Geological Interpretation of Channelized Heterolithic Beds through Well Test Analysis

Rafael Osorio[a], Amin Sharifi Haddad[a,1], Ed Stephens[b], Hossein Hamidi[a]
[a] School of Engineering, University of Aberdeen, SCO, UK
[b] AGR TRACS, SCO, UK

Abstract

Well test analysis is a valuable tool to measure the dynamic response of a reservoir through determination of the hydraulic connectivity and effective permeability of the reservoir. Analytical models in well test analysis, are developed based on a simple geological structures, to provide reasonably good approximations for the description and performance of such reservoirs. Nevertheless, most prolific reservoirs such as channelized systems consist of sedimentological features with high degrees of heterogeneity that influence the pressure transient response where using conventional analytical models may result in misleading interpretations. The focus of the current study is on reservoirs which depositional environment corresponds to a main channel feature incising into heterolithic beds in lateral continuity. Analysis of the pressure response demonstrated that it can be used as a tool to predict the equivalent isotropic horizontal permeability of the channel. We explored that the ratio of well test permeabilities between the radial flows can lead to the identification of a secondary geological body next to channel. Thus, it can be used to find the distance of the interface between channel and heterolithic. The results of this study showed that particular features of pressure and its derivative curves from a channel-heterolithic system are useful well testing signatures for reservoir characterisation. Therefore, we proposed an algorithm for the recognition of pressure trends and the development of relationships to be used for well test interpretation of heterogeneous oil and gas reservoirs.

Keywords: Well test, Channelized heterolithic, Geological heterogeneity, Channel sand

[1.] Corresponding author: Amin Sharifi Haddad, Email:amin.sharifi@abdn.ac.uk, Tel: +44 (0)1224 272977 Fax: +44 (4) 1224 272497

Introduction

Well test provides a tool to describe the well and reservoir through dynamic conditions. From pressure transient analysis, well parameters such as skin factor, wellbore storage and well geometry, and reservoir properties such as pore pressure and permeability can be estimated. Furthermore, interpretation of well test data can lead to characterisation of the changes in facies, natural fractures, layering, and identification of their corresponding boundaries (Bourdet, 2002).

Commercially available well test interpretation tools are based on a series of known models and their analytical solutions. Therefore, geological interpretations in these software packages are carried out based on the predetermined behaviours. Interdependence between geology (static) and well test (dynamic) interpretation is well recognized (Massonnat and Bandiziol, 1991). Well test provides geologists with an improved knowledge of the reservoir system from a dynamic model such as confirming flow boundaries, and composite behaviours. In a similar manner, a good understanding of the geological setting allows us to make an appropriate selection of the possible analytical models from a wide range of possible solutions in well test tools.

These interpretations include the integration of geophysical, geological and petrophysical information (Toro-Rivera et al., 1994). The models provide a concept of the behaviour of a reservoir, as it can be for instance homogeneous, heterogeneous, bounded or infinite reservoir. The behaviour of a reservoir is a product of averaging its properties; thus, they are sometimes different from the geological or well logging models (Bourdet, 2002).

Analytical solutions can generate pressure responses whose parameters are adjusted until the response from the model is almost identical to the reservoir. Nevertheless, this can be a kind of pitfall since for reservoirs with several heterogeneities, different models may be used and tuned to describe the pressure behaviour. This uncertainty might be reduced using additional geological, petrophysical or geophysical data (Corbett et al., 1998).

The study of heterogeneous reservoirs most of the times is simplified by using composite models. The general case for composite reservoir models consists of two distinct media in the reservoir, each one is characterized by a different porosity and permeability. No type-curves are commercially available for these types of configurations, and the procurement of one will be discussed in the current study. Therefore, the evaluation of non-continuous reservoir units is critical for the resolution of lateral continuity and channel connectivity (Massonnat et al., 1993). There are many reservoirs located in channelized settings; hence, it is necessary to understand how accurate well test analyses can describe the heterogeneity due to lateral continuity and channel connectivity in this type of reservoirs (Bourgeois et al., 1996; Massonnat et al., 1993; Azzarone et al., 2014).

Radial composite systems have been studied in the past (Hurst, 1960; Carter, 1966), and in these models it is assumed the first zone is near wellbore, and the second zone belongs to the reservoir, where they have different effects on pressure response. The purpose of such models is to describe a radial change in properties from the vicinity of the well toward the reservoir (e.g., acidification treatment, damage, among others). The numerical models for radial composite, as in dual porosity formations, are tested and validated by several studies (Guo et al., 2012).

In linear composite systems, on the other hand, it is assumed a vertical plane at the interface between two reservoir media exist (Bixel et al., 1963; Ambastha et al., 1987; Idorenyin et al., 2015). This configuration can reflect two different sedimentological elements such as a channel and heterolithic, as we use it in this study. Schematic representations of both radial and linear composite reservoirs are shown in Figure 1.

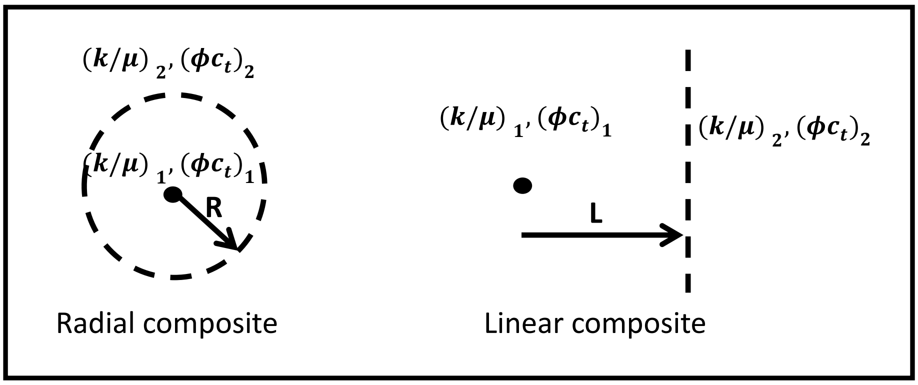

Figure 1. Conceptualized model for radial and linear composite reservoirs (After Bourdet, 2002).

As shown in Figure 1, each zone has a specific mobility ratio which is the ratio of rock permeability to viscosity of the host fluid (Ambastha, 1995). The composite model assumes that the thickness of the reservoir is constant, the change of properties is abrupt, and flow across the interface of regions is without any resistance.

Analysis of the pressure response of the linear composite systems, gives a first radial flow that describes the main reservoir body next to the well, and a second radial flow describes an equivalent of the total system i.e., main reservoir body and next lithology (Bourdet, 2002). However, in the radial composite model only the external region influences the second radial flow. Furthermore, if the system is followed by a sealing boundary, pressure response will be a linear function of the square root of time. Linear flow can be identified from the derivative pressure on a logarithmic plot through a straight line with slope of one-half. This type of flow is a common characteristic for channels and it is observed at late time response of the pressure transient tests (Lee, et al., 2003).

Different models are developed to characterize reservoir heterogeneities through pressure transient analysis. Chen et al. (2012) developed a workflow for stratigraphic well test analysis in turbidite reservoirs; Ezulike et al. (2012) obtained a three-dimensional semi-analytical solution for horizontal wellbore drawdown response in composite clastic reservoirs; and Mijinyawa et al. (2010) presented a multi-disciplinary method linking history matching of well test data to seismic and geological evidence using a simple numerical simulator. Recently Walsh and Gringarten (2016) investigated the well test responses to different geological settings for a fluvial reservoir system.

A high percentage of productive reservoirs are highly heterogeneous as turbidites, braided fluvials, and meandering channels among other laterally channelized complexes (Kuchuk and Habashy, 1997). Therefore, permeability contrast, between different facies, influences the pressure transient responses. Investigators (Toro-Rivera et al.,1994; Chandra et al., 2011) concluded the presence of a secondary body next to the main sand directly influences the obtained effective permeability through well test analysis. On the contrary, heterogeneities in porosity can slightly impact on the pressure response (Savioli et al., 1995).

To analyse the well test response of complex geological features, investigations have broadly made with the use of reservoir numerical modelling to emulate pressure transient analysis. Many investigations have been conducted on understanding well test signatures associated with different heterogeneities such as lateral and vertical connectivity of facies, channelized environments, geochok, geoskin, ramp effect, interaction between fluid and geological heterogeneities among others, and found that such heterogeneities should be given a careful attention in reservoir characterisation process through well test analysis (Corbett et al. 1996; 2005; 2012; Hamdi, 2014; Hamdi et al., 2012; 2015). Bourgeois et al. (1996) studied the influence of levees in a channel. They used a three-zone composite model, and their qualitative analysis of the pressure response showed the effect of changing the mobility ratio between facies, distance to the levees, and the width of the channel. They found that for limit cases such as a perpendicular fault to a channel, or a parallel fault at a very far distances from the channel, responses have similarities with a closed or infinite acting system respectively.

Similarly, Massonnat and his co-workers (1993) conducted two stochastic models with varying the frequency of facies, a case of 20% channel and 20% levees, and then another case of 50% channel and 20% levees. They were able to contrast their results with a real drill stem test from a field to validate one of the models. Zambrano and his colleagues (2000) carried out well test simulations to study the behaviour of heterogeneities including channels with symmetric and asymmetric composite thickness profile and a degree of channel sinuosity. They found that well-test results are sensitive to the thickness ratio of the zones.

Mijinyawa and Gringarten (2008) extended the work of Zambrano et al. (2000) to include the pressure derivative response for wells at different locations in semi-infinite channel with different systems of non-parallel boundaries, T-shaped channels, meandering channels and pinch-out boundaries, through the variation of angles and channel measurements. They reported that the well location on every configurations changed the trend of well test derivative response. Mijinyawa et al. (2010) showed that well test analysis for complex environments can be performed integrating dynamic and static data into numerical simulations. They found that the integration between engineering and geology disciplines may lead to a better understanding of pressure transient data that initially could be considered as uninterpretable. Therefore, one can conclude that the geological setting cannot be interpreted from the well test pressure transient analysis, but conversely the well test pressure transient analysis can be used to calibrate any given geological model, in particular permeabilities and length scales; and the correspondence between interpreted parameters and other data (e.g., core data) may be used to assess the likelihood that the geological model is representative of the actual reservoir.

In 2012, Obinna and his co-workers carried out synthetic pressure transient analysis of a horizontal well to monitor the impact of anisotropy in a composite reservoir. They obtained a semi-analytical solution for pressure response of horizontal wells considering the impact of well angle for low and high permeability anisotropy, and fault conductivity. Tianhong et al. (2012) performed a sensitivity analysis for key fine-scale geological parameters driving flow behaviour as the shale drape coverage for a turbidite system. They showed that for these systems, the shale coverage, lobe size and channel width have a strong influence on well test pressure response.

Recently, Walsh and Gringarten (2016) made a very comprehensive catalogue of well test responses rendering several simulations for the effect of sand channel content, seed number or the position of geologic bodies in the fluvial system, horizontal and vertical permeabilities, channel features such as length ratio, width, amplitude, thickness, and fault distances. The results of this study compiled a large number of parametric analysis in a systematic way generating an extensive library of pressure derivative tendencies.

Unlike the studies performed earlier (Zambrano et al., 2000; Mijinyawa and Gringarten, 2008; Walsh and Gringarten, 2016), this study is more focused on the interaction inside the channel between a main sand body and a secondary one, or heterolithics. We are aware of the heterogeneity in petrophysical properties of the real lithology, and they have been considered through statistical distribution in our static model. In our study, the main geological body is classified as one which has a range of favourable petrophysical properties compared to the next laterally one. This study aims to deepen the work of Bourgeois et al. (1996) through finding explicit relationships with predictive values in the interactive sand-heterolithics or main-secondary bodies.

The approach taken in this work consists of a numerical simulation of well test using stochastic modelling based on the model developed from an outcrop in the UK, with the presence of different types of fluid (light oil, viscous oil and dry gas). The depositional environment of the modelled field is mainly deltaic with a mixture of alternating marine and non-marine settings. During its formation, the area was close to the coastline, and there was fluctuation of sea level with the range of approximately 50 m of the deltaic reservoir. Part of the channelized environment, the main channel sand and the coal are continental (fluvial origin) while the heterolithics are from shallow marine environment (tidal or shoreface) (Bentley and Ringrose, 2015). The results of this study provide a method to infer common patterns from well test responses in heterogeneous reservoirs. This investigation demonstrate that how the existence of heterolithics in a channel sand can affect the pressure transient analysis for different permeability ratios, distances to the interface, and anisotropies.

Methodology

In this study we first demonstrate how a proper grid refinement can save processing time and show coherent analytical results. We follow our study with analysis and interpretation of build-up and drawdown tests for the light and viscous oil, and gas models without integrating the geological information, to get an insight of non-unique solutions for the known models in commercial well testing simulators for different type of fluids. In the next step, the geological and petrophysical knowledge of the field (model was built in Petrel® software) can be integrated into the model where there are interbedded channels and heterolithics. Then, we run parametric studies related to channel and heterolithics; we analyse permeability anisotropy in the channel (main body), distance to the interface of channel-heterolithics, and the effect of permeability ratio of the channel to heterolithics on the pressure transient analysis. These results provide us with a tool to characterise anomalies and develop an accurate static models based on well test analysis.

Therefore, based on the signature from pressure transient analysis and current analytical models one might be able to identify the influence of a petrophysical poorer elements (lower permeability) on a main sand body in addition to the incidence of the fluid type. Finally, insightful type curves that are developed from the analysis of log-log and semi-log plots are presented.

Impact of the fine-gridding in simulation results

To select an adequate grid size for the field-scale simulation in our model, a reservoir model of 6560 ft ×6560 ft ×16.4 ft (approx. 2 km × 2 km × 5m) was build. Two cases were tested:

In the first case, the reservoir was divided into grid blocks of uniform dimensions of 32 ft × 32 ft × 3.28 ft (approx. 10 m × 10 m × 1m) in X-Y-Z plane (Figure 2).

In the second case, the reservoir was divided into hybrid grid blocks with variable dimensions. A local grid refinement was performed in both X and Y directions from the grid block where the tested well is located (Figure 3). Original grid block size was assigned to be 164 ft×164 ft (approx. 50 m×50 m) in X and Y directions, and near the well grid block to a distance of 820 ft (approx. 250 m), the reduction in the size of grid blocks followed an exponential relationship with a smallest grid size of 1.28 ft × 1.28 ft (approx. 0.39m × 0.39m).

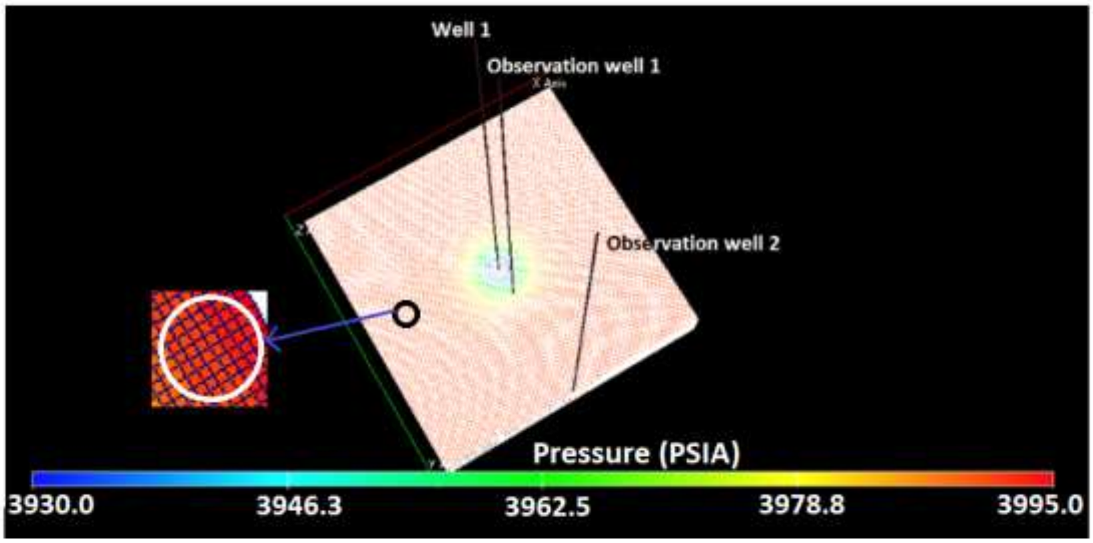

Figure 2. Pressure distribution in 3D homogeneous grid block size model.

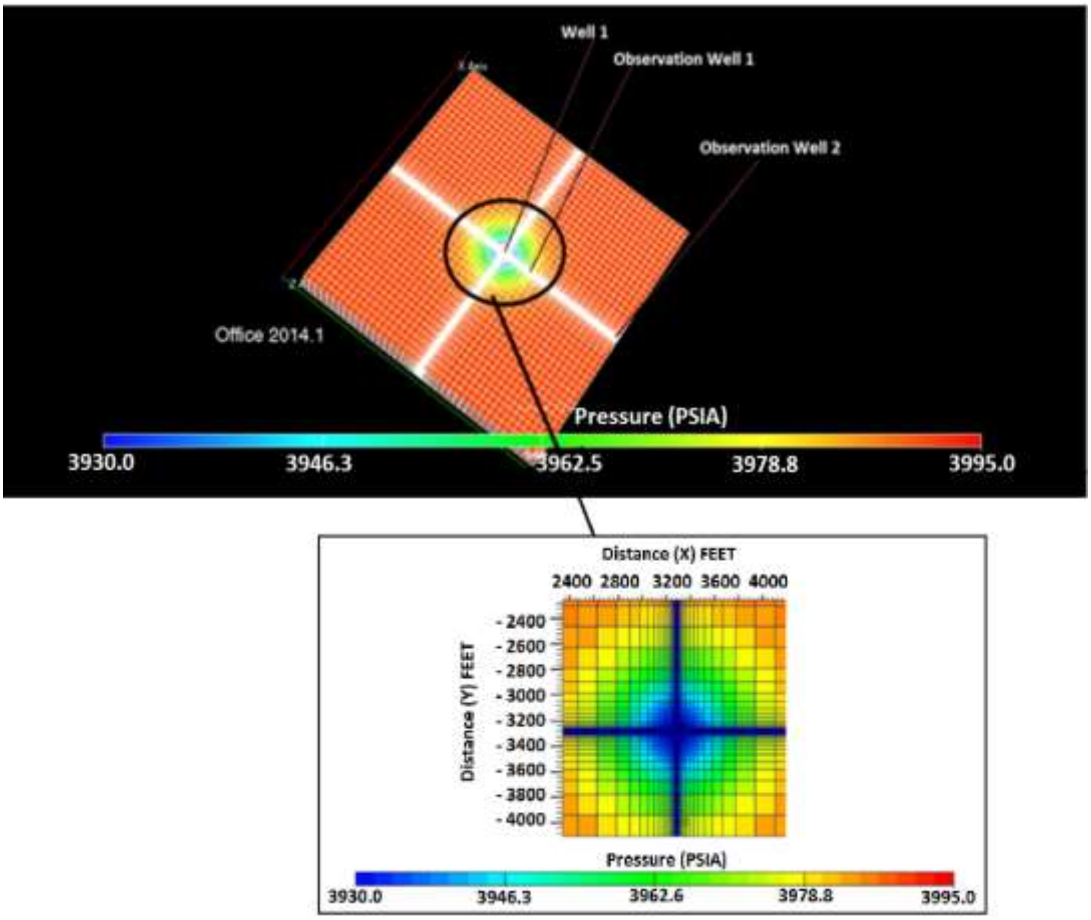

Figure 3. Pressure distribution in 3D hybrid block size model.

Local grid refinement is performed to produce accurate well test profiles (Chen et al., 2012). After running both square block models in Eclipse®, pressure response generated and was imported into a well test analysis software (Saphir®) to analyse the impact of the grid refinement. The results showed an extra bump in the derivative of pressure for the uniform grid block size model, which does not reflect the expected radial flow (Figure 4).

Conversely, analysis of the hybrid grid block size model, demonstrated a reduction in the numerical error and showed an adequate derivative response for pressure in the radial flow, as it is expected for the homogeneous reservoir. Furthermore a hybrid grid block size scheme can substantially reduce the cell count and therefore simulation time compared to the homogeneous grid block size model. It should be noted that for comparison of the numerical well test results and real well test data, further grid refinements or modification of cell transmissibilities might be required (Romeu and Noetinger 1996; Hamdi et al., 2014).

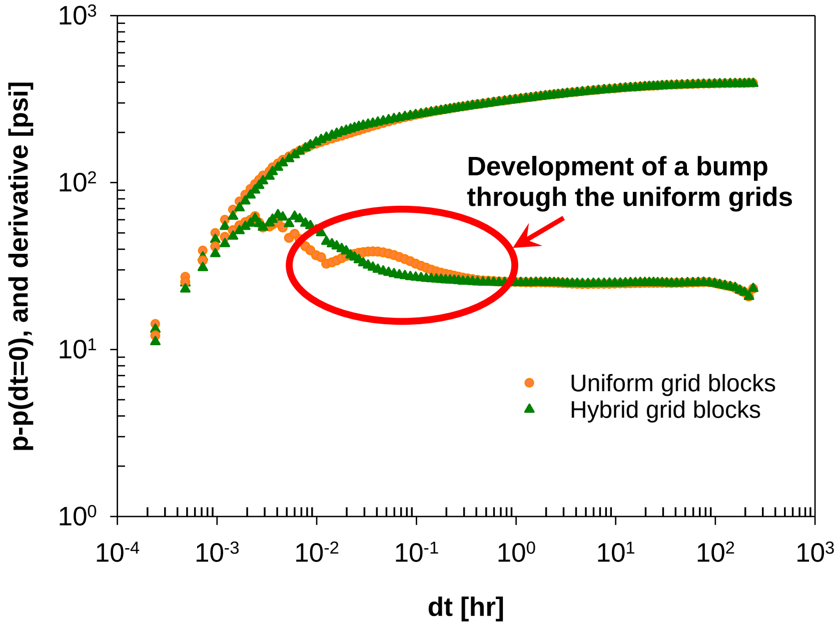

Figure 4. Comparison between the pressure responses after simulating homogeneous and hybrid block size models.

Field geological model

The static model belongs to a synthetic field based on analogue outcrops from Shallow Tree Bay, located in Pembrokeshire, Wales, UK.

The well test analysis is carried out on a well with perforations in the middle reservoir, a zone consisting of channels and heterolithics (i.e., sand and mudstone). Heterolithic bedding means a sedimentary structure comprising interbedded inputs of sand and mud that is formed in tidal flats.

The static model has 111×66×36 grid blocks in the X, Y and Z directions respectively. In this model different facies of mudstone, calcrete, tuff, siltstones, sheetfloods, mudstone, coal, carbonate, karst, and the two main facies of channel (yellow) and heterolithics (green) are considered (Figure 5). The static model can be calibrated through geostatistical methods if well test data are available (Hamdi and Costa Sousa, 2016).The well was perforated in the layers 13 to 16 (Z-direction) with a total thickness of 26 ft in the sand interval. The reservoir is a closed and volumetric system with no aquifer.

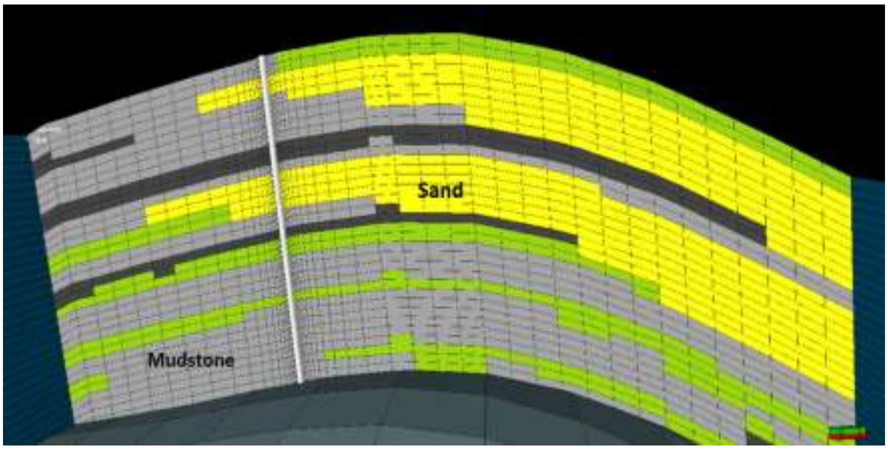

Figure 5. Cross-section of the modelled field along the well.

The sedimentological setting of this field was deltaic, a channel of sand of good petrophysical properties with an average porosity of 24% and horizontal permeabilities ranges between 1500-2000 mD (Figure 6). The channel is intersected by heterolithics, which has poorer petrophysical properties, with an average porosity value around half of the one in the channel zone, and permeabilities around 32 mD. The distance to the interface of the original model is about 150 ft.

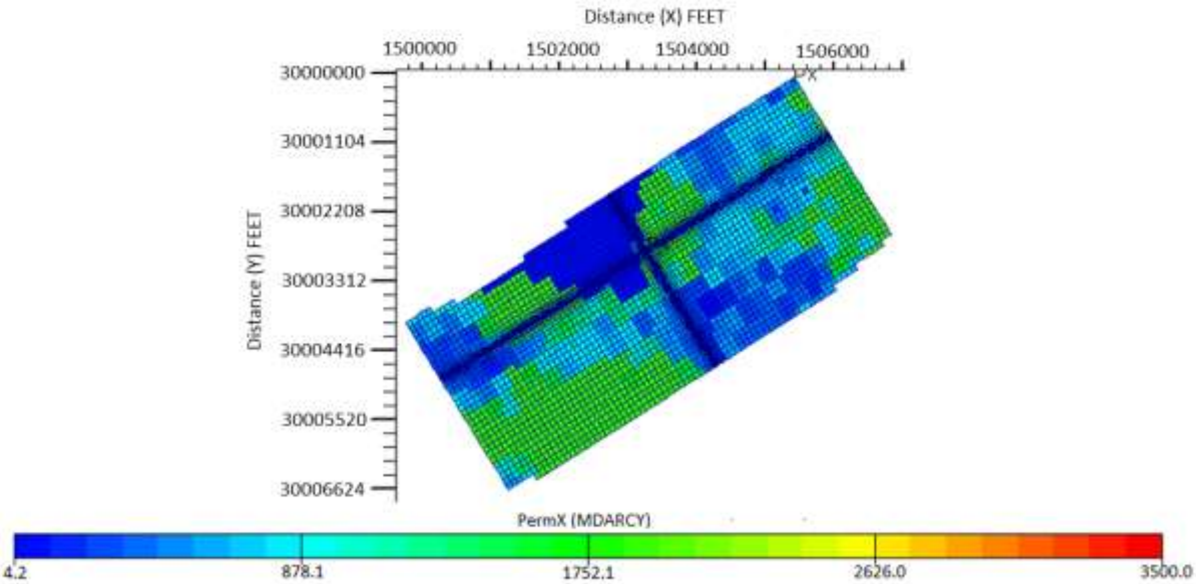

Figure 6. Range of permeability in a layer of model (k=16) for Pembroke Field, blue colour represents the heterolithics.

There are three types of fluids can be used in the model: water, oil and gas.

According to the produced fluids, three cases were developed:

1. Light oil, with an API of 35 and viscosity of 1 cp.
2. Viscous oil, with an API of 20 and viscosity of 20 cp.
3. Dry Gas, with a specific gravity of 0.6.

Oil and gas formation volume factors and their viscosities are shown in Figure 7. The initial pressure and temperature of the reservoir are 4090 psi and 200 °F respectively, the bubble point pressure is 1000 psi, and the initial water saturation is 20%.

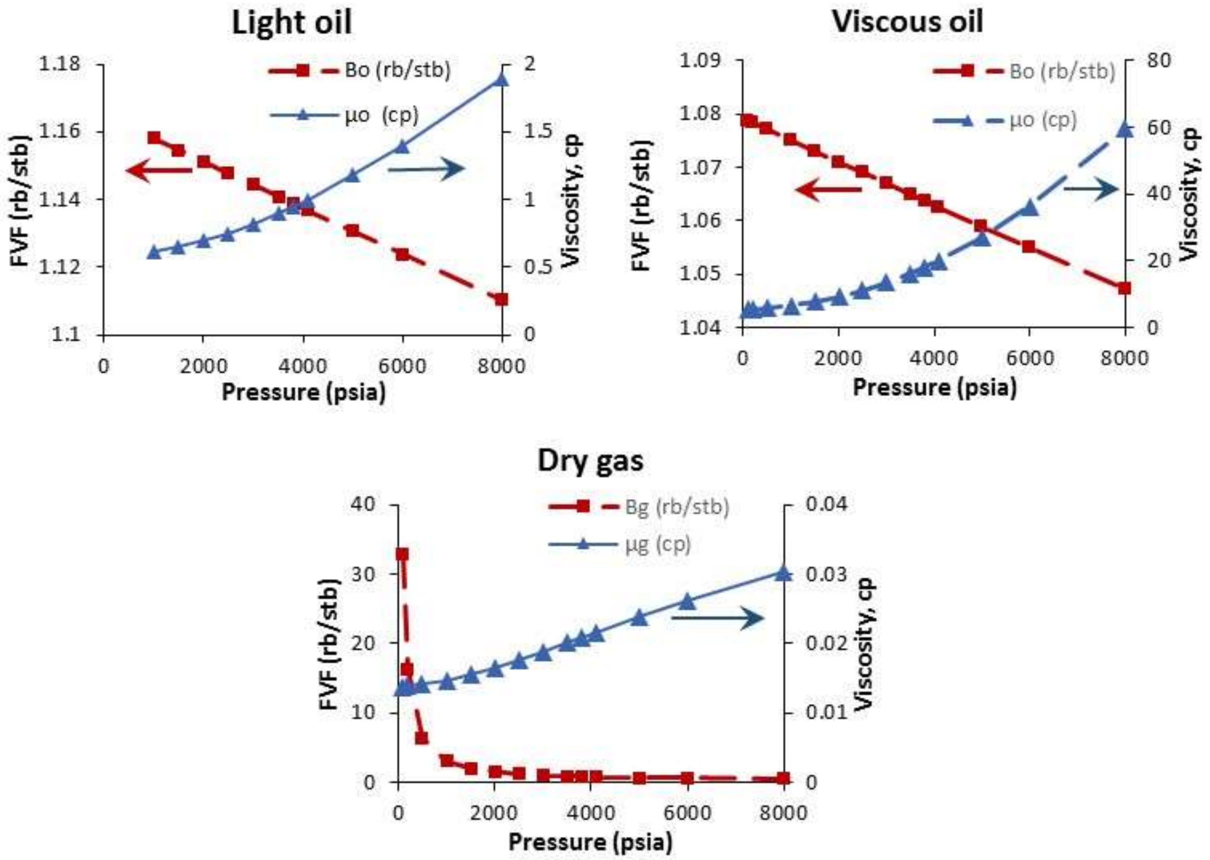

Figure 7. Formation volume factor and viscosity of light and viscous oil, and dry gas.

Once the dynamic model was build, the following simulations were run to analyse the impact of heterogeneity on the pressure transient analysis:

1. Sensitivity to fluid type.
2. Effect of permeability anisotropy of the channelized environment.
3. Effect of distance to the interface of channel-heterolithics.
4. Effect of mobility contrast between channel and heterolithics.

Simulation case studies

We designed a well test that involves both drawdown (DD) and buildup (BU) periods. An initial drawdown period of 24 hours followed by a buildup period of 240 hours. We used buildup data for our analysis in this study. Results showed that in the case of light oil, boundary effects were recorded after first 20 hours of the buildup test where we observed a declination in the derivative pressure curve consistent with a closed system as shown in Figure 8.

Results and Discussion

In this section, we run simulations based on different scenarios to investigate the effect of different rock and fluid properties on pressure transient analysis. Once comprehensive simulations are performed, type curves can be developed and proposed for characterization of heterogeneities in oil and gas reservoirs.

Current simulators can analyse the pressure responses from leaky faults, intersecting faults, parallel faults and composite. However, these possible scenarios are not satisfactorily able to explain the heterogeneity involved in a channel-heterolithic environment. Thus, in our analysis we intended to develop relationships that reflects the responses caused by this type of geological heterogeneity.

Sensitivity to the type of fluid

Three types of fluids were used in well test analysis of the model to investigate their influence on the pressure response of the reservoir.

In all simulation cases two radial flows were developed: the first one of higher permeability corresponds to the channel and the second one, of lower permeability is associated to a combined effect of channel and heterolithics (Figure 8).

Results show that, viscous fluids have higher wellbore storage (WBS) effect. This is due to the compressibility factor and viscosity (compressibility factor multiplied by viscosity) of fluids, which is lower for light oils than for viscous oils. Figure 8 shows how the pressure response of different oils generate different WBS effects. Compressibility factor of the light and viscous oils are roughly 20×10^{-6} psi^{-1} and 5×10^{-6} psi^{-1} respectively. For the case of viscous oil, more than 80 hours in the buildup period are required in order to analyse the second radial flow and later the boundaries effect.

Furthermore, there is a direct relation between the start of radial flow (t dp/dt) lines and the viscosity of fluids. The first radial flow for viscous oil is observed much later than the case of light oil.

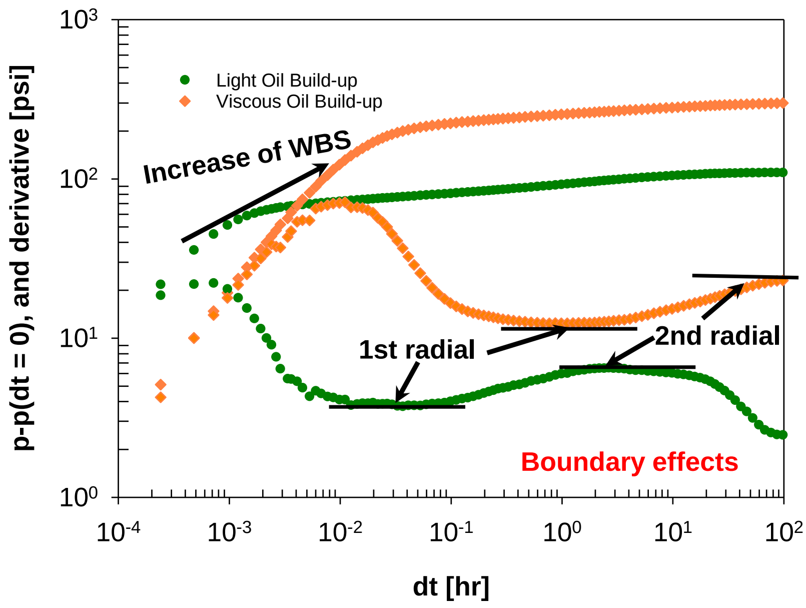

Figure 8. Pressure buildup (BU) responses for light and viscous oil.

For the dry gas case, the graph of pseudo pressure versus time shows that both first and second radial behaviours are achieved earlier compared to oil cases. Figure 9 shows the effects of boundaries in an earlier time on the pressure response.

Also the WBS effect was higher for dry gas reservoir compared to oil reservoirs, which is expected as the WBS coefficient for a well filled with a liquid phase is generally up to two orders of magnitude smaller than a well filled with gas (Spivey and Lee, 2013).

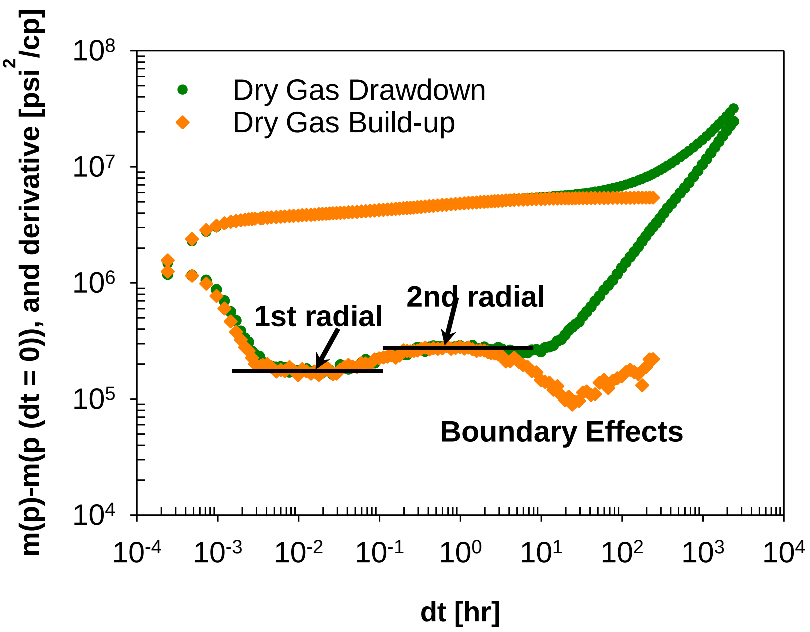

Figure 9. Dry gas pressure behaviour for buildup and drawdown tests.

Both the buildup and drawdown curves for three types of fluids that are compared for the closed system in this study (Figures 8 and 9), validate the expected theoretical behaviour for first and second radial flows.

Since the estimated permeability from a well test is the effective permeability that reflects the type of fluid and reservoir heterogeneity, therefore, a better approach to compare fluid flow in porous media is through analysis of the mobility ratio M. It is defined as the ratio of rock permeability (read from first radial well test) to fluid viscosity, thus:

For light oil: 852 mD/0.9892 cp= 861 mD/cp

For viscous oil: 486 mD/20 cp= 24.3 mD/cp

Effect of the equivalent isotropic horizontal permeability

Generally, it is common for practical purposes to assume the horizontal permeabilities are equal in both X and Y directions (a horizontal layer). In this section we quantitatively investigate the impact of varying the permeability in one of the directions on pressure transient analysis. When permeabilities in X and Y directions are different, the formation is anisotropic. In such cases, the horizontal permeability, k_h, is defined as the following equation (Spivey and Lee, 2013),

$$k_h = \sqrt{k_x k_y}$$

Where k_x and k_y are permeabilities in X and Y directions respectively.

The above equation is known as the equivalent isotropic horizontal permeability of the formation. In order to conduct a sensitivity analysis on an anisotropic system, the variation has been made in a range of fractions of permeability in the X direction, and the corresponding equivalent isotropic horizontal permeabilities have been compared against the variation in the first radial permeability (where channel permeability is mainly effective) from the well tests. Figure 10 represents pressure transient analysis of equivalent isotropic horizontal permeabilities cases for different types of fluids (Table 1 shows the details). Through a range of different anisotropic cases we were able to construct a relationship with predictive values of equivalent permeability as shown in Figure 11. It should be noted that due to the presence of initial water (water saturation 20%), relative permeability for different fluids can affect the well test permeability from the slope of first radial flow. Also since the well test permeability is an equivalent (effective) of horizontal and vertical permeabilities, its value is different from horizontal permeability.

Through this plot we can estimate an equivalent isotropic horizontal permeability of the channel. The obtained first radial permeability from the well test, can be entered on the Y axis, then the intersection with the corresponding fluid of the reservoir (e.g., light oil in Figure 11) can show the equivalent isotropic horizontal permeability of the sand channel or the main body. This predictive relationship is important because starting from the value of a radial permeability from a well test, we could infer an approximate equivalent isotropic horizontal permeability which is a valuable input for geological purposes; nevertheless, it should be noted that this plots are generated for the reservoir described earlier in this manuscript.

Table 1. Well test permeabilities for each type of fluid obtained through different equivalent isotropic horizontal permeability

			LIGHT OIL	VISCOUS OIL	GAS DRY
kx	**ky**	**Sqrt (kx*ky)**	**Well Test Permeability (First Radial)**		
1600	1600	1600.0	801	465	1060
1600	1440	1517.9	753	442	984
1600	1200	1385.6	701	398	890
1600	960	1239.4	621	356	792
1600	800	1131.4	558	323	719
1600	640	1011.9	500	290	631
1600	400	800.0	395	230	475
1600	320	715.5	347	202	429
1600	160	506.0	243	143	300
1600	80	357.8	166	101	202
1600	16	160.0	70	45	84

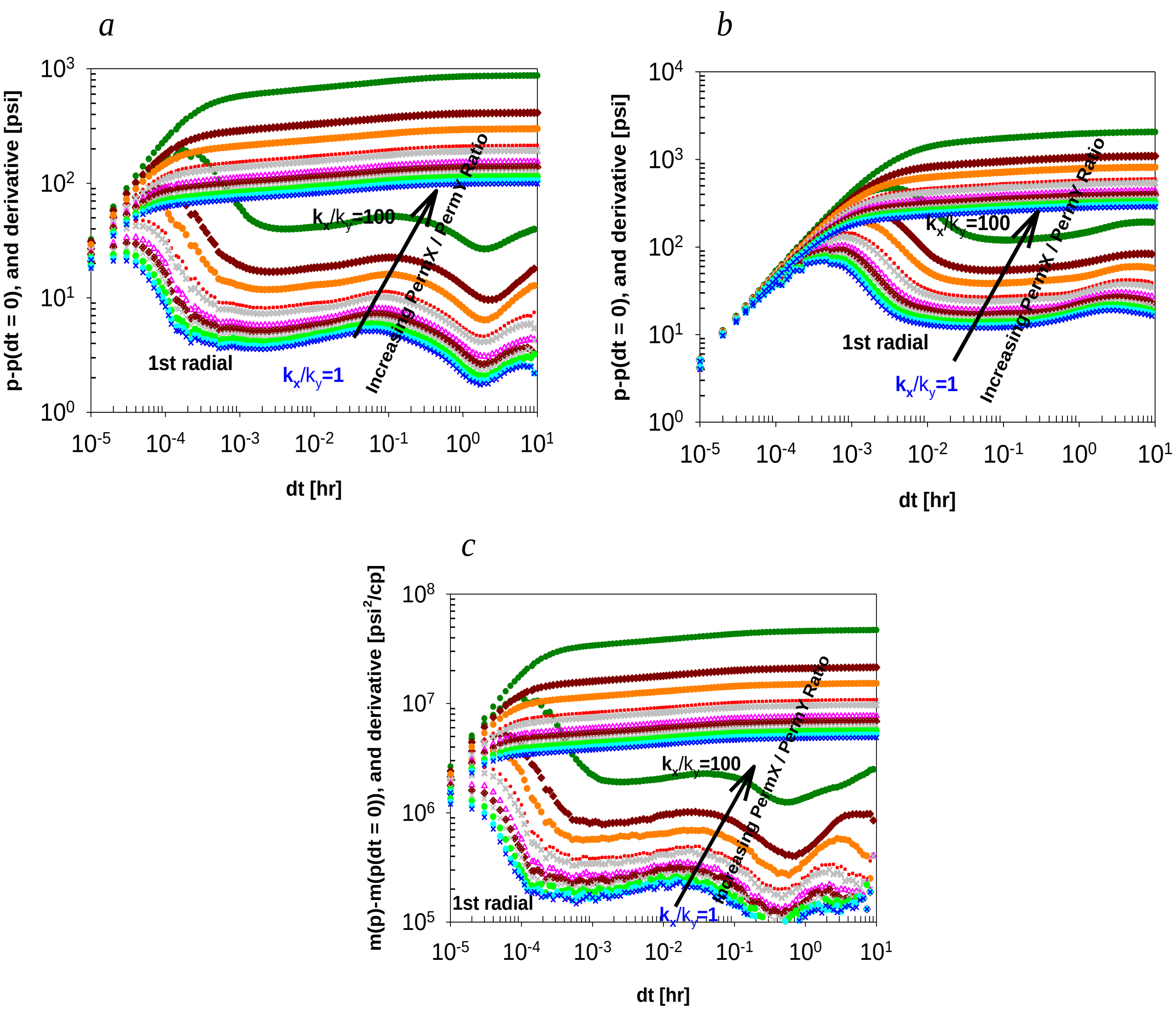

Figure 10. Pressure responses for different equivalent isotropic horizontal permeability of the channel for a) light oil, b) viscous oil, c) dry gas.

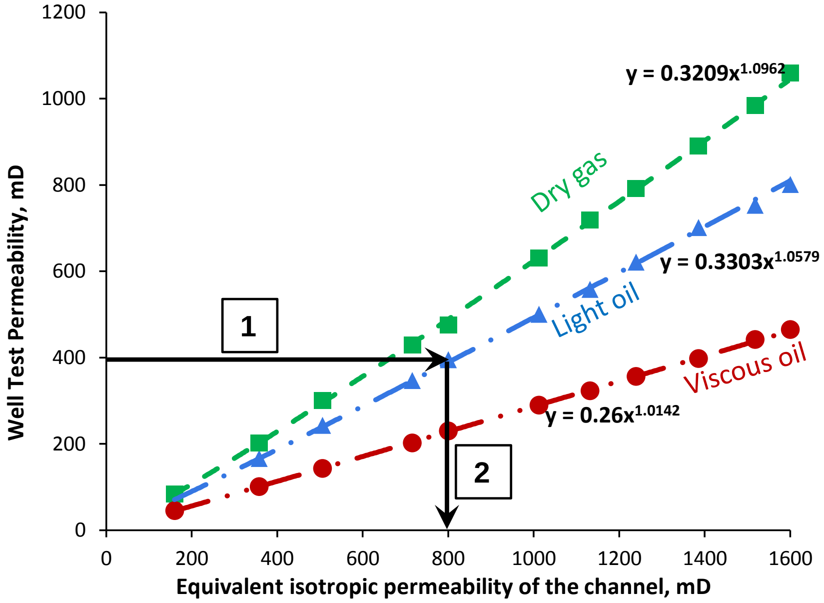

Figure 11. Relation between the first radial permeability from the well test and the equivalent isotropic horizontal permeability of the channel.

Effect of the distance to the interface of channel-heterolithics

This section focuses on the sensitivity analysis of the effect of distance to the interface of channel and heterolithics. For this analysis we divided our investigation into two parts; first it is assumed that channel and heterolithics have homogeneous permeabilities, and in the other part, we combined the effect of permeability heterogeneity of channel and heterolithics with distance to the interface of channel-heterolithics.

Case 1: Homogeneous permeabilities in channel and heterolithics

To investigate the effect of distance from the wellbore to the interface of channel-heterolithics, simulations were performed for different distances (between 13 and 351 ft, Table 2 shows the details), assuming homogeneous permeabilities of 1600 and 32 mD for channel and heterolithics facies respectively.

Although there is a qualitative pattern in the log-log plot, it is not easy to determine a clear and practical relationship from this analysis (Figure 12 a, c, e). However, the semi-log analysis of normalized pressure versus superposition time can be used to develop a relationship to characterize the distance to the interface of channel-heterolithics. As it is shown in Figure 12 b, d, and f, depending on fluid type, normalized pressure curves show a uniform qualitative trend versus time, at times larger than a characteristic value which is indicated by a dash line. At this characteristic time, depending on the distance to the interface of channel-heterolothics, different normalized pressure can be observed, which might be a good signature for reservoir characterization.

Light oil and dry gas, showed that at the superposition time of -1 onwards, a uniform behaviour of the normalized pressure curves for different distances to the interface channel-heterolithics can be expected. However, for the viscous oil, the uniform behaviour of the normalized pressure for different distances to the interface happens at a superposition time of -0.15.

Thus, the corresponding normalized pressure values at the characteristic time were embodied in Table 2 (Case 1) and the graph of these normalized pressure values versus distance to the interface of channel-heterolithics provides a logarithmic relationship (Figure 13).

This plots can be used to identify the distance from the wellbore to the interface of channel-heterolithics through the following two steps:

First, the normalized pressure from the semi-log analysis can be entered into the Y axis. Then, the intersection with the corresponding fluid of the reservoir (e.g., light oil in Figure 13) will provide the user with the distance to the interface of channel-heterolithics on the X axis.

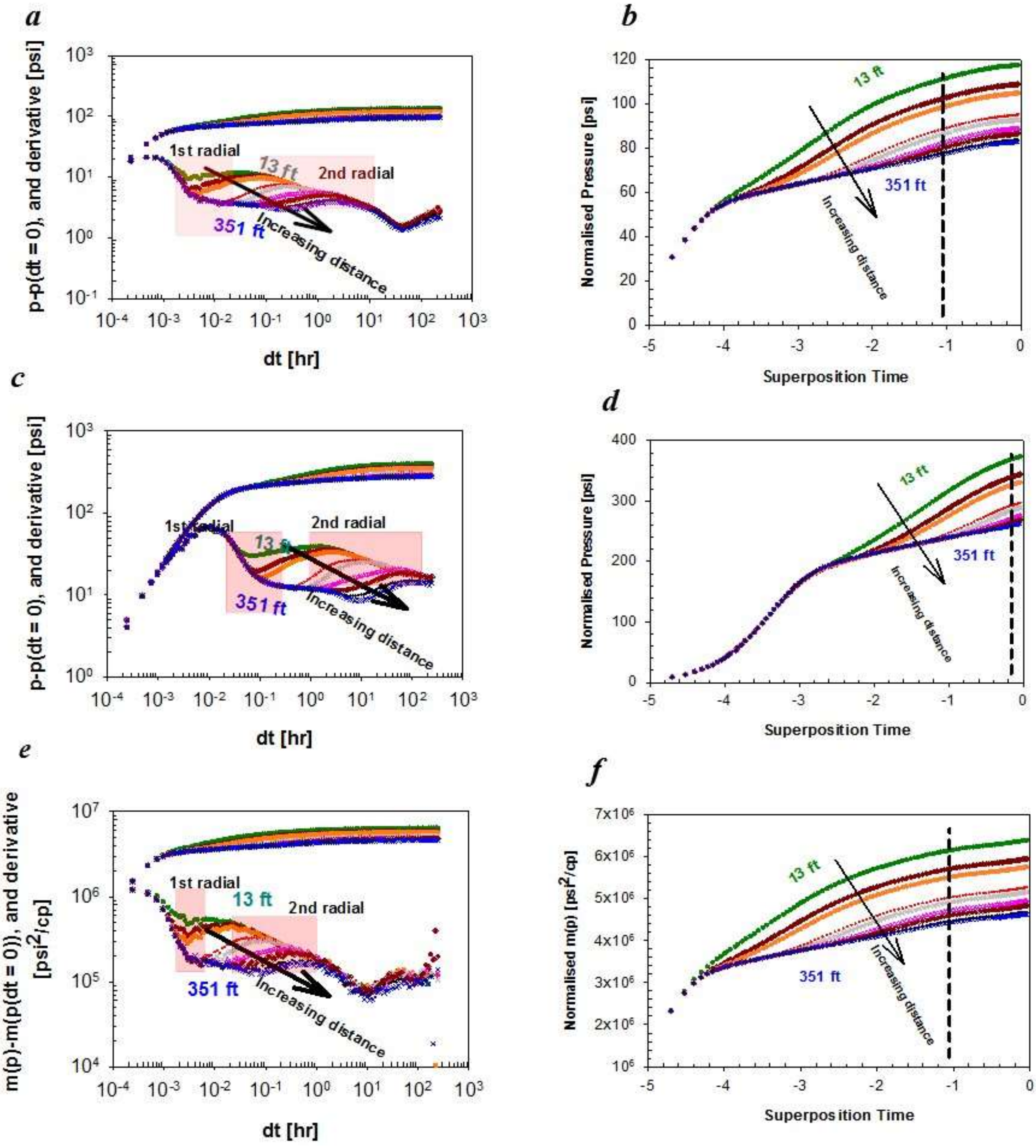

Figure 12. Pressure response sensitivities for different distances to the interface of channel-heterolithics for a reservoir with a) light oil, c) viscous oil, e) dry gas, Normalized pressure versus superposition time for a reservoir with b) light oil, d) viscous oil, f) dry gas.

Table 2. Pressure normalized values from a semi-log plot for the different distance to the interface tested for the different fluids involved.

	LIGHT OIL		VISCOUS OIL		DRY GAS	
	CASE 1	CASE 2	CASE 1	CASE 2	CASE 1	CASE 2
Distance to the Interface (ft)	**Normalized Pressure (psi)**		**Normalized Pressure (psi)**		**Normalized m(p) (psi^2/cp) × 10^6**	
13	111.805		369.796		6.18	
23	106.424	109.327	340.77	355.299	5.744	6.215
32	102.569	105.233	327.22	341.556	5.538	6.008
78	92.422	94.81	293.23	306.619	5.051	5.493
105	90.257		285.012		4.941	
142	85.9285	88.07	271.302	283.934	4.734	5.152
192	83.777		264.729		4.625	
260	81.216		260.89		4.491	
351	80.11		258.88		4.433	

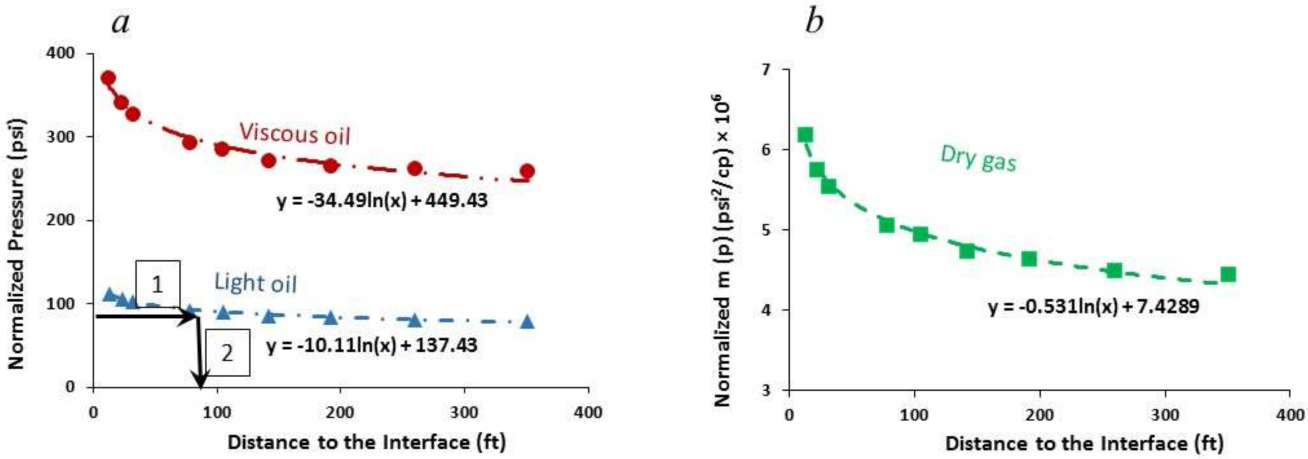

Figure 13. Normalized pressures/pseudo-pressure vs distance to the interface of channel-heterolithics for a) light and viscous oil reservoirs, b) a gas reservoir.

Case 2: Heterogeneous permeabilities in channel and heterolithics

In order to generalize the application of the relations extracted in previous section, a second case was designed considering the channel and heterolithics facies with permeability heterogeneity as shown in Figure 6.

Therefore, for the second case, heterogeneous model that was developed with petrophysical properties propagated in the reservoir through statistical distribution tools, was used. It is remarkable that there is a great difference in permeability ranges between the channel (1500 – 2000 mD) and heterolithics (roughly 32 mD).

The pressure behaviours were very similar to the developed plots for Case 1 (due to qualitative similarity of the graphs with those reported for Case 1, they are not presented here). And the analysis of the normalized pressure versus distance to the interface of channel-heterolithics (four different distances) for Case 2 were performed and the same characteristic times were observed. Finally, the relationships obtained between the normalized pressures and the distance to the interface were plotted along with those developed for Case 1. As shown in Figure 14, the relationships practically remain the same.

The results from Case 2 reaffirm the application of the relationships obtained for Case 1. Therefore, it is possible that the normalized pressures can be used to characterize the distance to the interface of channel-heterolithics.

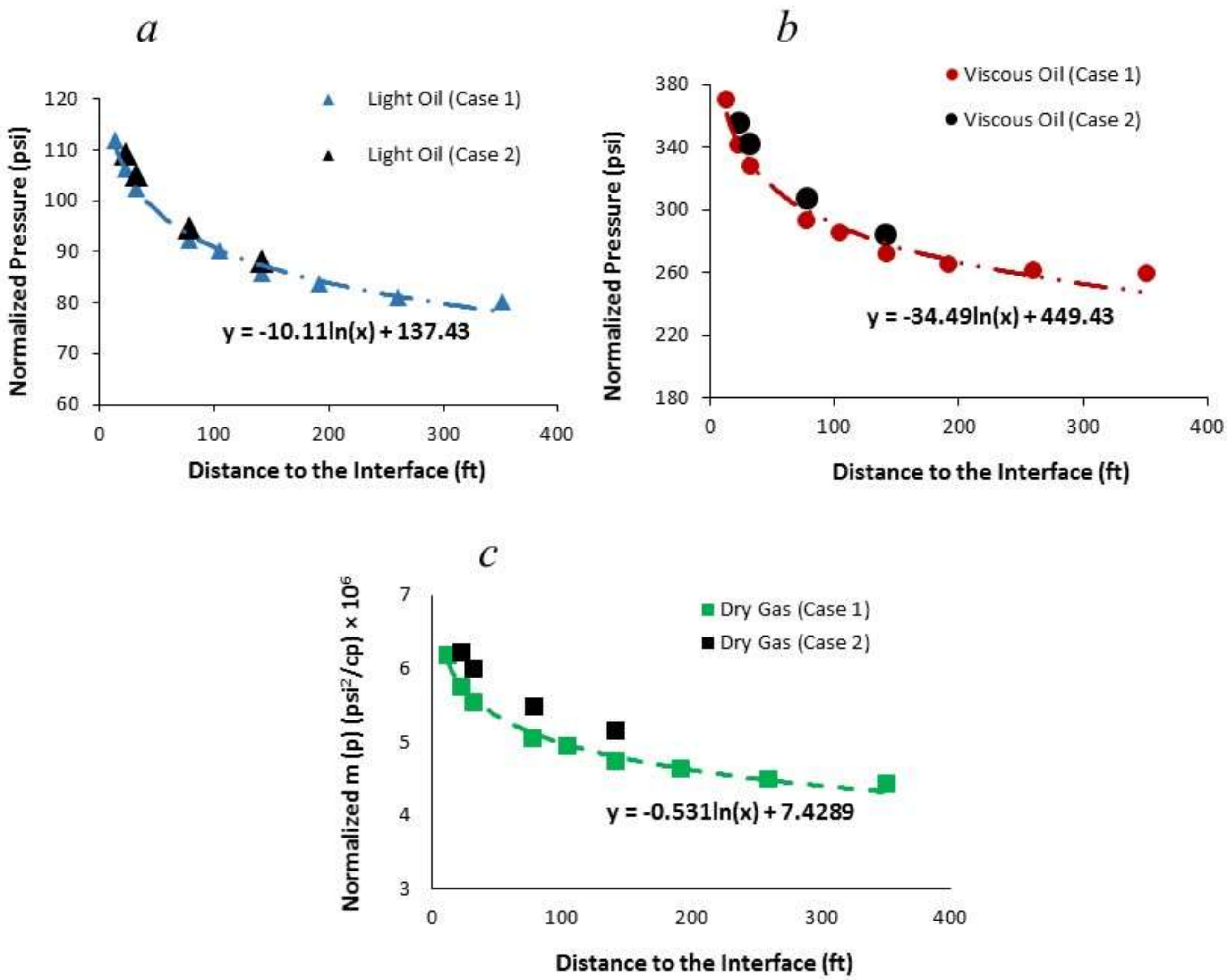

Figure 14. Normalized pressures versus distance to the interface for a) light oil, b) viscous oil, and c) dry gas reservoir, with uniformized and heterogeneous facies for channel-heterolithics.

Effect of the permeability contrast between the channel and heterolithics

Another petrophysical property that needs to be explored in such heterogeneous formations is permeability change between the channel and heterolithics.

Each formation has its own mobility ratio, also there is a relation between the mobility ratio of the channel and the mobility ratio of the heterolithics. Since the viscosity is assumed constant for both facies, the mobility ratio between the facies will lie entirely on the ratio of permeabilities: k_1/k_2, with k_1 as an absolute permeability of the channel and k_2 as an absolute permeability of the heterolithics.

In order to make a systematic comparison and analysis, the initial permeabilities of the facies were uniformized to 1600 mD and 16 mD for channel and heterolithics respectively, then the absolute permeabilty of heterolithics is varied.

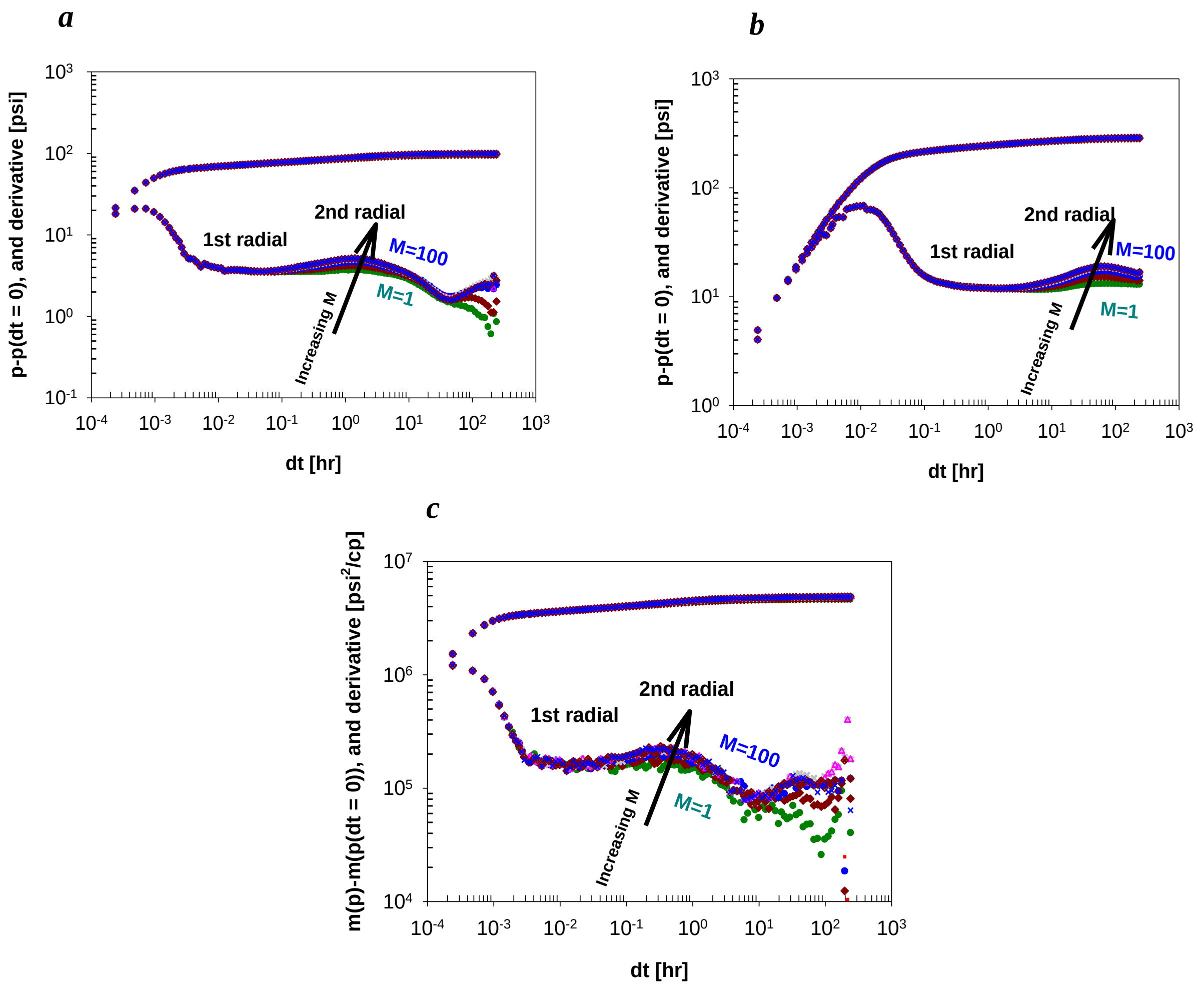

Figure 15. Pressure response sensitivities to change in Mobility ratios (M) for reservoir with a) light oil, b) viscous oil, c) gas.

Figure 15 shows the higher permeability ratio between facies (higher difference between channel and heterolithics permeability), the lower second radial well test permeability. Similar trends were developed for the light, viscous and dry gas reservoirs.

The interesting result of this sensitivity analysis is a relationship established between the known permeability ratios (absolute permeabilities from facies) k_1 and k_2 as inputs to the model, and the effective permeabilities obtained from well test analysis of both radial flows, k_1' and k_2' (well test permeabilities) that are presented in Table 3.

Based on these values, it is possible to observe interesting logarithmic relations between absolute permeability ratios and obtained permeability ratios from well test as shown in Figure 16. This can be used as a type curve for analysis of heterogeneities in the reservoirs through the following steps:

1. Obtain the well test permeabilities from well test, and locate the value on the Y axis of Figure 11.
2. The intersection with the corresponding fluid of the reservoir (e.g., light oil) can predict the ratio of absolute permeabilities of the channel and heterolithics (or other poorer petrophysical lithology; k_1/k_2) on the X axis.

Table 3. Permeability values obtained from pressure derivative analysis for each type of fluid.

	LIGHT OIL			VISCOUS OIL			DRY GAS		
Mobility Ratio k1/k2	k2' read from Analysis	k1' read from Analysis	k1'/k2'	k2' read from Analysis	k1' read from Analysis	k1'/k2'	k2' read from Analysis	k1' read from Analysis	k1'/k2'
1	852	852	**1.00**	486	486	**1.00**	1100	1100	**1.00**
2	731	852	**1.17**	385	486	**1.26**	1000	1100	**1.10**
5	654	852	**1.30**	338	486	**1.44**	913	1100	**1.20**
10	643	852	**1.33**	323	486	**1.50**	874	1100	**1.26**
25	608	852	**1.40**	309	486	**1.57**	832	1100	**1.32**
50	603	852	**1.41**	309	486	**1.57**	830	1100	**1.33**
75	595	852	**1.43**	305	486	**1.59**	826	1100	**1.33**
100	596	852	**1.43**	303	486	**1.60**	817	1100	**1.35**

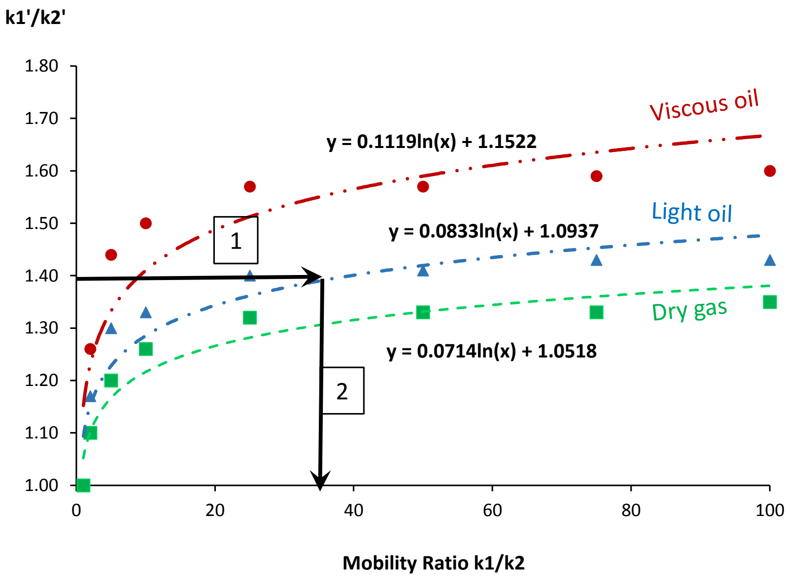

Figure 16. Effective vs. absolute permeability ratios for light, viscous and dry gas.

This type curve is geologically helpful, as by knowing the ratio of effective permeability (well test permeabilities), one can infer the absolute permeability of other geological body next to the main sand body. Therefore, this method could provide geologists with numerical evidence of an abrupt change in permeability between bodies; although, it is under certain reservoir assumptions such as volumetric, closed system and no aquifer.

Characterization algorithm

Based on the results from parametric studies in previous sections, we can propose a characterization algorithm for the heterogeneity associated with channelized heterolithic beds. First step is to generate type curves similar to Figure 11, based on the observation from core data and fluid type. Then through first radial permeability of well test results, one can find the equivalent isotropic permeability around well ($k_1=k_{eq}$). Next step is to develop type curves for the distance to the interface of channel-heterolithics by having a close guess for an average permeability of heterolithics ($k_2=k_{guess}$). Thereafter, type curves similar to Figure 13 can be generated, and the distance to the heterogeneity will be estimated. Now an estimate of the distance to the interface of channel-heterolithics is available, type curve for permeability ratio estimation can be developed (similar to Figure 16). Based on this type curve a permeability value for heterolithics will be estimated. If the estimated permeability of heterolithics is in the range of tolerance with its initial guess, then the characterization is complete, and permeabilities of channel and heterolithics, and the distance to the interface of channel-heterolithics can be reported. If permeability of heterolithics and its initial guess are different, then the guess value needs to be updated with the new permeability of heterolithics, and steps should be repeated until the algorithm converges to the tolerance limit. Figure 17 shows the algorithm that can be used for reservoir characterization.

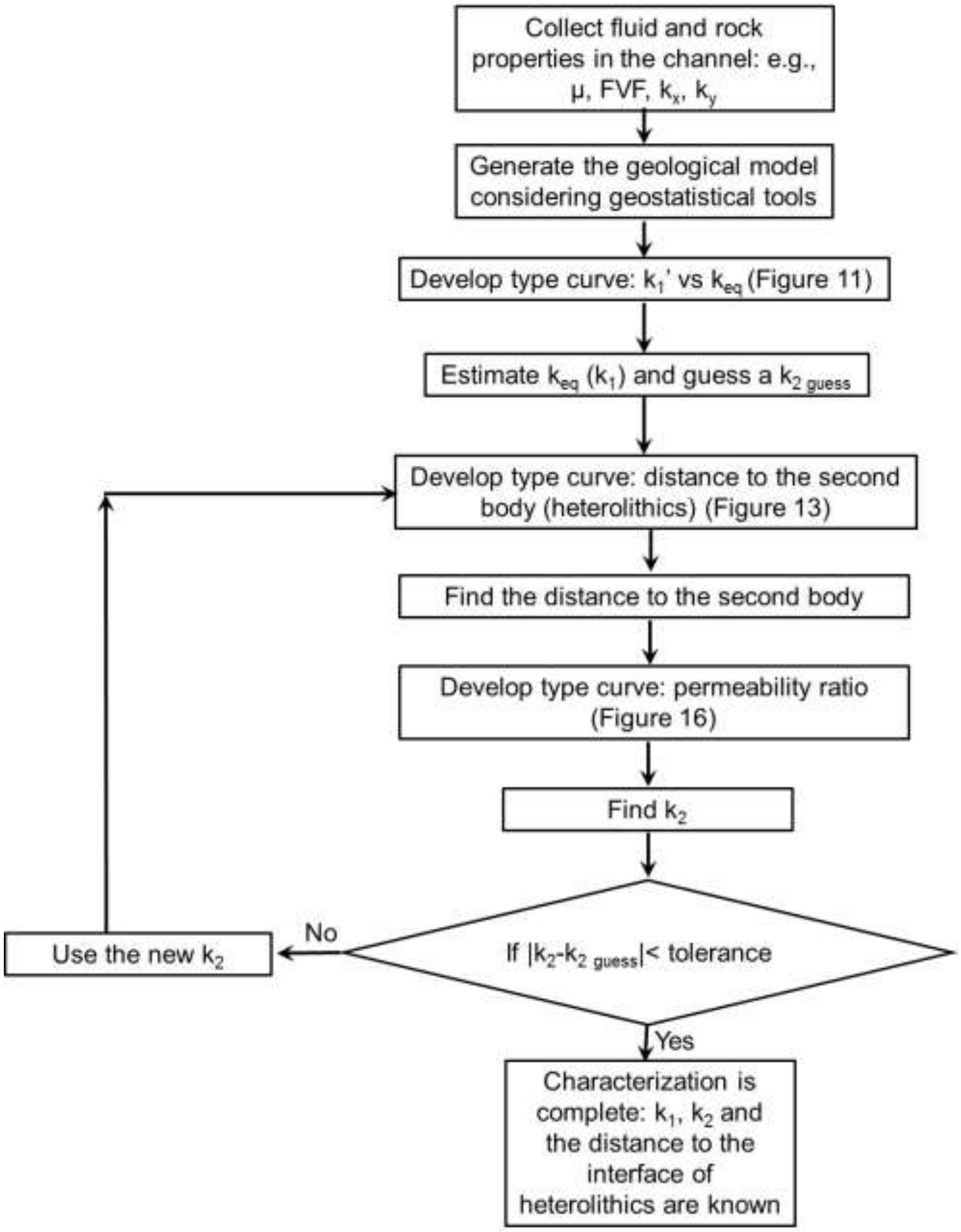

Figure 17: Characterization algorithm for channelized heterolithic beds.

Conclusions

The data generated through synthetic well tests have been analysed and used to determine informative signatures of pressure transient analysis. These well test signatures could provide geologists and engineers with insights about the pressure transient responses in heterogeneous reservoirs, mainly in a channel-heterolithic environment.

A series of type curves can be developed based on the algorithm presented in this study. First a valuable relationship between well test permeability and the equivalent isotropic horizontal permeability of the channel can be obtained. Then, using the normalized pressure data from semi-log plots, we found out that there is a relation between the normalized pressure and the distance to the interface of channel-heterolithic. Therefore, through this type curve the distance to the interface of channel-heterolithic can be estimated. Once the distance to the interface of channel-heterolithics and isothropic permeability of the channel are known, the last characterization type curve can be developed based on the ratio of well test permeabilities for the channel and heterolithics. Through this type curve one can determine absolute permeability of the secondary geological body i.e., heterolithics, next to the main channel. These type curves can provide insightful tools to discern quantitatively how the facies are changing, and they might be used with other characterization techniques to reduce the uncertainties in reservoir characterization process.

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