Abstract

Well test analysis has greatly improved over the years. It remains the most suitable source for determining the hydraulic connectivity and effective permeability in large reservoir volumes, and has become an important tool for reservoir characterization, especially with the recent development of complex interpretation models which account for detailed geological features.

Well test analysis in fluvial reservoirs is still challenging, however, due to a depositional environment conducive to significant internal heterogeneity. Analytical models used in conventional analysis are limited to simplified channel geometries and therefore fail to capture key parameters such as sand body dimensions, orientations and connectivity which control fluid flow and pressure behaviour. This paper aims at a better understanding of the impact of channel content in complex fluvial channel systems on well test derivative responses. To achieve this, a catalogue of 870 drawdown type curves was generated (using a 3D numerical simulator) for different channel contents, body shapes, body dimensions and permeability contrasts.

The paper also illustrates how geological reservoir parameters can be identified, using data from a fluvial North Sea reservoir. A workflow is described for matching field test data with the type curves generated in this study to obtain the fluvial channel characteristics. This then enables the geological description in a full field simulation model to be constrained to well test data, thus reducing uncertainty, aiding development decisions, and improving predictions of the final recovery. Because the match is non-unique, a large number of geological realizations is required, which can be reduced by a good geological understanding of the reservoir.

Introduction

The movement of fluids underground is of interest to many aspects of engineering. Reservoir engineers are concerned with the movement of hydrocarbons and water in the subsurface that affects the development strategy of a reservoir. This movement is affected by the architecture of the subsurface, which is difficult to understand for complex geological depositional environments.

Fluvial reservoirs are economically important worldwide due to their large hydrocarbon reserves (Corbett et al., 1998 and Toro-Riviera, 1994) and are typical of the North Sea. Fluvial deposits are sediments transported and deposited by rivers in continental environments. These include: i) alluvial fans formed at the base of mountains or mouths of rivers with fan shaped sedimentary bodies; ii) fan deltas...
formed at the base of mountains in marine waters; iii) braided rivers formed at the base of mountains extending on a steeply inclined surface; and iv) meandering river deposits formed on gently inclined floodplains. There is a high variability in architecture (sinuosity and shape), internal heterogeneity (petrophysical properties), spatial distribution (connectivity), and channel patterns which range from single storey channel bars to multi-storey and laterally interconnecting channel complexes. Consequently, the characterization of reservoir properties is difficult and subject to large uncertainties (Corbett et al., 2012).

Reservoir characterization combines geological and reservoir engineering knowledge. The mutual dependence between disciplines is now well-recognized (Massonnat et al., 1993). The integration of geological description and dynamic behaviour through geological modelling and numerical simulation (Zheng et al., 2007) allow to identify heterogeneities influencing fluid flow, evaluate reservoir properties and predict reservoir dynamic behaviour. The architectural make-up of the reservoir is particularly important in fluvial systems due to the dimensions of architectural elements, their amalgamation, areal coverage and the potential presence of flow barriers. These affect fluid connectivity, pressure response and final recovery (Alpak et al., 2008).

Well test analysis is a powerful tool for understanding reservoirs (Gringarten, 2008) through the use of analytical models that account for dominant geological features, such as pinch out boundaries (Horne, 1981; Mijinyawa and Gringarten, 2008); channel boundaries in long, narrow reservoirs (Nutakki, 1982), etc. Well test interpretation can be used by geologists to improve their geological understanding of the reservoir system by confirming no-flow boundaries (Corre, 1990), composite (Carter, 1966) and double porosity behaviours (Bourdet and Gringarten, 1980) and by allowing estimates of sand body dimensions that are critical for geological modelling (Alabert and Massonnat, 1990). Conversely, good geological knowledge of the depositional environment helps well test interpreters in selecting the most appropriate analytical well test model from a series of possible solutions (Massonnat and Bandiziol, 1991; Chen et al., 2012). The overall objective is to optimize the development strategy (Zambrano et al., 2000).

The drawback of analytical well test analysis solutions is that they can only be derived by reducing complex architectures to simplified geometries. For example, a channelized reservoir is represented as two parallel sealing boundaries (Nutakki, 1982), or as a composite linear strip reservoir with different mobilities and diffusivities to represent the levee complex (Bourgeois et al., 1996). In reality, channelized systems are very complex networks of intersecting and meandering sand bodies with varying permeabilities, porosities and connectivity, leading to complex well test behaviours (Figs. 1 and 2). This complexity is not captured in analytical models, and therefore the information associated with the complexity cannot be obtained.

Figure 1—Schematic well test response of the flow regimes from a fluvial well test. The flow regimes are illustrated schematically in Fig. 2.

[Graph: Schematic well test response of the flow regimes from a fluvial well test. The flow regimes are illustrated schematically in Fig. 2.]
Numerical simulations, on the other hand, can represent complex fluvial environments more easily. They allow a more realistic representation of the subsurface and consequently, more information from well tests.

Massonnat et al. (1993) used stochastic modelling and numerical simulation to investigate the ability of well tests to capture the stratigraphy of a fluvial reservoir. Zambrano et al. (2000) and Mijinyawa and Gringarten (2008) simulated meandering channels and found that qualitative and quantitative information on the meander could be obtained from the derivative shape in the transition between the radial flow stabilization and the final channel boundary behaviour. Chen et al. (2012) simulated well tests in turbidite reservoirs and demonstrated that object dimensions and shale drape coverage had the greatest influence on the pressure response. Corbett et al. (2012) identified a characteristic ramp effect on the pressure derivative, defined as a monotonic increase between an initial and a final radial flow stabilization lasting at least one logarithmic cycle (Fig. 1). The ramp effect could have many causes, including changes in connectivity and permeability thickness, hydraulic fractures, fluid heterogeneity, and differential depletion between layers. The gradient of the ramp increases as the vertical permeability decreases and, for certain gradient ranges, the ramp could be mis-interpreted as indicative of linear flow. Hamdi et al. (2014) generated a catalogue of simulated well test type curves for different reservoir realizations and demonstrated that facies distribution was a stronger controlling factor of the well test response than petrophysical variations such as porosity or permeability.

Hamdi et al. (2014) describe situations where no single realization could match actual test data entirely, requiring the combination of two different realizations. More common, however, is a situation where data can be matched with several different realizations. This is the well-recognized non-uniqueness problem (Massonnat and Bandiziol, 1991; Corbett et al., 1998; Sahni et al., 2007; Mijinyawa et al., 2010). The non-uniqueness decreases as the amount of information increases (Gringarten, 2008).

The objective of this paper is to further investigate how well test analysis can be used to interpret field data in fluvial environments in order to reduce uncertainty in the geological parameters, improve reservoir characterization and ultimately facilitate better field development decisions. Well test pressure and derivative type curves for various geological realizations of a fluvial reservoir system are generated using 3-D geological modelling and simulations to investigate the effects on connectivity and effective permeability, of changes in model parameters such as body dimensions, orientations, net to gross (NTG) ratio, presence of structural barriers and permeability contrasts between facies. A workflow to determine fluvial channel characteristics from field test data is presented, and illustrated with a North Sea example.
Methodology

A three-stage approach was followed, adapted from the workflow used by Chen et al. (2012), and modified by Hamdi et al. (2014), to generate enough geological realizations to capture the respective behaviours: (1) 3-D geological models were created to generate multiple geological realizations; (2) the geological realizations were numerically simulated to generate pressure responses. The pressure responses were analysed using a commercial well test analysis software package to compare pressure derivative behaviours from the different realizations and build a catalogue of drawdown type curves; (3) deconvolved field well test data were checked against the catalogue of drawdown type curves to estimate the reservoir properties of a North Sea field.

Geological modelling

3D geological models with a centrally located well were generated and populated with varying fluvial geologies. A 6950m by 6950m by 300ft geological model was set-up which allowed the averaging effects of the heterogeneities and the reservoir boundaries to be visible on the derivative at late times. The grid cell size was based on the size of sand bodies found in a high temperature high pressure reservoir in the Skagerrak formation of the North Sea (field X). The geology of Field X is similar to that of the Williams Fork formation (Mamm Creek field), with numerous isolated and amalgamated channels, and sandstone deposits from meandering and braided river systems (Pranter et al., 2013). The primary reservoir is Triassic and consists of a succession of stacked fluvial deposits with the moderate net to gross ratio of the Joanne member of the Skagerrak formation. It includes channelized, sheet flood and crevasse splay components, with unspecified degree of reservoir to non-reservoir facies interaction (Archer et al., 2010).

Modelling the geology of a fluvial system is challenging due to changes in channel amplitude, amalgamation and other processes through geological times, which yield highly variable distribution and shapes of fluvial deposits. As recommended by Pranter et al. (2013), Field X was modelled as isolated elliptical sand bodies and channel bodies, with sand body dimensions of 105m (width) by 420m (length) by 5ft (thickness) for the base case. The sensitivities carried out are summarized in Figure 3. The sand and channel bodies are schematically represented in Figs. 4 and 5. Object orientated modelling was used instead of stochastic, sequential indicator simulation and Gaussian simulation to retain control over the modelling parameters in order to study the effects of sand body parameters and modelling techniques on the pressure derivative responses.

![Figure 3—Schematic of sensitivities undertaken during the study to investigate the influences on pressure derivative responses in fluvial systems.](image-url)
Numerical simulation

The corresponding pressure and derivative dynamic responses were generated using a proprietary finite element simulator with a uniform grid and a fine local grid refinement (LGR) around the wellbore. The grid cell size was selected to be compatible with the expected dimensions of the geological bodies. LGR was optimised to reduce run times and give accurate and non-spurious pressure derivative responses, free of modelling artefacts. The fluid was black oil at a reservoir pressure well above the saturation pressure and the relative permeability to water was low enough to limit water movement within the model. The simulated pressure responses were checked against analytical solutions to verify that PVT and relative permeability were adequately captured in the analytical model.

A total of 870 responses were catalogued based on Fig. 3, that cover sensitivities to horizontal and vertical permeability, sand body type and dimensions, presence of faults and barriers and seed number.

Results and Discussion

Base case model

A drawdown of 115 years was simulated for a geological model 6950m x 6950m x 300ft with a cell size of 50m x 50m x 5ft in the x, y and z directions, respectively (total cell count without LGR = 1,159,260), with a fine cartesian local grid refinement around the wellbore to reduce numerical artefacts around the wellbore (total cell count with LGR = 1,327,200). The model consists of two facies with the properties listed in Tables 1 and 2, respectively. All simulations were performed without including wellbore dynamics or mechanical skin.

Table 1—Base case model properties

<table>
<thead>
<tr>
<th>Description</th>
<th>Facies 1 (sand/channel)</th>
<th>Facies 2 (non-sand/shale)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir quality sand channels represented as</td>
<td></td>
<td></td>
</tr>
<tr>
<td>isolated and elongated ellipses</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>20</td>
<td>20</td>
</tr>
<tr>
<td>Horizontal permeability (mD) (k_x)</td>
<td>100</td>
<td>0.01</td>
</tr>
<tr>
<td>Vertical permeability (mD)</td>
<td>k_x* 0.1</td>
<td>k_x* 0.1</td>
</tr>
</tbody>
</table>
Effect of channel content

The channel content was increased from 5% to 100% in 5% increments. Varying the sand content in the geological model affects the connectivity and flow communication within the reservoir. The models generated contained a column of sand around the wellbore to allow all layers to be connected. Figure 6 shows the dimensionless simulator-generated responses. They all exhibit the monotonically increasing ramp effect between early and late time stabilizations described by Corbett et al. (2012).

The average permeability can be estimated from the value of the derivative of each plateau, with the late time stabilization corresponding to the final effective permeability of the system. That permeability decreases with channel content, indicating a decrease in mobility away from the well, Fig. 6.

An increase in channel content increases the lateral connectivity (and hence pressure communication). The initial radial flow stabilization is followed by a shallow gradient transition of short duration, followed by a low final stabilization. This indicates a high mobility reservoir. The response for a 70% channel content is similar to that of a fault, with a stabilization at twice the initial radial flow stabilization, another example of non-unique well test interpretation.

A decrease in channel content corresponds to an increase in the duration of the transition zone (6 log cycles at 5% channel content) with the gradient between the two stabilizations increasing to a near unit-slope as channel content approaches 5%. Pressure derivative responses show that the effective permeability does not decrease to zero as channel content decreases, but tends to the lowest permeability value of the system. The time for reaching the boundaries (around a dimensionless value of 10^8 at high channel content) increases with decreasing channel content. Figure 7 shows how effective permeability changes with distance, with a rapid decrease close to the wellbore in low channel content channels.

### Table 2—Geometric body dimensions for base case model

<table>
<thead>
<tr>
<th>Geometric body dimensions</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Width (m) (W)</td>
<td>105</td>
</tr>
<tr>
<td>Thickness (m)</td>
<td>W*4</td>
</tr>
<tr>
<td>Orientation (°)</td>
<td>180</td>
</tr>
</tbody>
</table>

Figure 6—Base case model: the effect of channel content on the pressure derivative response (seed number: 1992). Inset table quantifies the initial, stabilization and effective permeability of each system.
Effect of seed number

The seed number controls where the geological bodies are positioned when generating the geological model. As the number changes the sand bodies are positioned in different locations. This number is random during model construction, and therefore investigating the effects on pressure derivative will give an insight into the caution required for model construction. The geological model here is generated using geological bodies based on the base case model changing the seed number only.

The effect of changing the seed number does not affect fundamentally the construction of the model; keeping the same properties, dimensions and dispersion of each facies per layer, with the location of the sand bodies changing with seed number only. Figure 8 shows the response of changing seed number in a 40% channel system. The effect on pressure derivative is small, affecting the shape of the transition period between initial and final stabilization, with the latter remaining relatively consistent with changing seed number. This proves a difficulty for interpretation with a short duration well test. The early time behaviour is consistent between simulations, with variations occurring at early-late times.

It does however affect the static connectivity of the reservoir significantly below 25% channel content. This is explained through percolation theory, or the ability of clumping in random environments, i.e. when the channel content is low, the random distribution of the sand bodies has a significant impact on the
ability for these to be connected. In a system with less than 25% channel content there is a decrease in the connected volume of the system. Above this value the connectivity increases exponentially until 100%, displaying a characteristic S-curve (Larue et al., 2006).

This effect can also be created through the presence of impermeable barriers or mudstone drapes. The significance of this is the decision on development strategy and subsequent reservoir performance. The effect of seed number is more sensitive with increasing sand body dimensions. For instance, modelling using larger sand bodies decreases the likelihood of these being connected, as there is a smaller number of larger bodies at a certain channel content. This is seen in the results generated in Fig. 9, with the connected volume rapidly increasing from 20% to 25%, and then tending towards 100% thereafter. There is a loose correlation relating connected volume to the final effective permeability. The channel content at 20% highlights the importance of connected volume in respect to seed number, with one seed number representing a significant decrease in connected volume compared to the remainder.

Further simulations on varying channel content show similar results as Fig. 8, with variations in the transition zone and small differences in final effective permeability, with the effective permeability remaining constant above 40%. Fig. 10 shows how seed number affects the final effective permeability.

![Figure 9](image9.png)

**Figure 9**—Connected volume of the system with varying seed number at the extent of the model (3475m from wellbore).

![Figure 10](image10.png)

**Figure 10**—Effect of seed number on final effective permeability

**Effect of horizontal permeability**

The contrast in horizontal permeability between channels and shale is varied. The permeability of the channel sands remains constant at 100mD, with the shale varying from 0mD (an infinite permeability contrast) to 10mD. Fig. 11 presents the results of a 20% channel content system, showing the well-established trend of increasing permeability contrast corresponding to an increase in the gradient of the transitional ramp and final stabilization (or decrease in the final effective permeability of the system). With decreasing permeability contrast, the length of transition zone decreases, resulting in the heteroge-
neities averaging within a shorter time period and the boundaries of the model being detected sooner, due to the speed of the pressure transient wave through the model.

The effect is more prominent where the contrast in permeability is infinite, i.e. channel = 100mD, facies 2 = 0mD, and in low channel content systems. This is due to the connected volume resulting in the boundary of the reservoir being reduced for less than 25% channel content. The orange line in Fig. 11 for a 20% channel content system shows a unit slope response, indicating the boundaries of the model being detected earlier than other contrasts. With the permeability contrast high (facies 2 = 0.0001mD), there is a contribution from all parts of the reservoir, with the final effective permeability of the reservoir tending towards the value of the lowest permeability of the system.

At early and middle times, the responses are consistent with only minimal changes reflected in the gradient of the slope (again highlighting the non-uniqueness of interpretation in complex systems). Changes only occur at early-late times, at an approximate dimensionless time of $10^5$, where the gradients become shallower with decreasing permeability contrast.

When the permeability contrast is high, the flow experienced is predominantly transitional for the majority of the duration of the test, with a short period of radial flow experienced at late-late times. As the permeability contrast between the facies decreases, the period for transitional flow decreases, and a longer period of late-late time radial flow is experienced. Fig. 12 illustrates this through the pressure maps. Numerical simulation can replicate the results through linear or radial composite models with decreasing mobility away from the wellbore, representing a decrease in connectivity within the system rather than a change in reservoir properties away from the well. However, using a numerical model the geology is not captured, only knowing that there is a decrease in mobility (due to the connectivity of the system), but not gaining an insight into the geology causing this (i.e. size, dimension and orientation of sand bodies).
**Fig. 13** shows a summary of the effect of horizontal permeability on the final effective permeability of the system with respect to channel content. **Fig. 13** shows how an increase in channel content corresponds to a decrease in the range of effective permeability. This illustrates that in high channel content reservoirs, the difference in horizontal permeability between facies has a smaller effect on the final effective permeability compared to low channel content reservoirs that are more sensitive to changes in horizontal permeability. Therefore, the significance of horizontal permeability depends on the channel content, hence connectivity, of the system.

**Effect of vertical permeability**

Vertical flow communication is known to have a noticeable effect on the pressure derivative response, *Corbett et al.*, 2012. The vertical permeability, as a function of the horizontal permeability, of the model is increased from a highly anisotropic case (vertical permeability equal to zero, i.e. no vertical cross flow between layers,) to an isotropic case (vertical and horizontal permeability are equal). **Fig. 14** corresponds to a 20% channel content system. This shows how the gradient of the ramp response (transition zone) increases with decreasing vertical permeability. Similar characteristic responses are found in channel content systems varying from 5% through to 90%. Only a vertical well is used for the investigation, therefore the effect is expected to be less than experienced if a horizontal well is used.

**Figure 13**—Effect of horizontal permeability on final effective permeability

**Figure 14**—Comparison of varying the vertical permeability factor with respect to horizontal permeability in a 20% channel content system. Table inset illustrates the change in effective permeability of the system.
The gradient of the ramp increases inversely proportionally to vertical permeability, showing a lower effective permeability corresponding to a lower vertical permeability contrast. With a low vertical permeability the flow communication with the well decreases as vertical cross flow between layers decreases, resulting in layers away from the wellbore contributing less to production. Fig. 15 shows how the effective permeability of the system changes with distance from wellbore, illustrating the sharp initial decrease in permeability, especially in low vertical permeability. The vertical permeability eventually restricts flow, preventing the boundaries of the system being detected within the drawdown.

The effect of vertical permeability is significant, effecting the vertical communication between layers and therefore connectivity with the wellbore. The gradient of the ramp for the system presented in Fig. 14 ranges from 0.5 for an isotropic case to 0.7 for the strongly anisotropic case. This behaviour is witnessed through all channel content systems investigated, with gradients, final stabilizations and transition periods increasing with decreasing channel content. Slopes of 0.9 and 0.05 are experienced for the end member cases of 5% and 90% channel content with a vertical permeability of 0.0001$k_x$ and 10$k_x$ respectively.

Fig. 16 summarises the effect of vertical permeability on the final effective permeability of the system. A decrease in channel content corresponds to a large range of effective permeability. This shows that low channel content systems are more sensitive to variations and that the significance of vertical permeability depends on the channel content.

Fig. 16 illustrates the large effect of vertical flow communication between layers on the final effective permeability. If the vertical permeability is small, 0.0001$k_x$, a sharp increase in final effective perme-
ability is observed compared to a system with no vertical flow communication, highlighting the importance of cross flow for reservoir performance. High channel content systems highlight this effect where the final effective permeability is low with no vertical communication.

**Effect of channel length ratio**
The channel length is a function of channel body width when modelled using Petrel. This is varied using the channel length ratio, ranging from 4 to 32 times the width of the sand body (Base case model width = 105m). This represents the first sensitivity where the geometry of the model is adjusted, with all other properties remaining constant.

The size of channel body chosen for modelling is significant to predict as this will have a direct effect on the connectivity of the system and hence development strategy and potential production mechanisms for the field.

The end member cases chosen for the investigation were interpolated from the Williams Fork formation containing a study on the correlation between channel width and length (Pranter et al., 2013). Fig. 17 shows the effect of changing channel length ratio in a 20% channel content system with all other model parameters constant. The behaviour of the responses is complex; however a similar trend is shown through all channel content systems investigated.

![Figure 17—(L) Comparison of varying channel length ratio in a 20% channel content system. Table inset illustrates the change in effective permeability of the system. (R) Pressure maps of CLR 8 and 32 for 12 months and 111 year production.](image)

In channel content systems less than 60%, a low channel length ratio corresponds to the greatest gradient of transition zone at early-late times between stabilizations, with the late-late time stabilization developing within the shortest elapsed time. In high channel length ratios, a shallow slope is witnessed at middle-late times before a rapid decrease in mobility (or connectivity) at late-late times resulting in a sharp increase in the slope of the transition zone. In low channel content systems, with low channel length ratios the heterogeneities are encountered sooner resulting in a greater decrease in effective permeability initially before averaging (or stabilizing). However, in high channel length ratios the pressure wave travels along the path of least resistance along the length of the channels (north – south, Fig. 17, right), before spreading outwards, encountering heterogeneities later, with a corresponding decrease in mobility at late-late times (1e+8).

With increasing channel content, the behaviour reverses, with an increase in channel length ratio corresponding to the greatest slope before late time stabilization, reflecting linear flow. In low channel length ratios, the increase channel content coincides with increased connectivity, averaging the heterogeneities.
The general trend shown is with decreasing channel length ratios the earlier the heterogeneities are observed and thus the earlier the late time stabilization becomes, therefore having a greater final effective permeability.

In low channel content systems the static connectivity of the system is more sensitive to changes in channel length ratio. At a threshold of 25% channel content, an increase in channel length ratio corresponds to a decrease in connectivity, compared to channel length ratios of 4 and 8 times the channel width remaining well connected with distance from the wellbore as illustrated in Fig. 18. Therefore, an increase in channel length ratio requires a greater channel content before a threshold value is reached and the reservoir becomes fully connected.

**Effect of channel width**

Channel width is varied from 15m to 300m (with channel length ratio constant at 4*width), based on the outcrop study of the Williams Fork formation (Pranter, et al., 2013). Without knowing the characteristics of the sand bodies preserved sub-surface due to post-depositional events and non-uniform settlement, the size of these isolated sand bodies used to represent a fluvial system is unknown and verified through modelling.

Fig. 19 shows the response of changing channel width in a 20% channel content system. In channel widths greater than 105m, the pressure derivative response shows two further stabilizations after the initial radial flow stabilization. The intermediate radial flow period corresponds to a large sand body being detected. A transition zone follows where the heterogeneities of the system are detected with effective permeability decreasing until the final stabilization is reached at late-late times. This behaviour is consistent in low and high channel content systems.
The response of widths less than 200m do not experience an intermediate stabilization, showing a significant decrease in effective permeability (or greatest gradient slope), with the heterogeneities reducing the flow communication of the reservoir and ultimately decreasing the final effective permeability of the system.

Ultimately, a decrease in channel width corresponds to a greater slope of the transition zone and lower final effective permeability, with this behaviour consistent through all channel contents. The effect of changing the channel width on final effective permeability decreases with an increase in channel content until the effect becomes negligible.

**Effect of Full Sealing Fault - Distance**

The classical pressure derivative response for the presence of an impermeable boundary is a half unit slope followed by a stabilization level determined by Prasad, 1975, after the initial radial flow stabilization by:  

\[ P_D' = 0.5 \times \frac{\text{1000}}{D} \]  

This is developed in a homogeneous reservoir, whereas real reservoirs contain complex geological heterogeneities and fluid compositions.

A continuous perpendicular fault is modelled with increasing distance away from the wellbore to understand the effect on the pressure derivative in a complex heterogeneous system. **Fig. 20** shows the pressure derivative response of varying the distance of the northern fault from 100m to 3475m distance from the wellbore in a 40% channel content system.

![Figure 20](image-url)

*Figure 20—Varying fault distance away from wellbore in a 40% system. Table inset illustrates the change in effective permeability.*

The effect of the fault is only detected at middle-late times. However, the response generated is not unique for this feature. The classical double stabilization response for a fault is shrouded within the geological response of the model. With increasing channel content, the classical response becomes more apparent until a homogeneous system is reached in **Fig. 21**, showing the final stabilization two times the initial radial flow.
The early-late time transition is controlled by the geology of the system, increasing in gradient with decreasing channel content. This is followed by the $\frac{1}{2}$ unit slope due to the presence of the fault. With the fault closest to the well, a half unit slope is witnessed earlier, with the final stabilization corresponding to 2 times the final stabilization of the system without a fault, as shown in Fig. 20. This is difficult to interpret in practice as the response from a real system is non-unique and could be interpreted as a further decrease in connectivity away from the well instead of the presence of a fault nearby. In low channel content systems, below 40%, the $\frac{1}{2}$ unit slope response becomes shrouded in the geological response of the system, with the gradient of the transitional ramp response greater than a half unit slope. Therefore the ability to detect the presence of a fault decreases with decreasing channel content.

**Effect of Partial Fault - length**

The length of a partial fault at a constant 400m away from the wellbore is varied from 350m to 4850m in length perpendicular to the orientation of the sand bodies, representing the extreme case. Fig. 22 shows the response of a 40% channel content system. During middle-late times for a period of four logarithmic cycles, the responses are consistent, with the gradient of the transitional ramp determined by the geology of the system over physical features, such as a barrier.

The barrier is detected at an elapsed dimensionless time of $10^6$ (or an elapsed time of 100 hours). This represents a time greater than conventional build up periods, illustrating the difficulty in interpreting such features in heterogeneous systems. For the model with no fault, the initial radial flow stabilization is...
followed by a transitional ramp response, determined by the geology, before a late-late time stabilization corresponding to the average final effective permeability of the system. With decreasing channel content, the gradient of the ramp and stabilization increases respectively. With increasing fault length the effect of the fault becomes more prominent until a full fault is reached across the model corresponding to double the stabilization of the stabilization with no fault present. Intermediate fault lengths correspond to intermediate stabilizations between the two extreme cases of no fault and full fault across the model. The pressure transient propagates around the fault, returning to initial radial flow stabilization with an increase in mobility. The pressure wave encounters the remaining system and the stabilization tends towards the same level as a system with no fault, Fig. 22, right.

Similar to a full sealing fault, the presence of the fault becomes easier to interpret with increasing channel content. Fig. 22 presents a 40% channel content system that shows a ½ unit slope preceding the final radial flow stabilization. However, with decreasing channel content the ½ unit slope becomes shrouded in the geological response and becomes more difficult to detect, as the gradient of the transitional ramp is greater than a ½ unit slope.

**Effect of a partial fault with distance**

A partial fault with a fixed length of 2450m is varied with distance away from the wellbore. A similar response to those observed investigating the effects of a full sealing fault with varying distance, part 7, was established. Fig. L-1 shows the results of varying baffle distance from 100m to 3475m from the wellbore in a 40% channel content system. The responses observed show a ½ unit slope response after the first initial radial flow stabilization followed by a stabilization two times the stabilization of the heterogeneous system with no faults present. The shape and gradient of the ramp response in early-late times is dictated by the geology of the system. This re-iterates the non-uniqueness of interpretation, with a ½ unit slope the sole indication of the presence of a fault without knowing the stabilization due to the geology of the system without a fault, or verification through independent sources (e.g. seismic).

**Channel body modelling – Effect of amplitude**

Channel body modelling is used to represent a fluvial environment, representing the different techniques used in industry to model fluvial reservoirs. The amplitude (a) of the channels modelled is varied from 0m to 1000m based on the Williams Fork formation with a channel width of 100m and thickness of 20m. Fig. 23 shows the results in a 40% channel content system. There is no, or limited amalgamation between channels when the amplitude is 0m. The response is dominated by fluid flow travelling along the length of the channel, north to south, before the pressure wave propagates outwards, corresponding to a rapid decrease in effective permeability (increase in gradient) at late-late times with no final stabilization on the pressure derivative response. With increasing amplitude there is an increase in channel amalgamation resulting in a greater area of the system in communication and therefore earlier radial flow.
This phenomenon is observed in the pressure maps in Fig. 23, right, after 12 months production. This results in a higher final effective permeability. The effect of channel amplitude decreases with an increase in channel content. Above 50% channel content there is minimal difference in the pressure derivative response with varying channel amplitude. However it is difficult to assess the effect of channel amplitude as a change in amplitude results in the channel changing position when modelling using Petrel. Therefore a more thorough investigation with varying well location is recommended.

Channel body modelling – Effect of channel thickness

Fig. 24 shows the results of a channel of fixed wavelength, 2000m, width, 100m, and amplitude, 250m, with varying thickness from 10m to 75m in a 40% channel content system. With increasing channel thickness, the gradient of the transitional ramp response at early-late times and following stabilization at middle-late times increases, corresponding to a decrease in final effective permeability. This is a direct result of the ability to populate the geological model through Petrel. With an increase in thickness, the ability to populate the model laterally whilst honouring the channel content decreases.

The effect of channel thickness decreases with increasing channel content, showing minimal differences in responses at a channel content greater than 60% due to the connectivity and amalgamation of the system resulting in a 100% connected system with the complex heterogeneities becoming averaged.

Channel body modelling – Effect of channel width

The response of varying channel width using channel body modelling is identical to the behaviour experienced through varying the width with geometric body modelling. Fig. 25 shows the response of varying channel width from 50m to 400m in a 40% channel content system with all other parameters constant. With an increase in channel width, the initial radial flow stabilization increases in duration from 1 logarithmic cycle to 2 logarithmic cycles before the transitional ramp response is established at early-late times. Further channel contents investigated observed similar behaviour, with the increase in stabilization duration corresponding to the larger area of sand body initially in contact with the wellbore.
The shape of the transitional ramp response at early-late times is consistent between the varying channel widths with the following middle-late time final radial flow stabilization decreasing with increasing channel widths.

The results presented provide an illustrative guide on the effects using different geological modelling parameters has on the pressure derivative response in a fluvial reservoir. The catalogue of responses generated can be used as type curves for interpreting field well test data to understand the geological parameters to constrain full field simulation models to aid in reducing uncertainty, development decisions and predict final recovery from a fluvial reservoir.

**Identification of possible matching realizations**

In the final step of the workflow the simulated drawdowns generated are used as type curves to analyse a given well test. These represent different scenarios and are compared with field well test data from the North Sea. Possible geological scenarios are considered a match when the error between the type curve and field well test data is reduced to a 10% tolerance. The approach taken is adapted from Chen, et al., 2012, to allow the catalogue of type curves generated to be used as a reference in an attempt to capture the key fine scale and large scale geological parameters.

The workflow allows the catalogue of type curves simulated to be expanded to increase the variety of sensitivities and realizations. To increase the likelihood of an adequate match, a large number of realisations is required due to the highly non-unique problem of identifying small and large scale geological features in the sub-surface. This will identify possible geological modelling parameters to constrain full field simulation models. The following workflow is used:

1. Conventional well test analysis completed to identify flow regimes and boundary locations.
2. Deconvolution for all build-up periods of field well test data resulting in a constant rate unit drawdown in order to compare with the catalogue of simulated drawdown type curves.
3. Deconvolved field pressure response scaled to simulated conditions.
4. Simulated drawdown type curves compared to converted deconvolved derivative of field data to identify scenarios.

**Conventional well test analysis**  Fig. 26 shows the conventional analysis on a 40 hour build-up period from a well test from field X. After the initial wellbore storage and skin (Red) there is the beginning of radial flow stabilization at 0.015hours (Blue), but not established. After 0.02 hours the pressure derivative begins to rise sharply, indicating that the effective permeability of the system is decreasing away from the well. The geological information confirms this and characterises the system as a fluvial reservoir.
At middle times, the derivative stabilizes for half a half log cycle, representing either a background permeability consistency or complex geological changes (Green).

At late-middle times the derivative increases sharply again at a half unit slope (Orange) either due to parallel faults, channel boundaries, or a decrease in effective permeability.

A linear composite numerical model of decreasing mobility away from the well is constructed to represent a decrease in connectivity rather than a change of reservoir properties. Two full sealing faults constrain the numerical model, Fig. 28, right, to generate the corresponding pressure history and derivative match.

Deconvolution All the build-up periods of the field well test data are deconvolved. This achieved a greater radius of investigation and generated a constant unit rate drawdown that is interpreted and compared with simulated drawdown type curves. An initial pressure of 11,410psia is determined from the method proposed by Levitan, 2004. The deconvolved derivative is verified by a lack of late time oscillations and through the ability to reproduce the pressure history and derivative using the same numerical model as with the conventional analysis.

Field conditions scaled to simulated conditions Fluid properties and field conditions differ. Therefore the generated deconvolved derivative and pressure of the field well test data is scaled using equations 1 and 2 for time and pressure respectively (derived from Chen, et al., 2012) to convert field to simulated conditions. The converted pressure and derivative is converted to dimensionless variables using equations 3, 4 and 5.

Field data comparison The simulated catalogue of type curves generated are compared with the field well test deconvolved derivative and pressure, with a correct match accepted if a tolerance of 10% is achieved to determine possible geological modelling parameters.

Fig. 27 presents the results of three possible scenarios that match the deconvolved derivative and pressure response adequately from the type curves generated. However, due to the highly non-unique problem of identifying possible scenarios, the data shown does not match within the 10% tolerance over the entire history, with the likelihood of a match over its entirety increasing with further geological simulations. Table 3 summarises the difference in the scenarios presented.
A sound understanding of possible flow barriers, geological deposition and the extent of the reservoir is required, as these characteristics have a large effect on flow communication and subsequent pressure derivative response. A robust geological understanding of depositional environment and verification through conventional well test analysis can lead to limiting the number of models required to derive a possible scenario that adequately matches a given field well test.

Fig. 28 shows the simulation model used. The simulation model is constrained using conventional well test analysis, Fig. 28, right, and a sound geological understanding before an adequate match with field well test data is achieved. Fig. 28 and table 3 lists the differences between the scenarios used in the geological model compared to the numerical model used for conventional well test analysis. The numerical model, Fig. 28, right, shows how there is a decrease in connectivity away from the wellbore indicated by the decrease in mobility. However, the simulation model, Fig. 28, left, indicates the geological modelling parameters that cause the decrease in connectivity away from the wellbore. This information is used to develop full field simulation models to aid in development decisions and predict the long-term dynamic performance of the reservoir.

Table 3—Scenario properties

<table>
<thead>
<tr>
<th>Scenario</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>Numerical</th>
</tr>
</thead>
<tbody>
<tr>
<td>North fault, distance away (x), m</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>South fault, distance away (y), m</td>
<td>200</td>
<td>100</td>
<td>200</td>
<td>100</td>
</tr>
<tr>
<td>Channel content, %</td>
<td>40</td>
<td>50</td>
<td>40</td>
<td>-</td>
</tr>
<tr>
<td>Vertical Permeability, k_v, mD</td>
<td>0.1k_x</td>
<td>0.001k_x</td>
<td>0.01k_x</td>
<td>-</td>
</tr>
<tr>
<td>Horizontal permeability, k_x (non-channel), mD</td>
<td>0.001</td>
<td>0.001</td>
<td>0.001</td>
<td>-</td>
</tr>
<tr>
<td>Horizontal permeability, k_x (channel), mD</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>-</td>
</tr>
</tbody>
</table>
Field X is a fluvial oil reservoir. Conventional well test analysis located two potential sealing faults forming a channel, confirmed from independent data sources, including seismic. Log and core analysis suggested a high channel content system (~50%). Therefore, the connectivity of the system is responsible for the rapid rise in the deconvolved derivative. For this reason small dimension sand bodies are chosen to represent the dis-connectivity (length = 100m, width = 50m). This narrows the number of possibilities from the catalogue to increase the prospect of a match.

Table 3 summarises the difference in the scenarios presented. This is not an exhaustive comparison, with the majority of type curves generated without the presence of boundaries. Scenario 2 best compares to the numerical interpretation, but scenario 3 has the least error over the entire pressure history, within a 15% tolerance of the field well test, Fig. 29. The position of the fault at a dimensionless time of 10^5 affected the error greatest. The effect of vertical and horizontal permeability combined had a greater influence in providing an adequate match over other sensitivities tested for the given field well test data.

This workflow shows how the well test pressure profile is explained through the presence of large and small-scale features, with the presence of faults and permeability contrast needed to appropriately characterize the well test. It verifies the presence of flow boundaries and possible size of geological modelling parameters in the reservoir that honours the geological understanding. It shows that fundamentally different realizations can produce similar pressure derivative responses.
Conclusion

Previous publications have focussed on turbidite and to lesser extent fluvial reservoirs thus providing only limited understanding of the effect of heterogeneities on pressure derivative responses in a fluvial environment. This paper systematically investigates, through geological and 3-D reservoir simulation modelling, the well test derivative responses of 870 unique geological realizations from a fluvial reservoir for different channel contents, body shapes, body dimensions and permeability contrasts. It is shown that all derivatives exhibit two radial flow stabilisations separated by a monotonically increasing transition. Each radial flow stabilization yields an average permeability, with the late time stabilization corresponding to the final effective permeability of the system. A workflow is also presented for comparing field well test data to the generated type curves, in order to identify possible geological scenarios for a fluvial reservoir and calculate reservoir parameters.

The main conclusions of the sensitivity study are as follows:

● The seed number (which controls where channel bodies are positioned in the geological model) influences connectivity when channel content is less than 25%.
● An increase in the horizontal permeability contrast between channel and non-channel decreases the final effective permeability which tends towards the lowest value modelled in the system, in this case the non-channel. This effect is more sensitive to an increase of channel content when channel content is less than 40%.
● A decrease in vertical permeability decreases the vertical flow communication between layers and increases the gradient of the transition.
● In long channel bodies, the pressure signal initially exhibits a channel-type behaviour as it propagates along the length of the channel then potentially encounters heterogeneities as it spreads laterally. This delays the onset of the final radial flow stabilization. For a channel length to width ratio of 32, a 30% increase in channel content is required to achieve 100% connectivity.
● In channel contents greater than 40%, the transition develops a ½ unit slope when a sealing fault is encountered, before the derivative stabilizes at a level which is twice that without a fault. In channel contents lower than 40%, the ½ unit response is merged into the geological response of the system, and as a result, the gradient of the transition is greater than one half. Therefore, the ability to detect a fault decreases with decreasing channel content.
● In the case of a sealing fault of limited extent, the final radial flow stabilization is between that for a fault of infinite extent and that for no fault
● As channel amplitude increases, amalgamation of the channels increases resulting in an increase in the final effective permeability and in connectivity. The pressure signal propagates laterally whereas it moves along the length of the channel in a zero amplitude system.
● With increasing channel content, the influence of fluvial modelling parameters on the final effective permeability of the system decreases for all sensitivities investigated. Sensitivity to modelling parameters dramatically increases below 25%.

The main conclusions from well test analysis of field test data with the catalogue of drawdown type curves generated in this study are as follows:

● Identification of geological reservoir parameters is possible. As the type curve match is non-unique, a large number of geological realizations must be tested. A good geological understanding of the reservoir can help reduce the number of realizations that need to be tested before a suitable match can be found.
● Adequate matches with field well test data can be obtained with realisations that have different distances to faults, channel content and size of sand bodies. Conventional well test analysis
combined with a good geological knowledge can help selecting between the various realisations matching the field data.

**Equations**

\[ t_f = t_0 \left( \frac{k_h}{h_f} \frac{q_f}{q_i} \frac{P_f}{P_i} \right) \left( \frac{P_0}{P_f} \right)^2 \]  

\[ \Delta p_f = \Delta p_i \left( \frac{k_h}{k_f} \frac{q_f}{q_i} \frac{P_f}{P_i} \right) + 162.6 \frac{q_f}{k_f \mu_f} \log \left[ \frac{q_f}{q_i} \frac{P_f}{P_i} \right] \]  

\[ P_D = \frac{k_h \mu}{141.2 q_i} \Delta P \]  

\[ t_D = \frac{0.000264 \Delta t}{\mu \rho c_f} \]  

\[ c_D = \frac{0.0016 \rho}{\mu \rho c_f} \]

**Acknowledgement**

This study was conducted at ConocoPhillips by the main author in completion of MSc degree requirement at Imperial College. Supervision by Luke Buskie is gratefully acknowledged.

**Nomenclature**

- **B**: Formation volume factor, vol/vol
- **C**: Wellbore storage constant, Bbl/psi
- **CD**: Dimensionless wellbore coefficient
- **ct**: Total compressibility, psi\(^{-1}\)
- **D**: Object dimensions, m
- **h**: Reservoir thickness, ft
- **k**: Reservoir permeability, mD
- **P_D**: Dimensionless drawdown pressure
- **\(P'_D\)**: Dimensionless drawdown pressure derivative
- **\(\Delta P\)**: Pressure drop, psi (\(\Delta P = P_i - P(\Delta t)\))
- **q**: Flow rate, Bbl/day
- **r_w**: Wellbore radius, ft
- **t_D**: Dimensionless time
- **\(\Delta t\)**: Elapsed time for last rate change, hours
- **\(\mu\)**: Fluid viscosity, cp
- **s, f**: Subscripts for simulated and field conditions respectively
- **\(\Theta\)**: Reservoir porosity

**References**


