OR/18/013 The 'Cenozoic' 3D generic model

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Introduction

This chapter describes a 3D geological model of a sandstone reservoir built from a specific location in a Cenozoic submarine fan system in the UK Central North Sea using PETREL software.

The reader can visualize this model in 3D by clicking on this link.

The Forties and overlying Cromarty sandstone members of the Sele Formation (Figure 27) were selected as the main elements of the potential reservoir from which to build the model as they provide the hydrocarbon reservoir for numerous fields in the Central North Sea. Efficient hydrocarbon production from this type of reservoir requires reliable models of facies distribution and this has led to a large amount of published information becoming available (see Data used in building the model). Published descriptions of the reservoirs from the Forties and Nelson fields were unified to build a coherent 3D model of this part of the Cenozoic submarine fan.

The depositional setting of a submarine fan is complex and this, coupled with a post-depositional history of compaction and cementation processes, results in a marked lateral and vertical variation in facies relationships. As a result, the injectivity and storage capacity of a potential CO_2 store in this type of reservoir will vary depending on its location within the submarine fan. The Sele Formation submarine fan was divided into three 'Area Types' that define areas with broadly similar petrophysical, depth and thickness values. By populating the model with the defining attributes of the particular Area Type it is then possible to compare relative CO_2 storage performance by simulating CO_2 injection and migration in the tailored 3D geological model.

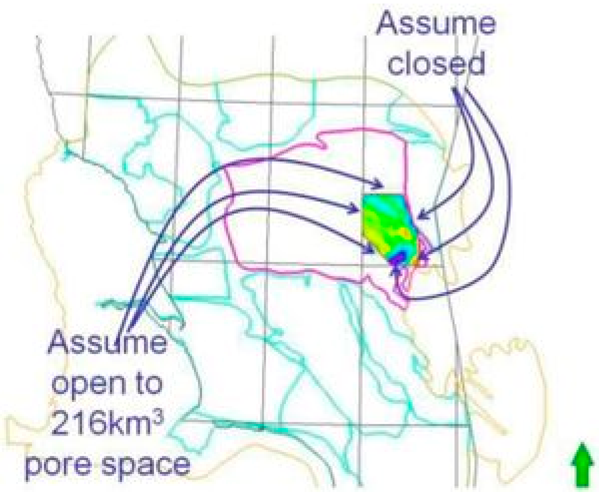

Figure 27 Lithostratigraphic nomenclature for the reservoirs of the Cenozoic 3D model (Modified after Knox and Holloway, 1992[1] and Ahmadi et al., 2003[2]).

Geological background

The Forties Sandstone Member forms the main reservoir in several hydrocarbon fields in the CNS (Ahmadi et al., 2003[2], their figure 14.3). The model is built around the Forties and Nelson fields that are situated on the Forties-Montrose High in the Central North Sea (Figure 28) and represent examples of hydrocarbon fields whose primary reservoir is the Forties Sandstone Member (Knox and Holloway, 1992[1]; Figure 4.1). Both fields are relatively low relief anticlinal structures with trapping of hydrocarbons facilitated by four-way dip closure.

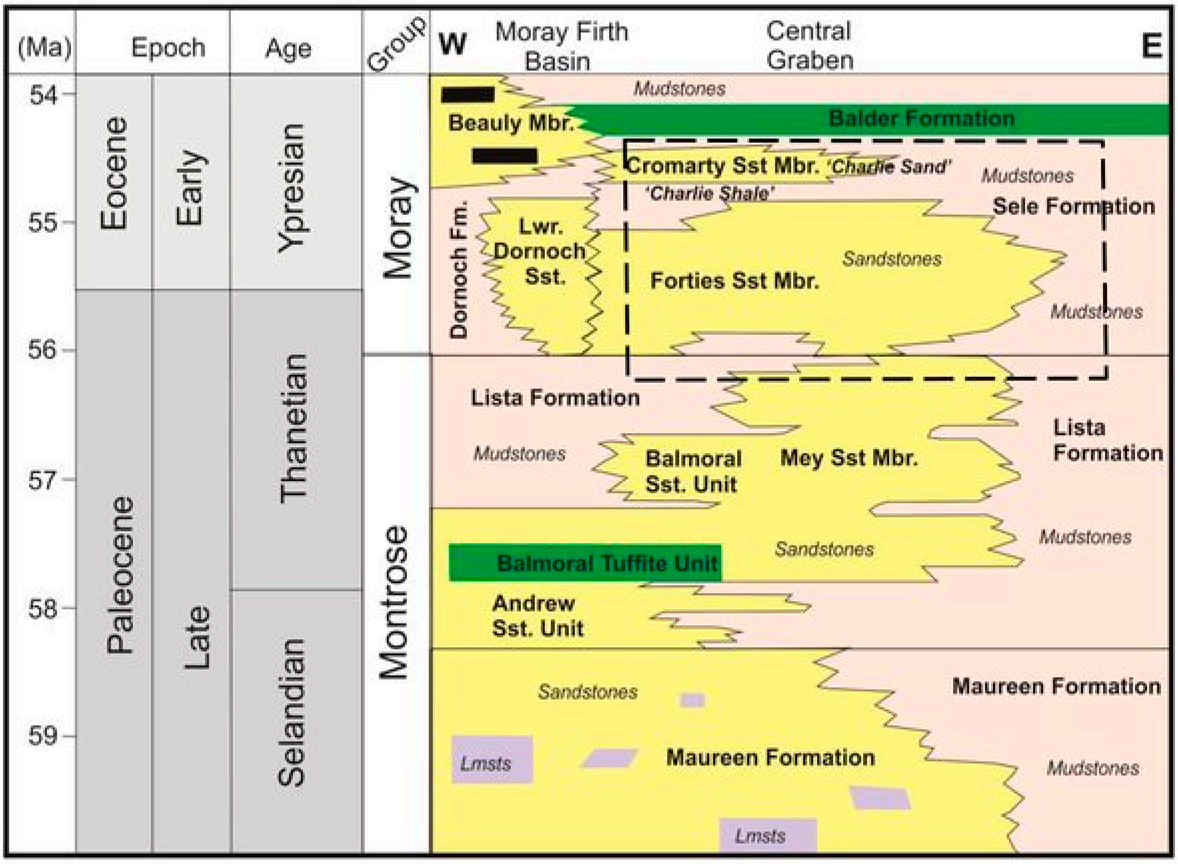

Figure 28 Limit of the 3D model (red outline). The model was built around the Forties and Nelson hydrocarbon fields and adjacent saline aquifer. Coloured polygons show approximate limits of the Forties (pale yellow) and Cromarty (purple) sandstone members.

The Forties Sandstone Member and the overlying Cromarty Sandstone Member are submarine fan sandstones whose varied lithologies are the result of the initiation, growth and eventual abandonment of a submarine fan system. These sandstones are part of the Sele Formation (Figure 27). The shale prone part of the Sele Formation forms the lateral and top seal of the model while the Lista Formation forms the base. The vertical succession records the evolution of a submarine fan system as it built out into the North Sea forming a complex sedimentary environment of amalgamated channels of varying width, depth and sinuosity and interchannel areas. Its petrophysical properties vary both laterally, depending on the location in the submarine fan system, and vertically. *Submarine channels*, the main hydrocarbon producing fairways of the reservoir, form a large proportion of the Forties Sandstone Member but sands are also present in *channel margin* and *interchannel areas*. Together, these three facies are a broad representation of different elements of what is a very complex submarine fan environment. These different elements of the submarine fan environment varied in their relative dominance and position through time resulting in a high degree of lateral and vertical variation in the representative lithologies and their associated petrophysical parameters. In order to aid in the distribution of petrophysical properties for model attribution, a series of polygons defining the possible location of amalgamated channels within a number of the defined reservoir zones were interpreted. These are described and illustrated in Methodology used in model construction.

Data used in building the model

The Cenozoic submarine fan sandstone generic model includes the Forties and Nelson oil fields (Figure 28). There are several peer reviewed scientific papers covering various aspects of both the Forties (Kulpecz and van Geuns, 1990[3]; Wills and Peattie, 1990[4]; Jones, 1999[5]; Carter and Heale, 2003[6]; Cawley et al., 2005[7]) and Nelson fields (Whyatt et al., 1992[8]; Kunka et al., 2003[9]; McInally et al., 2003[10]; Gill and Shepherd, 2010[11]; Gill et al., 2012[12]). The information from these papers formed the basis for building the Cenozoic model.

The published information was augmented by released well data specifically, composite and velocity well logs, deviation logs and company reports provided by CDA. Petrophysical data was compiled from published accounts, published core analyses and BGS interpretation of selected well logs. In addition, well stratigraphic information was obtained from the DECC (now OGA, https://itportal.ogauthority.co.uk/information/well_data/bgs_tops/geological_tops/geological_tops.htm) stratigraphic well database. Finally, regional maps of the Top Sele and Top Maureen supplied by PGS were integrated with the 3D geological model.

The model was built combining surfaces and well information from the Forties and Nelson hydrocarbon fields that are located in a relatively proximal part of the Sele Formation Fan System and could be used as a *broad* representation of these fields. In addition, information provided in this report allows the model to be considered generic and thus be tailored to represent different parts of a submarine fan system.

Methodology used in model construction

Operators of hydrocarbon fields invariably divide the reservoir interval containing the hydrocarbons into different layers or zones reflecting the variable levels of production that can be achieved. For this model, the different layers within the reservoir reflect the development of a submarine fan, the Forties Fan System, over a period of perhaps a little over 1 Ma (Kunka et al., 2003[9]). Each layer records a complex interplay of sediment deposition and erosion resulting in a lithological succession that varies rapidly both laterally and vertically.

The understanding of reservoir dynamics built up during the many years of hydrocarbon production is invaluable for any intended change of use, in this case to CO_2 injection and storage. This model has been built from the published accounts of reservoir architecture by the different operators of the Forties and Nelson fields, specifically by merging the reservoir zonations in the Forties and Nelson oil fields and then extending a short way beyond the fields to include part of the water-filled Forties Sandstone Member.

The boundary of the generic store was defined, encompassing the Forties and Nelson hydrocarbon fields and a surrounding area that contains numerous well penetrations (Figure 28).

The first step in the construction of the generic model was to produce a top reservoir surface in True Vertical Depth Subsea (TVDSS) in metres. This was generated by combining the published depth to top reservoir surface from each of the fields (Forties Field: Kulpecz and van Geuns, 1990[3], Nelson Field: Kunka et al., 2003[9]) and unifying the contours from exploration and appraisal wells outwith the field boundaries (Figure 29); this is the surface from which all other surfaces were constructed.

The top reservoir surface (red dashed line in Figure 30) is defined by the top of the producing reservoir sands in each of the hydrocarbon fields. These sands are of different age in the different fields; the top reservoir surface therefore crosses chronostratigraphic boundaries (Figure 30). A top seal map comprising the Sele Formation Unit S2/ S3 (Figure 27) was constructed by subtracting the average thickness of the seal (derived from wells over the area), estimated at approximately 30 m, from the top reservoir surface.

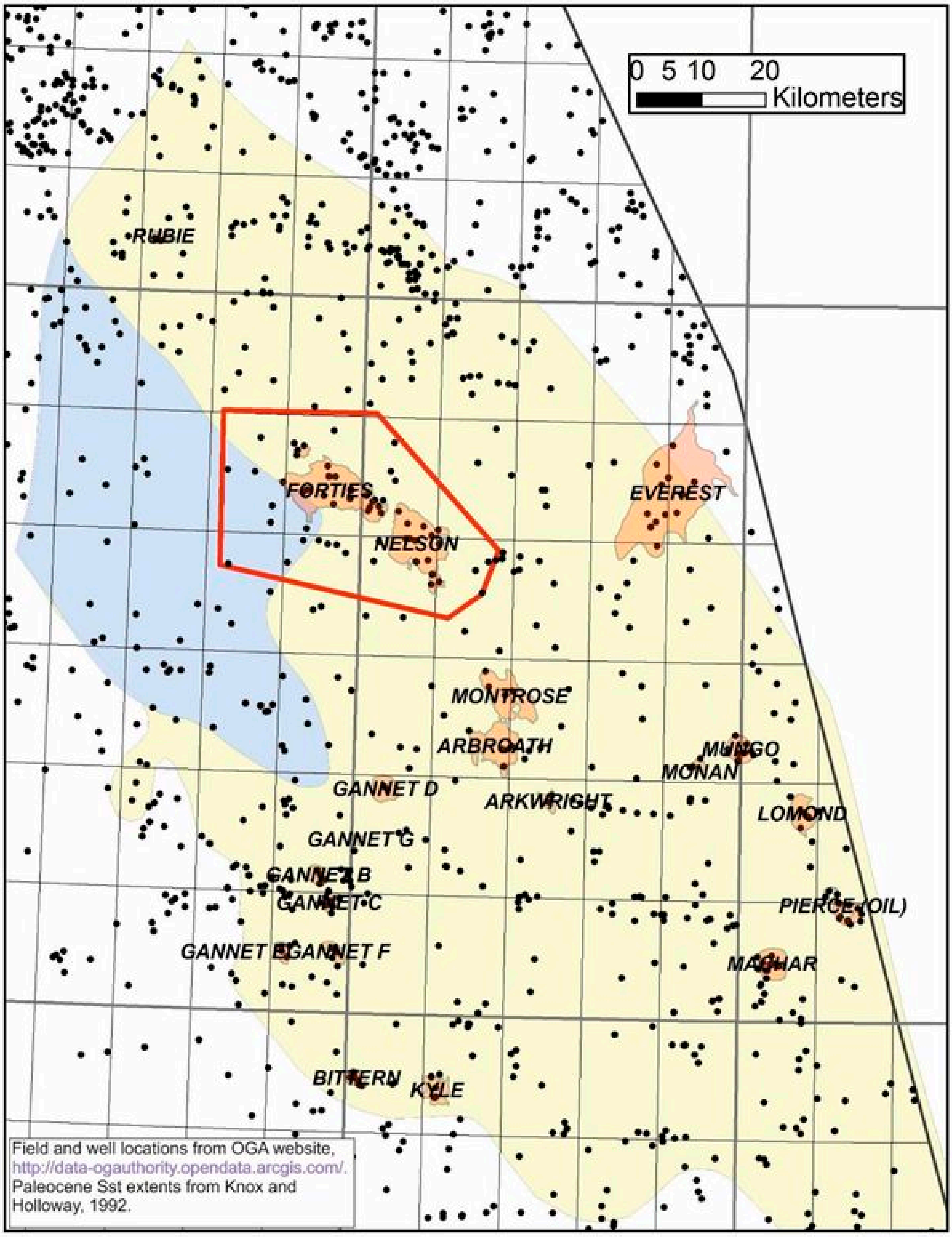

Figure 29 Depth to top reservoir (TVDSS in metres) over the model area constructed from published maps over the Forties and Nelson fields (defined by dashed amethyst coloured outlines) and data from some of the released wells shown (black dots).

The next step was to produce a reservoir zonation in the model that reflects the lateral and vertical variation in lithology seen in the area and that could be representative of the Cenozoic submarine fan sandstone and provide an attributable framework that can be utilised in the dynamic modelling. By attributing the model with different petrophysical parameters and changing the thickness and depth of the reservoir it can be used to represent different parts of any submarine fan system. The Forties and Nelson oil fields each have their own reservoir zonation scheme and thus to achieve this objective, it was first necessary to unify these two schemes (see Unification of the forties and nelson field reservoirs).

Published information includes thickness maps of the different divisions in each field (Forties: Wills and Peattie, 1990[4]; Nelson: Kunka et al., 2003[9]). Once the reservoir zones in each field had been unified, the contours of the thickness maps from each of the fields could be rationalised and then extended outwith field boundaries to the edge of the model. Each reservoir zone, beginning with the youngest, was added consecutively to the top reservoir depth surface in order to produce a set of zones that would form the basis of the structural model.

Each of the zones was then populated with the petrophysical properties that best reflect the facies associations observed in these different zones in the fields (see Attribution of the model).

Unification of the forties and nelson field reservoirs

In order to understand and manage production in the Forties Field reservoir, early attempts were made to identify reservoir zones by correlating sands using lithological variation. However, this was, on the whole, unsuccessful as identifying the same channel purely based on lithology, was not reliable (Kulpecz and van Geuns, 1990[3]). As a result, in both the Forties and Nelson fields, attempts have been made to divide up the reservoir chronostratigraphically to enable sands of the same age, and therefore possibly connected, to be identified. The Nelson Field has the most recent usable published attempt (Kunka et al., 2003[9]) using biostratigraphic information from 59 wells and the lithostratigraphic nomenclature defined in Knox and Holloway (1992)[1]. The most recent usable published information for the Forties Field is from Jones (1999)[5] that reviews earlier work and refines units defined by Wills and Peattie (1990)[4].

For this study, the two chronostratigraphic schemes were unified with reference to Knox and Holloway (1992)[1]. It is likely that the chronostratigraphic schemes in each of the fields will be refined and altered in the future and are likely to be different to that being used by the field operators at present and in the model constructed for this project. However, the existing chronostratigraphic framework reflects the evolution of the Forties Fan and will provide a view of the evolving nature of the deep submarine fans through time.

For the Nelson Field, Kunka et al. (2003)[9] divided the reservoir into seven chronostratigraphic zones (1, 2, 3a, 3b, 4a, 4b, 5) (Figure 30; Table 14) within the lithostratigraphic framework published by Knox and Holloway (1992)[1]. Although Knox and Holloway (1992)[1] was essentially a lithostratigraphic classification, biostratigraphic data was used as an aid to identification and correlation of lithostratigraphic units.

Unfortunately, Wills and Peattie (1990)[4] published information for the Forties Field prior to Knox and Holloway (1992)[1] and these authors defined their reservoir zones using an earlier lithostratigraphic framework (probably Deegan and Scull, 1977)[13]. Jones (1999)[5] also does not refer to Knox and Holloway (1992)[1].

Wills and Peattie (1990)[4] document the division of the Forties Field reservoir into eight chronostratigraphically defined units (D, E, F, H, J, K, L and M) (Figure 30; Table 14). Jones (1999)[5] identified eight different reservoir sands namely, Unassigned Sands 1&2, Main Sand, Alpha- Bravo Sands 1&2, Charlie Sands and Echo Sands 1&2 (Figure 30). Jones (1999)[5] dated the 'Unassigned Sands 1&2' as equivalent to Unit D of Wills and Peattie (1990)[4]. However, whereas Wills and Peattie (1990)[4] correlated the Main Sand and Charlie Sand as being of the same age and placed them in Unit J, Jones (1999)[5] assigned the Main Sands as approximately age equivalent to units E & F and lower part of H (Figure 30). Jones (1999)[5] placed the Charlie, Alpha-Bravo and Echo sands within the younger Unit J (Figure 30). This is more in line with Knox and Holloway (1992)[1] who place the Charlie sands in the Early Eocene and name it the Cromarty Sandstone Member. Thus, the Alpha-Bravo Sands 1&2, Charlie Sands and Echo Sands 1&2 all occur within unit S2 of the Sele Formation, above the S1 unit which marks top reservoir in the Nelson Field (Figure 30). These younger reservoirs reflect the retreat of the Forties Fan system through time.

Units J, K and L are sand prone in the west, chiefly over parts of the Forties Field but become shale prone eastwards (S2/S3 of Knox and Holloway, 1992[1]), including over the Nelson Field. Beneath Unit J a laterally continuous shale layer, known locally as the Charlie Shale, forms a marked pressure discontinuity over the Forties Field and forms part of the top seal for the Nelson Field to the east. Forties Field Units D, E, F and H have been roughly correlated with Zones 1 to 5 defined in the Nelson Field (Figure 30).

By combining the two separate reservoir zonal schemes over Forties and Nelson and with consideration of well information outwith the field boundaries, the Cenozoic 3D Model has been built comprising a unified 8-fold division of the potential Cenozoic submarine fan (Table 14). The basis for unification between the two hydrocarbon fields and the resultant layers, together with their palaeo-environmental context and expected facies distributions to be applied in the static 3D model, are detailed below and represent the initiation, evolution and abandonment of the Forties submarine fan in the Forties and Nelson field areas (see Zone D to Zone M).

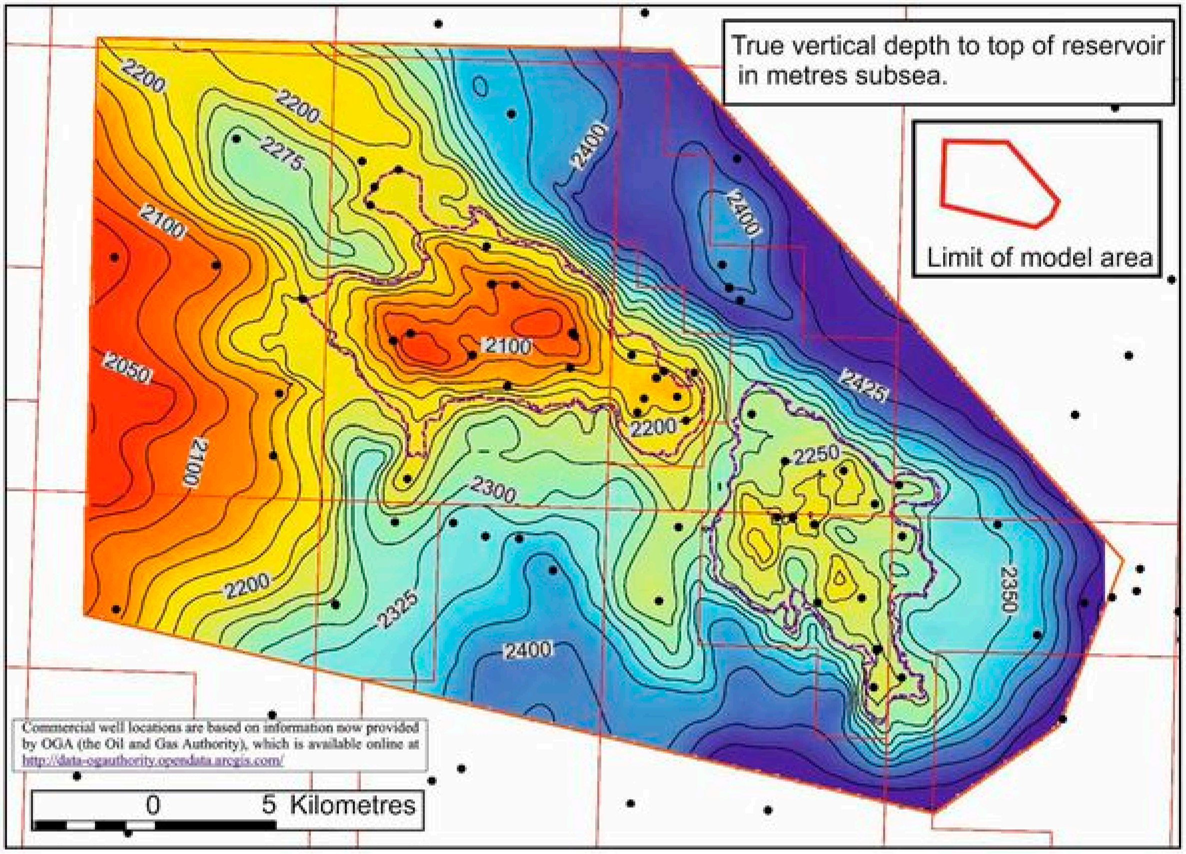

Figure 30 Summary diagram showing relationship between the Forties and Nelson

reservoir layers and their unification to produce zones from which the 3D model was built. The red dashed line shows position of Top reservoir surface. See also Table 14.

Table 14 Unification of reservoirs between the Forties and Nelson fields to produce the Zones in the 3D model.

3D Model	FORTIES	NELSON	Facies and environment
Zone M (Seal)	Unit M	S2 Sele Fm.	Mudstones
Zone L	Unit L	Not present or shale prone and very thin over Nelson.	Mudstone interbedded with thin sandstone (environment—low density turbidites).
Zone K	Unit K	Not present or shale prone and very thin over Nelson.	Thick bedded sandstone (environment—high density turbidites) and interbedded sandstone and mudstone (environment—low density turbidites).
Zone J	Unit J	Not present or shale prone and very thin over Nelson.	Thick bedded sandstone (environment—high density turbidites) and interbedded sandstone and mudstone (environment—low density and dilute turbidites) and mud-rich conglomerate to chaotic deposits (environment— debris flows and slumps).
Zone H(b)	Unit H	Zone 5	Field-wide pressure discontinuity 'the Charlie Shale' (but areas where thin or absent).
Zone H(a)	Unit H	Zone 5	Thick bedded sandstone (environment—high density turbidites) and interbedded sandstone and mudstone (environment—low density and dilute turbidites).
Zone F	Unit F	Zone 4	Thick bedded sandstone(environment—high density turbidites) and interbedded sandstone and mudstone (environment—low density turbidites).
Zone E	Unit E	Zone 3	Thick bedded sandstone (environment—high density turbidites) and interbedded sandstone and mudstone (environment—low density turbidites).
		Zone 2	Field-wide pressure discontinuity
Zone D	Unit D	Zone 1	Comprises succession of thin bioturbated sandstones (environment—low density turbidites), structureless sandstones (environment—high density turbidites) and mud-rich conglomerate to chaotic deposits (environment— debris flows and slumps). Overlain by a thick mudstone unit.

Zone D

Model Zone D comprises Forties reservoir Unit D of Wills and Peattie (1990)[4] and Nelson reservoir Zones 1 & 2 of Kunka et al. (2003)[9] (Figure 30; Table 14).

Wills and Peattie, (1990)[4] place their Unit D within the Andrew Formation of Deegan and Scull (1977)[13] now part of the Lista Formation, Mey Sandstone Member (Knox and Holloway, 1992)[1] (Figure 27). The Unit contains *Alisocysta Margarita* microflora and is impoverished with regard to pollen. Although Zone 1 of the Nelson Field is placed above the Lista Formation by Kunka *et al.* (2003)[9] they note that in the Knox and Holloway (1992)[1] scheme, Zone 1 occurs within the Lista Formation and has *A. Margarita* as a key biomarker. Their Zone 2 marks a regionally mappable slump event and contains microfloras and faunas derived from the Lista Formation. Kunka et al. (2003)[9] note that Zone 2 forms an intra-reservoir pressure seal and in this study it is made equivalent to the top part of Unit D of Wills and Peattie (1990)[4] who also note a prominent pressure discontinuity at the top (Figure 30; Table 14).

In the Forties Field, Unit D comprises a succession of thin bioturbated sandstones, thick-bedded structureless sandstone and deformed slump and debris flow deposits. The top of the Unit is marked by a thick argillaceous succession comprising laminated and slumped mudstone which represents a prominent pressure discontinuity. In the Nelson Field, Zone 1 represents the establishment of the Forties Fan system. Their Zone 1 is characterised by channel activity with blocky log profiles and little evidence of shale layers indicating a high degree of vertical aggradation and amalgamation. Zone 2 is often identified by the presence of a strong pressure break indicating that this unit forms an intra-reservoir pressure seal (Kunka et al. 2003)[9].

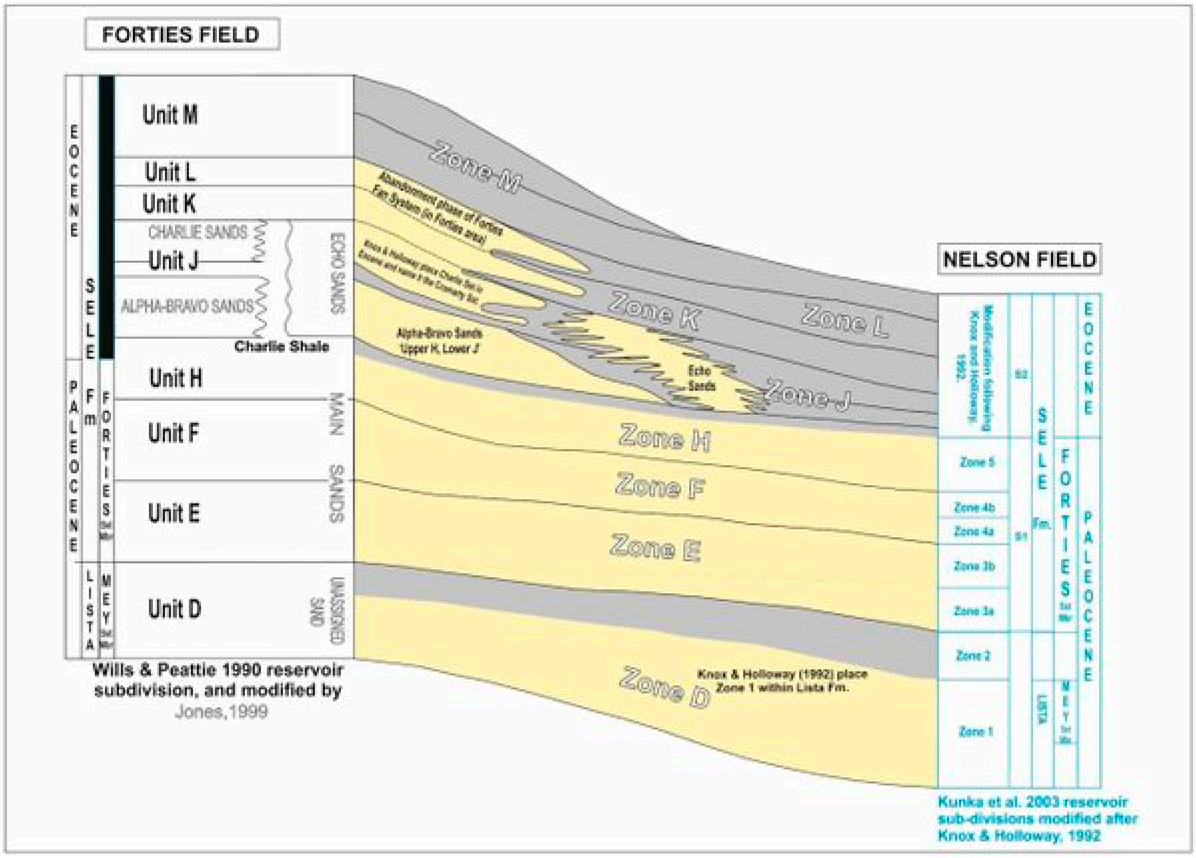

Figure 31 Zone D, total thickness centred on published net sand isochore (Wills and Peattie, 1990[4]), converted to total thickness using factor or 1.7 and extended over whole area.

A net sand map of Unit D was available over the Forties Field area (Wills and Peattie, 1990[4]). This contour map was then extended over the rest of the model area with reference to the contour values and trends and consideration of well information (Figure 31). Wills and Peattie (1990)[4] estimate that the ratio of net sand to gross rock volume in the Forties Field is generally about 0.6.

Therefore, a factor of 1.7 was applied to the contoured net sand thickness values to provide an estimate of the total thickness of Zone D over the model area.

The presence of amalgamated channels is implied by authors of papers pertaining to both the Forties and Nelson fields. Utilising the net sand thickness map that was available for the Forties Field (Wills and Peattie, 1990[4]) and released well information, the possible location of these amalgamated channels was mapped for this layer (Figure 31).

Zone E

Model Zone E comprises Forties reservoir Unit E (Wills and Peattie, 1990[4]) and Nelson Zones 3a and 3b (Figure 30; Table 14; Kunka et al., 2003[9]).

In both fields, the Zone is marked by a sand prone succession that is concentrated in stacked channel systems and separated from the underlying unit by a marked pressure discontinuity. The onset of Unit E of Wills and Peattie (1990)[4] is marked by a Lowstand with coastal onlap within the basin and this corresponds well with Zone 3 of Kunka et al. (2003)[9] who record a maximum extent of the subaerial delta top and delta plain. Biostratigraphic correlation is more difficult with the information available. In the Forties Field, Unit E is placed immediately beneath a 'Base Apectodinium boundary' although *Apectodinium Augustum* is recorded within this unit (Wills and Peattie 1990[4]; their figure 6). In the Nelson Field *Apectodinium* is recorded as becoming common in Zone 3.

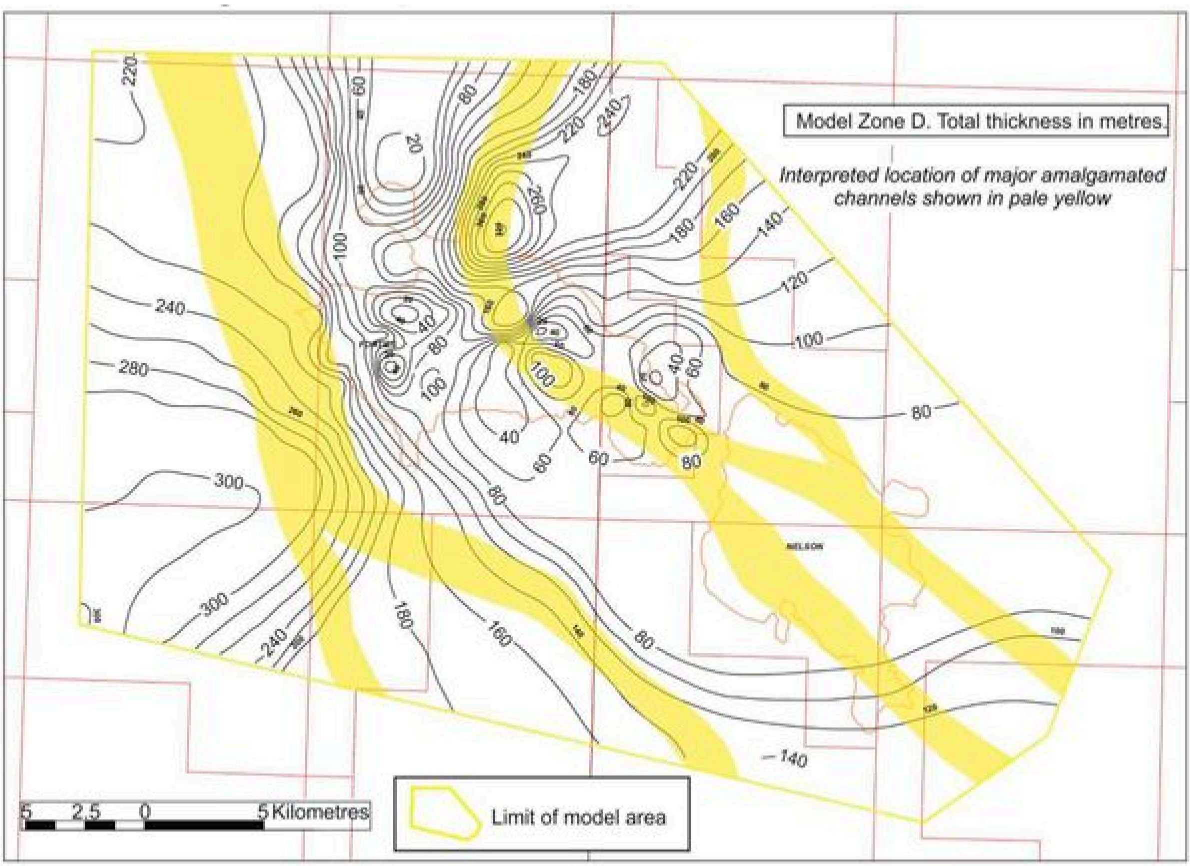

Figure 32 Zone E, total thickness constructed from published net sand isochore of Unit E over the Forties Field (Wills and Peattie 1990[4]) and isochore of Zone 3 over the Nelson Field (Kunka et al., 2003[9])

In the northern part of the Forties Field, the Zone is characterised by areas of thick bedded sandstone while in the south-west and south-east, interbedded sandstone and mudstone and debris flows are recorded. In the Nelson Field, deposition is focused on a NW-trending 'Central Channel' complex.

Contours from a net sand map of Unit E over the Forties Field area (Wills and Peattie, 1990[4]) and an isochore of Zone 3 covering the Nelson Field (Kunka et al., 2003[9]) were combined, correcting the net sand map of Wills and Peattie, 1990[4], by applying a factor of 1.7 to match the isochore of Kunka et al., 2003[9]. The map was then extended over the rest of the model area with reference to the contour values and trends and consideration of well information (Figure 32).

Amalgamated channels are a key facies in Zone E in both the Forties and Nelson fields. Using net sand thickness maps (Wills and Peattie, 1990 [4]), Net to Gross (NTG), and isochore maps (Kunka et al., 2003[9]) and well information, the possible location of these channels was mapped for this layer (Figure 32).

Zone F

Model Zone F comprises Unit F of the Forties Field (Wills and Peattie, 1990) and Zones 4a and 4b of the Nelson Field reservoir (Figure 30; Table 14; Kunka et al., 2003[9]).

In the Forties Field, the base of Unit F is marked by the 'Base Apectodinium boundary' with *Apectodinium* common throughout Unit F (Wills and Peattie 1990[4]; their figure 6). In the Nelson Field *Apectodinium* continues to be common in Zone 4. Both sets of authors record continuing sea-level rise during this time in both chronostratigraphic schemes with a decrease in terrestrially derived biofacies being recorded.

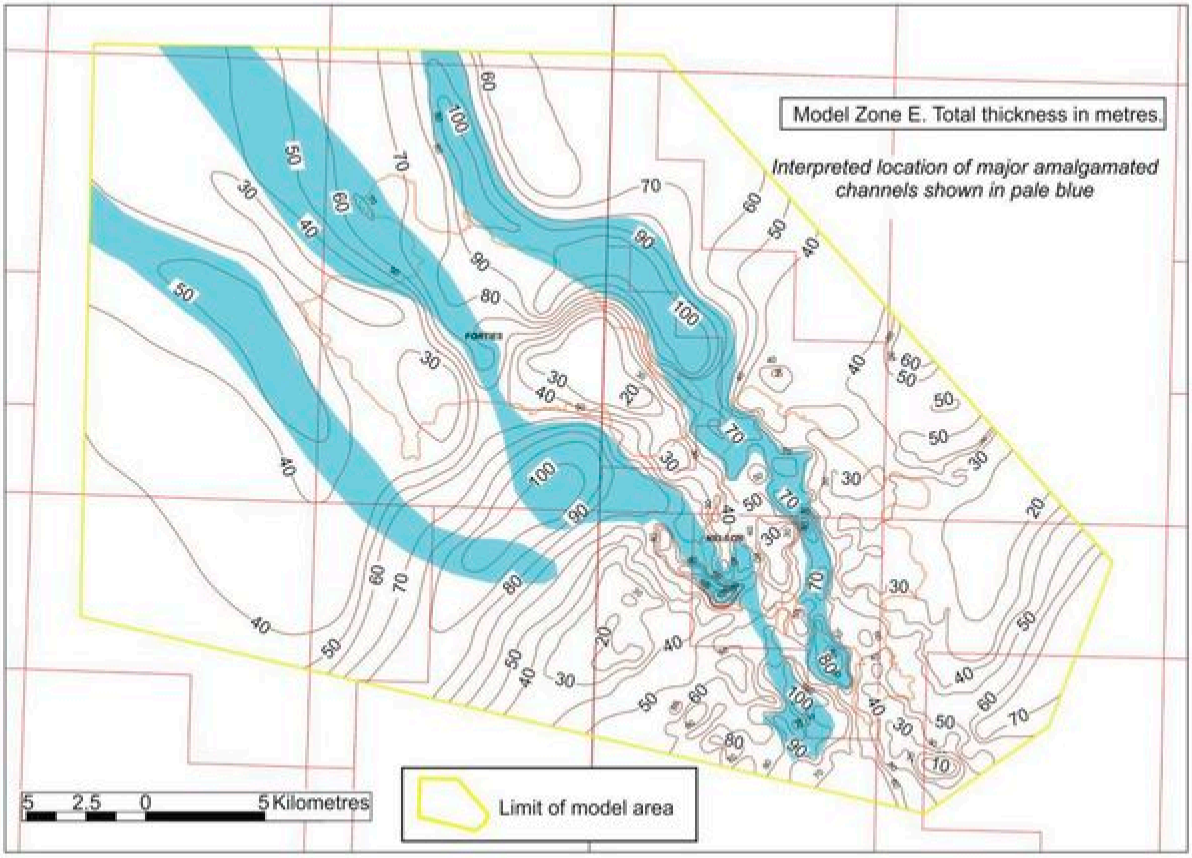

Figure 33 Zone F, total thickness constructed from published net sand isochore of Unit F over the Forties Field (Wills and Peattie, 1990ref name="wills1990"</ref>) and isochore of Zone 4 over the Nelson Field (Kunka et al., 2003[9]).

In the Forties Field, Unit F comprises thick bedded granular sandstones and interbedded sandstone and shale in the north with mudstone dominated facies in the southwest and southeast of the Field. In the Nelson Field (Kunka et al., 2003[9]), channel deposition continued but with the central channel complex becoming less dominant and main sedimentation becoming offset and concentrated on its eastern and western flanks (Figure 33).

Contours from a net sand map of Unit F over the Forties Field area (Wills and Peattie, 1990[4]) and an isochore of Zone 4 covering the Nelson Field (Kunka et al., 2003[9]) were combined and extended over the rest of the model area, with reference to the contour values and trends and consideration of well information, to produce the total thickness map of the model's Zone F (Figure 33). Comparison of the isochore values over the Nelson Field and the net sand values over the Forties Field led to the conclusion that due to the sand prone nature of Unit F, applying the correction of 1.7 to the net sand values would result in an over compensation of unit thickness in the Forties Field compared to the Nelson Field. Hence for Zone F, a correction to the net sand thickness map was not carried out.

Amalgamated channels are a key facies in Zone F in both the Forties and Nelson fields. Using net sand thickness maps (Wills and Peattie, 1990[4]), NTG and isochore maps (Kunka et al., 2003[9]) and well information, the possible location of these channels was mapped for this layer (Figure 33).

Zone H

Model Zone H comprises Unit H of the Forties Field (Wills and Peattie, 1990[4]) and Zone 5 of the Nelson Field reservoir (Figure 30; Table 14; Kunka et al., 2003[9]).

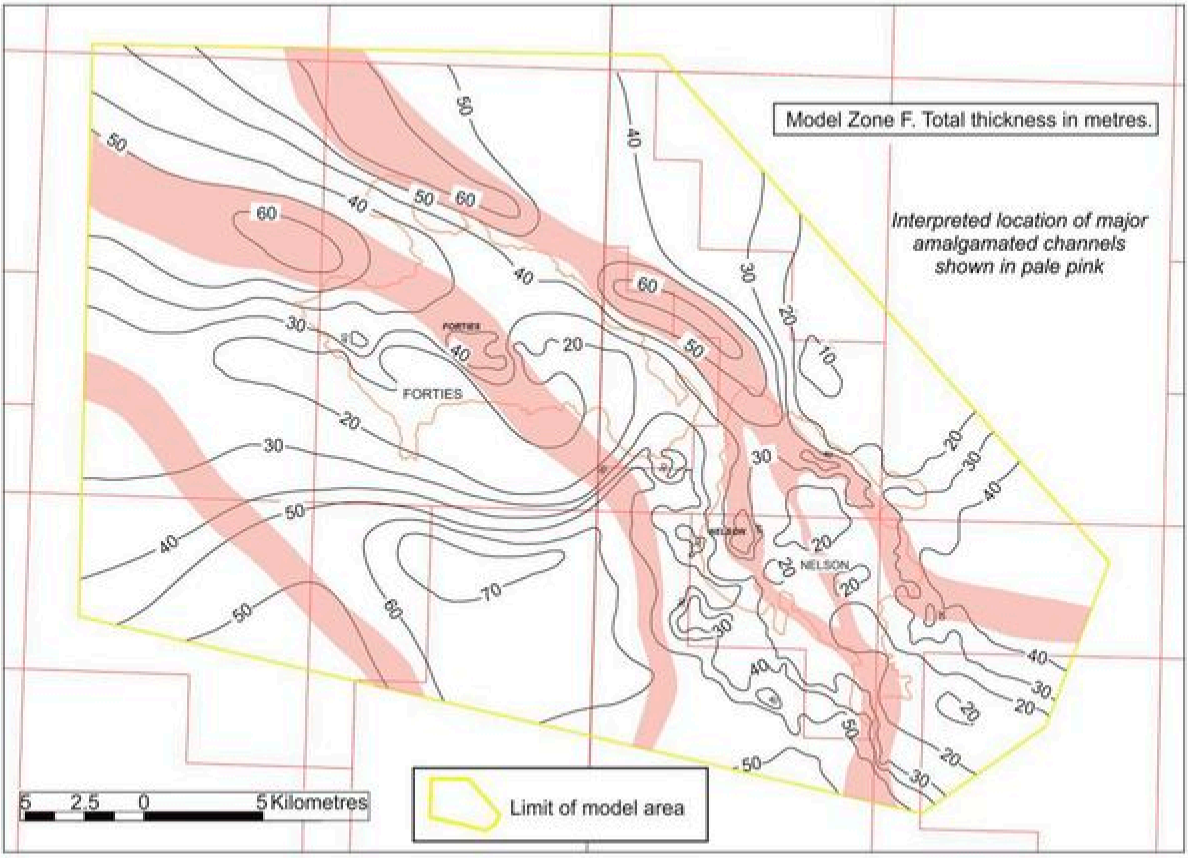

Figure 34 Zone H, net sand thickness from published map of Unit H over the Forties Field (Wills and Peattie, 1990[4]) and calculated isochore of Zone 5 over the Nelson Field (Kunka et al., 2003[9]).

In the Nelson Field, Zone 5 represents the final transgressive stage of the Forties Fan that culminated in the Sele Unit S1 maximum flooding surface that can be correlated over the entire Nelson Field. The top of Unit H of the Forties Field is marked by a prominent mudstone, the 'Charlie Shale'. Here, the overlying 'Charlie Sand' was named the Cromarty Sandstone Member by Knox and Holloway, (1993)[1], and classified as younger than the Forties Sandstone Member being situated within Unit S2 of the Sele Formation (Figure 27). For this model, we assign the Charlie Shale that marks the top of Unit H, as equivalent to the Sele S1 mudstone that overlies Zone 5 in the Nelson Field (Figure 30).

In the Nelson Field, Zone 5 is represented by low density turbidites comprising finely laminated sandstone and mudstone whereas further west in the Forties Field fining upwards thick-bedded sandstone and interbedded sandstone and mudstone predominate.

Contours from a net sand map of Unit H over the Forties Field area (Wills and Peattie, 1990[4]) were combined with an isochore map of Zone 5 over the Nelson Field, the latter calculated from the difference between the published Total Upper Forties Sandstone Member (Kunka et al., 2003[9]) and the sum of the Zone 3 and Zone 4 isochores also of Kunka et al. (2003)[9]. Contours were extended over the rest of the model area with reference to the contour values and trends and consideration of well information to produce the total thickness map of the model's Zone H (Figure 34). The net sand contours over the Forties Field from Wills and Peattie (1990)[4] were not corrected to total thickness because it was considered that, due to the sand prone nature of Unit H, applying the correction factor of 1.7 to the net sand values would result in an over compensation of unit thickness. However, the 'zero' net sand limit on the Unit H map of Wills and Peattie (1990)[4] was moved to the model boundary.

Amalgamated channels are a key facies in Zone H in the Forties Field. In the Nelson Field, major amalgamated channels are not expected to be present. Using net sand thickness maps (Wills and Peattie, 1990[4]) and well information, the possible location of channels were mapped for this layer (Figure 34).

Zone J

Model Zone J comprises Unit J of the Forties Field (Wills and Peattie, 1990[4]) with modifications proposed by Jones (1999)[5] (Figure 30; Table 14).

Wills and Peattie, 1990[4], place Unit J above the acme of several *Apectodinium* biomarkers and note that the unit consists of two major sandstone bodies, the 'Main Sand 'and the 'Charlie Sand'. However, Jones (1999)[5] notes that these sands are of different ages with the Charlie Sand being approximately age equivalent to the upper part of Unit J but the Main Sand older and approximately age equivalent to Units E, F and lower part of H. This fits well with Knox and Holloway (1992)[1] who place the Charlie Sand within the Cromarty Sandstone Member, above the Forties Sandstone Member and within the Sele Formation S2 subdivision (Figure 27). This places the sand at a younger age than the sands within the Nelson Field to the east. This unit, as defined in the Forties Field, is interpreted to pinch-out eastwards with its shale equivalent succession forming part of the overlying Sele Unit S2 in the east and over the Nelson Field.

Unit J, the 'Charlie sand' comprises thick bedded channel sandstones located in the south-western part of the Forties Field around the Charlie Platform (Wills and Peattie, 1990[4]; Jones, 1999[5]).

Jones (1999)[5] also identifies the age equivalent Alpha-Bravo sands (best developed around the Alpha and Bravo platforms of Forties and the Echo Sands, best developed around the Echo Platform.

Wills and Peattie (1990)[4] provide a net sand map showing development of the Charlie Sands in the SW of the field. Good developments of sandstones running through the Bravo, Alpha and Echo platforms are taken to be the sands Jones (1999)[5] dated as the Unit J Alpha-Bravo and Echo sands. Polygons outlining these sands were used to define possible amalgamated channels within Unit J. Unit J is expected to shale out eastwards and form part of unit S2 of the Sele Formation over the Nelson Field (Kunka et al., 2003[9]). A zero net sand thickness shown over part of the Forties Field (Wills and Peattie, 1990[4]) was continued over the model area (Figure 35). The net sand contours for Unit J (Wills and Peattie, 1990[4]) were not corrected to total thickness because it was considered that, due to the sand prone nature of Unit J, applying the correction factor of 1.7 to the net sand values would result in an over compensation of unit thickness.

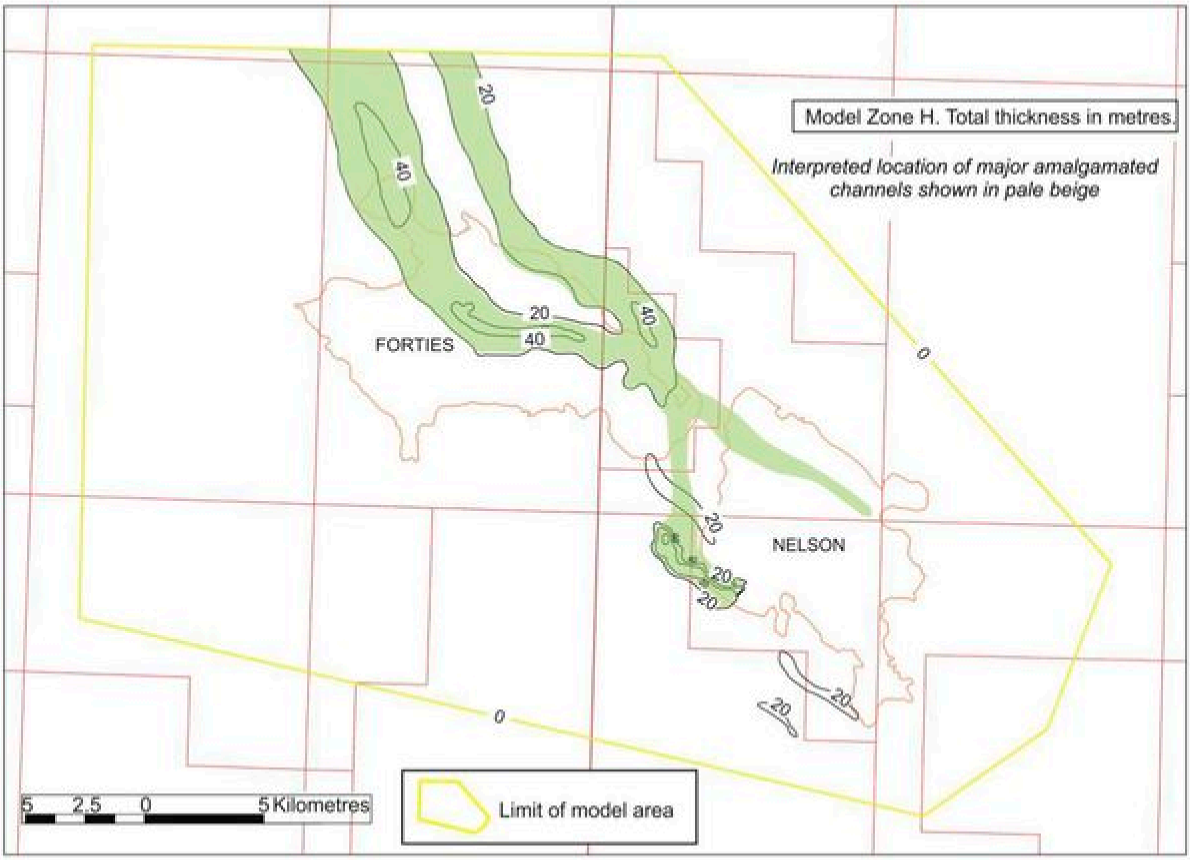

Figure 35 Zone J, net sand thickness from published map of Unit J over the Forties Field (Wills and Peattie, 1990[4]). The unit shales out eastwards and forms part of top seal in Nelson Field.

Amalgamated channels are a key facies in Zone J in the Forties Field. In the Nelson Field major amalgamated channels are not expected to be present. Using net sand thickness maps (Wills and Peattie, 1990[4]) and well information, the possible location of channels was mapped for this layer (Figure 35).

Zone K

Model Zone K comprises Unit K of the Forties Field (Figure 30; Table 14; Wills and Peattie, 1990[4]).

Wills and Peattie, 1990[4], describe a thin sandstone/mudstone succession lying immediately above the thick Unit J sandstones. The published net sand map for this layer shows net sandstone thicknesses of less than 20 m. According to Wills and Peattie, 1990, this unit represents the last major phase of coarse clastic sedimentation in the fan system.

The succession is described as comprising two main elongate sandstone bodies (thick-bedded granular sandstone separated by amalgamation planes) and flanked by areas of thin bedded sandstone and mudstone (classical and low density turbidites) and thin debris flows (mud-rich conglomerates to chaotic deposits). Maps from Wills and Peattie, 1990[4], suggest that the elongate sand bodies follow the same course as the channels in the underlying Unit J. According to the scheme set out here, Unit K will lie within the S2 Sele Formation (Figure 30).

Unit K is expected to shale out eastwards and form part of unit S2 of the Sele Formation over the Nelson Field (Kunka et al., 2003[9]). A zero net sand thickness shown over parts of the Forties Field (Wills and Peattie, 1990[4]) was continued over the model area (Figure 36). The net sand contours for Unit K (Wills and Peattie, 1990[4]) were not corrected to total thickness because it was considered that, due to the sand prone nature of Unit J, applying the correction factor of 1.7 to the net sand values would result in an over compensation of unit thickness.

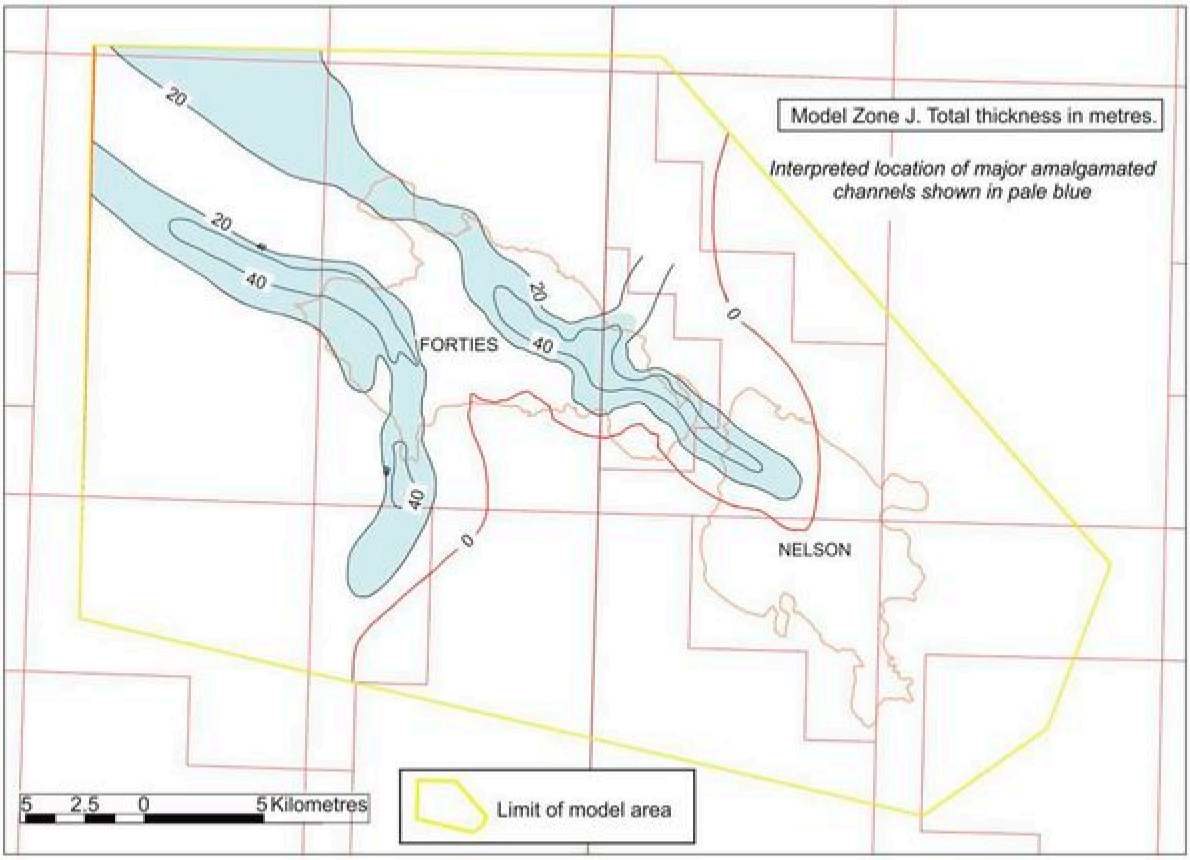

Figure 36 Zone K, net sand thickness from published map of Unit K over the Forties Field (Wills and Peattie, 1990[4]). The unit shales out eastwards and forms part of top seal in the Nelson Field.

Amalgamated channels are a key facies in Zone K in the Forties Field. In the Nelson Field major amalgamated channels are not expected to be present. Using net sand thickness maps (Wills and Peattie, 1990[4]) and well information, the possible location of channels were mapped for this layer (Figure 36).

ZONE L

Model Zone L comprises Unit L of the Forties Field (Figure 30; Table 14; Wills and Peattie, 1990[4]).

Interbedded mudstone, siltstone and very fine- to fine-grained sandstone representing the abandonment phase of the Forties submarine fan system (Wills and Peattie, 1990). No channel bodies have been identified in this Zone.

Zone M

Model Zone M comprises Unit M of the Forties Field (Figure 30; Table 14; Wills and Peattie, 1990[4]) and Unit S2 of the Sele Formation (Figure 27; Knox and Holloway, 1992[1]).

Lithologies comprise laminated grey mudstone with thin siltstone and sandstone beds. This Zone forms the caprock seal to the reservoir in the Forties Field (Wills and Peattie, 1990[4]). No channel bodies have been identified in this Zone.

The eight zones described above were built from a unification of published reservoir zonation from the Forties and Nelson fields and were extended to the limits of the 3D model with reference to released well information. Using the depth to top reservoir (Figure 29) as a reference surface, they form the building blocks of the 3D model.

Building the model in PETREL

The reader can visualize this model in 3D by clicking on this link. This section summarises the construction of a PETREL 3D geo-cellular grid for a volume that encompasses the Forties and Nelson Oil Field reservoirs and adjacent saline aquifer (Figure 28). The PETREL software version used for the modelling was Version 2009.2.1; 32 bit. 3D geo-cellular grid creation and the majority of processing steps utilised PETREL standard workflow processes for structural and property modelling and inbuilt calculator functions.

Regional stratigraphical surfaces were derived from the Petroleum GeoServices (PGS) Top Sele and Maureen formation grids and CDA/DECC (now OGA) well stratigraphy database (https://itportal.ogauthority.co.uk/information/well_data/bgs_tops/geological_tops/geological_tops.htm), to provide controlling surfaces for dynamic modelling beyond the oil-field areas.

PETREL 3D grid modelling procedure

The Primary starting dataset comprised:

- Z-Map ASCII format grids, ***in depth***, derived from well intercepts and published depth contours for the Top Seal Horizon and Top Reservoir Horizon (Figure 29);
- Z-Map ASCII grids, ***in thickness***, derived from well intercepts and published isochore contours for each of the seven reservoir zones (see Methodology used in model construction) (Table 14);
- Overall model and reservoir zone extent polygons;
- Well logs (Depth, location and track) for 93 wells.

Data file preparation

Horizon depth and zone isopach (interval thickness) grid files were exported from ArcGis in Z- Map ASCII format and were read directly into PETREL. Note the isopach grid files are stored as surface objects with the thickness values held as the point-node data Z attribute.

The isopach grids for the upper 3 reservoir zones (Zones J, K and L) only cover parts of the model area. To build the 3D grid competently, each zone must be represented across the full extent of the model to ensure that zero thicknesses are honored where appropriate and to minimise extrapolation artefacts. To accommodate this, the imported grids were extended out to the model boundary with the Z data-points set to zero in parts where the zone was deemed to be geologically absent.

For each reservoir zone, where required, the following was generated:

- an extent polygon for the imported isopach grid;
- a zero thickness surface across full model area from model outline polygon.

The zero thickness and measured thickness point-sets were then combined and a new set of isopach surfaces was created using the combined point sets. The new surfaces were checked to ensure they covered the full model area and any spurious negative data points were converted to zero.

Creating the 3D grid

After naming the new model, a 3D grid was created with top seal, top reservoir and base reservoir surfaces defining a higher stratigraphical unit for the seal and the underlying one for the reservoir; this set the framework for later zonation. The model boundary polygon was assigned as grid extent limit and the depth surfaces were input. The Horizon type was set to 'Erosional' so that horizons would truncate the underlying reservoir zones. The other horizons are set to 'conformable' by default. The grid increment (spatial resolution) was set to 200 m.

Creating the reservoir zonation and intra-zonal layering

Seven zones (D, E, F, H, J, K and L) were created within the reservoir interval (Figure 37). Vertical PETREL Zone subdivisions (Layers) were created to give an improved scale of resolution to the model and may be thought of as pseudo-bedding (Figure 38). The number and geometry of the zone layers (not to be confused with stratigraphical layering) were set proportionally with 10 subdivisions for each reservoir zone and 1 for the seal. A minimum cell thickness of 1 m was set and the sub-division was built from the base upwards (this will achieve the truncation at top reservoir level).

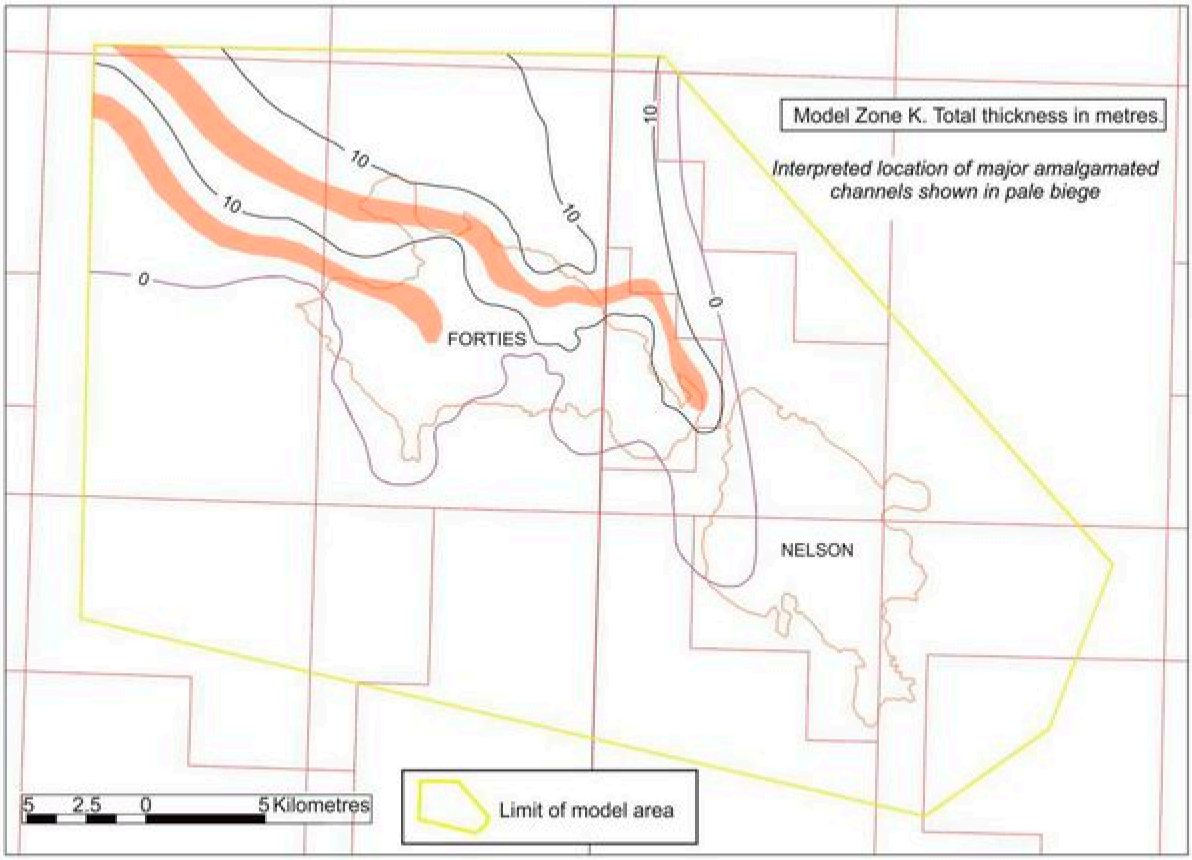

Figure 37 Grid cross-section illustrating lateral distribution of reservoir zones and overlapping seal zone. Dashed rectangle defines detail of reservoir zones shown in Figure 38.

Relatively thin, but laterally extensive, 'shale' units, considered to be internal reservoir seals, occur at two levels within the reservoir stack at the top of Zone D and Zone H ('Charlie Shale') (Table 14; Figure 30). These were not modelled as separate zones. The units were created within PETREL and treated as constant-thickness, minimal permeability layers within the model grid, but with cutouts where the horizons are known to be absent (Figure 39). Constant thicknesses of 10 metres and 25 metres were used for top of Zone H and Zone D respectively. [4]; Kunka et al., 2003[9]; Gill and Shepherd, 2010[11]) and released commercial well information described above in Methodology used in model construction.

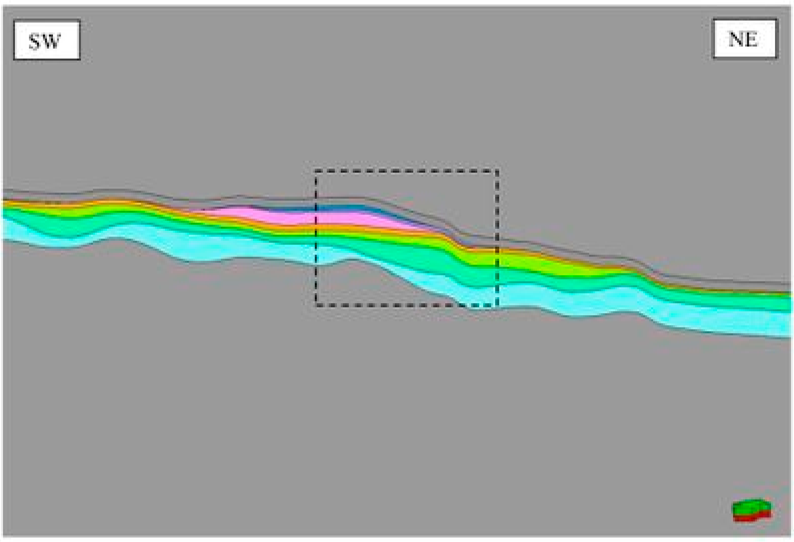

Figure 38 Expanded 3D grid cross-section illustrating lateral distribution of layering within reservoir zones.

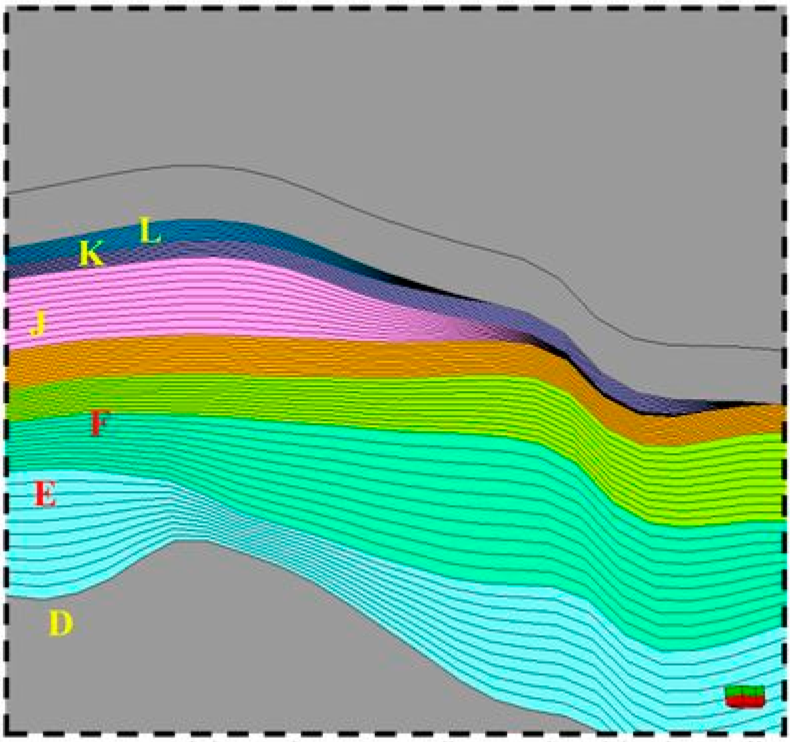

Figure 39 Modelled mudstone layer (Charlie Shale) at top of reservoir Zone H with gap created where known to be thin or absent in well logs.

Attribution of the model

Imperial College attributed the Cenozoic model based on information and guidance provided by the BGS and detailed in the following sub-sections. The Cenozoic model (Table 14) totals *eight Zones*. It is divided into seven reservoir Zones (D, E, F, H(a), J, K & L) a field-wide pressure discontinuity (Zone H(b) and a top seal (Zone M). The lower part of Zone H is a reservoir (H(a)), the upper part (H(b)) is a pressure discontinuity (Table 14).

The model is divided by two pressure discontinuities (top part of Zone D and Zone H(b)). Elsewhere, pressure communication *between* zones will be governed by juxtaposition of appropriate lithologies and variation in transmissibility should be controlled by the attribution of the individual zones.

The attributed Cenozoic model should capture the following geological elements:

- The layered/zoned nature of the reservoir;
- The horizontal pressure discontinuities between some of the zones;
- The transmissibility between other zones where pressure discontinuities are not present;
- The high porosity/permeability production fairways comprising amalgamated channels defined by polygons in Zones D, E, F, H, J and K;
- The generally lower porosity/permeability interchannel areas.

Each reservoir Zone in the model (Table 14) was attributed. Six of the Zones (D (lower part), E, F, H (lower part), J and K) are each divided into two facies associations namely 'Channel' (see Channels) and 'Interchannel' (see Interchannel) areas. The 'Channel' areas comprise amalgamated channels (defined by polygons) and are the main production fairways in the two hydrocarbon fields (Forties and Nelson) that make up part of the 3D model. If used as a CO_2 store, it is likely that injectors would be placed in the 'Channel' areas in order to benefit from the high permeability and connectivity present.

Channels

The amalgamated channels have a generally SE flow direction and have a marked horizontal and vertical variation in petrophysical properties. For this task we considered ***four Elements*** within an amalgamated channel system that need to be represented in the attribution (McHargue et al., 2011[14]; Mayall et al., 2006[15]). ***Element 1***, the channel sandstone (both high and low NTG), will have fairly consistent petrophysical properties parallel to the channel flow direction. ***Element 2***, low permeability basal lags, ***Element 3***, high permeability basal lags and ***Element 4***, intra-channel doggers, will all influence vertical and lateral flow.

The following petrophysical values were recommended to Imperial College:

Element 1. The channel sands:

- Porosity 25(21–38); (**data source:** from core data and Kunka et al., 2003[9]);
- Horizontal Permeability 376 mD (31–1610); (**data source:** from core data and Kunka et al., 2003[9]);
- Vertical permeability divide by 10 (**data source:** Kulpecz and van Guens, 1990[3]);
- NTG 0.72(0.21–1); (**data source:** Kunka et al., 2003[9]).

Element 2. The low permeability basal lags:

- Porosity 25(21–38);
- Horizontal Permeability—lower end of range 31–376 mD;
- Vertical permeability divide by 100 (**data source:** Kulpecz and van Guens, 1990[3]);
- NTG 0.72(0.21 – 1).

Element 3. The high permeability basal lags:

- Porosity 25(21–38);
- Horizontal Permeability—higher end of range 376–1610 mD;
- Vertical permeability divide by 10 (**data source:** Kulpecz and van Guens, 1990[3]);
- NTG 0.72(0.21–1).

Element 4. The intra channel ‘doggers’:

- Porosity <12%; (**data source:** Kunka et al., 2003[9]);
- Permeability <1 mD; (**data source:** Kunka et al., 2003[9]).

Interchannel

The Interchannel areas and associated channel margins contain muddy debris flows, slump deposits, thin-bedded turbidites and mudstones. Mudstones form vertical permeability barriers to the sandstones present. Reservoir properties are much more variable than within the ‘Channel’ areas but will include some very good quality sandstones, some of which will possess porosities and permeabilites equivalent to the Channel areas. Although interchannel areas are less likely to be primary targets for CO_2 injection, their attribution is important as the rate at which the injected CO_2 passes into the interchannel area will be reflected in the amount of pressure build-up in the channel area with implications for storage capacity and the injection rates that may be sustained.

The Interchannel areas in each layer should be attributed stochastically using the following data:

- Porosity 24.6(3–32.9); (**data source:** derived from core measurements);
- Permeability 163 mD(0.01–1769);(**data source:** derived from core measurements);
- For vertical permeability divide by 100 (min) and 1000 (max) (**data source:** Kulpecz and van Guens, 1990[3]);
- NTG 0.33(0.11–0.89); (**data source:** Kunka et al., 2003[9]).

Note that the range of porosity/permeability means that some values are on a par with those seen in the channel areas.

Modelling of lateral variation of petrophysical properties in reservoir zones

The Cenozoic model attempts to capture the reservoir properties of deep-water submarine fan sandstones. In the Central Graben area of the North Sea, a series of submarine fan systems built out into the area. This model is built around the Forties and Nelson fields where oil is trapped in the Forties and Cromarty sandstone members. The Forties Fan has been classified as a ‘Mud/Sand-Rich Ramp’ (Richards et al., 1998[16]) although they are difficult to characterise precisely and Kunka et al. (2003)ref name"kunka"></ref> prefer a ‘Sand-rich ramp’ classification.

The Forties and Nelson fields sit in a relatively proximal position within the present day Forties deep marine submarine fan limits. The interpreted location of amalgamated channels and interchannel areas of this model, and assigned NTG, porosity and permeability values reflect this proximal position. The possible changes in petrophysical properties along an amalgamated channel system, from those values more typical of a proximal position in the fan to those more typical in a distal position, were considered. For the majority of reservoir Zones (D, E, F and J; see Table 14), the difference between values is best represented by the variation generated by the maximum to minimum ranges in petrophysical parameters detailed above in Channels and Interchannel.

However, for Zone H(a) (Figure 40) and Zone K (Figure 41), the change from a more ‘proximal’ to a more ‘distal’ facies NW to SE, reflecting the final stages of Forties Fan deposition in the Nelson Field area and in the Forties Field area respectively, is expected to be more pronounced. This is already reflected in the channel widths and their limited extent towards the south-east (Figure 40 and Figure 41). NTG, porosity and permeability values recommended to Imperial College are detailed below and record a NW–SE variation.

For Zone H(a), NW proximal part of the model over the Forties Field (Figure 40):

1) we recommended using values detailed above in Channels and Interchannel for defined Channel and Interchannel areas;

For Zone H(a), SE distal part of the model over the Nelson Field (Figure 40) and Zone K where channels lie over Forties Field (Figure 41):

2) we recommended using values (after Kunka et al., 2003[9]) detailed below:

a. Attribute channels NTG 0.33 (0.11–0.89); b. Porosity 21.85 (15.22–33.72);
c. Permeability 166 (10–359);
d. For Interchannel areas according to data above (see Interchannel).

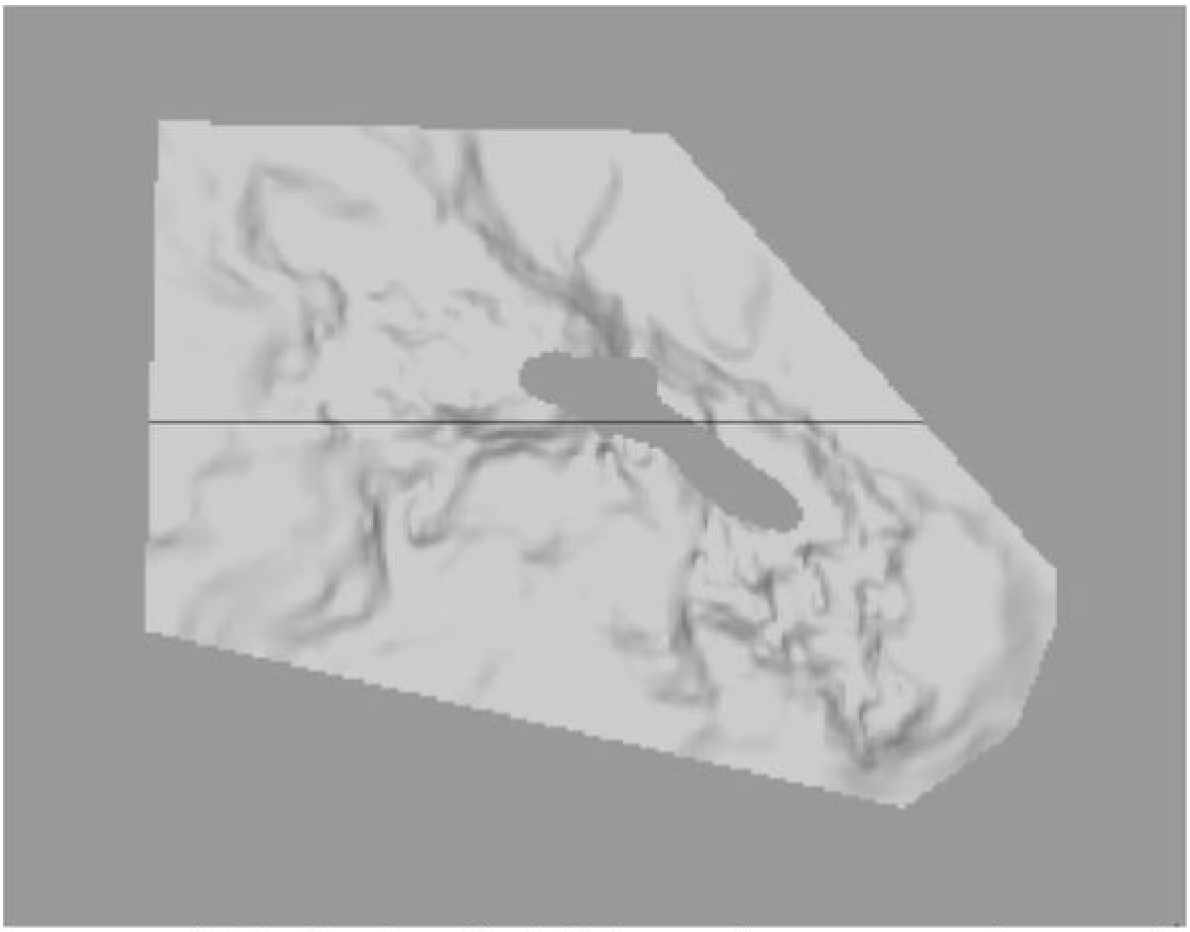

Figure 40 Zone H(a) of the Cenozoic model showing interpreted channel distribution.

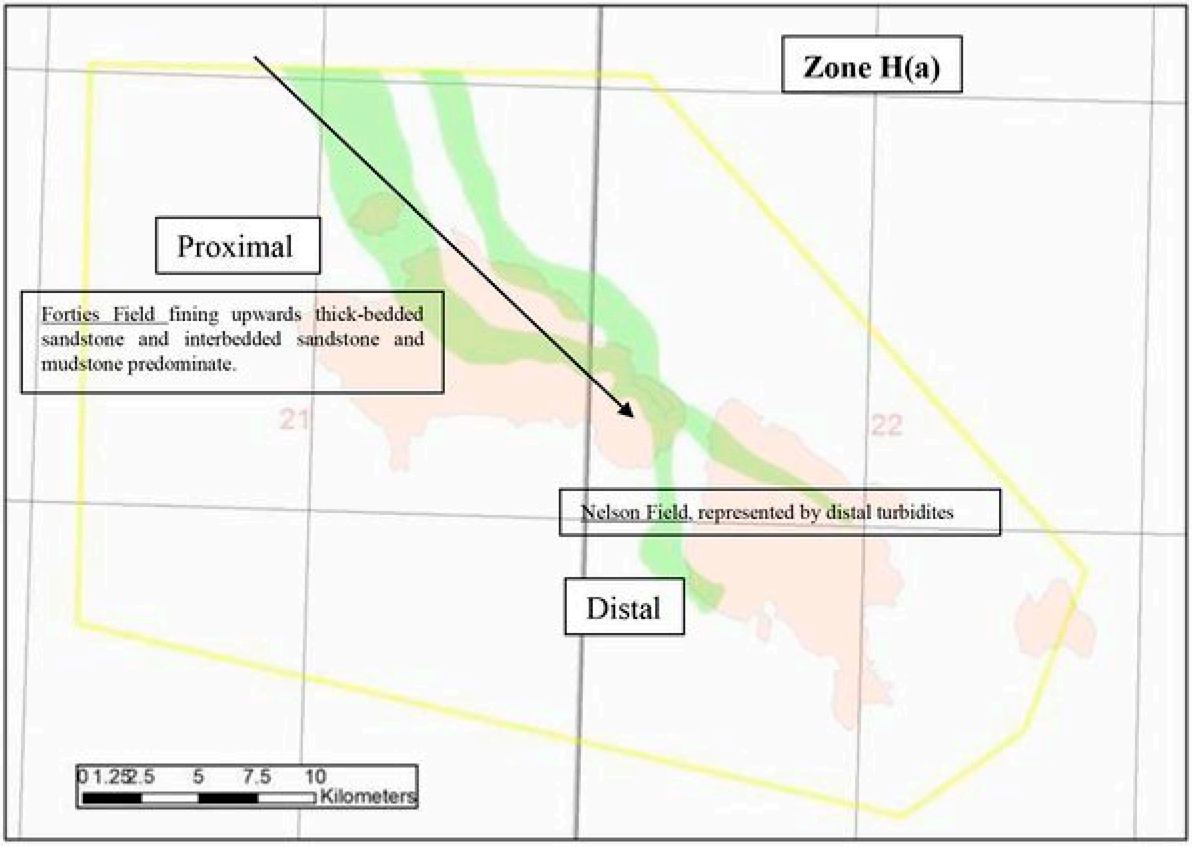

Figure 41 Zone K of the Cenozoic model showing interpreted channel distribution.

Modelling of slump facies within 'interchannel' areas

A further refinement to attribution of the interchannel areas was carried out with the consideration of the distribution and petrophysical properties of slump deposits.

Slump deposits can occur in a proximal fan setting where material has dislodged from the shelf slope and been deposited on the medial ramp adjacent to amalgamated channels. In the Nelson Field, a succession of slumped and contorted sandstones and mudstones and chaotic muddy conglomerates forms an intra-reservoir pressure seal (represented in the Cenozoic model as 'Field- wide pressure discontinuity' in upper part of Zone D–Table 4.1). This slumped succession is thought to be due to slope failure during a phase of sea level lowstand (Kunka et al. 2003[9]).

Slumps are also associated with turbidite channels where channel sides may collapse. They form most commonly during early stages of lowstand (Mayall et al., 2006[15]). Kunka et al. (2003)[9], also record muddy debris flows and disorganised slump deposits on channel margins in the Nelson Field. Mayall et al. (2006)[15], describe slump facies being composed of a muddy matrix with muddy to clean sands but with complex contorted geometries. Mayall et al. (2006)[15], note that they generally do not form effective reservoirs for oil but can contribute to production in gas reservoirs. These authors also note that they have potential for forming important permeability barriers or baffles during production.

Thus, slump facies may be associated directly with shelf slope failure, when in proximal parts of the fan, or channel margin collapse, here they are often located immediately adjacent to the amalgamated channel reservoir polygons. There are therefore two distributions of slump deposits to consider:

a) Slumped material associated with shelf slope failure in proximal location;

b) Slump facies associated directly with channel margin collapse—These slumped facies will often be located in the channel margin immediately alongside the channel polygons in each layer. Percentage distribution will vary in each Zone in the model, decreasing through the life of the fan. At the location of the model build (Area 1– see Definition of area types), we recommended to Imperial College that slumped facies should be randomly distributed along channel margins, and decreasing through the life of the fan, with distributions as follows:

- 35% for Zone D;
- 25% distribution for Zones E, F, H(a), and J;
- 15% distribution for Zone K;
- 10% for Zone L.

It was recommended that the ranges of porosity and permeabilities provided for the 'Interchannel' areas (see Interchannel) be applied, but distributed in such a way as to distinguish the slumped areas from the stochastically attributed parts of the 'Interchannel' areas. Slumped deposits impact on the reservoir model by forming pressure discontinuities between reservoir layers (see above). In the Interchannel areas, they will also impact on the distribution of petrophysical properties and it was suggested that they generally be attributed to act as barriers or baffles to flow. However, there may also be clean sands within the slump deposit that have reservoir quality poroperm values; they may or may not be in communication with facies outside the slumped areas.

Construction of regional surfaces

Top Sele and Top Maureen formation surfaces, in depth below mean sea level in metres, were supplied by Petroleum GeoServices (PGS). These were imported into Petrel and clipped to the generic 3D model top and base surfaces.

Definition of area types

The Cenozoic submarine fan 3D model has been built from an area that includes the Forties and Nelson fields located in the central part of the Forties fan (Figure 28). The reservoir in this 3D model exhibits lateral and vertical variation in petrophysical parameters and charts the evolution of the Forties fan at this relatively proximal location. The model has been attributed using data from the Forties and Nelson fields and information from wells drilled in the 3D model area.

This project aims to model injection of CO_2 in a set of defined geological settings (named here as **Area Types**), using a 3D generic model, in order to compare and quantify storage performance within different parts of a particular reservoir, here we examine a submarine fan sandstone. The model provides the framework that can be attributed according to its location on the submarine fan. It is likely that CO_2 injection wells would be sited in channels only and that wells could be located down-dip from structural closures; either hydrocarbon fields or brine filled aquifer.

Every site selected on the Forties Fan will be different and our aim is to define sufficient Area Types to represent all potential Cenozoic submarine fan reservoir CO_2 stores.

Overview of the forties submarine fan

The Forties Fan is made up of a huge number of interconnected amalgamated channels and interchannel areas that change laterally and vertically creating a very complex 'plumbing system'. The Forties Fan can be regarded as an open system—though it is probably closed on its southeastern, southwestern and northeastern sides, it is probably open to the northwest. The Forties

Fan is 300 km by 100 km (at its widest) (Davis et al., 2009[17] note 260 km by 80 km) and trends NW–SE with sediment derived from the NW (Hempton et al., 2005[18]). Davis et al. (2009)[17] note that it is a mixed mud-sand, ramp-fed system (*sensu* Reading and Richards, 1994[19]). However, Kunka et al. (2003)[9] state that a sand-rich ramp is more appropriate (*sensu* Reading and Richards, 1994). Reading and Richards (1994)[19] state sand-rich ramps are not always easy to distinguish from sandier members of mixed mud-sand, ramp-fed systems.

In general, to the SE, the reservoir will be characterised by:

- Greater depths;
- Thinner reservoir intervals (Hempton et al., 2005[20]);
    - >259 m at Forties (proximal area);
    - mean c. 137 m at Pierce (distal area).
- Slumps and debris flows dominate BASAL and PROXIMAL parts of the submarine fan system (Davis et al., 2009[17]);
    - Overlain by large channel complexes that dominate the central part of the fan (50–100 m thick, 2.5–3 km wide). Separated by mud-prone inter-channel areas approximately 500 m wide in medial part of the fan (Davis et al., 2009[17]; Den Hartog Jager et al., 1993[21]).
- Lower mean NTG, lower, but still fair to good porosities, poorer permeabilities (by factor of 10 less);
    - **Proximal** —Forties and Nelson, turbidite reservoirs, mostly channelized;
        - High NTG (65%), Porosity 23–26%, Permeabilities hundreds of mD (Hempton et al., 2005[20]).
    - **Distal** – Pierce and Starling fields, turbidite reservoirs less frequently channelised, more typically overlapping lobes and/or sheets (Hempton et al., 2005[20]);
        - Lower NTG (58% at the Pierce Field, 50% at the Starling Field), Porosity 16–23%, Permeabilities tens of mD (Hempton et al., 2005[20]);
        - Distal and margins of fan, deposition characterised by development of sheet-like sandstone bodies (Davis et al., 2009[17]).
- Fewer reservoir channels;
- Reservoirs more likely to comprise lobes and/or sheets—less confined;

- Salt-induced and active highs form structural closure on hydrocarbon field and controlled direction and behaviour of sediment gravity flows. Majority of downdip fields are in salt produced closures or in ring-like structures where pierced (Hempton et al., 2005[20]);
- Progressively greater reservoir pore fluid overpressures (e.g. Robertson et al., 2013[22]);

    - There is a north-westerly flow of saline formation waters towards lower pressure and less saline water (Kantorowicz et al., 1999[23]).

- There is a progressive downdip decrease in oil saturation. In the Forties Field, oil saturation is 85% (Hempton et al., 2005[20]). In Nelson, it is expected to be less (but no figures available to confirm). In more southerly fields, oil saturation is around 62% and 52% (Hempton et al., 2005[20]). We suggest a figure of 80% oil saturation for Nelson.

Three potential Area types have been identified based primarily on palaeogeography (i.e. location within the fan complex) (Figure 42). Other factors that influenced the Area Type boundaries are depth, thickness and the type of closure. Suggested petrophysical values for Area Types 2 and 3 are shown in coloured boxes below (yellow box—Amalgamated channel areas, blue box—Interchannel areas).

Area type 1

The 3D model has been built in Area 1. Its attribution is based on data from the Forties and Nelson fields and information from individual wells in the area described in Attribution of the model.

Area type 2

Structures are generally broad closures related to buried NW trending horsts. The Montrose, Arbroath and Arkwright hydrocarbon fields are 4-way dip closures. The South Everest Field is a structural stratigraphic trap.

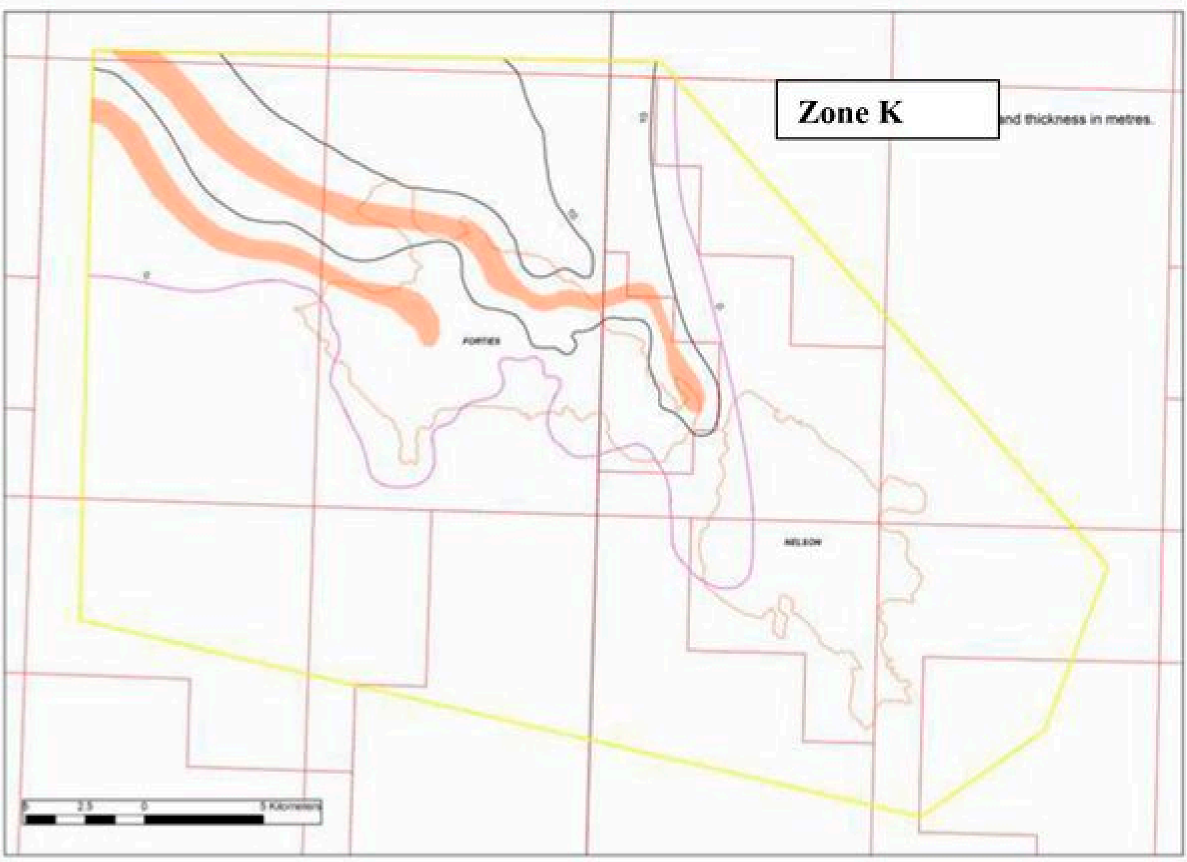

Figure 42 Location of Area Types. Field locations from OGA website - http://data-ogauthority.opendata.arcgis.com/'. **Paleocene Sst extents from Knox and Holloway, 1992[1].**

For Area Type 2, the thickness of the model will be reduced by removal of the Charlie Sand Zone and above (Zones J, K and L) from the 3D model as these are known to be absent SE of Forties Field. Zone M, the seal formation is retained.

The remaining layers (H, F, E and D) have 'Amalgamated Channel' and 'Interchannel' areas as described in Attribution of the model above.

Attribution of amalgamated channels (defined by the polygons shown in, for instance, Figures 31, 32 and 33 above).
As in Area 1 there are four elements to the amalgamated channels—channel sands, low permeability basal lags, high permeability basal lags and intra channel doggers. Petrophysical values are detailed below.

Amalgamated channel areas
Channel sands:
• **Porosity**, 22(16–30);
• **Permeability**, 80 mD(1–1250);
• **NTG**, 0.61(0.3–0.91).
Low permeability basal lags:
• **Porosity**, 22(16–30);
• **Permeability**, 1 mD.
High permeability basal lags:
• **Porosity**, 22(16–30);
• **Permeability**, 1250 mD.
Intra channel doggers:
• **Porosity** <12%;
• **Permeability**, <1 mD.
For vertical permeability divide by 10 (*Kulpecz and van Geuns, 1990*[3]).

Area Type 2 reservoir attribution is based on data from Montrose, Arbroath, Arkwright and South Everest fields and core measurements in Core reports for wells 22/18–5 and 22/23a–3. Porosity and (particularly) permeability values are very variable. Porosity minimum is based on data from the Arkwright Field (Kantorowicz, 1999[23]), maximum based on Arbroath and Montrose Fields (Crawford et al., 1991[24]; Hogg, 2003[25]) and core data. Permeability minimum based on Arbroath and Montrose fields (Crawford et al., 1991[24]; Hogg, 2003[25]), permeability maximum (1250 mD), is based on comparison with Area 1 (reduced to below maximum applied in Area 1 attribution (which was 1610 mD)) and Hempton et al., 2005[20].

Attribution of interchannel areas
Following on from description of slump facies and their attribution in Modelling of slump facies within 'interchannel' areas above, we recommended that for Area 2, there will be slump facies distributed along the channel polygons in each layer but no slumped areas associated with shelf slope failure in this more medial position on the submarine fan. We suggested that the percentage distribution along channel polygons for each layer would be less than that for Area 1, namely, 25% for Zone D and 20% for Zones E, F and H.

For 'Interchannel' areas, including slumped areas, we recommended that the following parameters were used shown in box below. Values were taken from core measurements in well 22/23a–3 where Kantorowicz et al. (1999)[23] identified the different facies—except for the upper permeability value which is taken from the channel sands. It was suggested that the non-slumped areas could be attributed stochastically (PoroPerm used is mean of all values from core analysis). For slumped areas, values derived from interpretation of core from well 22/33a-3, (Kantorowicz et al., 1999[23] their Figure 2, , their Layer E1) were taken.

Interchannel areas
- **Porosity** 20 (2–29); Slumped areas; 20 (4–29);
- **Permeability** 39mD (0.01-1250); Slumped areas; 34mD (0.02–231);
- **NTG** 0.33 (0.11–0.89) – Kunka et al., 2003[9];

For vertical permeability divide by 100 (min) and 1000 (max) (*Kulpecz and van Geuns, 1990*[3]).

Area type 3

Structures are compact, generally circular, smaller closures related to salt diapirs. Radial faults may act as baffles but are unlikely to compartmentalise the reservoir as fault throws rapidly decrease away from the diapiric intrusion (Birch and Haynes, 2003[26]; Kantorowicz et al., 1999[23]).

For Area Type 3, as for Area 2, we recommend that the Charlie Sand (Zone J) and above are removed from model as these are known to be absent SE of Forties Field. In addition, it was recommended that Zone D was also removed as this is not a significant reservoir in the fields in Area Type 3 (e.g. Birch and Haynes, 2003[26]).

The remaining Zones (H, F & E) have 'Amalgamated Channel' and 'Interchannel' areas as described in Building the model in PETREL.

Attribution of amalgamated channels (defined by polygons)
As in Area 1, there are four elements to the amalgamated channels – channel sands, low permeability basal lags, high permeability basal lags and intra channel doggers. Petrophysical values are detailed below.

Amalgamated channel areas
Channel sands:
• **Porosity**, 20 (16–27);
• **Permeability**, 20mD (1–600);
• **NTG**, 0.51 (0.01–0.77).

Low permeability basal lags:
• **Porosity**, 20 (16–27);
• **Permeability**, 1mD. High permeability basal lags:
• **Porosity**, 20 (16–27);
• **Permeability**, 600mD. Intra channel doggers:
• **Porosity** <12%;
• **Permeability**, <1 mD.
For vertical permeability divide by 10 (Kulpecz and van Geuns, 1990[3]).

Area Type 3 attribution is based on data from Pierce (Birch and Haynes, 2003[26]), Mungo (Pooler and Amory, 1999[27]), Machar (Pooler and Amory, 1999[27]), and North Everest (Thompson and Butcher, 1991[28]) fields. In addition porosity and permeability data in Core reports for wells 23/22a- 3 and 29/03a- 7 were also used. Average Permeability measurements from well 29/03a- 7 Core report are considered anomalously high but the maximum value in the range is included to reflect the possibility of high permeability reservoir in the distal parts of the fan.

Attribution will reflect change from more confined channels (sand-rich fairways of Hurst et al., 1999[29]) to overlapping lobes and sheets in the Distal areas.

'**Attribution of Interchannel areas'** As with Area 2, we suggested that there will be slump facies distributed along the Channel polygons in each layer — however, no slumped areas associated with shelf slope failure are expected. Please see Modelling of slump facies within ‘interchannel’ areas for percentage distribution on each layer.

For ‘Interchannel’ areas, including slumped areas, we suggest that the following parameters are used (taken from core values in well 23/22a–3 in Pierce Field). A mean of all values from the core analysis were taken; for slumped areas values we suggest values from Area 2 to be reduced slightly: NTG for Interchannel Areas were taken as the same as in Area Type 2. Petrophysical values are detailed below.

Interchannel areas
• **Porosity** 17 (2.2–22.5); Slumped areas; 15 (2.2–22.5);
• **Permeability** 11mD (0.01–600); Slumped areas; 10mD (0.01–60);
• **NTG** 0.33 (0.11–0.89) – Kunka et al, 2003[9];
For vertical permeability divide by 100 (min) and 1000 (max) (*Kulpecz and van Geuns, 1990*[3]

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