Figure 7.40. Comparison of water displacement process in scenarios 1-3 after 244 days of production. (A) scenario 1, (B) scenario 2, and (C) scenario 3.
well, the waterflood front begins to advance faster because of the drop in vertical connectivity. The smooth displacement pattern encourages delay in water breakthrough (Figure 7.41, A), allowing more oil production (see Figure 7.30) at much higher rates (see Figure 7.27) than in scenarios 2 and 3. Because of the most delayed water breakthrough and highest oil production rates, scenario 1 is the candidate with the highest cumulative oil production over the five-year period among the three scenarios considered.

In a turbidite reservoir that is characterised by the architecture in scenario 2, average static connectivity is slightly lower (61%) compared to a turbidite reservoir that is typified by the architecture in scenario 1 (68%). As indicated by the SCI profile (see Figure 7.13, B), the static connectivity is relatively uniform over the entire inter-well spacing. Contrary to the SCI profile, the sharp drop in VCI, like in scenario 1, results in a differential displacement within 725 ft radius of the production well. Due to the lower VCI in this region, injected water preferentially sweeps the middle to upper parts of the system rapidly, leaving the lower part to lag behind in oil displacement (Figure 7.40, B). Although VCI is reduced within this region, LCI is increased, allowing injected water to displace more oil laterally. The implication of the near-uniform static connectivity in scenario 2 is evident in the consistently high oil recovery efficiency, which rises higher than in scenario 1 (Figure 7.24). However, the lower static connectivity in the vicinity of the production well translates to lower oil production rates than in scenario 1 (Figure 7.27). The lower rates, in addition to earlier water breakthrough (Figure 7.41, B), result in lower cumulative oil production before and after water breakthrough (Figure 7.30).

Like scenario 2, scenario 3 is characterised by a near-uniform SCI profile (see Figure 7.13, C) but a much higher average static connectivity (69%) and slightly higher lateral connectivity, particularly in the vicinity of the production well (72%). A more prominent influence on the pattern of fluid displacement is the stratigraphic architecture, which in scenario 3 encourages gravity segregation (Figure 7.40, C). This gravity segregation enforces differential oil displacement in favour of layers characterised by high static connectivity. These layers have high net-to-gross and are quickly swept at the expense of lower net-to-gross layers. The lower net-to-gross layers also suffer from low lateral connectivity which, in effect, creates a larger permeability contrast that supports differential oil displacement. As a consequence, the high permeability layers become conduits for injected water after displacing their oil at the time when the displacement fluid is really struggling in sweeping the low-permeability layers (Figure 7.41, C). This situation leads to early water breakthrough (see Figure 7.23), much lower oil production
Figure 7.41. Comparison of water displacement process in scenarios 1-3 after 609 days of production. (A) scenario 1, (B) scenario 2, and (C) scenario 3.
rates (see Figure 7.27) and lower cumulative oil production (see Figure 7.30) in comparison with scenarios 1 and 2. In the long run, as water injection continues, oil in the low permeability layers will be eventually displaced and produced at considerably lower rates in the presence of high water production.

7.5.4 Reservoir performance and oil production decline forecast

The contrasting stratigraphic architecture and reservoir geometry in the three scenarios considered influence their respective production decline. Scenario 1 is characterised by a gradual decline in (oil production) rate with time (Figure 7.33). Scenario 2 by contrast, is marked by initial rapid decline in rate with time (Figure 7.34). Although scenario 3 is associated with initial rapid decline in rate with time, the decline is less rapid than in scenario 2 (Figure 7.35).

The implication of the variation in oil production decline is that in turbidite reservoirs with initial rapid decline in rate as typified by scenarios 2 and 3, oil production with time suffers in the presence of high production rate, giving rise to lower cumulative oil production in the long term. In such reservoirs, recovery efficiency does not suffer, but cumulative oil production suffers in addition to, rapidly declining oil production rates and increasing water production (see Figures 7.24, 7.27, and 7.30). By contrast, in turbidite reservoirs that typify scenario 1, gradual decline in oil production rate encourages higher recovery efficiency before water breakthrough. As a result, such reservoirs are associated with more cumulative oil production than turbidite reservoirs that typify scenarios 2 and 3 (see Figure 7.30). Furthermore, in reservoirs that are marked by the architecture in scenario 1, slowly declining oil production rate gives rise to lower cumulative water production in the presence of lower, but highly consistent, recovery efficiency (see Figures 7.24 and 7.33).

7.6 CONCLUSIONS

Static connectivity is directly influenced by facies types and distribution. These variables vary considerably with stratigraphic architecture as observed in the three scenarios considered in this chapter. The results show that stratigraphic architecture may slightly improve oil recovery efficiency as in scenario 2, but it may also impact negatively on producibility as observed in scenario 3. In addition to the displacement pattern, overall
stratigraphic architecture, geometrical shape and continuity of reservoir facies, and the resultant static connectivity, have profound influence on oil production rates and production decline. Permeability heterogeneity is largest in scenario 3, followed by scenario 2, and causes characteristic flow fingering in these two scenarios. Scenario 1, by contrast, has the lowest permeability contrast and is characterised by a gradual decline in oil production rate, and higher oil recovery efficiency, before water breakthrough.

The nine cases simulated for each of the three scenarios considered reveal that net-to-gross distribution has a profound influence on connectivity and flow properties. As observed in the results, two key controlling factors that increase the variability of net-to-gross distribution are stratigraphic architecture and internal geometry of reservoir strata. The results indicate that the lowest range of uncertainty in connectivity is associated with scenario 2, whereas scenario 3 has a higher mean connectivity associated with the highest range of uncertainty. It can be deduced from the results, everything else being equal, that the vertically-stacked channel geometry with a characteristic multi-storey stratigraphic architecture typified by scenario 2, is a better candidate for development than the multilaterally-stacked channel-levee system, because of the lower range of uncertainty in connectivity, higher oil production rate, higher oil recovery efficiency, a more delayed water breakthrough, and higher cumulative oil production. Relatively low uncertainty in connectivity (lower than in scenario 3), lowest uncertainty in oil production rate, most delayed water breakthrough, and gradual decline in oil production rate (unlike rapid decline in scenarios 2 and 3), which results in highest cumulative oil production, make scenario 1 the best candidate for development.
PART 4

SUMMARY, CONCLUSIONS AND FURTHER WORK
Chapter 8

Summary

Sand-rich sheet turbidite succession
Silurian Mynydd Bach Formation
Aberystwyth Grits Group
Ceredigion (Mid Wales), UK

This chapter provides a brief synthesis and discussion of principal results. Part of the chapter (together with part of Chapter 2) was submitted as a joint publication with my principal supervisor in AAPG Memoir 115 (Turner and Cronin, 2017 in press). Selective sections have been compiled for publication in Marine and Petroleum Geology. References have been collated at the end of the thesis.
Deepwater systems are dominated by thin-bedded turbidite (TBT) and very thin-bedded turbidite (VTBT) facies. These facies have great significance as principal and marginal reservoirs, and as contingent resources in many fields that are producing from deepwater reservoirs. Mud-prone VTBTs have huge potential as deepwater source rocks, unconventional reservoirs and, as good sealing rocks.

From an abundant turbidite literature published over the past 65 years, it is very clear that TBT and VTBT have not commanded the same level of research interest as medium and thick-bedded turbidites. Consequently, our understanding of and models for turbidite systems are still somewhat biased in favour of the thicker-bedded, sand-rich systems. Undoubtedly, more work has been carried out in industry on TBT/VTBTs, especially in the last 5 years, but little if any of this has been published.

Furthermore, complete published predictive flow models of thin-bedded reservoirs are very rare, if they exist at all (Weimer & Slatt, 2004). By contrast, medium and thick-bedded turbidites have been the central focus of many reservoir modelling and flow simulation studies (Eriksson, 1981; King, 1990; Weber & van Geuns, 1990; Cossey, 1994; Martinius & Nieuwenhuijs, 1995; Mijnssen, 1997; Peijs-van Hilten et al., 1998; King et al., 2002; Stephen et al., 2002; Habgood et al., 2003; Larue, 2004; Sullivan et al., 2004; Pyrcz et al., 2005; Sprague et al., 2005; Falivene et al., 2006; Larue & Hovadik, 2006; Mayall et al., 2006; Hovadik & Larue, 2007; Labourdette, 2007; Pedersen et al., 2007; Bentley & Smith, 2008; Chakravarty et al., 2008; Labourdette et al., 2008; Lawrence et al., 2009; Hovadik & Larue, 2010; Richards et al., 2010; Lopez & Davis, 2011; Funk et al., 2012; Sadeghnejad et al., 2012; Alpak et al., 2013; Amy et al., 2013; Stright et al., 2014; Soleimani & Shokri, 2015; Villamizar et al., 2015; Sacchi et al., 2016).

Following the imbalance in these studies, it is not surprising that many subsurface and asset management teams are constantly seeking to understand the dynamics that TBT/VTBT introduces to reserve estimation and growth, particularly during a late phase of production decline. In some of the hydrocarbon-producing deepwater turbidite fields, there have been reports of incremental reserves by unlocking reservoir potentials hidden as bypassed pays within TBT/VTBT intervals (McGann et al., 1991; Wills, 1991; Garland, 1993; Garland et al., 1999; MacGregor et al., 2005; Jones et al., 2015; Rose & Pyle, 2015).
The results presented in this thesis are aimed at providing valuable insights into the hidden reservoir potential of TBT/VTBT facies, and to better understand the characteristics of the *connectivity bridge* (defined here as the connectivity between primary and secondary reservoir facies) between intervals of TBT/VTBT facies and other turbidite facies within a channelised setting, on the one hand, and in a typical basin-plain setting, on the other hand.

8.2 THESIS OBJECTIVES AND ACHIEVEMENTS

8.2.1 Objectives

The principal objectives of this thesis can be summarised as follows:

(i) Review and appraise TBT/VTBT depositional processes and resultant facies and sequences within the range of deepwater architectural elements.

(ii) Develop a new approach for the characterisation of the various sedimentary attributes of thin-bedded successions in a way that can be easily quantified for application to reservoir models.

(iii) Apply this quantitative approach as a tool to predict lateral and vertical connectivities within individual TBT/VTBT packages and, in particular, across the ‘connectivity bridge’ between TBT/VTBT and thicker-bedded turbidite facies.

(iv) Evaluate small-scale sedimentary heterogeneity in TBT/VTBT attributes and its impact on oil recovery from related reservoir architecture.

(v) Assess the critical risks posed by TBT/VTBT facies to oil recovery from the primary reservoir facies.

(vi) Develop a series of waterflood simulations to capture the connectivity between primary and secondary reservoir sands.
(vii) Quantify the impact of uncertainty in net-to-gross on connectivity of TBT/VTBT and associated channel sands.

The following discussion briefly summarises the advances made towards achieving these objectives, and also makes some more general observations on utilisation of the connectivity bridge concept. For more specific reference to the literature, see the relevant chapters.

8.2.2 Achievements

8.2.2.1 Thin-bedded turbidites overview (Objective i – Chapter 2)

Turbidity currents are one of the most common processes of sediment transport and deposition that operate in deepwater. Turbidite deposits, therefore, are a common facies in many deepwater systems and within these the TBTs and VTBTs are most abundant. These facies are defined for the purposes of this thesis, and specifically with industry application in mind, as having a basal sand/silt component 3-10 cm thick (TBT), and <3 cm thick (VTBT). In many hydrocarbon-bearing turbidite systems, they represent a huge and relatively underdeveloped potential for exploration and production. They are deposited from low-concentration flows (0.25-50 kg/m³) at low velocities (0.15-0.5 m/s) with individual beds deposited in 1 hour (thin sandy turbidites) to several days (silt-mud turbidites). TBTs are characterised by the standard Bouma facies model, whereas VTBTs are represented by the Stow model. Distinctive facies associations are characteristic of turbidites in channel, lobe, open slope and basinal settings, whereas vertical sequences of bed thickness are less easily attributed to specific environments. Small-scale sequences (i.e. micro-sequences), typically of 3-7 beds arranged in symmetric to asymmetric patterns, are the most commonly observed.

8.2.2.2 Attribute indices (Objective ii – Chapters 3 and 4)

The principal geological attributes of TBT-VTBTs include: facies and facies associations, sand-shale ratio, bed geometry, sand connectivity, sediment texture, sedimentary structures and vertical sequences of bed thickness. Their combination enables definition of four fundamental attribute indices that reflect the reservoir quality of TBT-VTBT successions. These indices include: facies net-to-gross, sand connectivity, facies ratio
and sediment textural indices. They can each be readily quantified on a dimensionless scale from 0-1, and thence used as input data for reservoir modelling and simulation, and for characterising associated architectural elements. Typical facies associations of TBT/VTBT systems can be characterised (and hence quantified) by a typical range of attribute indices. Having developed this scheme for TBT/VTBTs, it is evident that the same can be applied to all turbidite types, and so has been extended to medium and thick-bedded turbidites in this thesis.

8.2.2.3 The connectivity bridge (Objective iii – Chapters 5 and 7)

The connectivity bridge is defined in this thesis as the connectivity between primary and secondary reservoir facies. In particular, this thesis has focused on the nature of the connectivity between TBT/VTBT facies (typically the secondary reservoir) and medium to thick-bedded turbidites (typically the primary reservoir). The sedimentary attributes of the constituent facies within this connectivity bridge impacts the scale of permeability heterogeneity, which in turn controls fluid flow. Two separate studies were undertaken in order to apply a quantitative approach to estimate connectivity between: (a) a channel and its associated splay lobe, and (b) a channel and channel-margin-to-slope turbidites. Both studies used real data from the North Brae Field to condition the models. Three different scenarios were erected for each example, each showing different facies continuities, and these clearly demonstrated the significant effects of sediment heterogeneity within the connectivity bridge on water displacement process, oil sweep, oil production rates and water cut. The results demonstrate the importance of siting injector wells strategically to enhance oil sweep, whilst reducing the risk of high water cut, and enhancing ultimate oil recovery.

8.2.2.4 Small-scale heterogeneities affect waterflood (Objective iv – Chapter 6)

In turbidite reservoirs with a significant proportion of TBTs, low-pay sands may be bypassed during reserve estimation, resulting in underestimation of in-place and/or recoverable hydrocarbon. This is commonly due to poor vertical resolution of conventional logging tools. This issue was addressed by the application of selected TBT/VTBT attributes to assess the impact of bed-scale sedimentary heterogeneity on connectivity and oil recovery. Outcrop-based attribute data were collected from a basin-
plain succession in the Basque Basin, Northern Spain, and used to define six scenarios with different bed-scale heterogeneities (especially sand content and thickness). The geological attributes of these scenarios were combined to develop their attribute indices, notably facies Net-to-Gross Index (NGI) and Sand Connectivity Index (SCI). They were then used as input for constructing three-dimensional high resolution models for waterflood simulation studies.

The results of these simulation studies show clearly that high net-to-gross systems have a considerably lower degree of sedimentary heterogeneity and higher values of attribute indices. In these systems, the bed vertical stacking pattern encourages better vertical connectivity (high SCI values) and hence more effective oil displacement, a broader waterflood front, and reduced risk of early water breakthrough. By contrast, low net-to-gross systems have a higher degree of heterogeneity, which leads to early water breakthrough, pockets of undrained oil, and lower cumulative oil production. It is therefore important to use the depletion strategy that will optimise production and minimise bypassed oil for different turbidite system types.

8.2.2.5 TBT/VTBT facies and associated risks to oil recovery and the impact of uncertainty in net-to-gross on connectivity (Objectives v, vi and vii – Chapter 7)

Thin-bedded turbidites are a key element of heterogeneity in many turbidite fields and result in significant uncertainties in net-to-gross distribution and resultant connectivity. In order to evaluate these uncertainties, nine net-to-gross realizations were interpreted from a combination of neutron and density logs using real data from the North Brae Field. These realizations were subsequently modelled and conditioned to three slope-centred channel-levee scenarios, to assess the impact of stratigraphic architecture and uncertainty in net-to-gross on connectivity and reservoir performance in each scenario. These object-based scenarios show distinctive variations in the distribution and range of net-to-gross and connectivity. Waterflood simulations were performed on the resultant property models to assess flow performance in the simulation cases.

For the scenarios considered, the results indicate that the architectural style influences the internal arrangement of sand bodies and hence net-to-gross distribution. In terms of reservoir performance, turbidite reservoirs that are characterised by a single-storey channel-fill succession have less continuous sand bodies with a 23.5-39.8% range of connectivity. The connectivity in multi-storey channel-levee systems ranges from
22.0% to 37.2%. Scenario 3, marked by multi-lateral stratigraphic architecture, has the highest range of uncertainty, with connectivity ranging from 24.0% to 41.5%. While the uncertainties in net-to-gross are reduced by multiple realizations, the implications of the uncertainty on connectivity is undeniably profound, and can, therefore, have a significant effect on reserve estimation and overall project value.

8.3 VARIATIONS FROM THE STANDARD TURbidite FACIES MODELS

There is some dissent as might be expected, and this helps us to better refine and establish what we do know. In particular, Shanmugam (2000, 2006) questions our understanding of the turbidity current process and hence of turbidite facies models. One of his key concerns is that turbidite has become a bucket term for a wide range of processes and facies and that some, especially the coarse-grained facies, might be more accurately attributable to debris flows. This issue is discussed by Cronin et al. (in press). Three observations can be made here: (a) downslope processes, including turbidity currents, evolve during a single event, from debris flow to high then low-concentration turbidity current; (b) the process of deposition through the traction carpet or boundary layer will markedly affect the nature of the deposit; (c) the well-documented range of turbidite facies can be clearly attributed to a process-facies continuum of turbidity currents and turbidites, as outlined in Chapter 2.

In terms of composition, turbidites can comprise siliciclastic, bioclastic, volcaniclastic and chemoclastic types, as well as mixtures of these different components. Both the Bouma and Stow models were developed from siliciclastic systems, but have been shown to apply equally to bioclastic and volcaniclastic turbidites (Stow, 1984a; Eberli, 1991; Stow et al., 1998). Some differences have been documented for calcareous bioclastic turbidites (Figure 8.1). For example, calcarenite (sand-grade) turbidites in some cases have a large-scale dune cross-bedded division, which is typically missing from siliciclastic turbidites. Calcilutite (mud-grade) turbidites show a less distinct silt laminated division than siliciclastics, and a more gradual, often reverse-graded, upward transition into hemipelagic or pelagic ooze (Stow et al., 1984c; Piper & Stow, 1991). Too few examples of chemoclastic turbidites have been described to establish what differences they may display (Stow et al., 1995b).

In distal turbidite environments and in channel levee-overbank settings, silt beds (>70% silt-sized particles) are more abundant than sands and commonly occur as thin or
Figure 8.1. Facies models for associated turbidite facies. Typical of medium and thin-bedded turbidites (from Stow and Omoniyi, in press).
medium-bedded turbidites. These silt beds exhibit the same suite of structures (the Bouma sequence) as sandy turbidites. Ungraded structureless silts are found more proximally and can be attributed to AE-division Bouma turbidites. Strachan et al. (2016) describe other variations of silt and silty-sand turbidites with a wide range of grading styles, including ungraded, reverse and normal graded silt turbidites from proximal settings.

Medium to very thick-bedded mud turbidites, with and without a thin basal silt division (see Figure 8.1), are known from a variety of environments including: ponded basins (Blanpied & Stanley, 1981; McCave & Jones, 1988; Wynn et al., 2000), channel-fill successions (Stow et al., 1996), open slope and base-of slope settings (Tabrez, 1995), and distal fan lobes (Stow et al., 1990). Such thick mud turbidites in distal and basin plain settings may be associated with hemiturbidites, the result of very slow deposition from the suspension cloud that develops above and beyond the feather edge of true turbidite deposition (Sparks & Wilson, 1983; Stow & Wetzel, 1990). Hemiturbidites have the same composition as the associated mud turbidites but are structureless, ungraded, very fine grained and bioturbated throughout (Figure 8.2).

8.4 DISORGANISED TURBIDITES

There is a group of thin, medium and thick-bedded turbidites that do not show clear Stow or Bouma sequences, have absent or very indistinct lamination and do not have a clear separation between the sand/silt and mud fractions. Some show distinctive normal grading whereas others have poor grading and abundant small mudstone clasts (see Figure 8.1). These are interpreted as the deposits of immature, surge-type turbidity currents. They may have developed from debris flows but never developed into uniform turbidity currents.

8.5 FACIES ASSOCIATIONS

TBTs and VTBTs occur in close association with a variety of other deepwater facies depending on the different depositional settings and sediment supply. In turbidite-dominated systems, such as down channels, pro-delta slopes, submarine fans, depositional lobes and small, well-supplied basins, the interbedding of a range of different
Figure 8.2. Schematic diagram of the hemiturbidites depositional process and facies (modified from Stow and Wetzel 1990).
turbidite facies is commonplace. Where TBT and VTBT facies are most abundant, the turbidite facies associations most commonly observed include:

(a) Closely-spaced, sand-rich TBTs with repeated Bouma CD mid-divisions;

(b) Separated sand-mud TBTs with Bouma CDE divisions, interbedded with minor VTBTs and hemipelagites;

(c) Widely-spaced TBTs with a range of mid-upper Bouma divisions, interbedded with common VTBTs and minor hemipelagites;

(d) Closely-spaced sand/silt-rich VTBTs with repeated Stow $T_{0.2}$ basal divisions, interbedded with rare Bouma TBTs;

(e) Silt-mud VTBTs with a range of mid-upper Stow divisions, interbedded with some lower-division Stow turbidites and Bouma TBTs;

(f) Mud-rich VTBTs with mainly upper Stow $T_{4.8}$ divisions, and some interbedded thicker mud turbidites and hemipelagites.

These six turbidite facies associations represent a continuum of deposition from more energetic (a) to less energetic (f) turbidity currents. They may occur in more proximal to distal settings, or across a fan-levee systems away from the channel axis, or vertically superimposed as the result of channel abandonment.

Other facies associations also occur together with the TBT-VTBT suite. In many slope apron settings they are interbedded with more abundant and thicker hemipelagites or pelagites, ranging from slowly accumulated biogenic-rich facies at low latitudes to rapidly deposited terrigenous (including glacigenic) at high latitudes. Such facies are often referred to as the background sediment in turbidite systems. They are not always easy to distinguish from turbidite mud divisions unless there are clear compositional and bioturbation differences.

Slumps, slides, debrites and disorganised turbidites are especially common at high latitudes, on active margins and wherever slope gradients are high. This association is also typical of many channel-fill successions, which further include a range of thicker-bedded and coarser-grained turbidites.
Where bottom currents sweep across the turbidite system, then contourites occur as interbedded facies and characteristic modification/reworking is typical, yielding hybrid turbidite/contourite facies (Habgood et al., 2003; Haughton et al., 2009; Haughton et al., 2010; Talling et al., 2012; Mutti et al., 2014). In open basin plains they are associated with pelagites and hemipelagites; whereas in confined basins, there may be thick mud and sand turbidites, megabeds and debrites.

8.6 VERTICAL SEQUENCES OF TBTS

Vertical sequences of bed thickness in turbidite successions are commonly used to infer depositional environments and architectural elements for ancient examples. Early work focussed on thinning-upward sequences as characteristic of channel fill, and thickening-upward successions as representing lobe progradation (Walker & Mutti, 1973). The sequences, typically 10-40 m thick, also showed fining-upward and coarsening-upward trends of turbidite grain size, respectively. More recent work recognises a greater variety of types and scales of sequences (Piper & Stow, 1991; Stow et al., 1996) as outlined below.

Whereas many studies rely on visual inspection and estimation of bed-thickness trends, Hiscott (1981) has demonstrated that such sequences are typically not statistically significant. A variety of statistical techniques – including autocorrelation, trend series analysis, runs test, Fourier analysis and Markov chain analysis – have therefore been applied to turbidite successions (Forster, 1995; Chen & Hiscott, 1999; Awadallah et al., 2001; Talling, 2001; Pickering & Bayliss, 2009).

These studies have had some success in characterising small-scale sequences of <10 m, but more difficulty with the medium and large-scale sequences. There is much work still to do on the statistical data and analyses that are required to determine sequence types and significance.

The following summary focuses on sequences that contain wholly or mainly TBT and VTBT beds, and are described using a slightly modified terminology from Piper and Stow (1991).
8.6.1 Mega-sequences (>100 m)

Over a few hundred metres of succession, turbidite systems commonly evolve from thick to thin-bedded (coarse to fine-grained) and vice versa. This can be at the scale of a basin-fill episode or within large-scale turbidite systems (Bouma et al., 1986; Manley & Flood, 1988) and is generally attributed to allogenic controls, such as sea-level fluctuation or tectonic cyclicity (Shanmugam & Moiola, 1982; Klein, 1985). Such sequences are observable on seismic reflection profiles.

8.6.2 Meso-sequences (10-100 m)

It is at the scale of good outcrops and subsurface boreholes (with cores or wireline logs) that most debate has centred on the recognition and interpretation of turbidite sequences. A considerable database now exists from 50 years of scientific drilling into deepwater systems and exploration/production drilling of turbidite reservoirs (Forster, 1995; Stow et al., 1996; Stow & Mayall, 2000; Shanmugam, 2006).

(a) Thinning-up (fining-up) sequences are common in coarse-grained turbidite systems, where they are widely interpreted as channel-fill deposits. The upper parts of these sequences comprise TBTs and VTBTs. Channel migration and abandonment are invoked as causal mechanisms, as well as tectonic pulsing and lateral migration of the supply system over time.

(b) Thickening-up (coarsening-up) sequences are observed in coarse, medium and fine-grained turbidite systems and are classically interpreted as representing basinward progradation of fan lobes, although this is not the only sequence type representative of lobes. Tectonic pulsing, sea-level oscillation and variation of sediment input can yield similar cyclicity.

(c) Symmetrical and partially asymmetrical sequences – thickening then thinning-up, for example – are one of the most common style of thickness variation in medium and thin-bedded turbidite systems, although in visual assessment the eye is often drawn preferentially to either thinning-up or thickening-up packets. Such sequences can be caused by the progradation of lobes followed by lateral migration or by temporal variation in sediment input.
(d) Block-like packets of thicker (coarser) beds, showing relatively abrupt transitions with the encasing thin-bedded and finer-grained succession, are another common indication of channel-fill deposits, from large-scale mid-fan or feeder channels to small-scale lobe-cutting distal channels. They may also represent sudden influx of coarse-grained turbidites into a basin plain.

(e) Random non-cyclic successions are another very common sequence type, especially in TBT and VTBT series. Many of the slope apron and basin-plain systems are of this type, as also are levees and interchannel deposits.

8.6.3 Micro-sequences (<10 m)

The patterns recognised as meso-sequences also appear to be present in micro-sequences, although grain-size is not always so closely linked with bed thickness (Piper & Stow, 1991; Forster, 1995). Mutti (1977) related micro-sequences to specific depositional environments. Thickening-up and symmetrical micro-sequences were linked to lobe-fringe and fan-fringe environments; block-like sandy TBTs separated by mud-rich units to interchannel areas; random, irregular non-cyclic series to channel mouth and channel margin areas; and random but regular non-cyclic series to basin plain environments. Drilling on modern systems has shown a certain degree of accuracy in these inferences, although more statistical work is needed in this area. Mutti (1977) proposed wholly autogenic controls on this cyclicity, whereas Lash (1988) ascribed similar micro-sequences to allogenic controls.

Compensation cycles were first described by Mutti and Sonnino (1981) as repeated thinning-up sequences, each just a few beds in thickness. They ascribed this variation as due to the influence of the slight positive relief of the previous turbidite on the next turbidity current. Both theoretical and observational evidence now shows that compensation cycles can be thinning-up, thickening-up or, more commonly, symmetrical (Stow et al., 1984a; Melvin, 1986; Stow et al., 1990; Forster, 1995). They are especially characteristic of lobes and basin plains.
Both TBTs and VTBTs occur throughout the spectrum of architectural elements in a variety of deepwater environments (Figure 8.3). The principal features of these facies within the different elements are summarised below.

(a) Sheets and drapes on non-channelised slope aprons, delta-front slopes and seamount flanks are dominated by TBTs and VTBTs, together with variable amounts of background hemipelagites. These occur in association with thick silt-mud turbidites, disorganised turbidites and debrites (Ineson, 1989; Pickering et al., 1989; Bell & Suarez, 1995; Satur et al., 2000; Wagreich, 2000; Talling, 2013), especially where deposition is rapid, slope angles are high, or seismic activity is prevalent (Stow et al., 1983; Hans Nelson & Maldonado, 1988; Richards et al., 1998; Talling et al., 2013; Talling, 2014). The bed thickness variation is generally random and non-cyclic (Piper & Stow, 1991). Sand-shale ratio is relatively low and mean grain size is fine. Each of the attribute indices (NGI, SCI, FRI and STI) are low or very low.

(b) Channel-fill in erosional, mixed and constructional channels is characterised by coarse-grained facies, slumps and debrites in the lower parts, overlain by medium-bedded turbidites and then TBTs/VTBTs (Cronin, 1995; Clark & Pickering, 1996; Campion et al., 2000; Gardner, 2003; Lien et al., 2003; Labourdette, 2007; Wynn et al., 2007; Cross et al., 2009; Mayall et al., 2010; Pringle et al., 2010; Hubbard et al., 2014; Bayliss & Pickering, 2015; Pickering et al., 2015). There is considerable variation between erosional and depositional channels, larger troughs and canyons, smaller gullies and distributaries, and abandoned channel segments. The general pattern is one of Bouma TBTs passing upwards into Stow VTBTs within an overall thinning-up meso-sequence. Blocky sequences are also common. Disorganised and thick mud turbidites, slumps and debrites are common, especially in the channel-margin region. Thick structureless siltstone turbidites may be common. Hemipelagites are rare, except towards the very topmost fill. Erosive features and shale clasts may be common. Sand-shale ratio and mean grain-size vary from high to low upwards through the thin-bedded channel-fill section. The lower parts of this
Figure 8.3. (A) Distribution of TBTs/VTBTs within different deepwater architectural elements. Numbers shown represent sub-environments: 1. Non-channelised slope aprons. 2. Channel-fill erosional, mixed and constructional channels. 3. Channel margin. 4. Levee and overbanks. 5. Slide and slump masses. 6. Interchannel area. 7. Isolated and clustered lobes, splay lobes and interchannel lobes. 8. Lobe fringe. 9. Basin plain. 10. Canyon.
Figure 8.3 continued. (B) Transverse sections showing distribution of thin- and very thin-bedded turbidites in relation to deepwater channel.
C.

Figure 8.3 continued. (C) Transverse sections showing distribution of TBT and VTBT in relation to channel-lobe setting.
section show relatively good NGI, SCI, FRI and STI indices, decreasing in value upwards.

(c) Levee and back-levee deposits flanking constructional channels, and channel over-bank deposits adjacent to more erosional channels, are all dominated by TBTs and VTBTs (Walker, 1985; DeVries & Lindholm, 1994; Browne & Slatt, 1997; Pirmez et al., 1997; Clark & Gardiner, 2000; Browne & Slatt, 2002; Deptuck et al., 2003; Gervais et al., 2004; Cronin et al., 2007; Hubbard et al., 2007b; Kane et al., 2007; Kane et al., 2009; Kane et al., 2010b; Di Celma et al., 2011; Kane & Hodgson, 2011; Khan et al., 2011; Masalimova et al., 2011; Sylvester et al., 2011; Campion, 2012; Rotzien et al., 2014; Hansen et al., 2015). Both meso- and micro-sequences are mostly random and non-cyclic. They show systematic variation in properties in both down-channel and away-from-channel direction. The near-channel locations comprise the more sand/silt-rich facies – i.e. more Bouma TBTs, more Stow VTBTs with base-only divisions, higher sand-shale ratios and greater mean grain-size. They also show more chaotic and convolute-laminated silt-mud structures, and distinctive thin-bedded silt-rich turbidites. However, in a down-channel direction, there is commonly an increase in sand-rich facies in the more distal regions where the levee height has diminished. In the more sand/silt-rich deposits, the NGI, SCI, FRI and STI indices are all intermediate in value, becoming low to very low away-from-channel and in high proximal levees.

(d) Isolated and clustered lobes in channel-terminal locations, splay lobes, interchannel lobes, and ponded lobes comprise a high proportion of TBTs in a proximal lobe position and more VTBTs in a distal lobe position (Bernhardt et al., 2011; Grundvåg et al., 2013). The relative proportion of these and of medium-bedded and silt turbidite facies depends on the size and scale of the depositional system and of how far down-system the lobe occurs. Symmetrical and thickening-up sequences are both common as well as compensation cycles. The proximal parts of lobes have some of the highest values for NGI, SCI, FRI and STI indices, decreasing distally. Proximal lobes and the channel-lobe transition zone can show more chaotic, and convolute sedimentary structures, a greater lenticularity of beds (large and small-scale), and marked erosive features and shale clasts.
Sheet turbidites in basin systems, including small, confined and large, open basin types, typically comprise abundant TBTs and VTBTs (Mutti & Johns, 1978; Hiscott et al., 1993; Plink-Bjorklund et al., 2001; Ielpi & Cornamusini, 2013). These are associated with medium and thick-bedded turbidites and with thick silt and mud turbidites, especially in the smaller basins of tectonically active regions. The large open basins comprise a greater proportion of VTBTs and hemipelagite/pelagite facies. The intercalation of megaturbidites and turbidites of markedly different compositions is also typical of basin deposits. Both symmetrical meso-sequences and random non-cyclic patterns of bed thickness are common, as also are small-scale compensation cycles. Small basins may show moderate to good values of NGI, SCI, FRI and STI indices, whereas large open basins may show very low values.

8.8 RESERVOIR IMPLICATIONS OF THE CONNECTIVITY BRIDGE IN TBT-ASSOCIATED DEEPWATER ARCHITECTURAL ELEMENTS

Deepwater turbidite reservoirs are internally complex, with their connectivity patterns varying from one deepwater architectural element to another. In this thesis, five types of connectivity bridge between primary reservoir turbidite facies and associated secondary TBT facies are identified (Figure 8.4). Because connectivity between an injector well and a producer well can present an opportunity as well as a challenge for oil recovery, the characteristics of each type of connectivity bridge identified are discussed in the following subsections in the light of their flow performance.

8.8.1 Channel to splay lobe setting

The connectivity between typical channel and associated splay lobe is captured in three scenarios (see Chapter 5), based on data from the North Brae Field. These scenarios are composed of facies associations that have markedly variable lateral continuity and connectivity. In the three scenarios, findings show that facies associations that largely make up the channel fill (FA3_{NBF} and FA4_{NBF}) have high Sand Connectivity Index (SCI), in contrast to the minor facies associations (FA1_{NBF} and FA2_{NBF}) that dominate the top layers. In the channel-splay lobe system characterised by high connectivity (high-to-very high SCI), reservoir layers are susceptible to water flow (early water breakthrough in
1 and 2: transverse to flow sections

3, 4 and 5: downflow sections

Figure 8.4. Types of connectivity bridge in TBT-associated deepwater turbidite reservoirs. Connectivity bridge in deepwater settings 1, 2, and in part, 5, are covered in this thesis. Types 3 and 4 connectivity bridge are not covered and are earmarked for future research. Note that colour relates generally to grain size.
scenarios 2 and 3; Chapter 5). In these systems, rapid passage of injected water from the injector to the producer, results in differential oil sweep, with injected water displacing quickly the oil in high connectivity layers, and thereafter these layers become conductivity pathways to cycle water from the injector to the producer. However, the initial high oil recovery efficiency, caused by the acceleration of injected water in the high connectivity layers, in the long run, translates to higher cumulative oil production than in the intermediate connectivity (intermediate SCI) systems.

Channel-splay lobe systems that are characterised by intermediate connectivity are marked by more efficient vertical and horizontal oil sweep than systems with high connectivity. Considering the need for more water injection because of the slow displacement of oil, such intermediate connectivity systems are characterised by higher water cut and higher cumulative water production than in the high connectivity systems (see Chapter 5; Figures 5.13 and 5.19). Despite the tendency for higher water cut, intermediate connectivity systems have relatively stable oil production rates in the presence of long-delayed water breakthrough that culminate in less bypassed oil than in the high connectivity systems (see Chapter 5; Figures 5.12, 5.13 and 5.14).

In channel-splay lobe systems, the findings in this thesis indicate that connectivity decreases from the channel axis towards the splay lobe (Figures 8.5 and 8.6). The implication of this trend is that the connectivity between the injector and the producer is considerably influenced by the location of the injector (Eschard et al., 2014). In a low-continuity channel-splay lobe system, there is a 47% connectivity between the injector (16/07a-B9) and the producer (16/07a-B8) (Figures 8.5, A; 8.6, A). By contrast, for the same configuration, there is a 46% connectivity in a high-continuity channel-splay lobe system (Figures 8.5, B; 8.6, B). In another instance, if the injector well were to be placed at location 3 in a low-continuity channel-splay lobe system, there would be a 46% connectivity between the injector and the producer, in contrast to a 50% connectivity in a high-continuity channel-splay lobe system. In such systems, therefore, the location of an injector relative to a producer will have a profound impact on the efficiency of oil sweep.
Figure 8.5. Connectivity as a function of distance away from the producer (16/07a-B8) in a typical channel-splay lobe system that is characterised by (A) low facies continuity, and (B) high facies continuity. Selected locations 1, 2, and 3 together with terminology are arbitrarily positioned.

[CH=channel, A=axis, OA=off-axis, M=margin, SL, splay lobe]
Figure 8.6. Connectivity (SCI-derived and components) trends in a typical channel-splay lobe system that is characterised by (A) low facies continuity, and (B) high facies continuity. Connectivity is calculated as a function of distance at selected locations (1-4) from the producer (16/07a-B8).
8.8.2 Channel to channel-margin setting

Three contrasting channel to channel-margin architectures are identified:

(a) single-storey,
(b) multi-storey with prominent vertical stacking, and
(c) multi-storey with prominent lateral stacking.

As indicated by the results presented in Chapter 7, connectivity in turbidite reservoirs with a single-storey channel-fill succession within a slope system decreases from the channel axis to the channel margin (Figure 8.7, A). The high connectivity (very high SCI of 0.84, Figure 8.8, A) within the channel axis in this system, supports downward movement of injected water under the influence of gravity, resulting in effective displacement of oil in the lower layers. This displacement process produces a uniform pattern that supports delay in water breakthrough, allowing more oil to be produced. The high connectivity in the channel axis also increases the rate at which oil is displaced towards the producer. Thus, oil is produced in such systems at rates higher than in turbidite systems that are characterised by multiple channel-leves (Chapter 7; Figure 7.27). In channelised systems within a typical slope system, intermediate-to-high SCI (0.59-0.84) indicates an increasing connectivity towards the channel axis. The increasing connectivity allows uniform oil displacement with the high connectivity layers in such systems contributing to the rapid oil production, effectively resulting in higher oil production rates. The stratigraphic architecture in such systems supports injected water to slowly sweep the low connectivity layers in the lower parts of the system (Chapter 7; Figures 7.40, A; 7.41, A), effectively delaying water breakthrough (Chapter 7; Figure 7.23).

In turbidite reservoir systems marked by multi-storey architecture (vertically-stacked channel-leves), average connectivity is lower, when compared to a slope-centred channelised system, reaching an average of 61%. In such systems, the near-uniform connectivity over selected locations (Figures 8.7, B; 8.8, B), result in consistently high oil recovery efficiency (Chapter 7; Figure 7.24). However, the presence of low-continuity channel sands in individual channels adversely affects flow performance. As a result, such systems are typified by lower oil production rates (Chapter 7; Figure 7.27) in spite of the high vertical connectivity brought about by vertical stacking pattern. In addition to the lower oil production rates (at least lower than in turbidite system with single-storey architecture) and the differential oil sweep in such systems, oil displacement is
A. Scenario 1

B. Scenario 2

Figure 8.7. Extracted section from channel-centred systems showing variation in connectivity of reservoir facies at selected locations from the producer (16/07a-B1). (A) Single-storey channel-fill succession (B) Multi-storey channel-levees (C) Multi-lateral channel-levees (overleaf).
C. Scenario 3

Figure 8.7 continued.
Figure 8.8. Connectivity (SCI-derived and components) trends in a typical slope-centred system that is characterised by (A) single-storey channel-fill succession, (B) multi-storey channel-levees, and (C) multi-lateral channel-levees. Connectivity is calculated as a function of distance at selected locations from the producer (16/07a-B1).
accelerated in the high connectivity layers at the expense of the low continuity and low connectivity layers that are located at the lower parts of the system. The effect of this variation in connectivity results in the waterflood front advancing faster in the high connectivity layers, causing a much earlier water breakthrough, with more unswept oil in the lower layers (Chapter 7; Figures 7.23; 7.27; 7.40, B; 7.41, B). Such systems are characterised by lower cumulative oil production than in the turbidite reservoirs with single-storey architecture (Chapter 7; Figure 7.30).

In turbidite reservoir systems with multi-lateral architecture (laterally-stacked channel-leves), high continuity and high connectivity layers support a more pronounced gravity segregation. These layers are quickly swept by the rapidly advancing waterflood front. Such systems are characterised by a higher variability in connectivity (Figures 8.7, C; 8.8, C) with a corresponding larger permeability contrast, resulting in differential oil sweep, causing the high connectivity layers to be swept quickly by the rapidly advancing waterflood front (Chapter 7; Figures 7.40, C; 7.41, C). Because of the rapid oil sweep, occasioned by the high connectivity, the high continuity sand-rich layers become conductivity pathways (or thief zones), channelling water to the producer after displacing their oil. As a result, the risks of early water breakthrough, low cumulative oil production, and low oil production rates, are highest in these systems, when compared to the turbidite reservoir systems with single-storey or multi-storey architecture (Chapter 7; Figures 7.23; 7.27; 7.40, C; 7.41, C).

Considering reservoir flow performance over time, the results indicate that channel-channel margin settings with single-storey architecture, are characterised by a gradual decline in oil production rate that results in high oil recovery efficiency before water breakthrough, leading to higher cumulative oil production with lower cumulative water production. By contrast, channel-channel margin settings with vertically-stacked and laterally-stacked architecture have initial rapid decline in rate that results in lower oil production rates and lower cumulative oil production in the long term with attendant water production that tends to increase in such systems (Chapter 7; Figures 7.33-7.35; 7.24, 7.27, and 7.30).

8.8.3 Associated basin-plain setting

In deepwater turbidite reservoir systems that are characterised by a basin-plain succession, the findings in the high-resolution integrated flow simulation studies indicate
that a considerable variation in small-scale heterogeneities (Weber & van Geuns, 1990) will have a profound impact on connectivity, and thus, flow performance in such systems. These heterogeneities, particularly facies types and distribution, lateral variation in bed thickness, and net-to-gross variation and distribution, strongly control the degree of permeability contrast in these systems.

In basin-plain systems with high net-to-gross (high-to-very high facies net-to-gross index), the degree of sedimentary heterogeneity is relatively low, resulting in high connectivity with low uncertainty (Chapter 6; Table 6.1, Figure 6.16) that supports water displacement process with uniform oil sweep over the entire interval. The uniform sweep results in less of a fingering pattern of the waterflood front (Chapter 6; Figure 6.30, A-C), effectively delaying water breakthrough. The delayed water breakthrough results in higher cumulative oil production than in low net-to-gross basin-plain systems (Chapter 6; Figures 6.22; 6.26, A).

By contrast, basin-plain systems that are characterised by low net-to-gross and higher degree of sedimentary heterogeneity are marked by low connectivity, both in the vertical and lateral components (Chapter 6; Table 6.1; Figure 6.16). In such systems, the large permeability contrast favours high initial oil production rates, which after water breakthrough, sharply decrease (Chapter 6; Figures 6.22 and 6.24). The early water breakthrough, in addition to rapid decline in oil production rate, results in lower cumulative oil production, even in the presence of high oil recovery efficiency (Chapter 6; Figures 6.26, A; 6.31). This is largely the result of differential oil sweep that favours high connectivity layers. These layers become principal conduits for injected water, and thus, allow accelerated displacement of oil to the producer. This rapid acceleration in oil displacement is accompanied by high water cut (Chapter 6; Figure 6.22), with the low net-to-gross and low connectivity layers largely bypassed (Chapter 6; Figures 6.30, D-F). As a result, such systems are typified by rapid decline in oil production rates after water breakthrough and much lower cumulative oil production.

8.9 CONTINUITY AND CONNECTIVITY RELATIONSHIPS IN TBT-ASSOCIATED DEEPWATER ARCHITECTURAL ELEMENTS

The results in this thesis have been used to develop a relationship between continuity and connectivity of sand bodies in TBT-associated deepwater architectural elements. The proposed deepwater architectural Continuity-Connectivity Scheme provides a range of
connectivity over a range of continuity scenarios for selected TBT/VTBT systems (Figure 8.9). On the basis of these relationships, TBT-associated deepwater turbidite reservoir systems can be grouped into six principal categories, namely:

i. Low continuity and high connectivity systems (single-storey channel);

ii. Low-to-intermediate continuity and intermediate connectivity systems (laterally-stacked channel-levee);

iii. Intermediate continuity and low connectivity systems (distal basin plain);

iv. Intermediate-to-high continuity and intermediate-to-high connectivity systems (vertically-stacked channel-levee);

v. High continuity and intermediate connectivity systems (proximal basin plain); and

vi. High continuity and high connectivity systems (channel-splay lobe).
Figure 8.9. Schematic view of the proposed deepwater architectural Continuity-Connectivity Scheme. The scheme shows a range of connectivity from low to high over a range of low-to-high continuity scenarios.
Chapter 9

Conclusions and further work

This chapter summarises the significance of the principal results presented in previous chapters, and further work that will help to advance these contributions.
9.1 LESSONS LEARNED AND SIGNIFICANCE

The findings made in this research serve to provide a better understanding of the impacts of geological attributes of TBT/VTBT facies associations on flow performance in deepwater turbidite reservoirs. In particular, these findings can be related to water displacement process and oil sweep from sand bodies in typical channelised, channel-splay lobe, and basin-plain settings. Based on the results presented in this thesis, the lessons learned, therefore, can be summarised as follows:

1. TBTs are clearly demonstrated in this thesis as an important potential reservoir in all turbidite fields, either as a primary or secondary reservoir.

2. This thesis has demonstrated a new method for the quantitative characterisation of TBT/VTBT attributes and hence their potential as reservoirs, flow conduits, baffles or barriers.

3. The attribute indices developed reflect the reservoir quality of TBT/VTBT facies and facies associations, enable their quantitative characterisation in a variety of deepwater architectural elements, and serve to condition turbidite reservoir models.

4. Connectivity affects producibility of turbidite reservoirs and resultant recoverable hydrocarbon.

5. Understanding the distribution of sedimentary heterogeneity in turbidite reservoirs is pivotal to predicting connectivity and permeability anisotropy for a depletion strategy that will maximise oil sweep.

6. The novel concept of a *Connectivity Bridge* showcases the effect of sedimentary heterogeneity and permeability anisotropy on flow performance. The characteristics of the *Connectivity Bridge* varies from one deepwater setting to another.
Generally, architectural style influences the internal arrangement of sand bodies in turbidite reservoirs, which in turn impact net-to-gross distribution and resulting connectivity.

The proposed deepwater architectural Continuity-Connectivity Scheme can be used to classify TBT-associated turbidite reservoir systems into six groups:

i. Low continuity and high connectivity systems (single-storey channel);

ii. Low-to-intermediate continuity and intermediate connectivity systems (laterally-stacked channel-levee);

iii. Intermediate continuity and low connectivity systems (distal basin plain);

iv. Intermediate-to-high continuity and intermediate-to-high connectivity systems (vertically-stacked channel-levee);

v. High continuity and intermediate connectivity systems (proximal basin plain); and

vi. High continuity and high connectivity systems (channel-splay lobe).

The nature of fluid flow through or its impedance by various TBT/VTBT associations is critical in assessing reservoir performance and developing reservoir management strategies.

The six TBT/VTBT lithofacies associations in the North Brae Field (fa1NBF-fa6NBF) show different patterns in the attribute indices cross-plots (Chapter 4). Average values from these plots serve to quantify each attribute and for type facies, and can be used to condition reservoir modelling and simulation (Chapters 5, 6, and 7). These average values also serve as a predictive tool to infer quality and flow performance of turbidite reservoirs. TBTs/VTBTs facies that have low-very low attribute values, as indicated on the attribute indices cross-plots, may not support flow. These facies (otherwise referred to as tight
reservoir facies) may trap hydrocarbon fluids, and thus, present a huge potential for stratigraphically-trapped contingent resources.

11. This thesis proves that sedimentary heterogeneity influences uncertainties that relate to spatial connectivity of reservoir facies. The spatial connectivity between injector and producer may present an opportunity for incremental reserves as well as a challenge for oil recovery. The results reveal that high-to-very high connectivity is associated with the risk of thief zone, occasioned by a less-efficient oil sweep, and does not necessarily guarantee high oil recovery efficiency (see Chapter 5). By contrast, very low connectivity may necessitate high pump rates to flow water through the reservoir.

12. The degree of sedimentary heterogeneity influences the scale of permeability contrast, which control oil recovery. Vertical stacking patterns, bed thickness, facies continuity, sand and shale dimensions, facies and facies associations, NGI and SCI vary considerably in a basin-plain turbidite succession (Chapter 6). In the presence of high facies net-to-gross index and very high lateral continuity of beds, amalgamation stacking pattern encourages better static connectivity than any other type of stacking pattern.

13. Like permeability heterogeneity and anisotropy, stratigraphic architecture and reservoir geometric shape profoundly control hydrocarbon recovery. Channelized reservoirs are marked by non-uniform distribution of net sand caused by regular and irregular low net-to-gross facies that typify in-channel TBT, off-axis-to- channel margin TBTs and overbank facies. As a result of the associated permeability contrast between these classes of reservoir facies, they behave differently during the passage of fluids (Chapter 7).

14. A high-net-to-gross channel within a slope system is characterised by progressive decrease in net-to-gross from the channel axis through the channel margin to the bounding slope system. In this system, discontinuity of sandstone beds beyond channel margin results in poor connectivity between injector in the slope system and producer in the channel axis. A big risk in this system is poor oil sweep in the lower channel-fill strata.
15. The sandstone beds that top vertically-stacked channel-levees may form sand-rich levees that extend to surrounding slope system, helping to connect injection well in the system to production well in the channel axis. The amalgamated stacking pattern of channel-fill and levee strata that characterises this system enable effective oil sweep in individual channel fills and levees by the injected water. This system is a better candidate for development than laterally-stacked channel-levees. Associated risks to oil recovery in this system are rapidly declining oil production rate (especially at high initial rate) and early water breakthrough (not earlier than in multilaterally-stacked channel-levees).

16. Multilaterally-stacked channel-levees within a slope system may be characterised by laterally continuous sand-rich beds that serve to connect injection well in the slope system with production well in the channel axis more effectively than in single channel-fill succession or vertically-stacked channel-levee system. Associated risks to oil recovery in this system are high water production and rapid decline in oil production.

17. Uncertainty in connectivity is lowest in vertically-stacked channel-levee system and highest in multilaterally-stacked channel-levee system. In relation to this uncertainty, a channel system with single-storey architecture is in-between the two systems. In addition to relatively low uncertainty in connectivity, lowest uncertainty in oil production rate, most delayed water breakthrough, gradual decline in oil production rate, and highest cumulative oil production make this system the best candidate for development.

18. The initial high oil production rates in some of the systems studied should be viewed with caution in order to avoid rapid decline in oil production rate that may follow such high initial oil production rates. As a result of high cumulative water production that characterises such systems, more powerful pumps may be needed to recycle water produced, thereby influencing the project cost.
9.2 FURTHER WORK

In advancing the concept of Connectivity Bridge using TBT facies attributes and attribute indices, the following studies will be explored in the near future.

1. More outcrop-based high-resolution reservoir flow simulation studies to assess the impacts of small-scale sedimentary heterogeneities on connectivity and flow properties, particularly in channel-basin plain, channel-terminal lobe, and lobe-basin plain settings.

2. The most economic secondary and/or tertiary recovery mechanism that suits oil recovery in the various systems studied.

3. Application of the connectivity bridge to the Forties Sandstone Member of the Paleocene Sele Formation, using data sourced from Pierce, Starling and Fram Fields.

4. Integration of three-dimensional seismic data to generate seismic attributes that will be used to further constrain deepwater architectural elements, and provide geometrical parameters for subsequent object-based modelling. The resultant models will be used to assess the connectivity bridge in deepwater settings that are not covered in this thesis.

5. Integration of Sediment Textural and Facies Ratio Indices into deepwater reservoir modelling and flow simulation.

6. Development of purpose-built, state-of-the-art software for high-resolution modelling of TBT facies associations and flow simulation at reservoir and/or field scale.

7. Statistical analyses of bed thickness data to determine medium and large-scale sequence types and significance, and evaluate the primary controls on the cyclicity observed at these scales.
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Talling, P. J., Paull, C. K. & Piper, D. J. W., 2013. How are subaqueous sediment density flows triggered, what is their internal structure and how does it evolve? Direct observations from monitoring of active flows. Earth-Science Reviews 125: 244-287.


A. Logged sections in the Silurian Aberystwyth Grits Group, Mid Wales
B. Attribute indices at the connectivity bridge (Chapter 5)

VCI and SCI calculations

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<th>Net</th>
<th>Non-net</th>
<th>NGI</th>
<th>S/S</th>
<th>S/NS</th>
<th>(S/S) + (S/NS)</th>
<th>VCF</th>
<th>VCI</th>
<th>LCI</th>
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LCI calculation

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<th>Hr (ft)</th>
<th>Nrc</th>
<th>hc (ft)</th>
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C. Volumetric equation for calculating oil initially in place (OIIP) (Passey et al., 2006)

\[
\text{OIIP} = A \times h \times \phi \times (1 - S_{wi}) \times 7758 \times \left(\frac{1}{B_{oi}}\right)
\]

\[
= A \times \text{HPT} \times 7758 \times \left(\frac{1}{B_{oi}}\right)
\]

Where

- \(A\) = gross rock area (ft\(^2\))
- \(h\) = average oil-bearing rock thickness (ft)
- \(\phi\) = average total porosity of oil-bearing rock (fraction)
- \(S_{wi}\) = average total initial water saturation of oil-bearing rock (fraction)
- \(B_{oi}\) = average initial oil formation volume factor (rb/stb)
- \(\text{HPT}\) = hydrocarbon pore thickness (ft)
D. Check for the conditions of a legitimate pdf (Chapter 6)

D.1 Check for pdf for water cut (W)

\[ P(a \leq X \leq b) = \int_{a}^{b} f(x)dx \]

Using limits from -1 to 1

\[ a = -1 \]
\[ b = 1 \]

\[ P(a \leq W \leq b) = \int_{-1}^{1} \frac{1}{0.2} e^{-w/0.2} dw \]

\[ = \frac{1}{0.2} \left[ -0.2e^{-w/0.2} \right]_{-1}^{1} \]

\[ = \left[ \left( -e^{1/2} \right) - \left( -e^{-1/2} \right) \right] - \left[ \left( -e^{-1/2} \right) - \left( -e^{-1/2} \right) \right] \]

\[ = \left[ -e^{1/2} - e^{-1/2} \right] - \left[ -e^{1/2} - e^{1/2} \right] \]

\[ = -0.6065 + 0.6065 \]

\[ = 1 \]

So the area under the pdf curve is 1.
D.2 The probability that water cut is up to 0.1 is given as a function:

\[ P(a \leq X \leq b) = \int_{a}^{b} f(x) \, dx \]

Mean water cut = 0.2

\[ a = 0; b = 0.1 \]

\[ P(0 \leq W \leq 0.1) = f(w) = \int_{0}^{0.1} \frac{1}{0.2} e^{-\frac{w}{0.2}} \, dw \]

\[ = \frac{1}{0.2} \left[ -0.2e^{-\frac{w}{0.2}} \right]_{0}^{0.1} \]

Simplifying,

\[ = \left[ (-e^{-0.1/0.2}) - (-e^{0}) \right] \]

\[ = \left[ (-e^{-0.1/0.2}) - (-e^{0}) \right] \]

\[ = \left[ (-e^{-0.1/0.2}) + e^{0} \right] \]

\[ = \left[ 1 - e^{-1} \right] \]

\[ \approx 1 - 0.6065 \]

\[ = 0.39 \]

The probability that the water cut is up to 0.1 is 0.39 or 39%.
E. Volume of shale realizations (Chapter 7)

E.1 At 16/07a-B1

Realization 1

Realization 2
Realization 9
E.2 At 16/07a-B14

Realization 1

Realization 2

Realization 3

Realization 4
Realization 9
F. Net-to-gross realizations (Chapter 7)

F.1 Scenario 1

Realization 1

Realization 2

Realization 3
Realization 4

Realization 5

Realization 6
F.2 Scenario 2

Realization 1

Realization 2

Realization 3
Realization 4

Realization 5

Realization 6
Scenario 3

Realization 1

Realization 2

Realization 3
Realization 4

Realization 5

Realization 6
Thin-bedded turbidites: a new approach toward better characterisation

Bayonle Omoniyi, Dorrik Stow and Andy Gardiner

Many producing and marginal turbidite fields comprise a significant proportion of thin-bedded (TBT) and very thin-bedded turbidites (VTBT). Understanding their nature, properties and flow behaviour is critical in reducing key uncertainties and associated subsurface risks that impact hydrocarbon recovery from such reservoirs. Based on a large number of studies of modern, ancient and subsurface systems, we identify the principal geological attributes of TBTs and VTBTs that can be used to discriminate between different architectural elements in deepwater systems. These are: facies and facies associations; sand-shale ratio; sand/shale geometry and dimensions; sand connectivity; sediment texture; small-scale sedimentary structures; and small-scale vertical sequences of bed thickness. We further define four fundamental attribute indices, derived from attribute combinations, which influence vertical and horizontal flow: (1) the sand connectivity index, derived from the nature of bed/lamination cross-cutting relationships; (2) the sediment textural index, derived from the mean grain-size property; (3) the proximality index, derived from Bouma/Stow sequence combination and selected facies ratios; and (4) the micro-fracture index, derived from the micro-fracture density, style and distribution.

This approach is now being applied to subsurface core data from four North Sea Brae Field wells, initially to assess vertical connectivity in the sand/silt parts of the TBT–VTBT succession. The eight facies classes identified in the study are characterised by varying textural characteristics, bed thickness patterns, and reservoir indices. The sand vertical connectivity index (SVCI), in particular, is an important discriminator for the prediction of sand continuity and connectivity. The next step is to run flow simulations for combinations of attribute indices. We propose that discrimination of TBT-VTBT facies, attributes and attribute indices has great significance for exploration and production of marginal turbidite systems, and for a variety of tight and ultra-tight reservoirs in deepwater systems, as well as for better characterisation of deepwater shale properties.
Characterisation of thin-bedded turbidites for field value optimisation
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Understanding the dynamic behaviour of hydrocarbon reservoirs is not only critical to the prediction of flow of fluids from a reservoir to a wellbore but also plays a pivotal role in field value optimisation, particularly in producing and marginal turbidite fields that have potential for development of thin-bedded (TBT) and very thin-bedded turbidites (VTBT). Drawing from a large number of studies of modern, ancient and subsurface systems, we identify seven principal geological attributes of TBTs and VTBTs that can be used to discriminate between different architectural elements in deepwater systems. These geological attributes are: facies and facies associations; sand-shale ratio; sand/shale geometry and dimensions; sand connectivity; sediment texture; small-scale sedimentary structures; and small-scale vertical sequences of bed thickness. Combination of these attributes enables definition of four fundamental attribute indices that impact patterns of flow. (1) Sand Connectivity Index, derived from the nature of bed/lamination cross-cutting relationships, is an important discriminator for the prediction of sand continuity and connectivity. (2) Sediment Textural Index, derived from the mean grain-size property, is related to sediment transport and deposition. (3) Proximality Index, derived from Bouma/Stow sequence combination and selected facies ratios, provides insight into distance from sediment source area and/or the energy regime of the depositing turbidity current. (4) Micro-fracture index, derived from the micro-fracture density, style and distribution, gives insight into micro-porosity capable of affecting fluid flow in hydrocarbon reservoirs.

This quantitative approach to reservoir characterisation is now being applied to subsurface core data from four North Sea Brae Field wells, initially to assess vertical connectivity in the sand/silt parts of the TBT–VTBT succession. The four facies associations identified in the study are characterised by varying textural properties, bed thickness patterns, attribute indices, bulk density, and core porosity and permeability. Preliminary relationships between these parameters indicate the value of using attribute indices for evaluating reservoir character. The next steps are to integrate porosity and permeability data and then run flow simulations for combinations of attribute indices with a view to predicting flow from pore scale to reservoir scale in TBT–VTBT successions.
Quantitative assessment of reservoir quality in thin-bedded turbidite facies
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Variation in the degree of heterogeneity in hydrocarbon reservoirs has significant impact on fluid flow during production and may lead to bypassed oil being trapped in low-permeability reservoir compartments. This is particularly critical in producing from marginal turbidite fields with significant thin-bedded turbidite (TBT) successions.

Principal geological attributes of TBTs have been extracted from a large number of studies of modern, ancient and subsurface systems. These attributes include: facies and facies associations; sand-shale ratio; sand/shale geometry and dimensions; sand connectivity; sediment texture; small-scale sedimentary structures; and small-scale vertical sequences of bed thickness. Combination of these attributes enables definition of four fundamental attribute indices that influence reservoir quality of TBT successions and consequently impact vertical and horizontal hydrocarbon fluid flow in producing turbidite reservoirs. The attribute indices are: (1) the Sand Connectivity Index (SCI), derived from the nature of bed/lamination cross-cutting relationships, which is useful in the prediction of sand continuity and connectivity; (2) the Sediment Textural Index (STI), derived from the mean grain-size property, which provides insight into sediment maturity, transport and depositional history; (3) the Facies Ratio Index (FRI), derived from Bouma/Stow sequence combination and selected facies ratios, which helps prediction of facies distribution and energy regime of the depositing turbidity current; and (4) the Micro-fracture index (MFI), derived from the micro-fracture density, style and distribution, which is useful as a predictor of fracture-induced porosity capable of affecting fluid flow in hydrocarbon reservoirs.

This approach has been applied to subsurface core data from eight North Brae Field wells to assess reservoir quality of sand/silt parts of the TBT. A combination of results, including analysis of backscattered electron (BSE) images, reveals that facies association 1 (FA1) is characterised by high-to-very high connectivity index and texturally mature, fine to medium-grained, moderately to well-sorted sand. In addition, core-based porosity, horizontal and vertical permeabilities indicate that it has the best characteristics favourable for development in producing turbidite fields. This is followed by FA2, for which vertical connectivity constitutes a major risk in the presence of shale lamination. FA3 is a promising reservoir-quality facies, particularly where sand
percentage and SCI are over 60% and 40%, respectively. FA4 comprises texturally mature, fine to medium sand grains that are largely well sorted. However, very low SCI constitutes a big risk to vertical fluid flow. Facies associations 5 and 6 are not considered suitable for conventional reservoir development but may represent favourable candidates for shale gas exploitation.
Capturing high-frequency heterogeneities introduced by thin-bedded turbidite (TBT) successions has become absolutely necessary in predicting the distribution of barriers and baffles to hydrocarbon flow.

In producing turbidite fields where TBT constitutes a significant proportion of the reservoir unit, failure to adequately assess stratigraphic compartmentalization during the early stages of model building can significantly favour the dominant thick and medium-bedded counterparts and downplay the key uncertainties that impact reservoir connectivity, and consequently pose a threat to optimising hydrocarbon recovery in such turbidite fields.

We have modelled a range of hypothetical scenarios using subsurface data from the mixed turbidite succession of the North Brae Field, UKCS, in addition to outcrop data from the mainly TBT succession of the Basque-Cantabrian Basin to assess the impact of these small-scale heterogeneities on net-to-gross distribution and static reservoir connectivity. Preliminary results support our hypothesis that TBT heterogeneity must be taken into account from the outset.

Further work will focus on running simulation on the static reservoir models to assess the impact of TBT facies variability on dynamic connectivity and thereby produce a range of hydrocarbon recovery scenarios.
Reservoir evaluation of thin-bedded turbidites and hydrocarbon pore thickness estimation for an accurate quantification of resource

Bayonle Omoniyi and Dorrik Stow

One of the major challenges in the assessment of and production from turbidite reservoirs is to take full account of thin and medium-bedded turbidites (<10cm and <30cm respectively). Although such thinner, low-pay sands may comprise a significant proportion of the reservoir succession, they can go unnoticed by conventional analysis and so negatively impact on reserve estimation, particularly in fields producing from prolific thick-bedded turbidite reservoirs. Field development plans often take little note of such thin beds, which are therefore bypassed by mainstream production. In fact, the trapped and bypassed fluids can be vital where maximising field value and optimising production are key business drivers.

We have studied in detail, a succession of thin-bedded turbidites associated with thicker-bedded reservoir facies in the North Brae Field, UKCS, using a combination of conventional logs and cores to assess the significance of thin-bedded turbidites in computing hydrocarbon pore thickness (HPT). This quantity, being an indirect measure of thickness, is critical for an accurate estimation of original-oil-in-place (OOIP).

By using a combination of conventional and unconventional logging analysis techniques, we obtain three different results for the reservoir intervals studied. These results include estimated net sand thickness, average sand thickness, and their distribution trend within a 3D structural grid. The net sand thickness varies from 205 to 380 ft, and HPT ranges from 21.53 to 39.90 ft. We observe that an integrated approach (neutron-density cross plots conditioned to cores) to HPT quantification reduces the associated uncertainties significantly, resulting in estimation of 96% of actual HPT. Further work will focus on assessing the 3D dynamic connectivity of the low-pay sands with the surrounding thick-bedded turbidite facies.