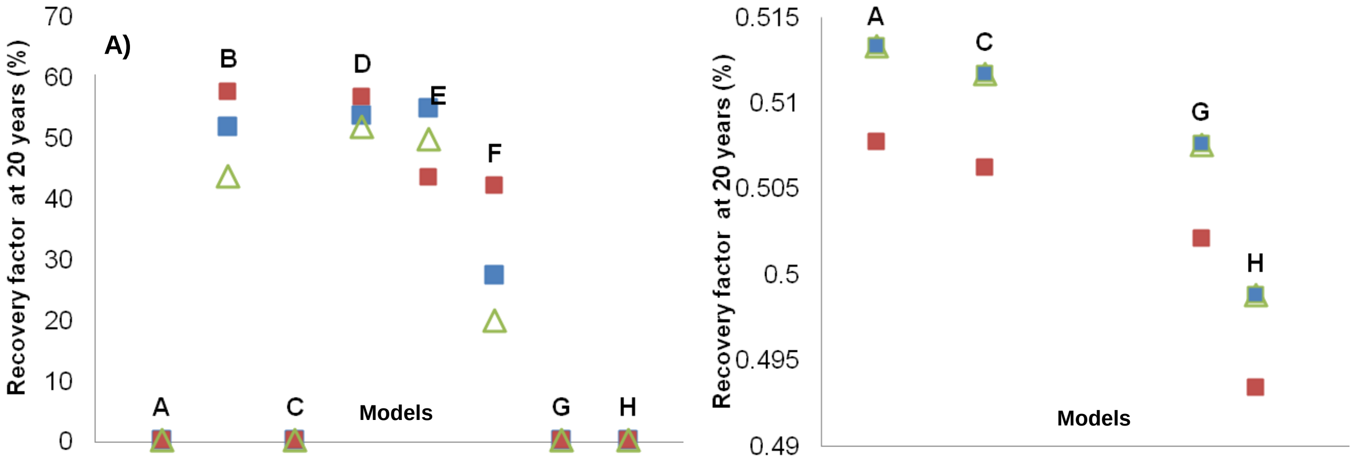

Fig. 15: Comparison in recovery factor of various well spacing for simulation models. The results are shown for all of the models (Models and the results are shown in a smaller scale for models A, C, G and H (B).

Discussion

Heterogeneity ranking

The heterogeneity ranking which impact on fluid flow in carbonate reservoir obtained in this study is resulted from a vertical flow profile of water flooding, which is shown different from the heterogeneity ranking that influences fluid flow by Fitch et al. (2012). Sequence boundary barrier (i.e. petrophysical properties of sequence boundary - Heterogeneity 5, Table 1) is the most significant heterogeneity affecting flow in all scenarios that we investigated, followed by rock properties of EOD-belts (Heterogeneity 3, Table 1). Transitional EOD-belt boundaries (i.e. interfingering of EOD-belt boundaries - Heterogeneity 6, Table 1) is the least important heterogeneity on fluid flow, but its effect is increased when well spacing is reduced. Stratigraphic heterogeneities which characterize EOD-belt architecture and geometry such as EOD-belt interfingering length (Heterogeneity 1, Table 1) and EOD-belt geometry (Heterogeneity 2, Table 1) generally have intermediate impacts on oil production after rock properties of EOD-belts. The rank of EOD-belt permeability anisotropy (Heterogeneity 4, Table 1) is generally low, however its impact on recovery factor increases when multiple imbibition curve sets are applied, or a patterned well placement (e.g., 1km repeat line drive or 500m five-spot pattern) is employed.

Fitch et al. (2012) focused on horizontal profile of water flooding, which showed that the flow barrier along sequence boundary had a low effect on fluid flow. Fig. 16 illustrates the heterogeneity ranking on flow obtained by the work of Fitch et al. (2012) using horizontal flow. Among the examined heterogeneities, the most important heterogeneity was rock properties of EOD-belts, followed by interfingering length and geometry of EOD-belts. The permeability anisotropy and transitional EOD-belt boundaries had negligible effects on fluid flow.

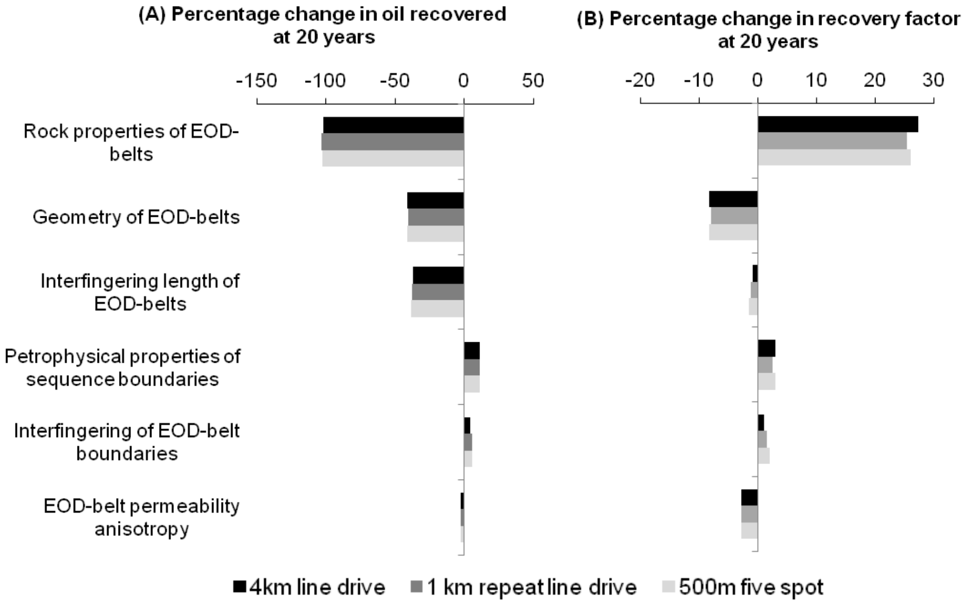

Fig. 16: Impact of six heterogeneities on oil recovered at 20 years (A), recovery factor at 20 years (B) using horizontal water flooding profile (Fitch et al., 2012). Simulation with different well placement using single imbibition curve set and favourable mobility ratio.

Impact of sequence boundary barrier (Heterogeneity 5, Table 1)

Our result clearly showed that a flow barrier along the sequence boundary is the governing factor for oil production. This heterogeneity causes a wide range in production across the models, which has suggested the large impact on flow. Fluid flow is shut at early time in the models which have barriers along the sequence boundary because of insufficient reservoir pressures to produce at the required bottom hole pressure. A sequence boundary barrier extends the whole field-wide, isolating the perforated interval of the injection wells and that of production wells, therefore prevents vertical flow. The sequence boundary barriers, which are characterised by 10-cm-thick layers with reduced rock properties in our reservoir models, cause a negligible reduction in the volume in place compared to the 67-m-total thickness of the models, leading to almost the same impacts of sequence boundary barrier on oil recovered and recovery factor. This implies that the effect of this heterogeneity on reservoir recovery does not change regardless of different production scenarios, i.e. different fluid mobility, imbibition models and well spacing. Whereas Fitch et al. (2012) showed that sequence boundary barrier had a low effect; furthermore this heterogeneity had a positive impact on oil production and recovery factor. The horizontal feature of this stratigraphic sequence boundary barrier does not act as a barrier to horizontal flow profile in this scenario.

Impact of rock properties of EOD-belts (Heterogeneity 3, Table 1)

Rock properties of EOD-belts have consistently been found to be an important parameter affecting oil recovery in this work and Fitch et al. (2012). This heterogeneity accounts for a reduction in cumulative oil produced when it varies from high to low rock properties. A poorer rock quality of EOD-belt corresponds to lower oil in place, as can be noticed in the predicted oil in place for models E to H (Setting B of heterogeneity 3, Table 1) compared to models A to D (Setting A of heterogeneity 3, Table 1). The volume of oil produced and the recovery factor are therefore reduced. The effect of EOD-belt rock properties is comparable with the approximate effect of this heterogeneity which was found by Fitch et al. (2012) (with less than 1% difference) when single imbibition curve, favourable fluid mobility ratio and 4km well spacing are used. With the same suite of simulation models, similar reservoir conditions and production strategies however different in completion profile; the comparable results with the work of Fitch et al. (2012) suggests a very slight change in the effect of EOD-belt rock properties on flow when different completion profiles are employed. The difference in the effects of EOD- belt rock properties on oil recovered compared with Fitch et al. (2012) is 5-8% when changing to a different well spacing (500m five-spot or 1km repeat line drive), or the same 4km well spacing is used but with unfavourable mobility ratio. This change however increases when multiple imbibition curve sets are used (12-20%). Fitch et al. (2012) found that a greater volume of oil in place could be recovered from a less cumulative oil production. Our result is more encouraging where it shows recovery factor has the same negative effect with oil production. This trend can be clearly observed from the production results in Fig. 9 where a decrease in oil production also leads to a decreased recovery factor.

Impact of interfingering length and geometry of EOD-belts (Heterogeneity 1 and heterogeneity 2, Table 1)

The next important heterogeneities on oil production and recovery factor are the factors which controls EOD-belt architecture and geometry i.e. interfingering length of EOD-belts and EOD-belt geometry. Longer interfingering length has a positive effect on oil production and recovery factor. This contrasts to the horizontal flow study (Fitch et al., 2012) which suggested that increasing interfingering length had a negative effect on oil production and recovery (Fig. 16). Fitch et al. (2012) explained the negative impact of interfingering length by accounting for the reduced proportion of high quality EOD-belt in the models with long interfingering length. In our study, longer interfingering length results in a more layer-cake geometry which can increase connectivity between producing zones. This is similar to what have been demonstrated by Larue & Friedmann (2005) that recovery efficiency increased as the proportion of the reservoir connected to the production and injection wells was increased in waterflood studies. Long interfingering length results in a more even thickness of EOD-belts, which provides a flow conduit to sweep oil along the favourable permeability layers into the production wells (Fig. 1). The EOD-belt geometry controls the volume of EOD units in the models (Fitch et al., 2012). A low setting in EOD-belt geometry (i.e. retrogradation-progradation) increases the presence of outer ramp and pelagic to the models, as can be observed in 2-D model E (Setting A, heterogeneity 2; Table 1, Fig. 1) and model F (Setting B, heterogeneity 2; Table 1, Fig. 1). These EOD-belts of poor rock quality decrease the oil in place and subsequently decrease the oil production and recovery factor in our reservoir models.

Impact of anisotropy of EOD-belt permeability (Heterogeneity 4, Table 1)

EOD-belt permeability anisotropy increases the oil production and recovery factor. Permeability anisotropy has long been identified to have significant effects on producing reservoirs (Larue & Friedmann, 2005; Abbaszadeh et al., 2010; Hollis et al., 2011). A reduced k_v/k_h implies an improved horizontal flow so that flow is better through the good quality layers in the reservoir, explaining the favourability of this permeability anisotropy for oil recovery in our study. Permeability anisotropy has a lower effect than other parameters on fluid flow, but appears to be more important than the results established by Fitch et al. (2012), causing a favourable 25% increase in oil recovered, while this effect is less than 5% negative change by Fitch et al. (2012). The increased effect indicates that the vertical flow profile has enhanced the effect of anisotropy of permeability on fluid flow.

Impact of transitional EOD-belt boundaries (Heterogeneity 6, Table 1)

The transitional EOD-belt boundaries slightly decrease the predicted oil production, recovery factor and water production. Its least influence on flow is explained by that a very small portion of the transitional EOD-belt boundaries occurs in our model compared to the whole model thickness. The minor impact of transitional EOD-belt boundaries on oil recovery is consistent with Fitch et al. (2012). However, the impact of EOD-belt boundaries on recovery factor increases when reduced well spacing (500m five-spot and 1km repeat line drive) are in place, in which it becomes the second most important factor after sequence boundary barrier. The transitional layers of the boundary reduce the permeability contrast between two neighboring EOD-belts, allowing flow to move easier between two neighboring EOD-belts and its effect on flow is enhanced when well spacing is reduced.

Impact of relative permeability and capillary pressure models, mobility ratio and well spacing

Our results show that in the favourable mobility displacement and using one single imbibition curve for the whole reservoir, patterned well placement significantly increases the effect of permeability anisotropy, geometry of EOD-belts and EOD-belt boundaries. The enhanced impacts of these heterogeneities on fluid flow support Hollis et al. (2011) that closer well spacing means smaller-scale reservoir heterogeneities can have more significant impact on production, for instance thin and high permeability layers can have more impact on recovery. The significant increase in the effect of EOD-belt boundary nature, permeability anisotropy and geometry of EOD-belts on recovery factor when a well pattern is introduced implies that these parameters are underestimated when examined with 4km line drive.

The approach of modeling relative permeability and capillary pressure has been shown to have a significant impact on production (Hollis et al., 2011; Choi et al., 2011); however, in our study, using multiple relative permeability and capillary pressure curve sets does not affect the heterogeneity ranking on flow. The multiple curve sets which we applied, are constrained from proprietary dataset, do not show much variation as compared to the range of multiple curve sets investigated by Hollis et al. (2011). The three relative permeability and capillary pressure curve sets were based on three rock types of different porosity, with residual oil saturation of 20% in low case and high case of 5%; and low case of k_{ro} of 0.5 and high case k_{ro} of 0.7. The unfavourable mobility ratio only changes the heterogeneity ranking on recovery factor when multiple sets of imbibition curves are used. The resulted change in the ranking suggests that the effects of EOD-belt geometry and permeability anisotropy are underestimated and the effects of EOD-belt rock properties, interfingering length are overlooked if single relative and permeability curve is applied to the whole reservoir.

Impact of permeability anisotropy

The effect of permeability anisotropy is enhanced with vertical flow profile in our study; however, the rank of EOD-belt permeability anisotropy impact on flow is generally low. This is due to: (1) The large effect of sequence boundary barrier have dominated and suppressed the effects of other heterogeneity factors on flow. Also, the sequence boundary barrier prevents vertical flow therefore the effect of k_v is reduced, leads to a reduced in the effect of permeability anisotropy on flow. (2) The range of investigated k_v/k_h in our study was approximated from a proprietary dataset from 0.4 to 1, which is consistent with the range of permeability anisotropy examined by Hollis et al. (2011); however the value of permeability anisotropy could be reduced due to an increase in thin, continuous bodies of mud- and grain-dominated depofacies. To allow larger distribution of k_v/k_h values, another examination was established to investigate how the heterogeneity ranking on flow is affected. Fig. 17 shows the ranking impact of heterogeneities on oil recovered and recovery factor when the sequence boundary barrier only acts as a feature of reduced rock properties but allows vertical flow; and with larger distribution of k_v/k_h values (setting B of permeability anisotropy is reduced 10 times). Faulting in the reservoir can allow vertical flow across the extensive barriers along sequence boundary; in this case, the sequence boundary barriers no longer dominate other heterogeneity factors on flow. The permeability anisotropy effect on flow is therefore enhanced, and by varying the range of investigated permeability anisotropy, EOD-belt permeability anisotropy was found to be the third-most important factor on oil recovered and the most important factor controlling recovery factor (Fig. 17). This suggests that as we investigate smaller-scale heterogeneities, allowing a larger range of permeability anisotropy, a change in permeability anisotropy effect on fluid flow would be expected.

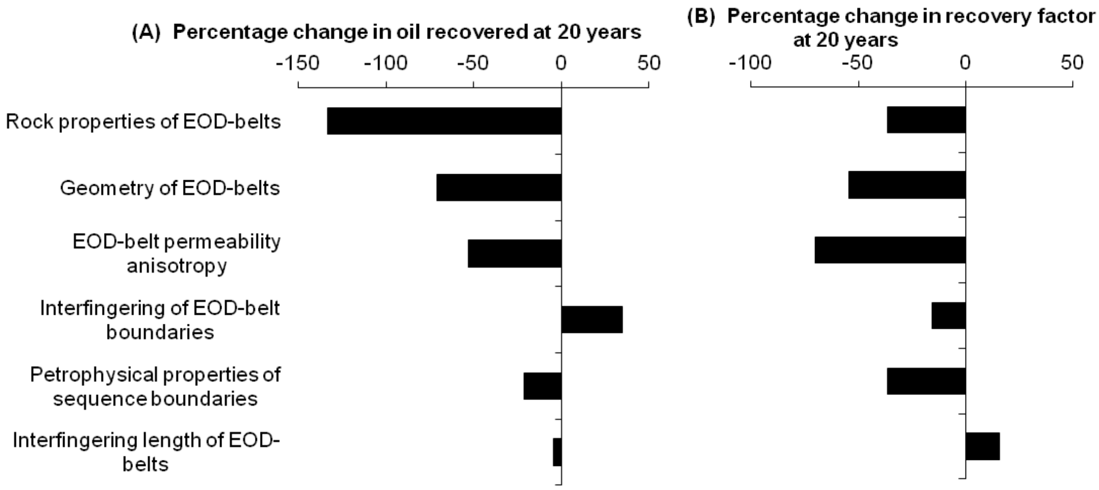

Fig. 17: Impact of six heterogeneities on oil recovered at 20 years (A), recovery factor at 20 years (B) when the range of permeability anisotropy is increased and the effect of sequence boundary barrier is turned off. Simulations using single imbibition curve set and favourable mobility ratio.

The results of this study are important for reservoir characterization and development in heterogeneous carbonate reservoirs. Because oil recovery is related strongly to reservoir heterogeneity, as has been discussed, optimal field development program should consider the effects of these heterogeneities presented in the field accordingly. Different subsurface parameters and development options we have examined in this study assist in decision-making and help justifications in both more optimistic and more conservative scenarios. This emphasizes the importance of future study and data collection programs to reduce the uncertainties in high-ranked parameters which most likely impact future field performance. Clearly, suitable data acquisition programs and multidisciplinary data application would be planned and despite the technology challenges in carbonate fields, applying the appropriate properties to reservoir models will improve history matching and forecasting. Another practical importance of this result is the guide for building and flow-simulating of reservoir models, for example transitional EOD-belt boundary is less significant in our study and should not be a focus on understanding fluid flow in field-scale production. Similarly, important reservoir architectures and heterogeneities would be characterized according to their impacts on the recovery.

Summary, conclusions and suggestions for future work

The stratigraphic heterogeneities which control the geometry and spatial distribution of EOD-belts and the associated rock properties in carbonate reservoirs were investigated in this study. These include six heterogeneities which were identified in the literature (Fitch et al., 2012). A production strategy to enhance the potential for vertical flow has been established for the reservoir models under examination. A ranking impact of stratigraphic heterogeneities on hydrocarbon recovery in carbonate reservoir was determined. Different rock, fluid properties and production strategies were then investigated for their impacts on the heterogeneity ranking on fluid flow. Based on the results of this study, the following conclusions were made:

1. A sequence boundary barrier and EOD-belt rock properties are the most influential heterogeneities which impact on fluid flow under vertical water flooding profile, and are the most significant heterogeneities to predict reservoir performance regardless of change in reservoir parameters and development strategies such as relative permeability and capillary pressure models, mobility ratio and well spacing. The EOD-belt geometry and interfingering length control the volumes of EOD-belts in the reservoir and have the intermediate impact on flow.
2. The heterogeneity ranking on cumulative oil is generally not affected when using multiple imbibition curve sets, unfavourable mobility ratio or a reduced well spacing. The heterogeneity ranking on recovery factor slightly changes when using multiple imbibition curve sets, unfavourable mobility ratio or a reduced well spacing.

The results of this study provide a framework for the data collection and reservoir characterisation to identify the key heterogeneities which control flow in carbonate reservoirs. It highlights what information is important to capture in subsurface models therefore suitable resources can be appropriately diverted in relation to their relevance to future production of carbonate fields. More time and effort would be spent on modelling and constraining the uncertainties of significant parameters. For example rigorous and cross-disciplinary data acquisition program including logging, coring and core analysis would be implemented to obtain appropriate petrophysical properties. Suitable data acquisition programs such as seismic, RFT and well test would be planned to identify the barriers to flow in the reservoirs.

The ranges of heterogeneity values in this work are adopted from published studies. For future study of the carbonate reservoirs having one or a combination of the investigated heterogeneities, a similar approach examining extended range of values between the end-members of the geological heterogeneities would improve our understanding and offer optimised development option for carbonate reservoir of interest.

The larger project (Fitch et al., 2012) continues to investigate full types and length-scales of stratigraphic, sedimentological and diagenetic heterogeneities on flow in carbonate reservoirs. As it examines the heterogeneities in carbonate reservoirs at smaller scales, change in the impacts of heterogeneities on flow would be expected.

Nomenclature

BHP	=	*Bottom hole pressure, bar*
c.p.	=	*Centipoise*
EOD	=	*Environment of deposition*
FOPT	=	*Field oil production total, Msm*^{3}
FWCT	=	*Field water cut total*
FWPT	=	*Field water production total, Msm*^{3}
k_r	=	*Relative permeability*
K_{ro}	=	*Oil relative permeability*
K_{rw}	=	*Water relative permeability*
k_h	=	*Horizontal permeability, mD*
k_v	=	*Vertical permeability, mD*
k_v/k_h	=	*Permeability anisotropy*
OWC	=	*Oil-water contact*
P_c	=	*Capillary pressure, bar*
RF	=	*Recovery factor*
sm^3	=	*Standard cubic meter*
Sor	=	*Residual oil saturation*

Swi = *Initial water saturation*

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APPENDIX A - CRITICAL LITTERATURE REVIEW

Journal / SPE Paper n°	Year	Title	Authors	Contribution
SPE 36209	1996	"Identifying controls on water flood performance in a giant carbonate reservoir"	M. E. O'Hanlon, B. C.J.J., and K. J. Webb	Examines waterflood characteristics which impact on field performance for one particular reservoir within a carbonate field.
SPE 79676	2003	"Experimental design as a framework for reservoir studies"	C.D. White, S.A Royer.	Describes the method of experimental design which is applicable for improved reservoir engineering workflows.
SPE 88730	2004	"Integrated characterization of UAE outcrops: from rocks to fluid flow simulation"	R.L. Vaughan, S. A. Khan, L. J. Weber, O. Suwaina, A. Al-Mansoori, A. Ghani, C. J. Strohmenger, M. A. Herrmann, and D. Hulstrand	Discusses a case study for integrated geologic modelling and fluid flow simulation.
SPE 123424	2009	"Long-term field development opportunity assessment using horizontal wells in a thin carbonate reservoir of the greater Burgan Field, Kuwait"	A. K. Ambastha, D. Al Matar, and E. Ma	Discusses the integrated geological and reservoir simulation in carbonate reservoir using horizontal wells.
SPE 62514	2010	"Integrated characterisation and flow modeling of a heterogeneous carbonate reservoir in Daleel Field, Oman"	M. Abbaszadeh, N. Koide, and Y. Murahashi	Illustrates a case study of reservoir characterisation and fluid flow modelling in a heterogeneous carbonate reservoir.
Petroleum Geoscience	2011	"Predicting the impact of sedimentological heterogeneity on gas-oil and water-oil displacements: fluvio-deltaic Pereriv Suite Reservoir, Azeri-Chirag-Gunashli Oilfield, South Caspian Basin"	K. Choi, M. D. Jackson, G. J. Hampson, A. D. W. Jones, and A. D. Reynolds	Investigates heterogeneity effects on oil recovery in clastic reservoir.
AAPG Memoir 96	2011	"Uncertainty in a giant fractured carbonate field, Oman, Using Experimental design"	C. Hollis, S. Price, H. Dijkm, L. Wei, D. Frese, M. van Rijen, and Al Salhi, M.	Provides a workflow and case study of modeling uncertainty on fluid flow in a carbonate reservoir using experimental approach.
Sedimentology	2011	"Capturing and modelling metre-scale spatial facies heterogeneity in a Jurassic ramp setting (Central High Atlas, Morocco)"	F. Amour, M. Mutti, C. Christ, A. Immenhauser, S. M. Agar, G. Benson, S. Tomas, R. Always, and L. Kabiri	Provides background to the sedimentology of the Amellago Formation
Sedimentology	2011	"Spatial and temporal distribution of ooids along a Jurassic carbonate ramp: Amellago outcrop transect, High-Atlas, Morocco"	A. Pierre, C. Durlet, P. Razin, and E. H. Chellai	Provides background to the geology of the Amellago Formation (Stratigraphic scale)

SPE 36209 (1996)
Identifying controls on water flood performance in a giant carbonate reservoir

Authors: O'Hanlon, M. E., B. C.J.J., and K. J. Webb

Contribution to Building the Simulation Model:

This paper assists the understanding of water flood behaviour which affects flow performance in carbonate reservoir.
It is useful in selecting permeability curves for the models and understanding the effects on fluid flow.

Objective of the paper:

To examine waterflood characteristics which impact on field performance for one particular reservoir within the carbonate field.
- Determine which rock data are most likely representative for modelling.
- Identify regional correlations and trends that will enhance consistency of application of these data for reservoir evaluation and performance prediction.

Methodology used:

1. Mechanistic screening was performed to identify core data validity based on the impacts of core acquisition and lab methods.
    - Representative lab relative permeability data, Swi, wettability were obtained.
    - Variations in waterflood characteristics when applying mechanistic screening were compared.

2. Statistical analysis was performed targeting average rock curves for given lithology, depths, wettability.
    To understand the physical properties that control relative permeability:
    - Single property dependencies were analysed
    - Linked properties were analysed:
        - Relative permeability curves were generated by averaging oil and transition zone curves.
        - Relative permeability curves were grouped by lithotype.

Conclusion reached:

- Mechanistic screening did not significantly reduce the scatter in the historical data.
- Statistical analysis established that no single property controlled waterflood behaviour. A combination of lithology, sample zone, permeability and Swi appeared to be the major control on water- oil relative permeability.
- Separating the data by sample zone, lithology, permeability and Swi significantly reduced the scatter in the experimental relative permeability data.

Comments:

Simulation in the project is in comparison with the results.
More high quality data are required to fully validate permeability trends observed in the historical data.

SPE 62514 (2000)
Integrated characterisation and flow modeling of a heterogeneous carbonate reservoir in Daleel Field, Oman
Author: Abbaszadeh, M., N. Koide, and Y. Murahashi

Contribution to Building the Simulation Model

Discussion part on Fluid Flow Simulation is an applicable guide for appropriate reservoir model.

Objectives of the paper:

1. To present the application of deterministic and conditional geostatistical reservoir characterisation methods to the heterogeneous carbonates in Daleel field, Oman
2. To compare simulation results from each case
3. To identify appropriate reservoir characterisation and flow modelling for the field
4. To identify proper representation of heterogeneity in flow simulation

Methodology used:

1. Deterministic reservoir simulation models were constructed:
    a. Based on geology, petrophysics, and well tests
    b. Three and six- layers with different oil bubble point pressure were modelled
    c. History match was performed and the results was compared
2. Geostatical models were constructed:
    a. Based on probability density function to result in reservoir properties
    b. 2 algorithms Sequential Gaussian Simulation (SGSIM) and Sequential Indicator Simulation (SISIM) were used
    c. History match results were compared between two methods and when combined with geology.

Conclusion reached:

1. Deterministic models matched field performance well.
2. One-zone SGSIM model with acceptable range of bubble point pressure did not produce good matches to field data; whereas three- zone model SGSIM results were in agreement with field performance.
3. SISIM with geology is superior than SISIM without geology in history match to field performance.
4. Geological information must be realistically included in geostatistical reservoir models.

Comments

Although deterministic models matched primary recovery well, future performance does not ensure to predict reservoir response to more elaborate recovery schemes, such as horizontal well or injection schemes.

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

Authors: Christopher D. White and S.A Royer

Contribution to understanding the method of experimental design in reservoir studies:

This study describes the method of experimental design which is applicable to integrate with reservoir engineering workflows.

Objectives of the paper:

1. To describe the approach of experimental design and its components
2. To present possible application of experimental design in reservoir studies.

Methodology used:

Designed approach used in a particular reservoir study:

1. Experimental design specifies factor combinations or cases. A full two-level factorial design requires 2^k cases and the number of cases can be reduced by a fractional factorial design.
2. Principle Component Analysis (PCA) is used to identify the most influential components and reduce the least important factors.
3. Factor dependencies are grouped into three groups of PCA responses: general quality, flow capacity and water drive.
4. Analysis of Variance (ANOVA) is used to identify the factors which affect the three groups of PCA responses.
5. Rank the impact of factors and identify most important factors.

Conclusion reached:

1. Designed simulation studies enumerate influential factors, identify response sensitivities, and yield estimates over the range of all factors.
2. This approach has been applied successfully to facilitate simulation, uncertainty analysis, performance forecasting and reservoir/ well parameters estimation and optimisation in reservoir development project.

Comments:

If factors interact, their importance varies with the values of all factors with which they interact. To be optimized, response models must include quadratic terms for controllable factors and interactions between controllable and other factors.
This paper did not evaluate the model accuracy and design efficiency, which could be an interest for the investigation.

AAPG Memoir 96, p. 137-157 (2011)
Uncertainty in a Giant Fractures Carbonate Field, Oman, Using Experimental Design

Authors: Hollis, C., S. Price, H. Dijkm, L. Wei, D. Frese, M. van Rijen, and M. Al Salhi

Contribution to setting up the simulation model and understanding of experimental design

This paper gives a specific example of the application of experimental design in understanding uncertainty a carbonate reservoir simulation, Oman.

Objectives of the paper:

1. To provide a workflow for modelling uncertainty using experimental approach, focus on a mature field redevelopment in a giant fractured carbonate field in Oman.
2. To present experimental design as a mechanism for assessing the impact of a combined range of subsurface parameters on future production.

Methodology used:

The approach follows these steps:
- A priori assumptions of the uncertainty range of each subsurface parameter were first modelled and then challenged during initial screening runs.
- Historical data were used to constrain the uncertainty range of those parameters that were sensitive to past production performance.
- A series of linear equations were used to determine the impact of individual parameters on the history match. For the highest impact parameters, a quadratic response was used to find the solution space within which a history match could be achieved.
- Consequently, the reservoir modeling workflow derives a ranking of the impact of each of the input parameters on the forecast.
- For the highest impact parameters, the data collection and study program were designed to reduce the range of uncertainty, whereas less effort was focused on lower impact parameter.

Conclusion reached:

- History match was achieved within a given solution space by accounting for the influence of multiple parameters and acknowledging their combined influence, sometimes with individual parameters offering a variable control on productivity at different stages in the production history.
- The workflow allowed a range of forecasts to be output, reflecting the full range of uncertainty on individual parameters, and their combined effect. The process also accommodated the functions of different parameters in controlling future productivity under different development options.
- Future data collection programs and resourcing were effectively planned by focusing only on those parameters that had a high impact on forecasts under a given recovery mechanism.

Comments:

Interactions between different parameter uncertainties were considered.
Discussion on "Modelling a Heterogeneous Fractured Carbonate Reservoir" in the paper is applicable for modelling process in the project.
This work demonstrates that the choice of relative permeability and capillary pressure data used in production simulations has a significant impact on performance results, and can be noted in our results.

Petroleum Geoscience (2011)
Predicting the impact of sedimentological heterogeneity on gas-oil and water-oil displacements: fluvio-deltaic Pereriv Suite Reservoir, Azeri-Chirag-Gunashli Oilfield, South Caspian Basin

Authors: Choi, K., M. D. Jackson, G. J. Hampson, A. D. W. Jones, and A. D. Reynolds

Contribution to Building the Simulation Model:

This paper assists in understanding heterogeneity effects on oil recovery in clastic reservoir examples.
The paper does not discuss carbonate reservoirs but can guide simulation set- up and similar project methodology.

Objectives of the paper:

1. To identify the key sedimentological heterogeneities which influence recovery by gas and water injection in a particular reservoir.
2. To determine whether these heterogeneities have a similar impact on flow in both gas- oil displacements.
3. To understand why these heterogeneities are important.

Methodology used:

High resolution models derived from outcrop analogue were constructed.
Ten sedimentological heterogeneities were investigated for their impacts on gas-oil and water-oil displacements.
Experimental design and analysis of variance were applied.

Conclusion reached:

Four key sedimentological heterogeneities which control production in oil-water and gas-oil displacements were identified.
Gas-oil displacements are also controlled by vertical-to-horizontal permeability ratio of channel-fill sandbodies and by the presence of mudstone clast lags at the base of the channels.

Comments:

This paper investigates the different reservoir type than carbonate reservoir in our project.
This work neglected capillary pressure data and apply two different relative permeability curve sets to the whole reservoir in separate simulations; one for an oil-water system, and one for gas-water.
This work demonstrates that the choice of relative permeability and capillary pressure data used in production simulations has a significant impact on performance results, and can be noted for our results.

APPENDIX B – SATURATION PLOTS

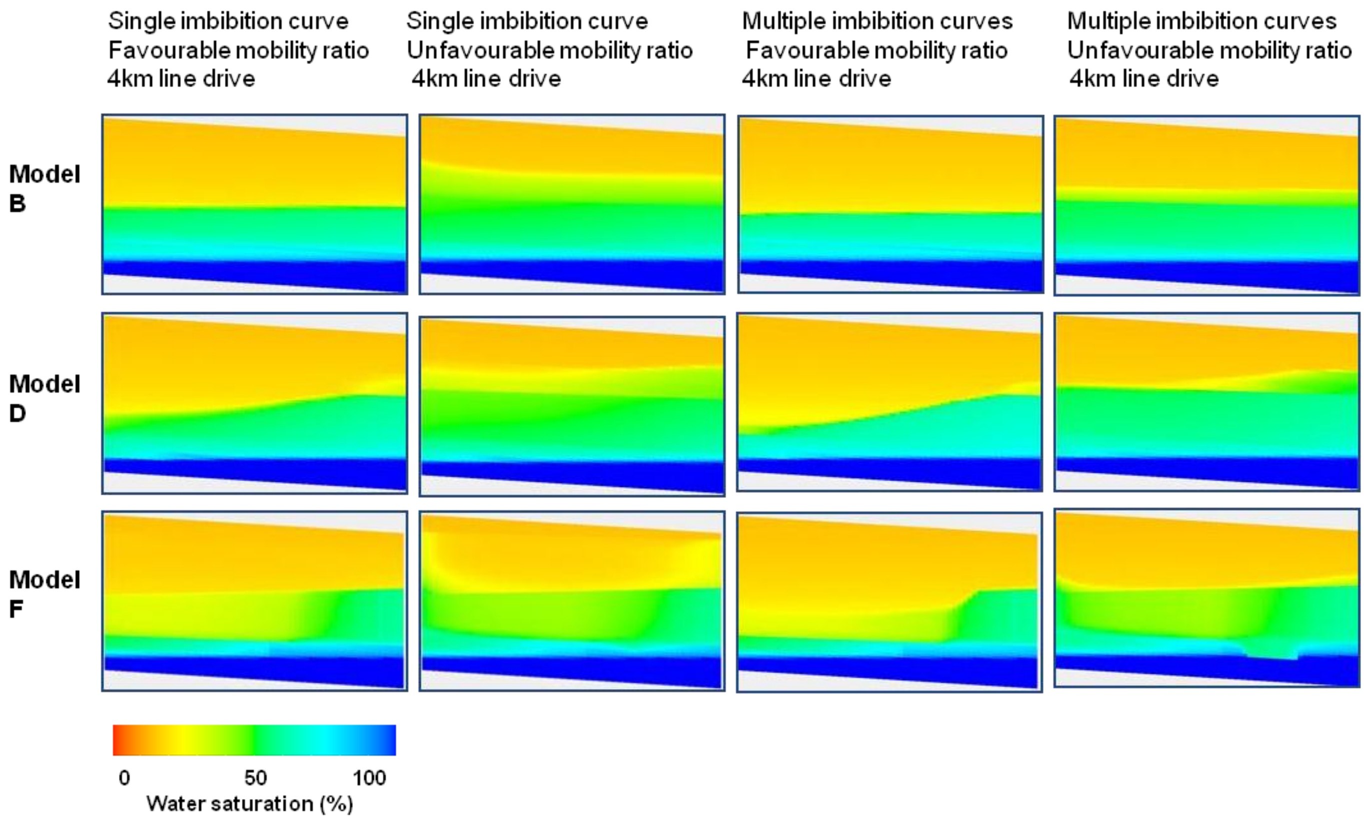

Fig. B-1: 2-D cross section of models B, D and F without sequence boundary barrier showing water saturation after 1 year of simulation.

APPENDIX C – PERMEABILITY ANISOTROPY EFFECT

In the main report, the permeability anisotropy effect was further investigated considering vertical flow across the barrier to sequence boundary, and the range of investigated k_v/k_h ratio was increased. The permeability values were therefore adjusted to reflect the decrease in permeability anisotropy by 10 times. Table C-1 summarizes the rock properties examined by Fitch et al. (2012) and Table C-2 shows the permeability values used to remodel the grids.

Table C-1: Rock properties investigated by Fitch et al. (2012)

Environment of Deposition (EOD)	Rock properties									
	High (grain dominated)					*Low (mud dominated)*				
Name	**Ø**	**k_h (mD)**	**k_v (mD)**	**k (mD)**	**k_v/k_h**	**Ø**	**k_h (mD)**	**k_v (mD)**	**k (mD)**	**k_v/k_h**
Inner Ramp (Semi-restricted ramp)	0.21	320	47	120	***0.15***	0.02	170	24	64	***0.15***
Mid Ramp (High energy ramp)	0.38	4200	2000	2900	***0.47***	0.18	840	390	570	***0.47***
Outer Ramp (Marly open ramp)	0.17	2.4	0.21	0.73	***0.08***	0.001	0.58	0.05	0.17	***0.08***
Pelagics	0.11	0.15	0.02	0.06	***0.1***	0.0001	0.01	0.001	0.003	***0.1***

Table C-2: Rock properties used to further investigate the effect of permeability anisotropy when the effect of sequence boundary barrier is removed, and the distribution of permeability anisotropy is enlarged.

Environment of Deposition (EOD)	Rock properties									
	High (grain dominated)					*Low (mud dominated)*				
Name	**Ø**	**k_h (mD)**	**k_v (mD)**	**k (mD)**	**k_v/k_h**	**Ø**	**k_h (mD)**	**k_v (mD)**	**k (mD)**	**k_v/k_h**
Inner Ramp (Semi-restricted ramp)	0.21	1006	14.8	120	***0.015***	0.02	525	7.7	64	***0.015***
Mid Ramp (High energy ramp)	0.38	13,395	624	2900	***0.047***	0.18	2,660	124	570	***0.047***
Outer Ramp (Marly open ramp)	0.17	7.81	0.066	0.73	***0.008***	0.001	1.83	0.016	0.17	***0.008***
Pelagics	0.11	0.47	0.006	0.06	***0.013***	0.0001	0.032	0.00032	0.003	***0.010***