Peterhead CCS Project

Doc Title: Static Model Reports

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1. Introduction

This Key Knowledge Deliverable comprises of three separate reports, which describe the inputs, assumptions, construction and results from the development of the following static geological earth models given in Appendix A, Appendix B and Appendix C of this report, under the following references:

- Appendix A
  - 11.108, Static Model (Aquifer) Report, PCCS-05-PT-ZG-0580-00003
- Appendix B
  - 11.108, Static Model (Full Field) Report, PCCS-05-PT-ZC-0580-00004
- Appendix C
  - 11.108, Static Model (Overburden) Report, PCCS-05-PT-ZG-0580-00005

The detailed Static Model information provides information on:

- Formations in hydraulic connection to the storage site.
- The formations where the CO_2 will be injected.
- The formations between the store and the seabed

The Executive Summaries of each report is presented here as an abstract to give a high level overview of this Key Knowledge Deliverable.

2. Executive Summary

2.1. Appendix A: Static Model Aquifer Report

A regional 3D static model of the aquifer associated with the Goldeneye field, the Captain Sandstone Fairway, was created for the Peterhead CCS Project to assist with understanding pressure evolution and CO_2 movement. The model forms input to dynamic simulation where it is used to assess aquifer fluxes for the Goldeneye field and to simulate potential migration pathways of CO_2 along the E-W trending aquifer. This report is an updated version of the report originally issued for the Longannet CCS Project, incorporating minor clarity and for changed field status, Cessation of Production (COP).

The report captures the geophysical, geological and petrophysical data and methodologies used to understand the aquifer and to create the 3D model. The resultant model indicates the Captain Sandstone aquifer dimensions to be 5 to 10 km wide and up to 100 km long, with average porosities of 25 to 30% and Darcy range sands. The model represents the approximate dimensions and regional porosity and permeability trends present in the Captain Sandstone fairway stretching from the Blake field in the west through Cromarty, Atlantic, and Goldeneye fields towards the Hannay field in the east. Pore volumes of the Captain Sandstone aquifer are calculate to range from 5,658 million m^3 if the aquifer is disconnected across a regional feature known as the Grampian Arch (east of the Atlantic field) to 14,252 million m^3 if fully connected.

The aquifer model is designed to complement the other static models over the Goldeneye field - the Goldeneye field-scale Static Reservoir Model (SRM) and the overburden 3D static model. The aquifer model gridding, zonation, and layering schemes were aligned with the Goldeneye Full Field Static Model (FFSM), so that the more detailed FFSM could be spliced into the regional aquifer model in the dynamic domain for future studies.

2.2. Appendix B: Static Model Full Field Report

The objective of the work reported here is to develop a suite of static reservoir models as a basis for the forward modelling of CO_2 injection and storage in the Goldeneye field for the Peterhead CCS Project. This involves creating a suite of models that are representative of current understanding of the field and that allow the investigation of geological uncertainties important for CO_2 injection and storage. The resultant models are used for volumetric calculations and as input to dynamic modelling of field performance in the historical production and post-production phases and also under subsequent CO_2 injection.

This report documents the geological background to the field, the geophysical and petrophysical data used to design and build the models and the main features of the modelling workflow. It lists the members of the model suite and their differences and provides a comparison of gross rock volumes between them, which range from 669 to 740 million m^3. The report is an update of the earlier Static Modelling Report for the Longannet CCS Project, and incorporates models creating for reservoir engineering sensitivity runs which were not available at the time of the Longannet report, plus minor edits for clarity.

The starting point for modelling was the Static Reservoir Model (SRM) generated by the Shell Goldeneye Asset Team in mid-field life, to support hydrocarbon volumetric assessment and dynamic simulation for history matching and field performance prediction. This model has been reproduced to cover a slightly enlarged model area needed to accommodate possible CO_2 migration effects, and is used as an initial case (SRM1). The Asset had determined that to achieve a reasonable match between predicted and observed performance during the production life-cycle of the field, some changes to the distribution of hydrocarbon volume in the dynamic simulation model were required. These dynamic model changes were addressed in SRM2.0, to provide geological foundations to the alterations made. Further models (SRM2.1-3.15) have been created to investigate other areas of geological uncertainty that could impact on CO_2 behaviour: variations in reservoir layering, reservoir connectivity and overall connected hydrocarbon volume, and variations in the field envelope that could influence CO_2 migration.

All these models were made available as input to dynamic simulation. The models that enabled history matches and were most useful for assessing CO_2 behaviour were SRM3.1 and its variants, SRM3.05 to test for the effect of a shallow flank and SRM 3.15 to test for a more southern truncation of the Captain Sandstone.

2.3. Appendix C: Static Model Overburden Report

In support of the Peterhead CCS Project an overburden assessment has been conducted above and adjacent to the planned storage site, the Goldeneye field, to identify possible secondary containment horizons and potential migration pathways out of the field and associated storage complex in the unlikely event of seal or fault leakage of the sequestered CO_2. As a part of the assessment, a 3D static model was constructed to capture the relevant data: this formed input to subsequent geomechanical modelling. This report is an update of the Overburden Model Report issued for the earlier Longannet CCS Project. It contains minor edits for clarity and Cessation of Production (COP).

The 3D geological model was constructed in the third-part software Petrel™ and depicts the overburden and underburden lithologies, covering an area approximately 17km by 8km around the Goldeneye field. The model extends from the seafloor (~2400 m above the Captain reservoir) down to the Top Triassic Heron Group (~900 m below the Captain reservoir).

The primary seal to sequestered CO_2 in the Goldeneye field is provided by the calcareous and chalky mudstones of the Rødby Formation. CO_2 is not expected to leak through the Top Rødby seal which has already trapped the Goldeneye gas over geological time, or via reservoir level faults as they do not offset the sealing caprock. At least two different fault sets are present in the overburden, but these faults are considered to be decoupled from the Captain reservoir faults.

The Lista Formation is identified as a secondary sealing interval in the overburden above the Goldeneye field. The Lista mudstone comprises non-calcareous, bioturbated, non-carbonaceous and non-pyritic mudstones, and is a proven hydrocarbon seal in the Central North Sea. CO_2 could also potentially be constrained by the shallower Dornoch Mudstone. There are, however, no additional structural closures identified in the overburden stratigraphy.

Overall it is anticipated that migrating CO_2 from the Goldeneye field is unlikely to reach the surface via pathways originating in deeper parts of the overburden.

APPENDIX 1. Static Model Aquifer Report

A.1. 11.108, Static Model (Aquifer) Report, PCCS-05-PT-ZG-0580-00003

Peterhead CCS Project

Doc Title: Static Model (Aquifer)

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Executive Summary

A regional 3D static model of the aquifer associated with the Goldeneye field, the Captain Sandstone Fairway, was created for the Peterhead Carbon Capture and Storage (CCS) Project to assist with understanding pressure evolution and CO_2 movement. The model forms input to dynamic simulation where it is used to assess aquifer fluxes for the Goldeneye field and to simulate potential migration pathways of CO_2 along the E-W trending aquifer. This report is an updated version of the report originally issued for the Longannet CCS Project, incorporating minor edits for grammar and clarity and for changed field status (COP).

The report captures the geophysical, geological and petrophysical data and methodologies used to understand the aquifer and to create the 3D model. The resultant model indicates the Captain Sandstone aquifer dimensions to be 5 km to 10 km wide and up to 100 km long, with average porosities of 25% to 30% and Darcy range sands. The model represents the approximate dimensions and regional porosity and permeability trends present in the Captain Sandstone fairway stretching from the Blake field in the west through Cromarty, Atlantic, and Goldeneye fields towards the Hannay field in the east. Pore volumes of the Captain Sandstone aquifer are calculate to range from 5,658 million m^3 if the aquifer is disconnected across a regional feature known as the Grampian Arch (east of the Atlantic field) to 14,252 million m^3 if fully connected.

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1. Introduction

The Peterhead CCS Project aims to capture around one million tonnes of CO_2 per annum, over a period of 10 to 15 years, from an existing combined cycle gas turbine (CCGT) located at SSE's Peterhead Power Station in Aberdeenshire, Scotland. This would be the world's first commercial scale demonstration of CO_2 capture, transport and offshore geological storage from a (post combustion) gas-fired power station.

Post cessation of production, the Goldeneye gas-condensate production facility will be modified to allow the injection of dense phase CO_2 captured from the post-combustion gases of Peterhead Power Station into the depleted Goldeneye reservoir.

The CO_2 will be captured from the flue gas produced by one of the gas turbines at Peterhead Power Station (GT-13) using amine based technology provided by CanSolv (a wholly owned subsidiary of Shell). After capture the CO_2 will be routed to a compression facility, where it will be compressed, cooled and conditioned for water and oxygen removal to meet suitable transportation and storage specifications. The resulting dense phase CO_2 stream will be transported direct offshore to the wellhead platform via a new offshore pipeline which will tie-in subsea to the existing Goldeneye pipeline.

Once at the platform the CO_2 will be injected into the Goldeneye CO_2 Store (a depleted hydrocarbon gas reservoir), more than 2 km under the seabed of the North Sea. The project layout is depicted in Figure 1-1 below:

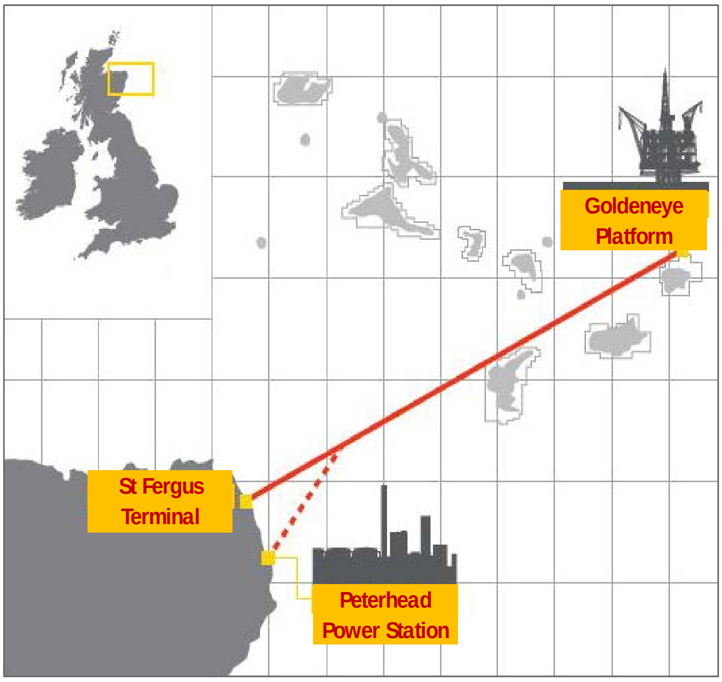

Figure 1-1: Project Location

1.1. Summary

This report documents the construction of a regional aquifer 3D static model in Petrel for the Captain Sandstone in the South Halibut Basin.

The aquifer static model was constructed primarily for reservoir engineering purposes to enable the visualization and dynamic modelling of the Captain Sandstone aquifer in order to understand aquifer fluxes and to simulate any potential lateral discharge of CO_2 out of the Goldeneye containment structure. The coarsely gridded 3D static model captures the approximate dimensions and regional porosity and permeability trends present in the Captain Sandstone fairway stretching from the Blake field in the west through Cromarty, Atlantic, and Goldeneye fields towards the Hannay field in the east.

2. Background & History

The Captain fairway (also known as the Kopervik fairway by some operators) has a history of exploration dating back to the mid-1970's. It is defined by the presence of the Captain Sandstone Member, a submarine mass-flow deposit of Lower Cretaceous (Aptian-Albian) age sourced from the area north of the Wick Fault (a splay from the Great Glen Fault that marks the southern boundary of the Caithness Ridge) and extending across the Smith Bank and Halibut Horsts and into the South Halibut Basin where it forms a narrow ribbon that fringes the southern boundary of the South Halibut Shelf (refer to Figure 4-1). Despite one or two early successes (the undeveloped North Glenn accumulation in 1975 and the Captain field in 1977) production did not commence in the area until the late 1990's (1). To date, eight fields have received development approval, combining to provide estimated ultimate recovery (EUR) of 437 MMbbl [69.4775×10^6 m^3] oil, 51 MMbbl condensate and 1.1 Tcf gas [31.1485 billion m^3] (2, 3). The Captain oil field (UKCS block 13/22a) saw the first production from the Captain Sandstone, in 1997. However, its position on the footwall of the southern bounding fault of the Halibut Horst means that it has been excluded from this study. Production from the ribbon of Captain Sandstones deposited within the South Halibut Trough commenced in 2001 with the Blake oil field (UKCS Blocks 13/24a and b & 13/29b). The Hannay oil field (20/5c) followed in 2002. The Goldeneye condensate field commenced production in October 2004 and was followed by Atlantic and Cromarty (a joint development located in 13/30a and 14/26a) in June 2006 and Brodgar (21/3a, east of Glenn) in July 2008. Rochelle (15/27b, north of Glenn) began production in October 2013.

The Goldeneye field is a gas condensate accumulation with a thin oil rim. The reservoir properties are very favourable for hydrocarbon production (average porosity is 25% and average permeability is 760 mD) and hydrocarbons are contained at normal pressure and temperature. The field was discovered in 1996 by Shell/Esso Well 14/29a-3, which encountered a gas column of 92 m. In the following years three appraisal wells were drilled: 1998 Amerada 20/4b-6 (south), 1999 Shell/Esso 14/29a-5 (south-east) and 2000 Amerada 20/4b-7 (south-west). In 2004 five development wells were drilled. The locations of the exploration and development wells are shown in Figure 2-1. Well 14/29a-2, is located north of the depositional limit of the fairway, and did not encounter any Captain Sandstone Member.

The Goldeneye field commenced production in October 2004 and continued until December 2010 when the last, crestal, development wells were shut in due to water production.

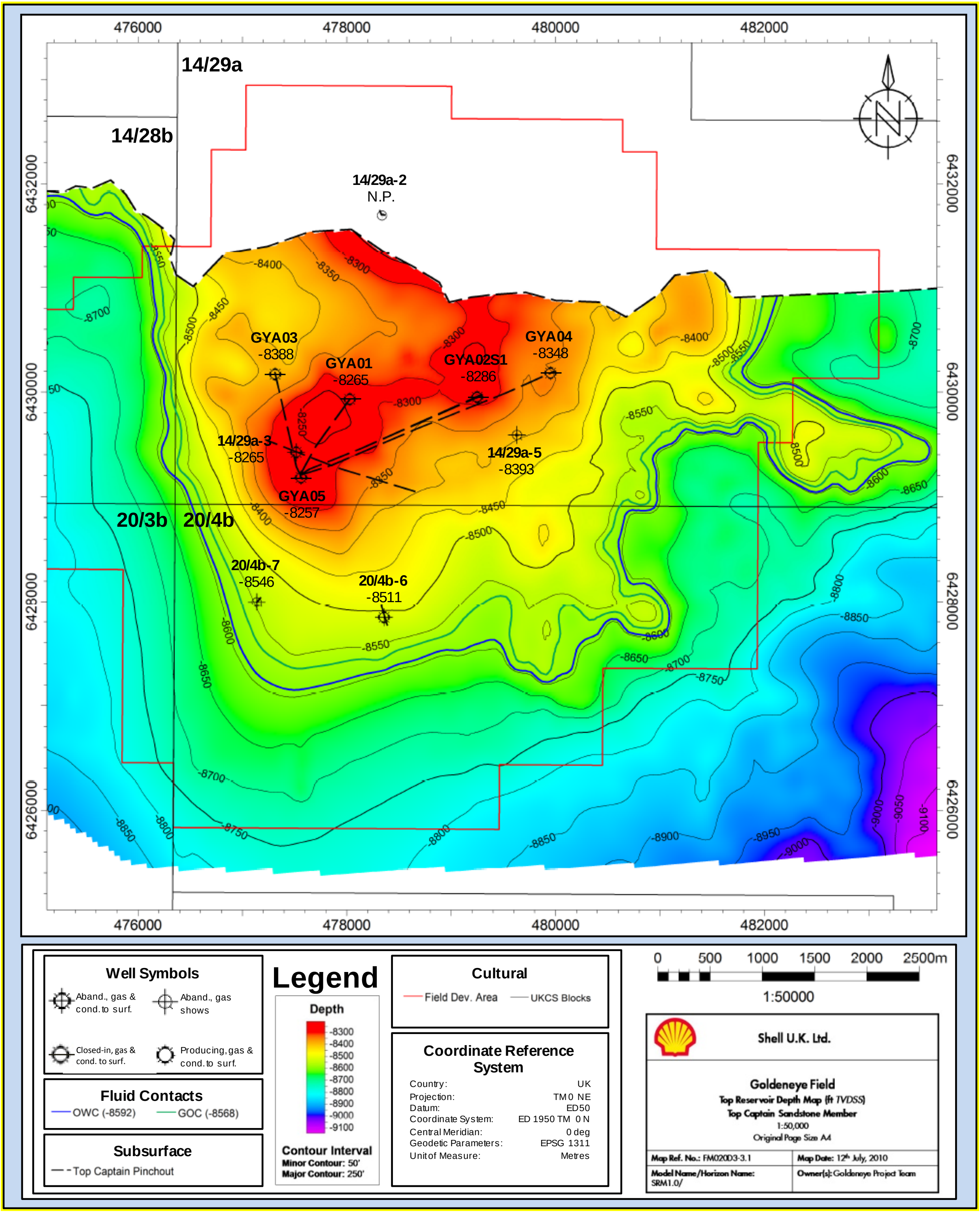

Figure 2-1: **Goldeneye field top structure map, True Vertical Depth Subsea (TVDSS) – Reference Case. Note absence of Captain Sands in 14/29a-2.**

3. Model Scope & Objectives

The main objective of constructing a 3D static model for the Captain Sandstone aquifer was to provide a simple geological model that could be used in dynamic simulation to help understand the aquifer fluxes and the impact of injection of CO_2 (into the Goldeneye field) on the Captain aquifer.

The aquifer fluxes affecting the Goldeneye field are complex due to a combination of depletion due to production and subsequent shut-in from the nearby Hannay field in the east and, production effects from the adjacent Atlantic and Cromarty fields in the west. By understanding the pressure history and characterising the aquifer fluxes to the east and west of the Goldeneye field, the dynamic simulation of the aquifer should help to improve the quality of the history match in the Goldeneye FFSM. It will also help to understand the rate of repressurisation of the Goldeneye field and the capacity of the Captain Sandstone fairway should it be a closed system.

The aquifer 3D static model is designed to complement the detailed 3D FFSM and the overburden 3D static model which are being constructed in parallel. Learnings from the construction of each model are mutually applied. The FFSM is designed to model detailed geological features in the Goldeneye field, and allow dynamic simulation to predict fluid interactions and movements during the injection and post injection periods. The Overburden 3D static model is intended to enable visualization of the overburden and underburden stratigraphy above and below the Captain Sands of the Goldeneye field, from the seabed down to the Top Triassic, to assist in CO_2 escape analysis and in geomechanical modelling. The Overburden model is restricted to an area 17 km by 8 km (determined by the extent of the prestack depth migration (PSDM) seismic data volume). The aquifer 3D static model is intended to enable the visualization and dynamic modelling of the Captain Sandstone aquifer in order to simulate any potential lateral discharge of CO_2 out of the Goldeneye containment structure.

The intention is to transfer the results of the detailed dynamic simulation to the other, less detailed models as required, so for example denser formation brine with CO_2 moving by gravity laterally 'out' of the FFSM should be modelled regionally in the aquifer model. This means that the three subsurface models should share sufficient common features, such as field volume, reservoir fairway dimensions, etc., for this to be consistent.

4. Geological Setting

Regional geological studies encompassing the Goldeneye field cover the Outer Moray Firth region of the UKCS Central North Sea. The region is dominated by the Halibut Horst, an area that remained emergent throughout most of the Jurassic and Lower Cretaceous periods. The Goldeneye accumulation is situated on the northern edge of the South Halibut basin adjacent to the southern margin of the South Halibut Shelf. The shelf edge depositional setting of the Lower Cretaceous (latest Aptian–earliest Albian) resulted in the 'ribbon like deposition' of the Captain Sandstones along the southern margins of the Halibut Horst (Blocks 13/23, 13/24, 13/29 and 13/30) and South Halibut Shelf (Blocks 14/26, 14/27, 14/28, 14/29, 14/30, 15/26, 21/1). The deposition of the Captain Sandstones continues along the southern margins of the Renee Ridge through the Glenn field and towards the Britannia field area (Blocks 21/2, 21/3, 21/4 and 21/5) (see Figure 4-1).

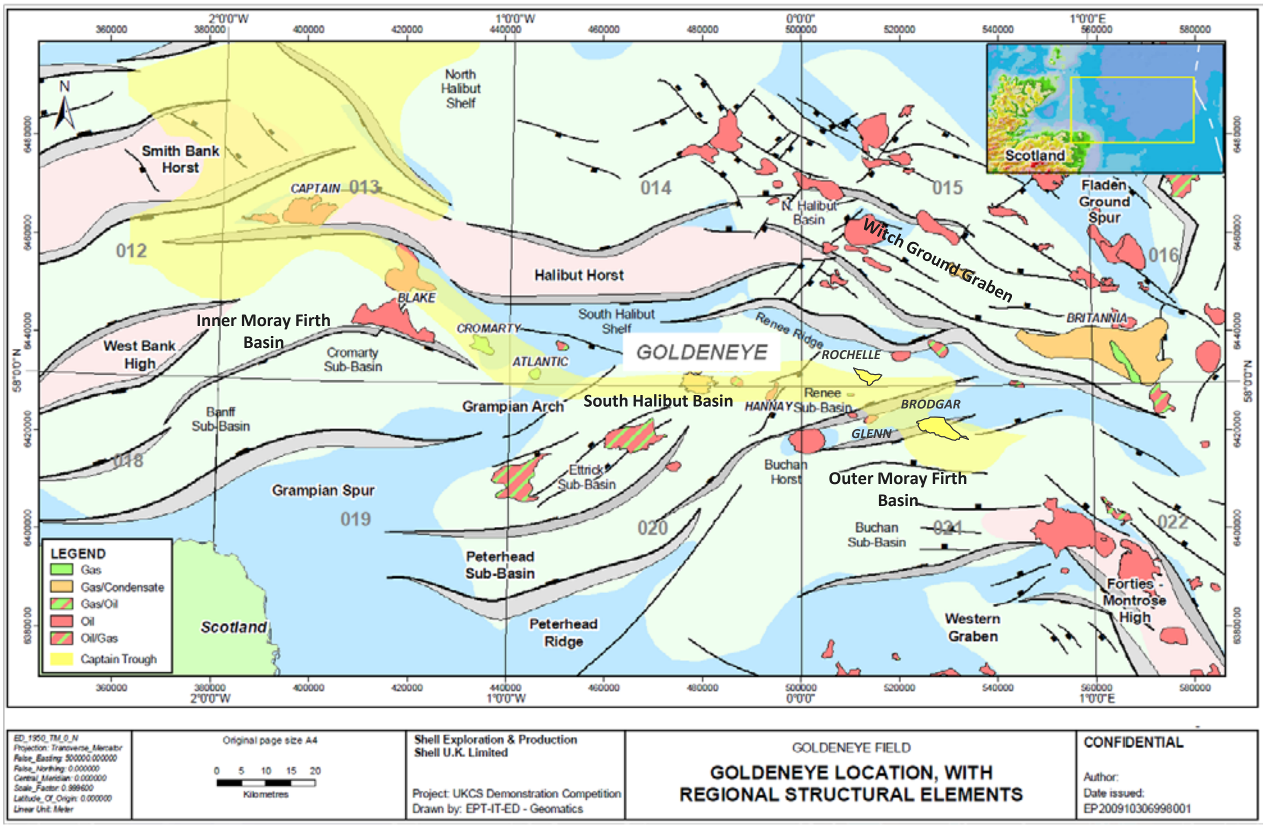

Figure 4-1: Distribution of Captain Sandstones across the outer Moray Firth: Captain fairway highlighted in yellow; basinal areas in pale green.

4.1. Structural History

The Moray Firth Basin is the name given to the complex series of tilted fault blocks and grabens that extend eastward offshore from the Moray Firth, Scotland. The present day structural fabric is the result of at least five orogenic episodes along with a failed attempt as a spreading centre that spans nearly 400 Ma.

The Outer Moray Firth Basin exhibits several structural compartments, of which the most significant are the Halibut Horst, the Witch Ground Graben, and the South Halibut Basin (Figure 4-1). Northwest-trending faults in the Witch Ground Graben and north of the Halibut Horst are likely to be Hercynian age structures which extend from the Central Graben; whereas faults running approximately east-west that fall between the Halibut Horst and Peterhead Ridge result from a complex interaction between Caledonian and Hercynian structures.

The Grampian Highlands extend north-eastward to form the Grampian Spur and Grampian Arch, which subdivide the Moray Firth into the Inner and Outer basins. The Grampian Arch and portions of the Halibut Horst probably owe their existence to the buoyancy of an underlying Caledonian-age granitic pluton that has provided a broad northeast trending high during several phases of the basin's history. The buoyant effect of the granite was evident as early as the Late Devonian, but more significant was uplift during the Middle Jurassic when it separated the Inner Moray Firth from the Halibut Basin, and erosion of the sedimentary cover of the Grampian Arch occurred. Basin subsidence together with a eustatic rise in sea level during the Late Jurassic and Cretaceous times resulted in thick sediments being deposited fairly continuously across the basinal areas, which thin or become condensed across the Grampian Arch.

A major change in structural regime and sedimentation occurred in the Palaeogene due to ~1 km of uplift of the Inner Moray Firth, Scottish Highlands and the East Shetland Platform areas which resulted in a regional eastward tilting of the area. During this period large quantities of clastic sediments were deposited in the Outer Moray Firth and Central Graben areas. There was also a continuation of the mild north-south compressive regime which warped the Top Chalk surface and funnelled the Captain Sandstones west-east through the basin.

4.2. Regional Stratigraphy

The regional stratigraphic column for the Outer Moray Firth is shown in Figure 4-2. The stratigraphy consists of an upper interval of Quaternary age sediments and a thick interval of Tertiary age deposits comprising interbedded sands, shales, claystones and lignites. A large variability is seen within the sand/shale ratios in the Tertiary age Montrose Group and shale appears more abundant towards the east.

Below the Tertiary clastics, is a chalk section of fairly uniform thickness across the area. The Upper Cretaceous Chalk is the oldest formation to have been deposited over the entire Halibut Horst. Prior to this the Halibut Horst is interpreted to have been emergent. The erosion of the Halibut Horst, and storage of the resultant clastic sediments in both the north and south Halibut shelfal areas, is understood to have contributed significantly to the deposition of turbidites throughout the Lower Cretaceous and Jurassic in the Outer Moray Firth (Figure 4-3). The periodic deposition of the sand rich turbidites took place within the background deposition of hemipelagic shales, marls and occasional limestones.

The term Kopervik Sandstone has been used to describe the late Barremian to early Albian mass flows in the Moray Firth, but has never formally been defined (4). The sequence stratigraphic framework by Jeremiah (5) has been used in this study which separates the Kopervik Sandstone into several sandstone members, including the Captain Sandstone Member (K80b and K85) of the Carrack Formation. These turbidite sands of Albian–Aptian age are generally more sand rich and massive than those of Berriasian-Barremian age. The latter appear (from log signatures and seismic expression) to be of more classical low density fan-type turbidites as opposed to the massive, blocky, sandy debrite/high density turbidites of the Captain Sandstones.

Good reservoir quality turbidite sands are also found within the Upper Jurassic Kimmeridge Clay Formation and underlying the Kimmeridge Formation, Upper/Middle Jurassic paralic sediments were deposited (e.g. Heather/Pentland formations).

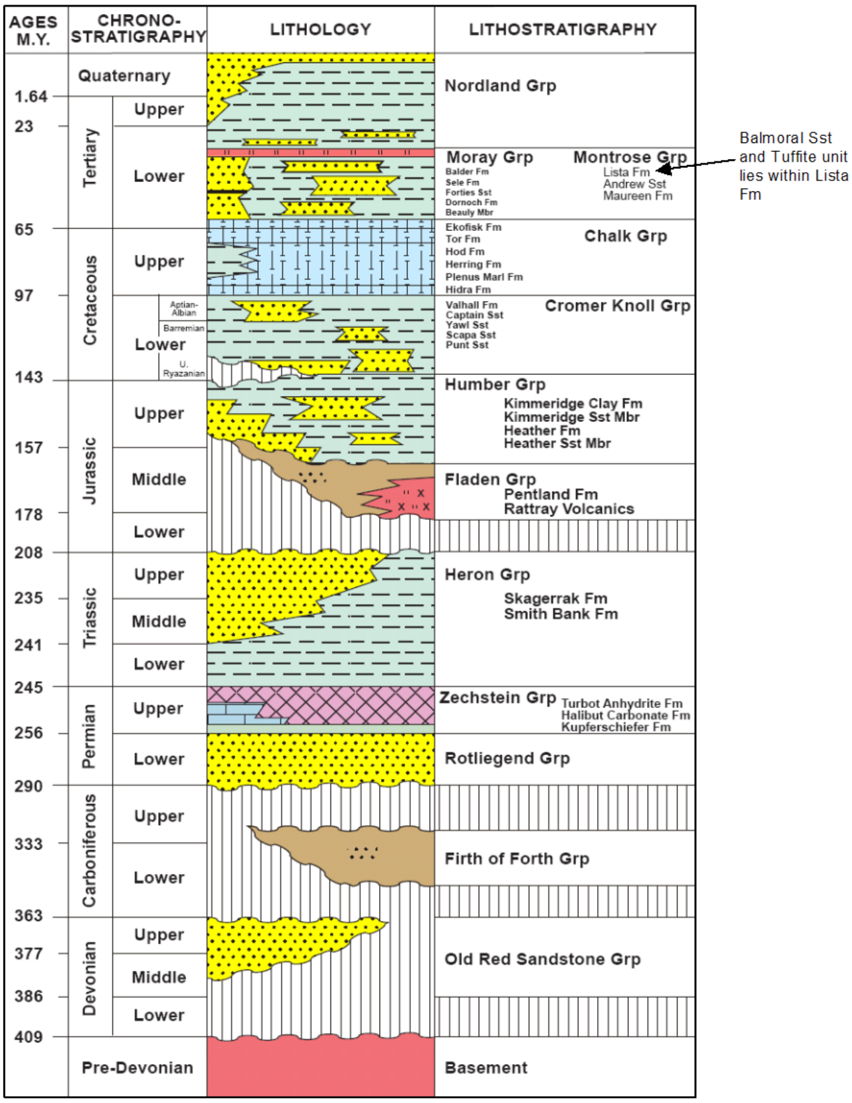

Figure 4-2: Generalised Stratigraphy of the Goldeneye area

The economic basement consists of Triassic age siltstones and shales of the Smith Bank Formation, Permian Zechstein and Rotliegend formations and the deeper sand rich clastics of Carboniferous and Devonian age. Below the Devonian sediments basement granites that form the core of the Halibut Horst are present.

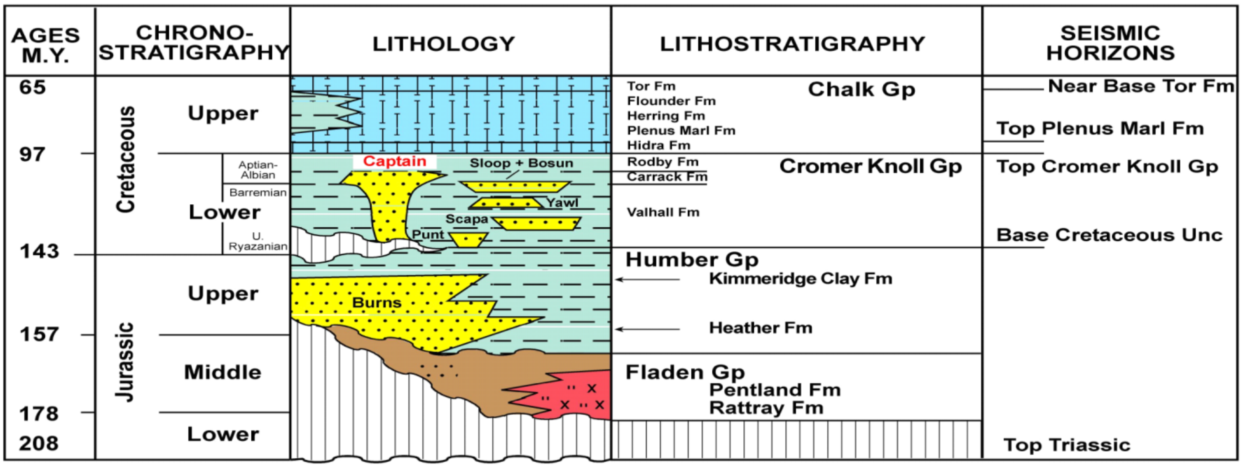

Figure 4-3: Jurassic and Cretaceous stratigraphy of the outer Moray Firth

4.3. Captain Sandstones

The Captain Sandstone turbidites were deposited in a deep marine environment, settling around the intra-basinal highs, within the background deposition of hemipelagic shales, marls and occasional limestones. Two contrasting depositional models exist for the Captain Sandstones along the Halibut Trough. The principle model envisages axial flow of turbidite sands along the Captain fairway from west to east. The collapse of the southern flank of the Halibut shelf led to the development of a west-east lineament parallel to the southern margins of the Halibut Horst. Sands accumulated up on the East Orkney High, could then flow along the southern flanks of the Halibut Horst into the Cromarty and Renee Sub-basins (5). The alternative model is of sand-prone turbidite fan systems feeding directly off the Halibut Horst from the north. However, it is considered likely that a combination of both depositional systems were active. Around the Blake field, the axial system probably predominates whilst around the Goldeneye field, and the eastern parts of the fairway, input from northerly sourced sediments may also have occurred (6). The Captain Sandstones are sealed vertically by the laminated calcareous shales of the Lower Cretaceous Rødby Formation, and the Upper Valhall Formation. Lateral seals are provided by the basinal mudstones and marls of the Lower Valhall Formation, onto which the Captain Sandstone turbidites were deposited.

The existing basin topography controlled the sand distribution of the Captain Sandstone fairway. The isochore map (Figure 4-4) shows that some of the thickest deposition of Captain Sandstones occurs in the Goldeneye field: 250 m [820 ft] thick in Well 13/29a-3. Typically however, the Captain Sandstones in the fairway are 60 m to 120 m thick.

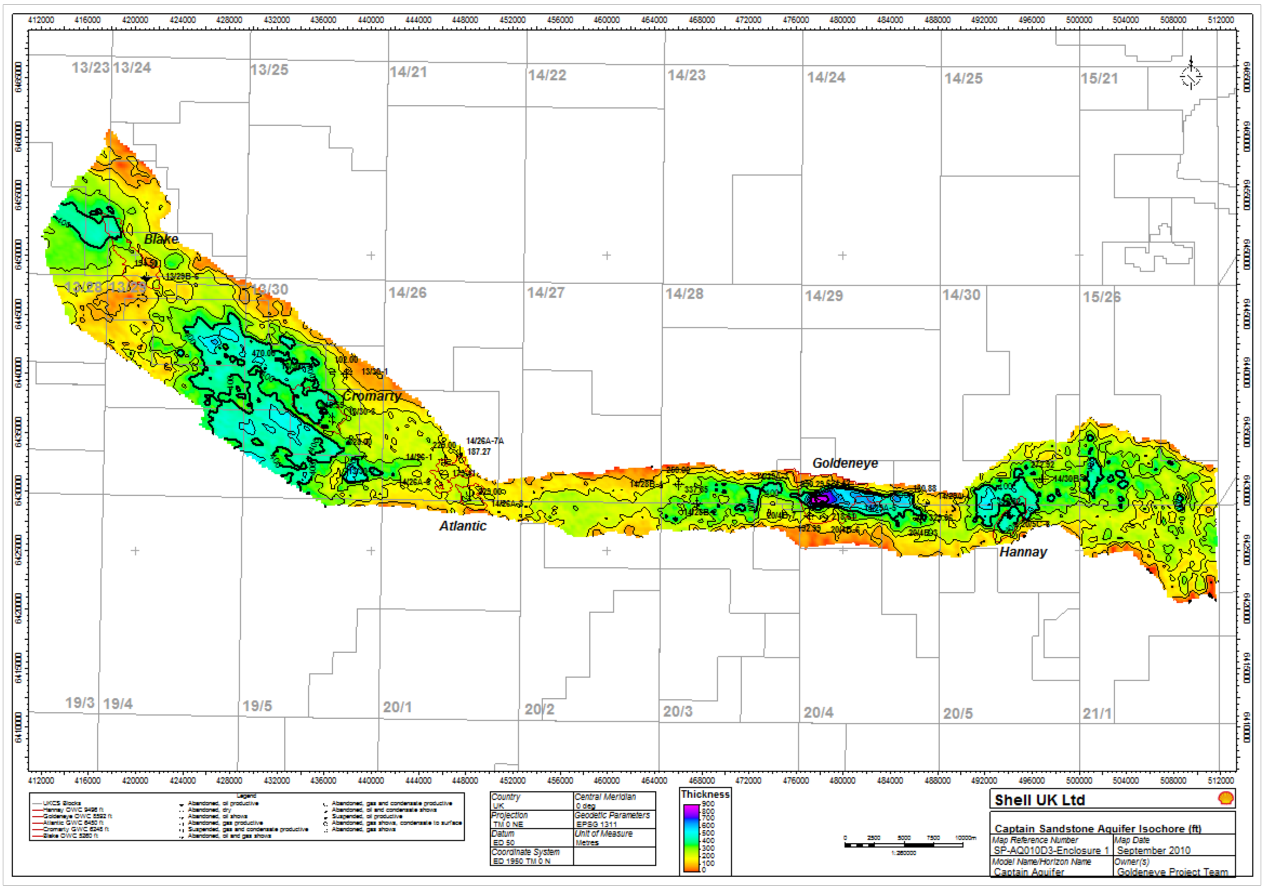

Figure 4-4: Captain Sandstone aquifer model isochore in feet.

There is a noticeable thinning of the Captain Sandstone over the Grampian Arch (a long-lived low relief feature in Blocks 14/26a and 14/27b), to the east of the Atlantic field. The base case scenario is that there is a thin but continuous Captain interval seismically interpreted over and across the Grampian Arch. However, if there is any disconnect along the Captain Fairway, then the Grampian Arch is the most likely position of a major structural break which may prevent communication along the fairway from the Blake field to the Hannay field. Such a disconnect is considered unlikely given clear pressure communication with fields to the west of Goldeneye but the scenario is taken as a sensitivity. The eastern extent of the Captain Sandstone fairway is interpreted to end at the Glenn Ridge (Blocks 21/2 and 21/3) where significant faulting appears to offset the Captain Sandstones. Pressure data seems to also support this disconnection. The western extent of the Captain Sandstone fairway is probably affected by the Captain Ridge (a major east-west Mesozoic tilted fault block that forms a westwards plunging extension of the Halibut Horst (7)) to the northwest of the Blake field, disconnecting the Captain field. It is, however, likely that the fairway crops out at surface to the west of Blake (Block 12) allowing the hydrostastic pressure gradient observed in the fairway. Access to production data from the fields along the Captain Sandstone fairway would help to answer many of the questions relating to the exact aquifer extent.

The Scapa Sandstone Member is not widely deposited across the Halibut Trough, and as such, is not included in the regional aquifer model. The Grampian Arch appears to have been a positive feature during the Early Hauterivian to earliest Barremian which restricted the Scapa Sandstone Member to the Cromarty Sub-basin. Around the Goldeneye field, the Scapa Sandstone Member is only present in three wells (14/29a-2, 20/4b-6 and 20/4b-7), and appears to be a localised sand fairway sourced from the Halibut Horst (with the main clastic flow to the north of the Halibut Horst into the Scapa field) (5). The relationship between the Captain Sandstones and the Scapa Sandstone Member in the Goldeneye area is documented in the Overburden Static Model report.

Within the Goldeneye field, the Captain reservoir can be sub-divided into four litho-stratigraphic units; Captain 'E', Captain 'D', Captain 'C' and Captain 'A' (see Figure 4-5). Although nomenclature changes between fields, operators and authors, in all cases the stratigraphy appears to be consistent throughout the fairway and so the Goldeneye terminology will be applied throughout this report.

The **Captain 'A'** unit is a massive, medium grained sandstone of latest Aptian age. Sandstone from this unit has been recovered in core from Well 14/29a-3 only. The depositional model for this unit at Goldeneye suggests a very localised deposition within a fault bounded basin or erosional scour, from a turbidite fan system sourced in the Halibut Horst, directly to the north of the field location.

The **Captain 'C'** unit is a heterogeneous clastic sequence which spans the Aptian/Albian boundary and contains a considerable proportion of extra-basinal material, presumably deposited through the action of mass wasting processes, as seen in core from Wells 14/29a-5, 14/29a-3 and 20/4b-7. The mixture of facies present testifies to a variety of processes being active during the period of its deposition. It is interpreted to have been dominated by the actions of debris flows sourced from the structural high to the north of the Goldeneye Field. High and low-density turbidity currents also flowed through the area during Captain 'C' times, producing reservoir sands of varying quality. The Captain 'C' shaley interval is interpreted to be of regional significance and is picked in nearly all the wells along the Captain Fairway, separating the upper Captain 'D' sands from the lower Captain 'A' sands.

The **Captain 'D'** sands are of earliest Albian age, and are the primary reservoir unit in the Goldeneye field. The 'D' unit has been cored in all of the exploration and appraisal wells in the Goldeneye field. It comprises medium grained massive sandstones that, with the exception of a fining-upwards sequence at the top seen in all wells in the field, show only subtle changes in grain size. Heavy mineral analyses and paleo-current indicators suggest that axially oriented (west-east) turbidite systems predominantly controlled deposition. Mud-clasts are dispersed throughout the massive sands, as well as locally being concentrated within individual debris flow beds. The sandstones are dominantly quartzose, with subsidiary quantities of plagioclase and alkali feldspars, glauconite, lithic fragments, clay and bioclasts. There is little cementation, and the bulk of authigenic minerals are composed of chloritic and kaolinite clays. Thin mudstone layers that are visible on wireline logs and in core material, cannot be reliably correlated in adjacent wells. Occasional dish-and-pillar structures and the featureless nature of the sandstones suggest post-depositional dewatering processes. This has probably destroyed depositional fabrics, and any shaley layers are therefore likely to be disrupted.

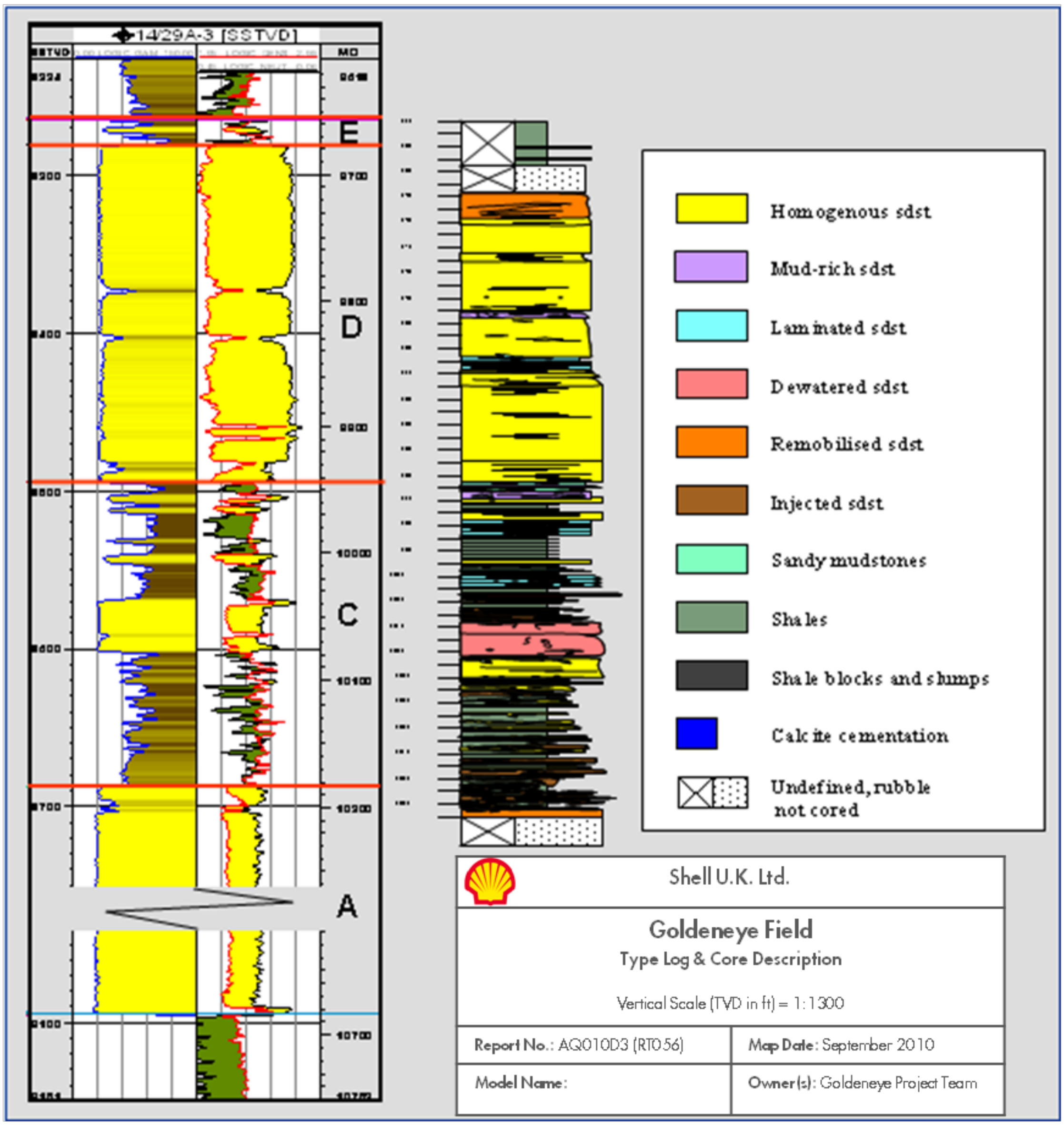

Figure 4-5: Subdivision of the Captain reservoir, Goldeneye area

Note: Log data on left (GR on left, Density Neutron on right, net sand yellow). with core facies log description on right. Note unit A is homogenous in parts and highly variable in thickness (shown partial log).

The uppermost division of the reservoir is the **'E' unit**. This is cored in Wells 14/29a-5 and 20/4b-7. Sandstones within this unit can appear 'dirty' due to 2% to 3% detrital clay fractions and also show evidence of dewatering. In some wells it may consist of sandstone dykes, presumably injected from the 'D' layer below, as observed in 14/28b-2 core, west of the Goldeneye field. The sands in the 'E' unit have been interpreted to have been deposited from high-density turbidity currents with minor contributions from mud-clast rich debris flows. Dewatering/sandstone remobilisation occurred subsequent to deposition, as caprock and overburden sediments accumulated.

Using biostratigraphy, log correlation and seismic stratigraphy, the individual lithostratigraphic units were correlated between the wells along the Halibut Trough drawing on the stratigraphic framework as defined by Jeremiah (2000) (5). To the west of the Grampian Arch, the Captain C unit is easily correlated from the Cromarty field to the Atlantic field as shown in Figure 4-6. However, in other wells such as 14/26a-7a and 14/26a-6, the correlation is more uncertain given the difficulty in correlating thin shale packages across large distances.

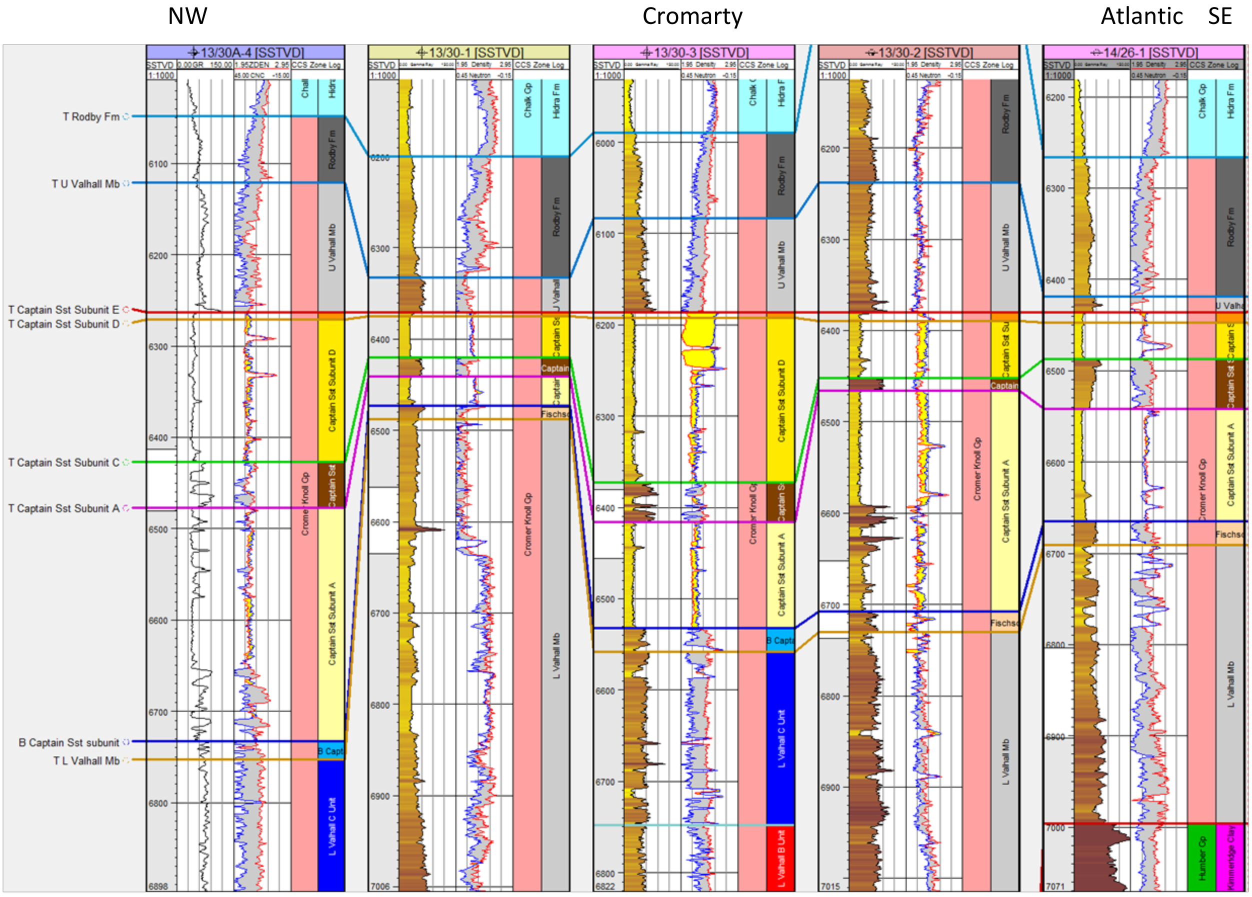

Figure 4-6: Correlation panel through Wells 13/30a-4, 13/30-1, 13/30-3, 13/30-2 and 14/26-1 from the Cromarty field to the Atlantic field

Note: Section flattened on Top Captain pick. Well locations on Figure 5-1.

There is also some uncertainty with the correlation to the east of the Goldeneye field, towards the Hannay field. Well 20/5c-6 in the Hannay field drilled a 120 m thick Captain interval, which features a large 65 m section of clean sands encased by a thick shaley package both above and below. The current Goldeneye reference case static model does not have the Captain 'C' sands present in Well 20/4b-3 to the west of Goldeneye and only a very thin 3m interval is present at the base of the Captain interval in Well 14/29a-4 (see Figure 4-7). Continuing east with this correlation towards the Hannay field suggests there is a thick Captain 'D' unit deposited to the east of the Goldeneye field.

By contrast, the Jeremiah correlation interprets a Captain 'C' interval to be present in all the wells to the east of the Goldeneye field, implying a thinning of the Captain 'D' sands to the east into the Hannay field and eventual shale-out. Following the Jeremiah correlation, the upper shale package in Well 20/5c-6 is attributed as the Captain 'C' unit, and as a result, implies a thin Captain 'D' and a thick Captain 'A' unit (see Figure 4-8). This has significant implications to the aquifer fluxes affecting the Goldeneye field from the east given that the Captain 'D' sands contain the majority of the Goldeneye field' gas initially in place (GIIP) and the effect of the Captain 'C' on vertical connectivity (*i.e.* the significance of bottom *vs.* edge aquifer drive).

Unfortunately the biostratigraphy in Well 20/5c-6 is not clear, and given the uncertainty, the two alternative regional correlations were used to create two separate 3D static aquifer models. Dynamic data indicates that the Jeremiah correlation to the east is unlikely, but both scenarios will be dynamically simulated to assess the impact of assigning this thick sandy section from Captain 'D' to Captain 'A' sands. Depending upon results from the regional simulations, this Jeremiah scenario may (or may not) be applied as a further realisation to the 3D Full Field Static Model.

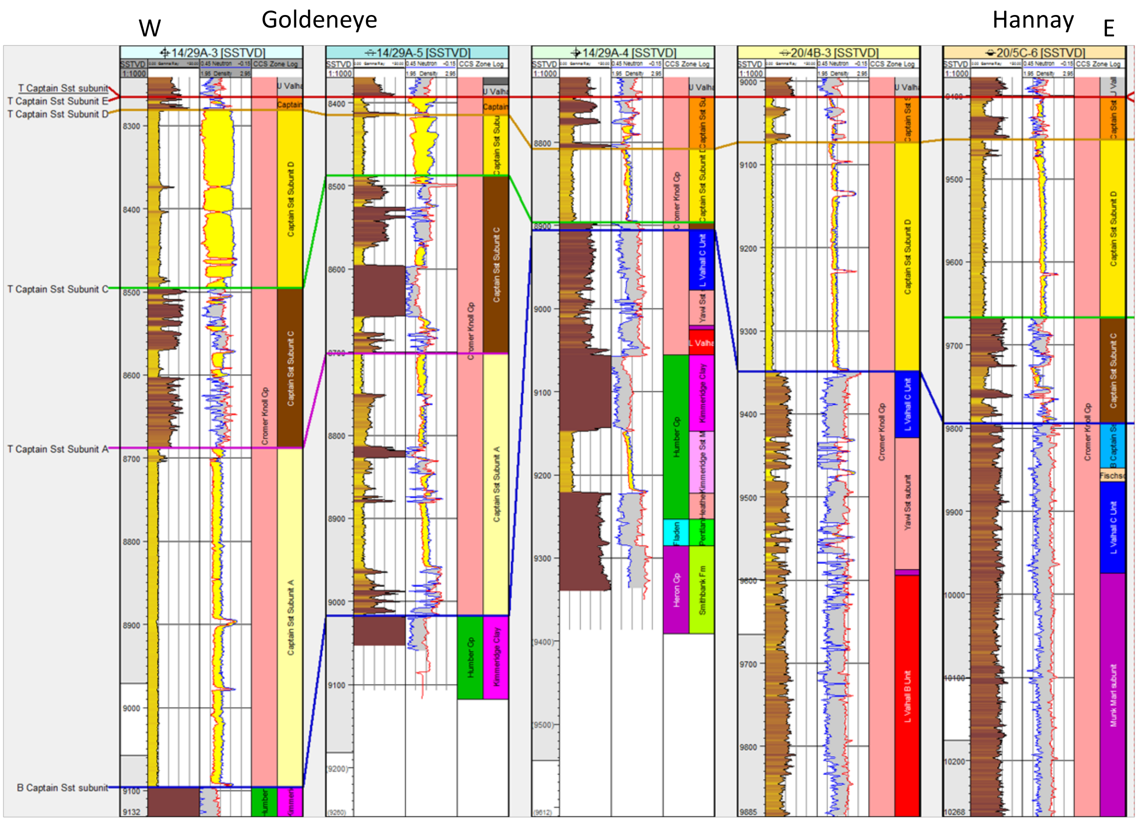

Figure 4-7: Reference case correlation through Wells 14/29a-3, 14/29a-5, 14/29a-4, 20/4b-3 and 20/5c-6 from Goldeneye to Hannay.

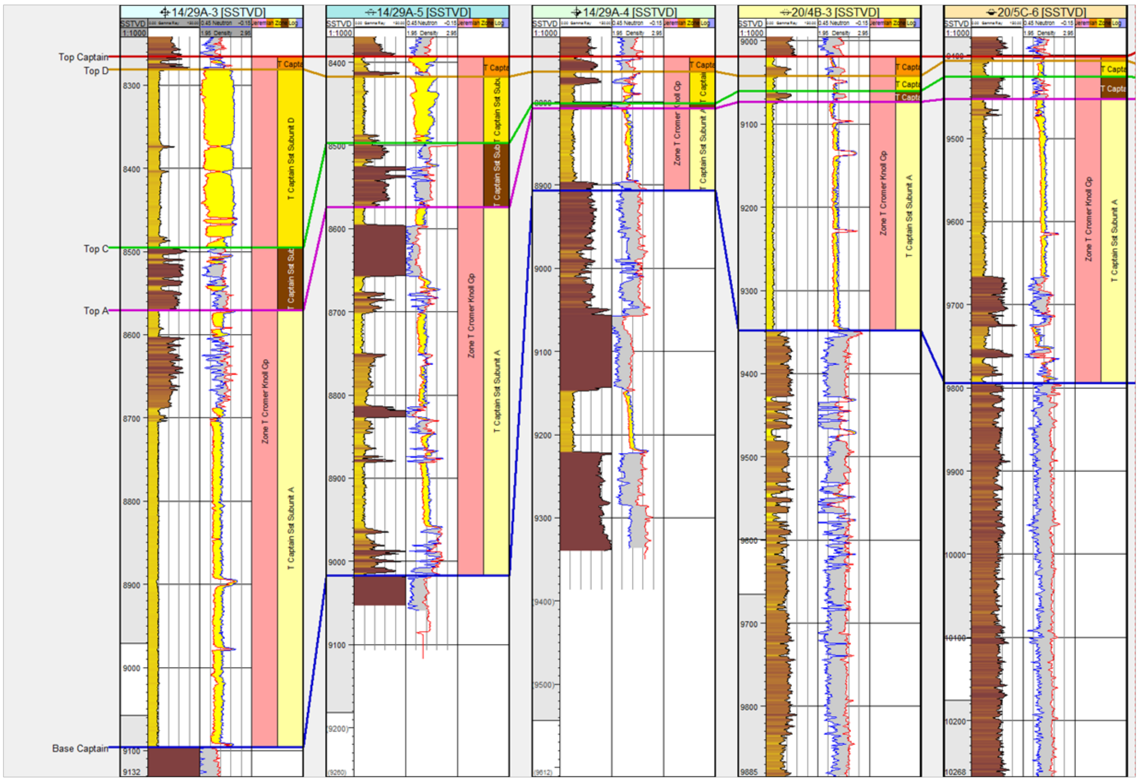

Figure 4-8: Alternative Jeremiah correlation through Wells 14/29a-3, 14/29a-5, 14/29a-4, 20/4b-3 and 20/5c-6 from the Goldeneye field to the Hannay field.

5. Aquifer Static Modelling

The model was built using Petrel 2009 software. All distance units are metric, with depths measured in feet.

5.1. Model AOI

Well penetrations suggest the presence of the Captain Sandstone from Quadrant 12 in the west, along the southern margins of the Halibut Horst, and into Quadrant 21 in the east. A Petrel model was constructed, approximately 30 km by 100 km, along the Captain fairway (see Figure 5-1). The area of interest (AOI) was limited by the extent of the available seismic data but covers most of the Halibut Trough from the Blake field in the west through to the Glenn West field in the east, and contains approximately 70 wells.

The aquifer model was gridded at a fairly coarse 200 x 200m scale resulting in a total of 25 million cells (488 x 240 x 213). The aquifer model grid cells were aligned with the Goldeneye FFSM, so that the more detailed FFSM can be merged into the regional aquifer model in the dynamic domain.

5.2. Input Data

The Goldeneye aquifer model was constructed from interpretations from several seismic datasets including several 2D regional lines, the 1997 East Ettrick 3D survey, the 2001 Goldeneye PreSDM 3D survey, the 2001 Blake 3D survey and primarily the 1994 Greater Ettrick Regional 3D survey due to its regional extent – see Figure 5-1.

The seismic data in the Halibut Trough is generally of poor quality, especially down at the Captain reservoir interval due to the laterally varying, low-velocity coal layers and the thick high-velocity Chalk section in the overburden. The shallow, Eocene-aged coal layers are responsible for buried statics (move-out distortion), and amplitude effects due to focussing of energy and absorption losses. The chalk layer causes marked ray bending which is exacerbated by the high degree of rugosity exhibited by the Top Chalk. Furthermore, the seismic data are contaminated with water-bottom multiples and strong long-period multiples generated by the coal and chalk interfaces. However, the biggest challenge is the lack of acoustic impedance contrast between the Captain Sandstones and the overlying Rødby Shales.

The mapping of the Lower Cretaceous Captain Sandstone fairway over part of the Halibut Trough was carried out on four different seismic projects using Shell's propriety interpretation software (123di) from 1999-2004. The regional seed grid density varied between 250 m to 800 m, depending on the seismic project and the mapping complexity, with an average of some 350 m (see Figure 5-2). In addition to the Top and Base Captain reservoir, the envelope of the Cromer Knoll Formation (Lower Cretaceous) interval was also defined by mapping the Base Hidra and Base Cretaceous Unconformity seismic markers. Seismic interpretation of the reflectivity data was carried out on the zero-phased data sets displayed with normal polarity (i.e. an acoustic impedance increase results in a hard kick shown as a red loop). The seismic character of the mapped horizons is summarised below:

- Base Hidra: Medium frequent soft (blue) loop, low to high amplitude.
- Top Captain Formation: Weak hard (red) loop, frequently discontinuous.
- Base Captain Formation: Weak to medium hard (red) loop, frequently discontinuous.
- Base Aptian Shale: Medium frequent, medium to high amplitude soft (blue) loop.
- Base Cretaceous Unconformity: Medium soft (blue) loop, showing good continuity.

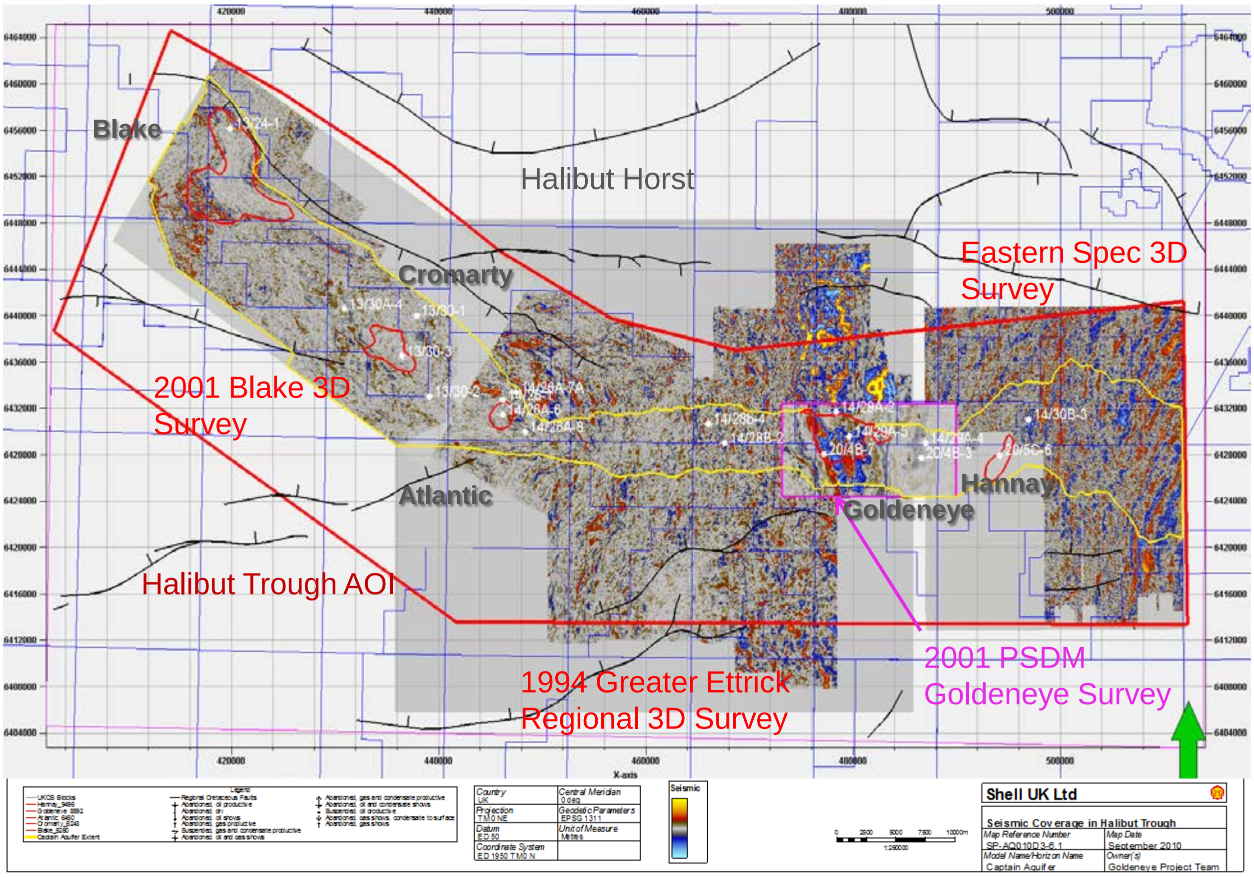

Figure 5-1: Regional Seismic Coverage in Halibut Trough. AOI is red outline.

After calibration with all the available well penetrations in the AOI, the Top and Base Captain events were mapped to delineate the reservoir fairway. As previously discussed, the Captain Sandstone is difficult to map along the fairway due to its weak expression on the seismic data as a result of the poor impedance contrast at top reservoir between the Captain Sandstones and the overlying Rødby shales. As a result, mapping of coeval shales using some of the basinal wells was carried out to constrain the position and extent of the Captain Sandstone fairway. This was achieved by mapping the basinal (i.e. shaley) equivalent to the Top Captain reservoir and the Base Aptian shale marker which slightly predates the deposition of the Captain Sandstone reservoirs. The individual seismic interpretations were appended together in Petrel with some minor editing where two different survey interpretations overlapped.

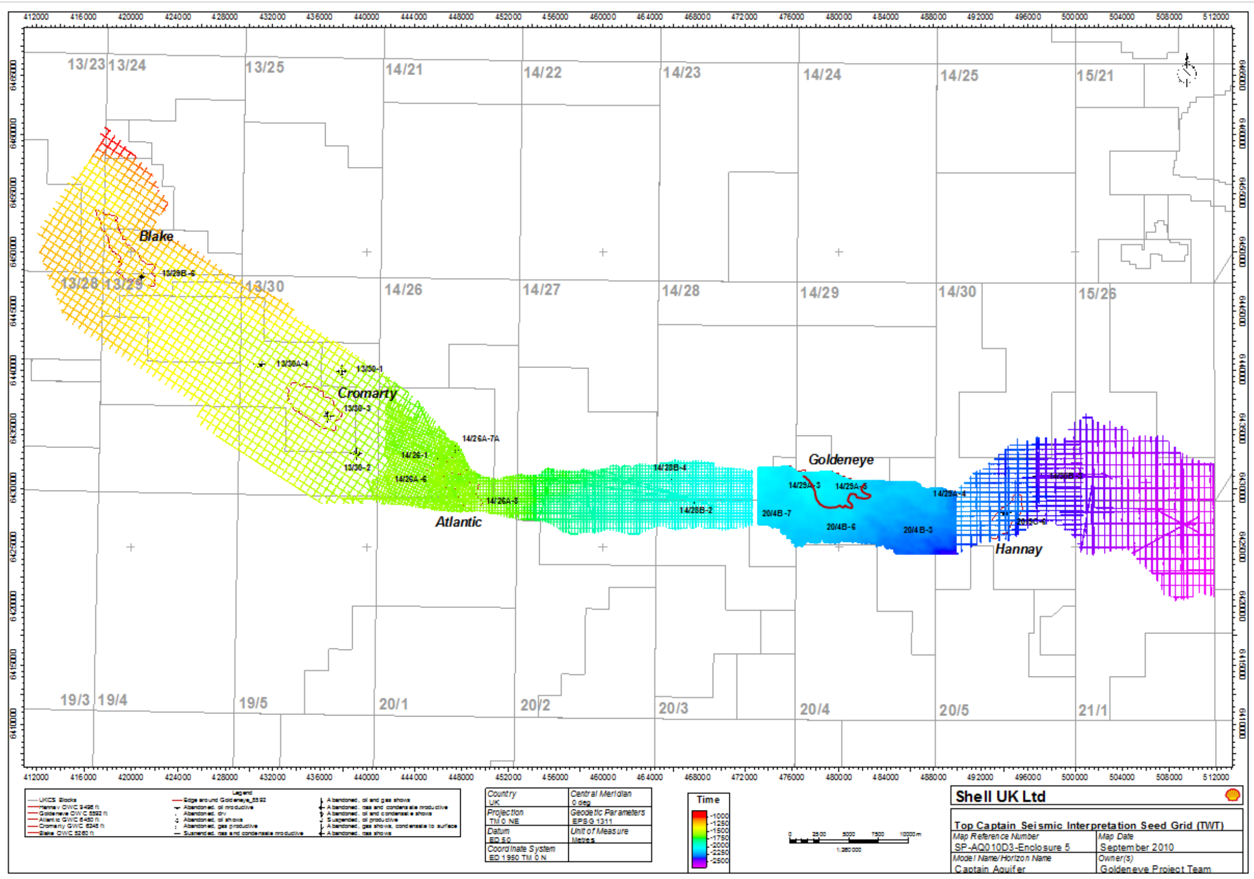

Figure 5-2: Top Captain TWT seed grid picked on seismic imported into Petrel.

The model is intended to pinchout to zero thickness along both the northern and southern margins of the fairway, but due to the poor seismic data quality and the regional interpretation and gridding process, this is not always the case. Whilst the position of the northerly pinch-out of the Captain reservoir could be recognised on seismic with some confidence, the delineation of the southerly shale-out/pinchout is more difficult to map however, especially in Blocks 20/2 and 20/3b. South of the Cromarty field in Blocks 13/29 and 13/30, interpretation is limited by the extent of the seismic data.

Along the mapped area, evidence for large scale faulting (clearly offset reflections) along the Captain Sandstone fairway is seen in only a few areas. There is significant faulting in Blocks 21/1 and 21/2 towards the Glenn Ridge which is interpreted as the easternmost extent of the Captain Sandstone fairway (see Figure 5-3). There is also substantial thinning of the Captain interval observed over the Grampian Arch (Blocks 14/26a and 14/27b) to the east of the Atlantic field. It is not clear whether the faulting around the Grampian Arch disconnects the Captain Sandstone fairway at this location. The base case interpretation however, is that there is a continuous thin package of Captain Sandstones deposited over and across the Grampian Arch. Continuity of the Captain Sandstone fairway across the Grampian Arch will be modelled as a sensitivity in the dynamic simulation.

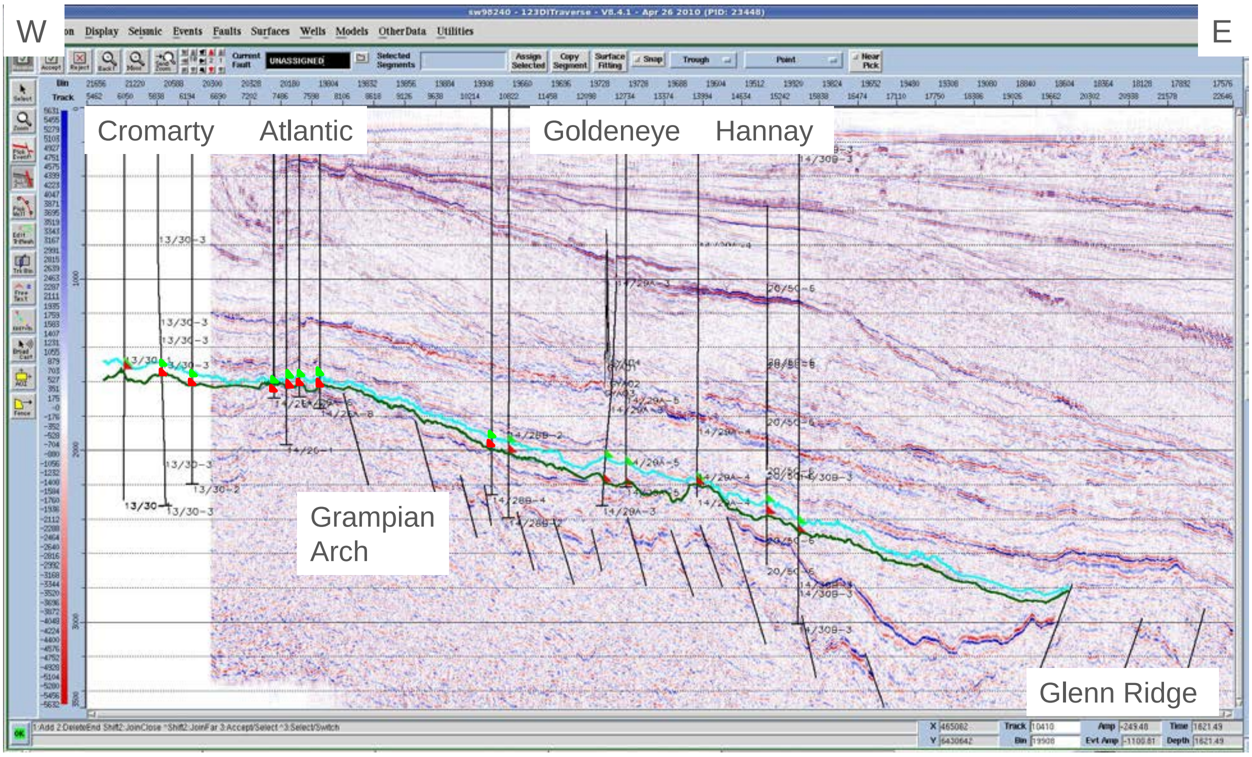

Figure 5-3: Regional west-east seismic section in TWT from the Cromarty field to the Hannay field with the Top Captain interpretation in light blue, and the Base Captain interpretation in green.

The Top and Base Captain Two-Way Time (TWT) surfaces were depth converted using an average velocity map. The average pseudo-velocity (from surface to Top Captain) at each well was extracted and the resulting velocity data points were gridded to create an average velocity map across the Halibut Trough AOI. This simplified approach was considered fit for purpose as a regional depth conversion. Depth conversion in the Halibut Trough is generally complex due to the variable Tertiary lithology and the rugosity of the Top Chalk surface (which marks an important velocity break).

Using the regional depth conversion produced a slightly altered Top and Base Captain depth surface over the Goldeneye field. However, in order for the detailed Goldeneye FFSM to be merged into the regional aquifer model at a future date in the dynamic domain, the exact same structural envelope of the Goldeneye field was required in both models. As a result, the average velocity over the Goldeneye field was back-calculated from the FFSM time and depth surfaces. This velocity grid was spliced into the regional average velocity grid (with smoothing at the interface) and used for depth conversion of the regional TWT seismic interpretations. The result is an identical structure (to the FFSM) over the Goldeneye field, and an average velocity depth converted Top Captain elsewhere (Figure 5-4).

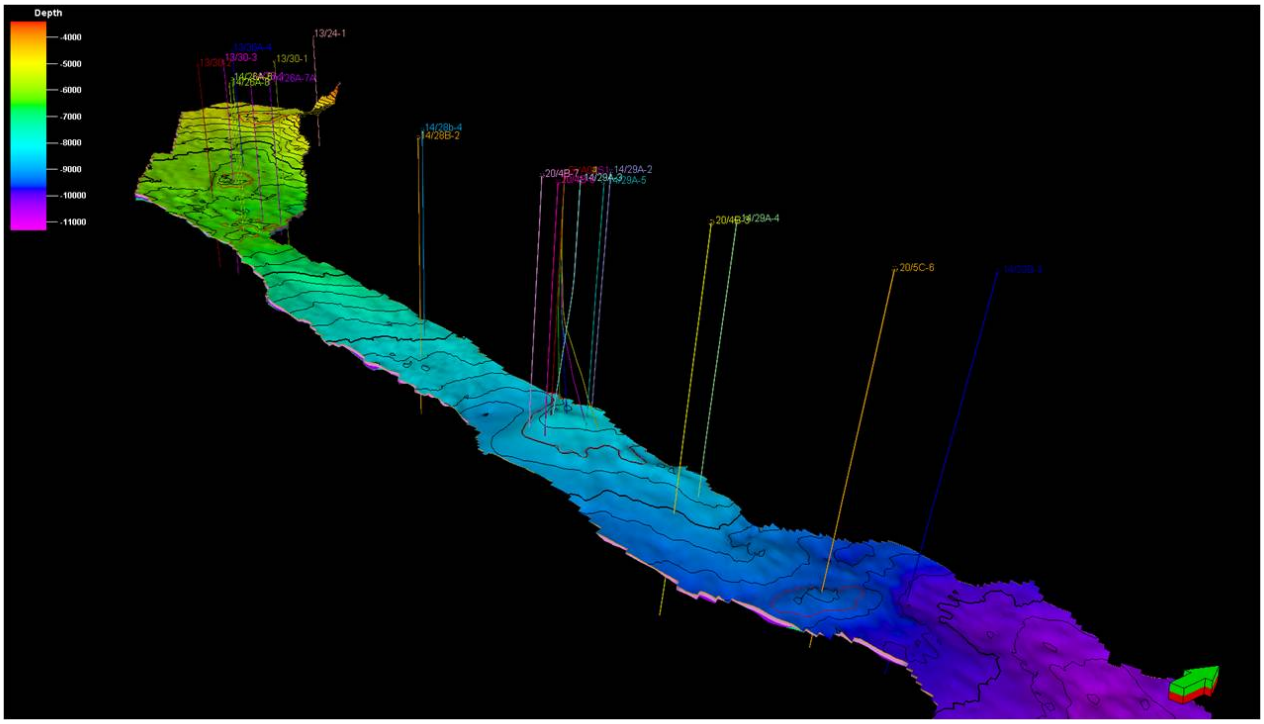

Figure 5-4: Regional Top Captain Sandstone depth surface.

The resultant Top Captain Sandstone depth surface required local hand editing to ensure that subtle (low relief) traps remained robust closures when gridded at a coarse 200 m x 200 m interval. The Blake, Cromarty, Atlantic and Hannay structures were therefore all hand edited to the approximate size and shape of the fields (see Figure 5-5). It is likely that the Cromarty field has some element of stratigraphic trapping in the closure but for simplicity, was modelled as a four way-dip closure. In the Blake field, only the massive thick turbidite 'channel' sands were modelled and the lower net to gross overbank facies of the Blake flank were not captured. These simplifications were considered fit-for-purpose given the intended use of the dynamic model to simulate the voidage effects from all the producing fields along the Captain Sandstone fairway.

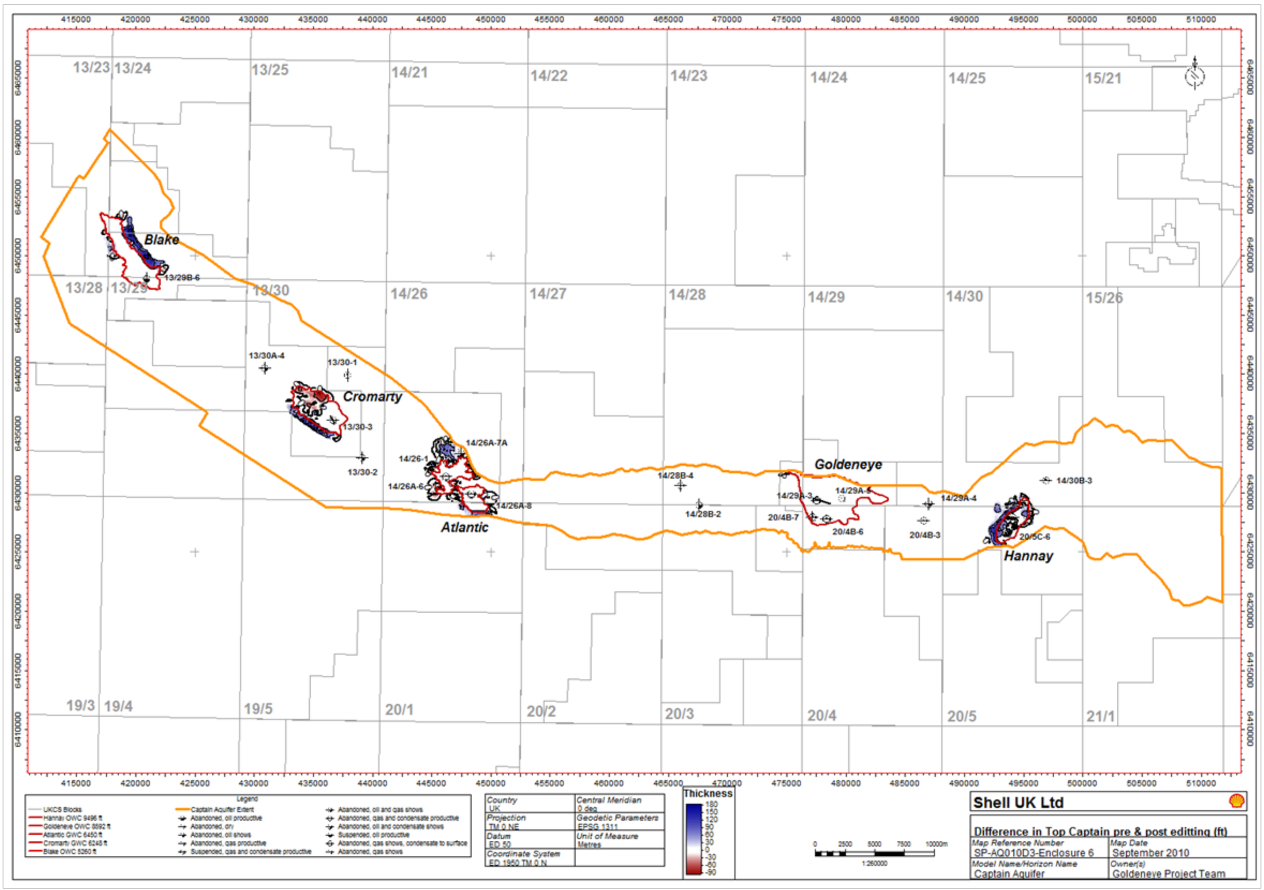

Figure 5-5: Difference map showing the editing applied to the structural closures of the Blake, Cromarty, Atlantic and Hannay fields.

5.3. Model Zonation & Layering

The aquifer 3D static model was subdivided into four zones representing the Captain 'E', 'D', 'C' and 'A' units. The Captain Sandstone reservoir zones were created in Petrel by stacking down isochores from the Top Captain surface. The isochores were generated by gridding up the thickness data at the wells based on the regional well log correlations. Some additional data points were required to constrain the gridding process. By utilising the same Top and Base Captain depth surfaces, the structural envelope of the Goldeneye field should remain similar in all three static models. Two sets of isochores were generated to honour the Goldeneye Reference Case reservoir correlation and the regional Jeremiah correlation in the east towards the Hannay field.

In Well 20/4b-3, the Captain 'D' sands are 85m thick and approximately 70m in thickness in nearby Wells 14/29a-3 and 14/28b-2. Within the Goldeneye field area, the Captain 'D' sand is predicted to be thickest in the centre of the turbidite fairway, and thinning to a 25-28 m thick interval to the north and south. The 'D' sand is typically around 20 m thick near the Atlantic field, thickening to about 45 m in the Cromarty field and then thinning to around 15 m in the Blake field (see Figure 5-6).

The main aim of the zonation and layering process was to reproduce the zonation and layering scheme of the Goldeneye FFSM as closely as possible in order to facilitate the future merging of the two models in Shell's dynamic simulation software, MoReS (see

Figure 5-7).

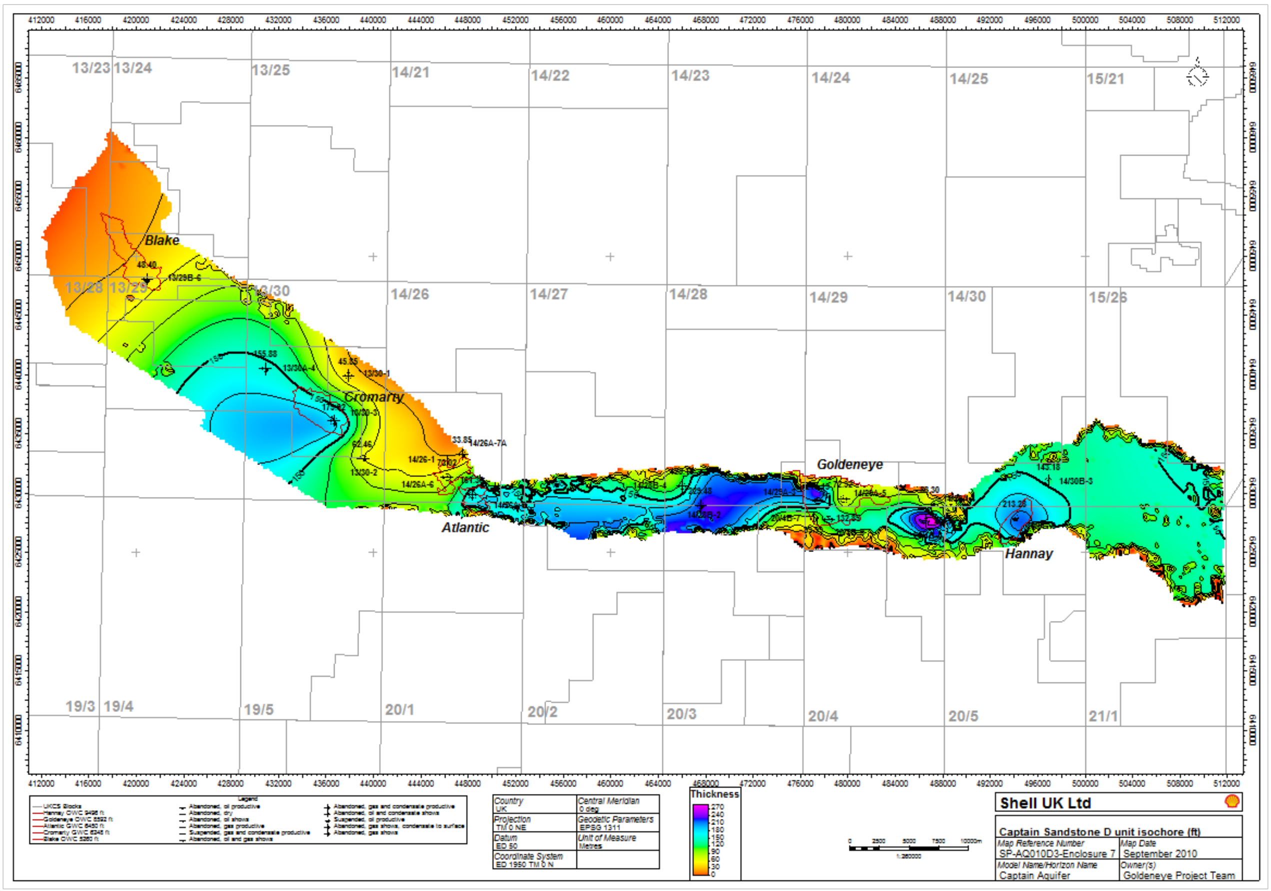

Figure 5-6: Captain D unit isochore from aquifer model.

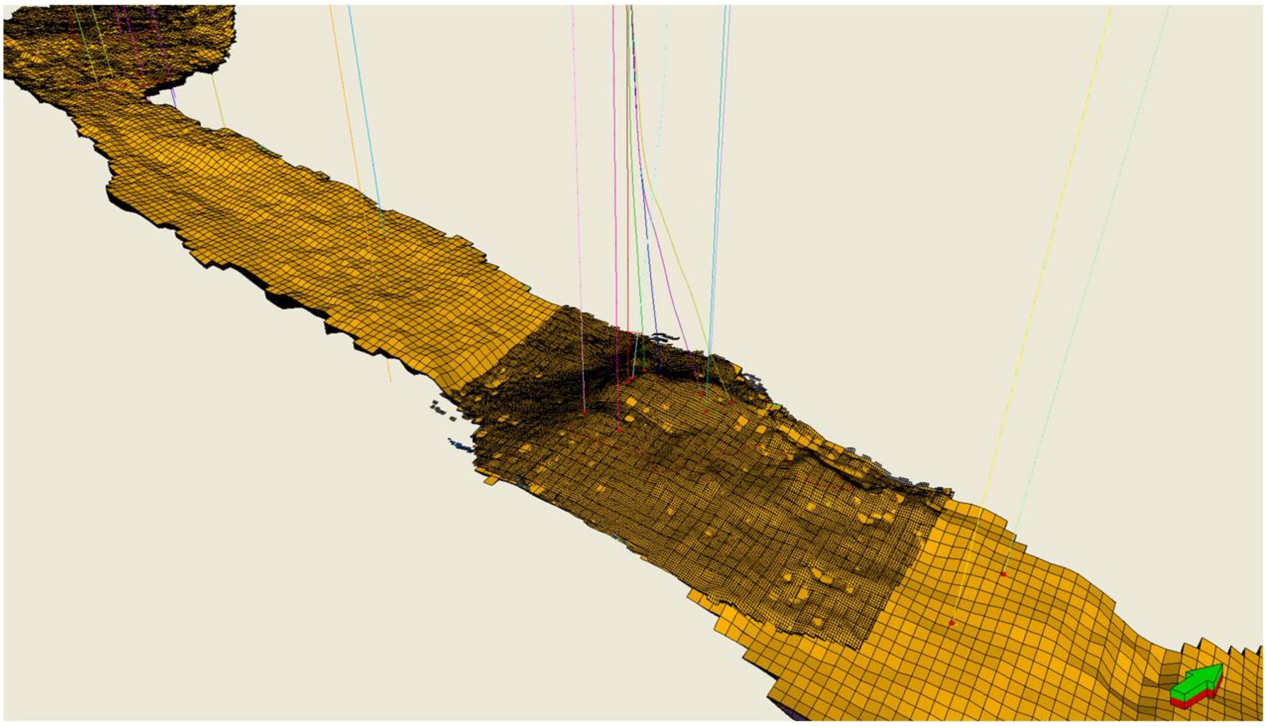

Figure 5-7: Goldeneye FFSM spliced into the regional aquifer model

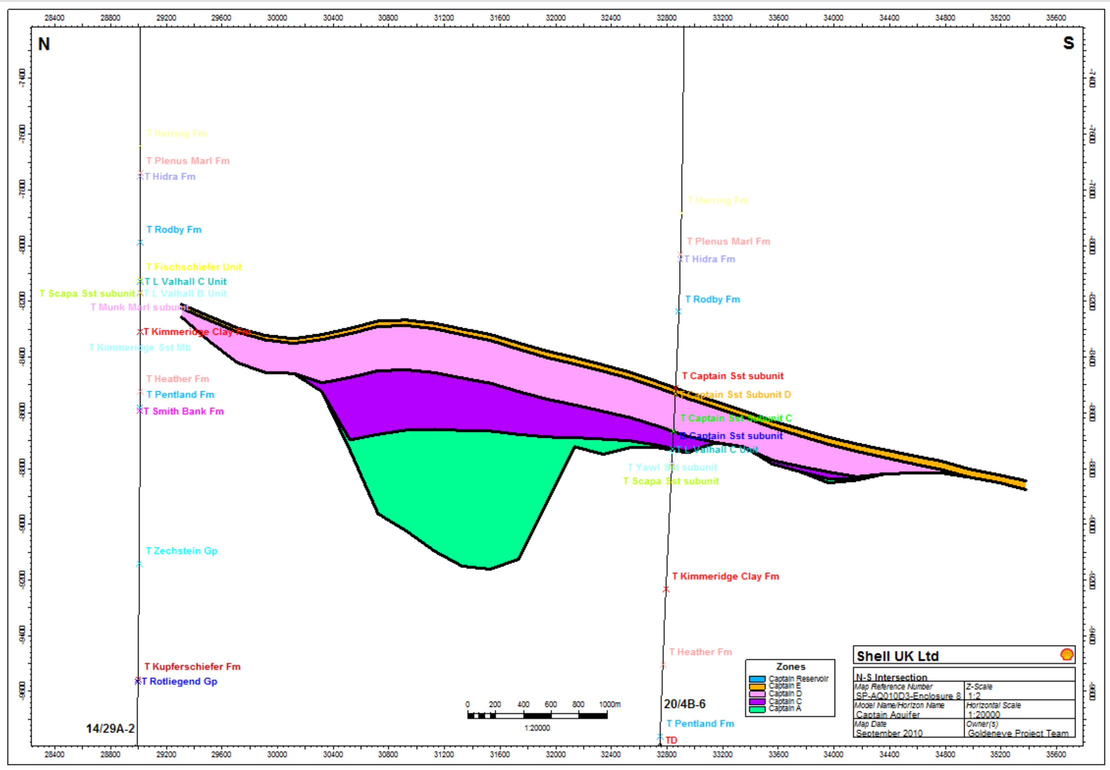

Figure 5-8: North-south intersection of aquifer model through the Goldeneye field.

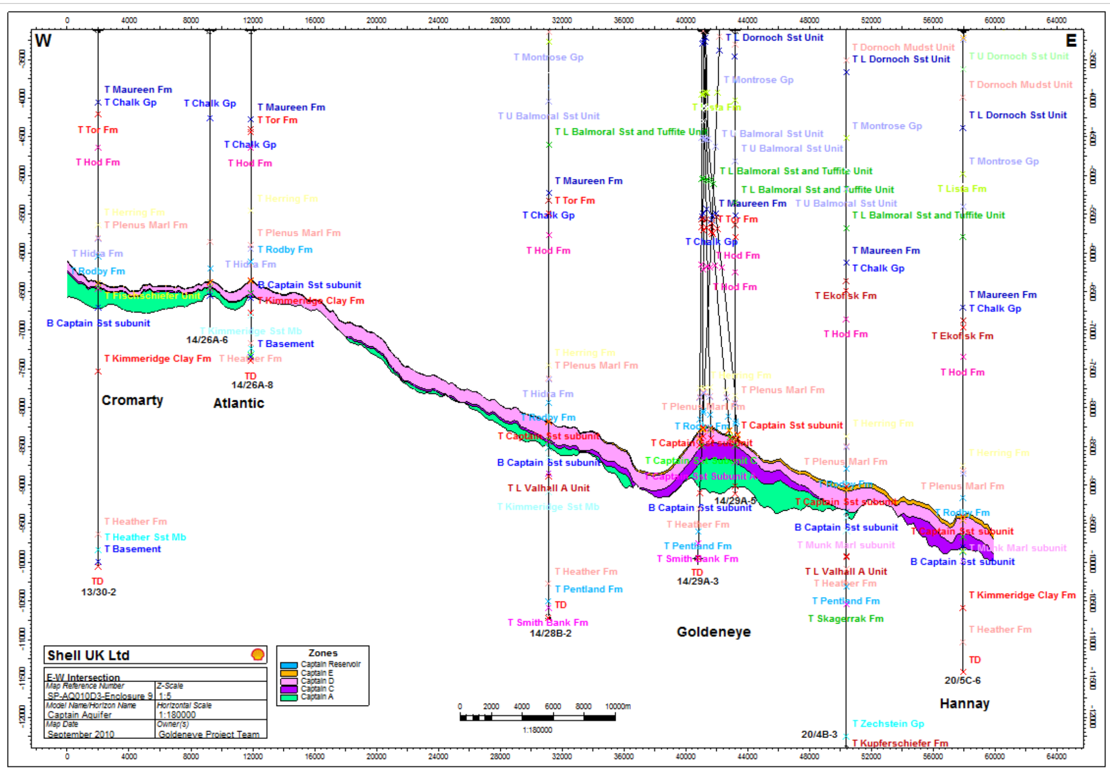

Figure 5-9: West-east intersection from the Cromarty field through Atlantic and Goldeneye and Hannay field.

In the aquifer model the same internal layering scheme as used in the reference case Goldeneye field Static Reservoir Model SRM 3.1 was applied, to facilitate the splicing of the full field dynamic model into the regional aquifer simulation model. The migrating CO_2 plume is expected to be concentrated in the uppermost layers of the model due to the buoyancy of the CO_2. As a result, to enable greater resolution during the simulation, the upper layers of the model are layered with smaller grid cells. The Captain 'E' (26 ft [8 m] average thickness) is divided into 15 proportional layers. All other units are layered top down. The massive sandstone beds of the Captain 'D' and Captain 'A' reservoir intervals only required a coarse layering scheme, and are populated with constant thickness cells 15 ft [4.5 m] thick. The Captain 'C' unit is populated with 3 ft [1 m] thick cells in order to capture the heterogeneity of this shaley interval. Figure 5-8 and Figure 5-9 show north-south and west-east cross-sections through the resulting aquifer zone model.

5.4. Property Modelling

5.4.1. Petrophysical Modelling

Porosity, permeability and net to gross were evaluated in 25 wells (20 exploration and appraisal wells and 5 Goldeneye production wells) along the Captain fairway. The log data from the petrophysical evaluations were imported into Petrel and were upscaled using arithmetic averaging into the model, and then distributed through the model layers using a sequential Gaussian Simulation algorithm together with a large variogram, orientated in a west-east direction. The parameters were chosen to bring out long-range regional variations in properties rather than local perturbations. All zones were modelled with the same settings (Table 5-1). An alternative property modelling algorithm (kriging) was also tested as a sensitivity. Facies modelling was not undertaken as it was considered the net to gross modelling would suffice at the coarse level of this model.

Table 5-1: Property modelling variogram parameters

Type	Range	Nugget
Exponential	2000 m W-E	0.1
	1000 m N-S	
	10 ft vertical	

Net sand was defined using gamma ray (GR) derived shale volume cut-off using following equation:

$$V_{shale} = \frac{GR - GR_{sand}}{GR_{shale} - GR_{sand}}$$

Where: V_{shale} = Shale Volume (v/v)

GR = Measured Gamma Ray (API)

GR_{sand} = Sand baseline Gamma Ray (API)

GR_{shale} = Shale baseline Gamma Ray (API)

The resultant shale volume is consistent with the shale volume that is derived from the neutron-density method, and is therefore considered robust for net sand calculation.

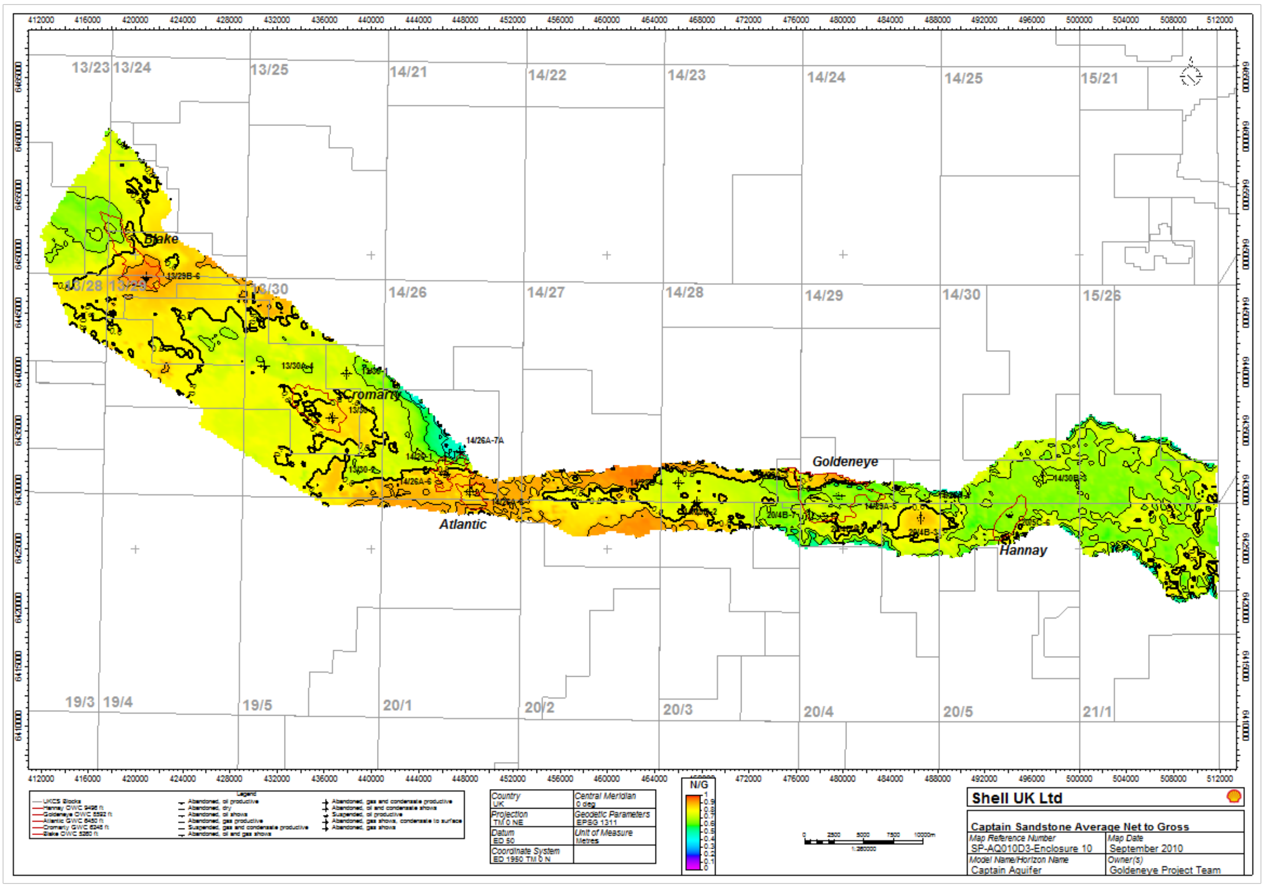

Figure 5-10: Average net to gross map for the Captain aquifer model.

Total Porosity is derived from density using the following equation:

$$\varphi = \frac{(\rho_{ma} - \rho_b)}{(\rho_{ma} - \rho_{fluid})}$$

Where:

ϕ = Total porosity (v/v)

ρ_{ma} = Matrix density (g/cm^3)

ρ_b = Bulk density (g/cm^3)

ρ_{fluid} = Fluid density (g/cm^3)

A generic matrix density of 2.65 g/cm^3 for sandstone was applied to the aquifer wells. Fluid density depends on mud type assuming moderate mud filtrate invasion during drilling. The respective values for water-based-mud and oil-based-mud are 1.1 g/cm^3 and 0.9 g/cm^3. A comparison of the distributions of the input and output populations of the porosity property is shown in Figure 5-11. In general, the highest porosities are underrepresented and the lower porosities slightly overrepresented in the model as compared to the log data.

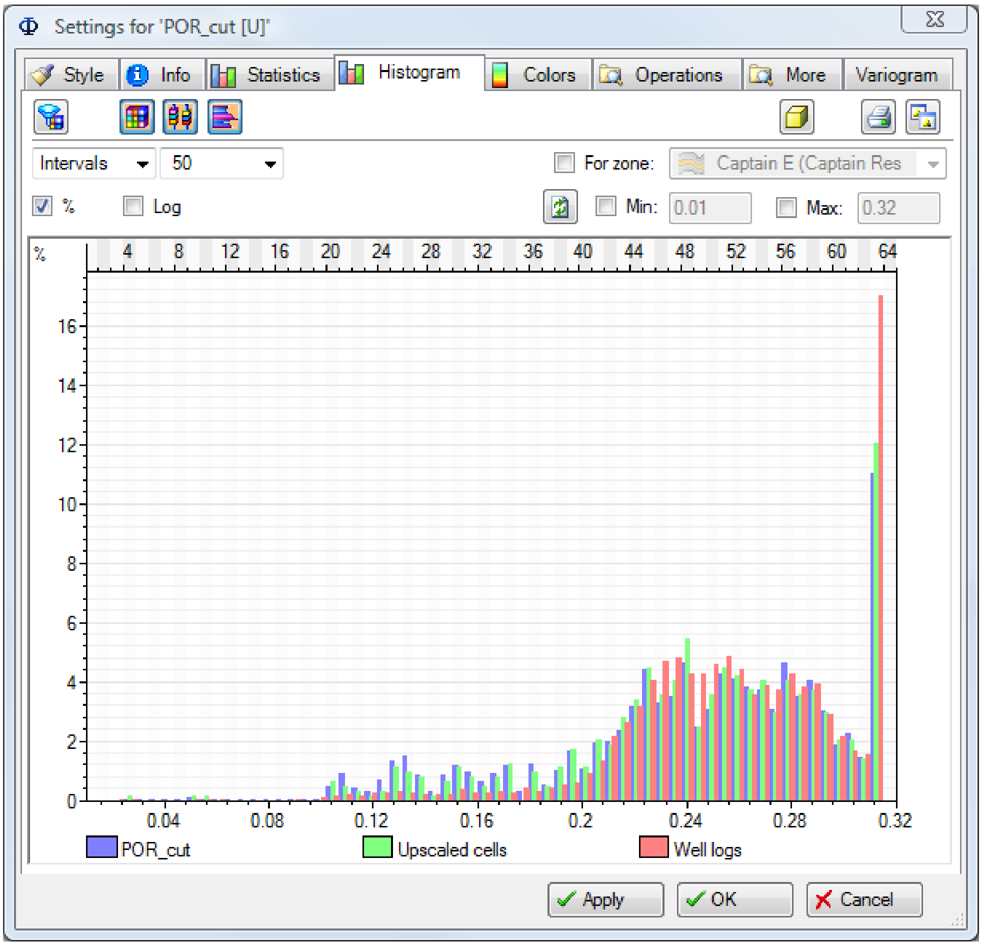

Figure 5-11: Porosity distribution in the Captain fairway.

Note: Porosity model in blue, upscaled cells in green and original well logs in red.

The maximum porosity was clipped at 0.3147 (to align with maximum permeability cut-off).

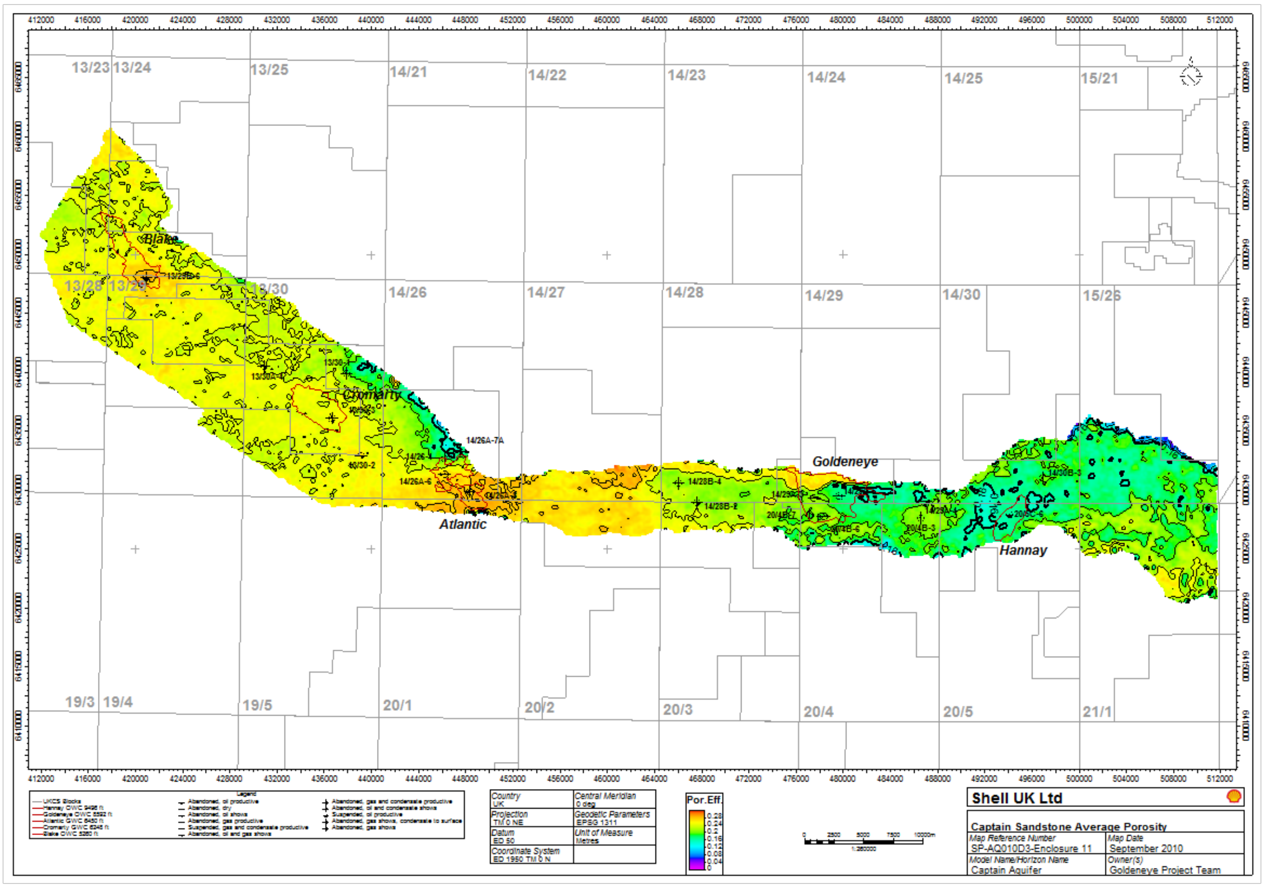

Figure 5-12: Average porosity map for the Captain aquifer model.

The porosity model shows a trend of decreasing quality with depth along the Captain Sandstone fairway as expected given the large depth range between the shallowest fields in the west (~1,600 m TVDSS) and the deeper Hannay field in the east (2900 m TVDSS) (see Figure 5-12).

Permeability was calculated from the porosity curve. Based on evaluations from several fields along the Captain fairway, a generic relationship was established between permeability and porosity (8).

$$k\_phi = 0.601 \times 10^{11.5 \times \Phi}$$

Where: k_phi = Permeability (mD)

ϕ = Total porosity (v/v)

Using this relationship provides a rough estimate of permeability along the Captain fairway. However, for very high porosities (greater than 32%) the equation extrapolates to unreasonably high permeabilities (3+ Darcies). Thus, the permeability curve was clipped at a maximum of 2500 mD (which corresponds to a maximum porosity of 0.3147) (see Figure 5-13).

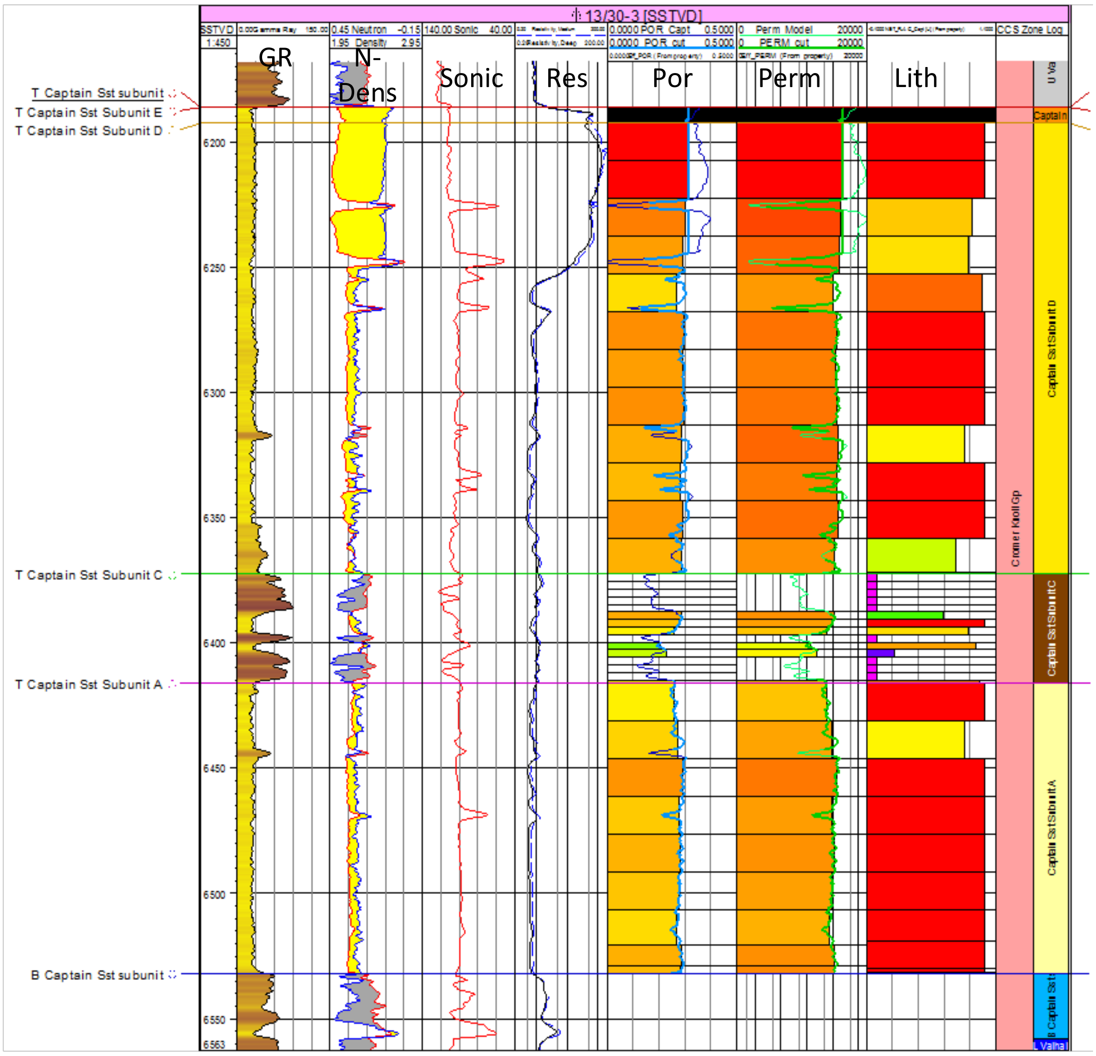

Figure 5-13: Clipped porosity (blue) and permeability (green) logs, and upscaled Por, Perm, & Lithology property model for Cromarty Well 13/30-3

Note: At the top of the Captain D interval the permeability log is limited to 2.5 Darcys, and the porosity log is clipped to 0.3147. The fine layering scheme in Captain E is obscured in this image.

The permeability was assigned a logarithmic distribution and was co-kriged with the porosity model, to ensure that if a cell has a high porosity value, it is more likely to have a high permeability. The resultant porosity and permeability distributions are shown in cross-section in Figure 5-14 and Figure 5-15 respectively. High values are given "hotter" colours and on the basis of these the four Captain subunits can be distinguished on both plots. On both sections an overall downdip deterioration in properties can be observed. There is a rather marked reduction in reservoir properties for the Captain D on the eastern flanks of the Captain field as compared to the western flank: this may be excessive and would impact on the effectiveness of the aquifer to the east of Goldeneye.

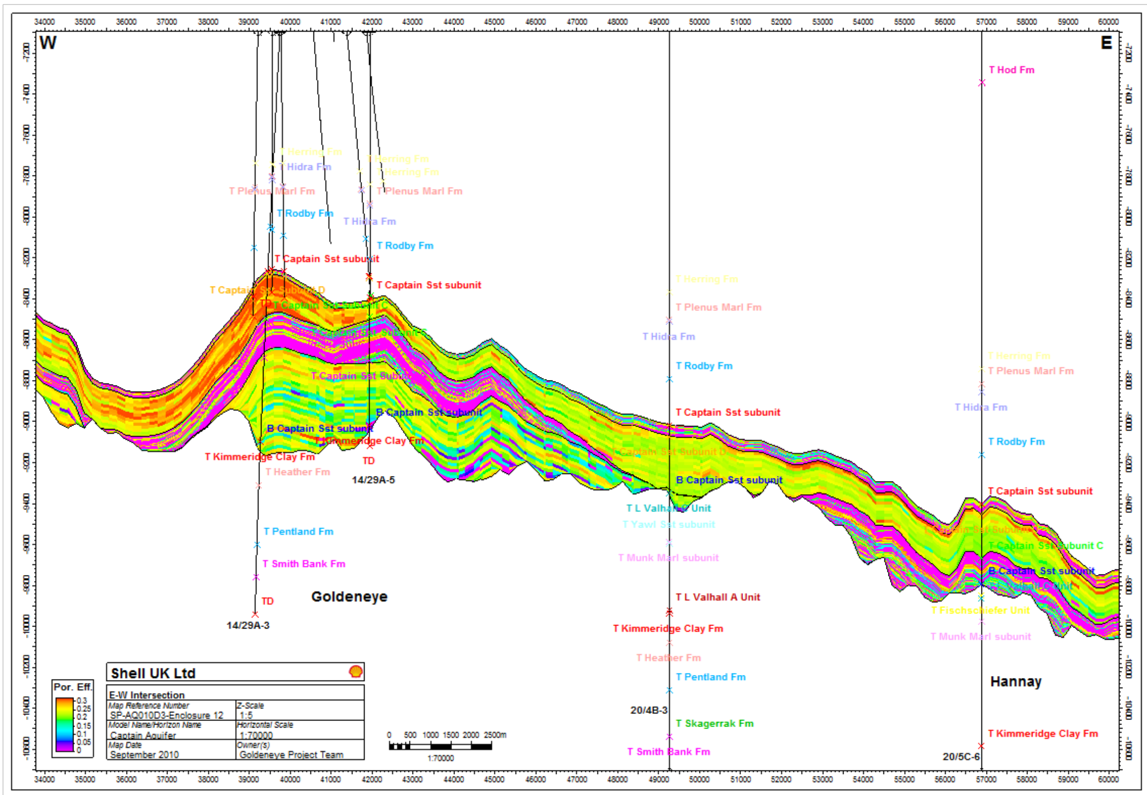

Figure 5-14: West to east cross-section from the Goldeneye field to the Hannay field showing the effective porosity distribution.

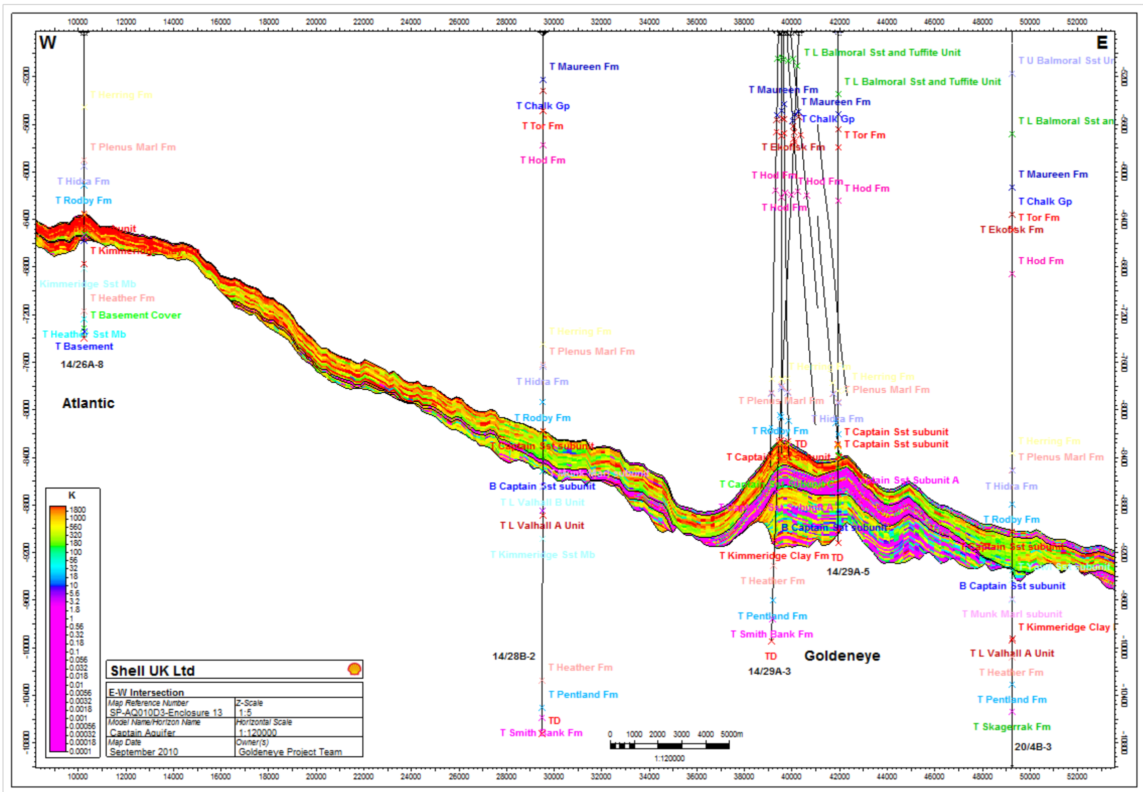

Figure 5-15: West to east cross-section from the Atlantic field to the Goldeneye field showing the effective permeability distribution.

5.4.2. Geometrical Modelling

Zones, layers, Field_ID and East/West_ID properties were also assigned to each cell in the model, primarily to provide filterable attributes for the reservoir engineer. The Field_ID tag labels every cell in each field (e.g. Hannay cells = 1, Goldeneye cells = 2 etc). The East/West_ID tag identifies the Eastern and Western aquifer cells either side of the FFSM area.

6. Conclusions

The Captain Sandstone fairway is interpreted to extend over 100 km in length along the southern margin of the Halibut Horst. The turbiditic Captain Sandstones are of Aptian-Albian age, with average porosities of 25% to 30% and Darcy range permeabilities.

Bulk, net and pore volumes were calculated for the Captain aquifer as detailed in Table 6-1. Low case volumetrics were also calculated where the lateral extent of the Captain fairway is limited by the Grampian Arch in the west (see Figure 6-1). If there is a disconnect, then this is the most likely major structural break point which may prevent communication from the Blake field through to the Hannay field. Two alternative correlations of the Captain Sandstones connecting the Goldeneye field to the Hannay field in the east were also modelled.

Table 6-1: Volumes of the Captain aquifer (x10^6 m^3) stretching from the Blake field in the west through to the Hannay field in the east.

	Bulk Volume	Net Volume	Pore Volume
Western Aquifer	47 579	39 414	10 400
Eastern Aquifer	18 080	12 773	3 045
Goldeneye FFM AOI	4 672	3 331	806
Total	**70 331**	**55 518**	**14 252**
Base Case – Connection across Grampian Arch			

	Bulk Volume	Net Volume	Pore Volume
Western Aquifer	7 913	6 775	1 806
Eastern Aquifer	18 080	12 773	3 045
Goldeneye FFM AOI	4 672	3 331	806
Total	**30 665**	**22 878**	**5 658**
Low Case – No Connection across Grampian Arch			

Note: For comparison, the low case volumetrics assume the western extent of the Captain aquifer is constrained at the Grampian Arch.

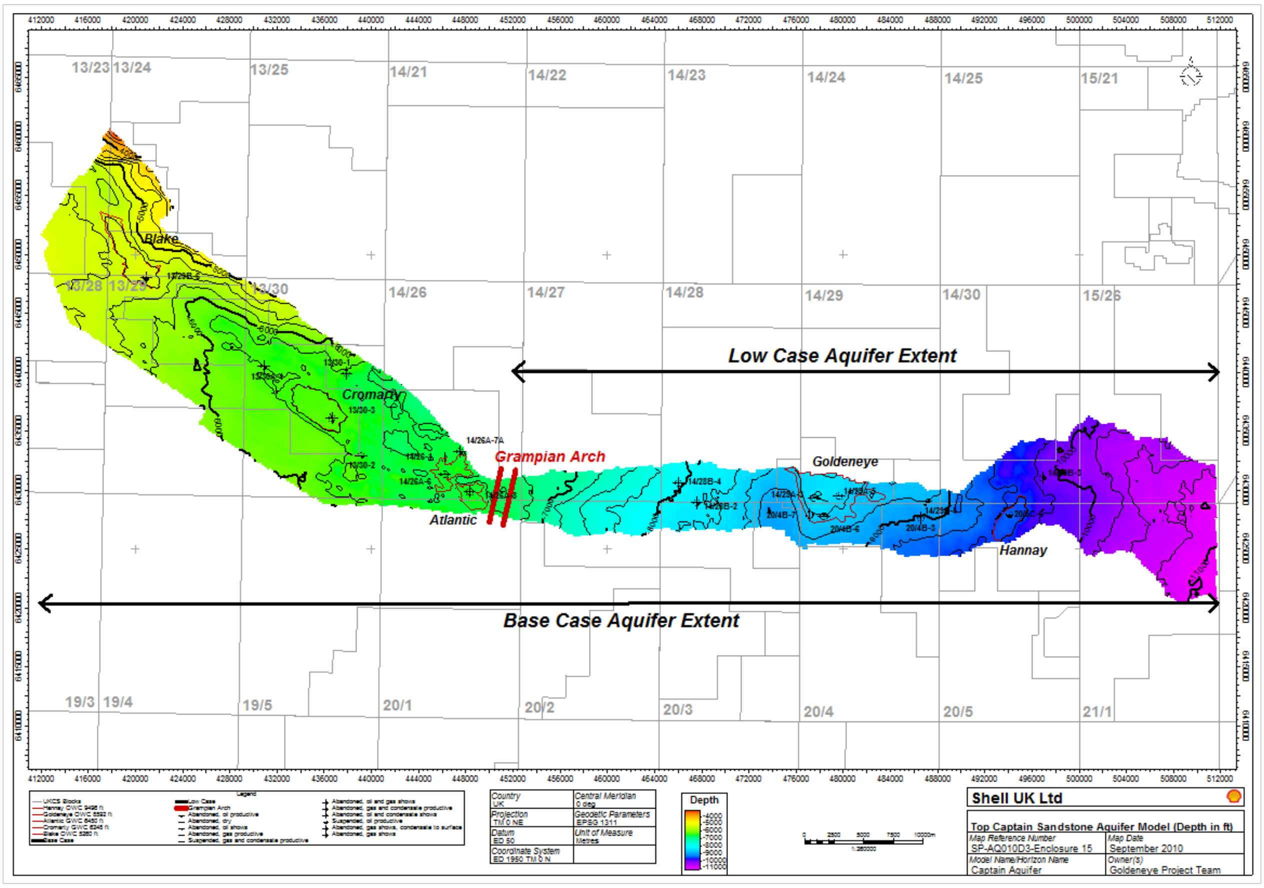

Figure 6-1: Lateral extent of the Captain Sandstone Aquifer models.

The aquifer static model was created primarily as a reservoir engineering tool to enable visualization and dynamic modelling of the Captain Sandstone aquifer to simulate any potential lateral discharge of CO_2 out of the Goldeneye structure. Understanding the aquifer fluxes and production history along the Captain fairway will also assist with the history matching of the Goldeneye FFSM.

The 3D aquifer model is designed to complement the other static models over the Goldeneye field - the Goldeneye field-scale SRM and the overburden 3D static model. The aquifer model gridding, zonation, and layering schemes were aligned with the Goldeneye FFSM, so that the more detailed FFSM could be spliced into the regional aquifer model in the dynamic domain for future studies.

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8. Glossary of Terms

Term	Definition
AOI	Area of Interest
CCGT GR	Combined cycle gas turbine Gamma Ray (wireline log)
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
COP	Commercial Organisation Political
EUR	Estimated ultimate recovery
FFM	Full Field Model
FFSM	Full Field Static Model
FFSMN/G	Full Field Static ModelNet to Gross
GIIP	Gas Initially In Place
GR	Gamma Ray (wireline log)
PSDM	Prestack depth migration
SRM	Static Reservoir Model
TVDSS	True Vertical Depth Subsea
TWT	Two-Way Time
UKCS	United Kingdom Continental Shelf

In the text well names have been abbreviated to their operational form. The full well names are given in Table 8-1 below.

Table 8-1: Production well name abbreviations

Full well name	Abbreviated well name
DTI 14/29a-A3	GYA01
DTI 14/29a-A4Z	GYA02S1
DTI 14/29a-A4	GYA02
DTI 14/29a-A5	GYA03
DTI 14/29a-A1	GYA04
DTI 14/29a-A2	GYA05

9. Glossary of Unit Conversions

Table 9-1: Unit Conversion Table

Function	Unit - Imperial to Metric conversion Factor
Length	1 Foot = 0.3048 metres
Volume	1 bbl = 0.159 m^3 1ft^3 = 0.02832 m^3

APPENDIX 2. Static Model Full Field Report

B.1. 11.108, Static Model (Full Field) Report, PCCS-05-PT-ZC-0580-00004

Peterhead CCS Project

Doc Title: Static Model (Field)

Doc No.	**PCCS-05-PT-ZG-0580-00004**
Date of issue:	**19/03/2015**
Revision:	**K03**
DECC Ref No:	**11.108**
Knowledge Cat:	**KKD - Subsurface**

KEYWORDS

Goldeneye, CCS, Static Model, CO_2, Petrel, In-Place Volumes, Turbidite, Debrite, Petrophysics, Depth Conversion, Lower Cretaceous, Captain/Kopervik Sandstone.

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Executive Summary

The objective of the work reported here is to develop a suite of static reservoir models as a basis for the forward modelling of CO_2 injection and storage in the Goldeneye field for the Peterhead Carbon Capture and Storage (CCS) Project. This involves creating a suite of models that are representative of current understanding of the field and that allow the investigation of geological uncertainties important for CO_2 injection and storage. The resultant models are used for volumetric calculations and as input to dynamic modelling of field performance in the historical production and post-production phases and also under subsequent CO_2 injection.

This report documents the geological background to the field, the geophysical and petrophysical data used to design and build the models and the main features of the modelling workflow. It lists the members of the model suite and their differences and provides a comparison of gross rock volumes between them, which range from 669 to 740 million m^3. The report is an update of the earlier Static Modelling Report for the Longannet CCS Project, and incorporates models creating for reservoir engineering sensitivity runs which were not available at the time of the Longannet report, plus minor edits for clarity.

The starting point for modelling was the static reservoir model (SRM) generated by the Shell Goldeneye asset team in mid-field life, to support hydrocarbon volumetric assessment and dynamic simulation for history matching and field performance prediction. This model has been reproduced to cover a slightly enlarged model area needed to accommodate possible CO_2 migration effects, and is used as an initial case (SRM1). The asset had determined that to achieve a reasonable match between predicted and observed performance during the production life-cycle of the field, some changes to the distribution of hydrocarbon volume in the dynamic simulation model were required. These dynamic model changes were addressed in SRM2.0, to provide geological foundations to the alterations made. Further models (SRM2.1-3.15) have been created to investigate other areas of geological uncertainty that could impact on CO_2 behaviour: variations in reservoir layering, reservoir connectivity and overall connected hydrocarbon volume, and variations in the field envelope that could influence CO_2 migration.

All these models were made available as input to dynamic simulation. The models that enabled history matches and were most useful for assessing CO_2 behaviour were SRM3.1 and its variants, SRM3.05 to test for the effect of a shallow flank and SRM 3.15 to test for a more southern truncation of the Captain Sandstone.

1. Introduction

The Peterhead CCS Project aims to capture around one million tonnes of CO_2 per annum, over a period of 10 to 15 years, from an existing combined cycle gas turbine (CCGT) located at SSE's Peterhead Power Station in Aberdeenshire, Scotland. This would be the world's first commercial scale demonstration of CO_2 capture, transport and offshore geological storage from a (post combustion) gas-fired power station.

Post cessation of production, the Goldeneye gas-condensate production facility will be modified to allow the injection of dense phase CO_2 captured from the post-combustion gases of Peterhead Power Station into the depleted Goldeneye reservoir.

The CO_2 will be captured from the flue gas produced by one of the gas turbines at Peterhead Power Station (GT-13) using amine based technology provided by CanSolv (a wholly owned subsidiary of Shell). After capture the CO_2 will be routed to a compression facility, where it will be compressed, cooled and conditioned for water and oxygen removal to meet suitable transportation and storage specifications. The resulting dense phase CO_2 stream will be transported direct offshore to the wellhead platform via a new offshore pipeline which will tie-in subsea to the existing Goldeneye pipeline.

Once at the platform the CO_2 will be injected into the Goldeneye CO_2 Store (a depleted hydrocarbon gas reservoir), more than 2 km under the seabed of the North Sea. The project layout is depicted in Figure 1-1 below:

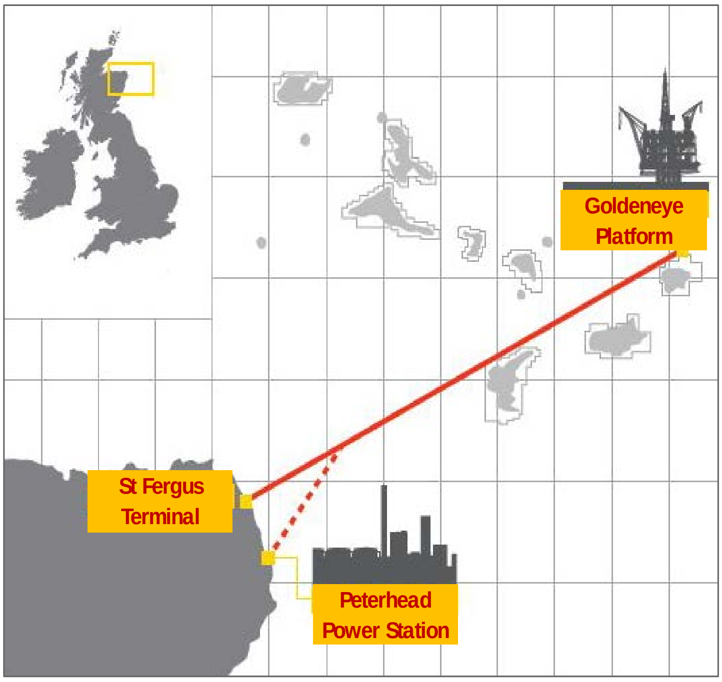


Figure 1-1: Project Location

1.1. Summary

A number of studies have been undertaken to evaluate the potential for using the Goldeneye field for CO_2 storage. This report documents the detailed static reservoir models (SRM) of the reservoir intervals, used as the basis for dynamic simulation of CO_2 injection into the Goldeneye field. A SRM had already been built by the Shell Goldeneye asset team in 2005 to assist in production management. This model was imported into the dynamic simulator to create a full-field simulation model (FFSM) in order to match and predict field performance. This current asset SRM was, therefore, used as the basis for the CCS project, with the sole modification of enlarging the model area to accommodate possible CO_2 migration effects such as dissolution into the aquifer over very long time scales. This extended asset SRM is referred to as 'SRM1'.

Although the *hydrocarbon production* performance is predicted by the current full field simulation model (FFSM), some sensitivities to this reference case SRM have been generated to investigate the effects of key geological uncertainties potentially impacting on *CO_2 injection* performance. Modifications implemented in the FFSM by the asset, to better match ongoing field performance, have also been investigated to ensure that they can be geologically supported. In addition, other modifications were implemented in the model to meet the different requirements of CO_2 injection simulation (model layering optimisation). These additional geological realisations/model modifications are referred to collectively as SRM2 (SRM2.1, 2.2, etc.).

Studies to investigate seal integrity in the overburden to the Goldeneye field are currently in progress. As a part of this study an alternative "overburden" reservoir model for the Captain sands has been generated, which has also been used to create an alternative realisation set for the reservoir static modelling (referred to as SRM3 & SRM3.1).

The 'end-member' SRM realisations have been exported to a dynamic simulator and were evaluated to get a robust history match. Feedback enabled some iteration to further investigate the impact of the key sensitivities (SRM3.05 and SRM3.15). This work is continuing and may result in further refinement of the SRM suite.

2. Background & history

The Goldeneye field is a gas condensate accumulation with a thin oil rim in the South Halibut Basin in the U.K. Sector of the North Sea. The main reservoir is formed by the Early Cretaceous-aged Captain Sandstone Unit, a sandstone turbidite with good reservoir properties (average porosity of Captain D reservoir=25% and average permeability=790 mD) and containing hydrocarbons at normal pressure and temperature. In 1996 Shell discovered the field by drilling well 14/29a-3, finding a gas column of 303 ft [92.354 m]. In the following years three appraisal wells were drilled: 1998 Amerada 20/4b-6 (south), 1999 Shell 14/29a-5 (south-east) and 2000 Amerada 20/4b-7 (south-west). In 2004 five development wells were drilled. The locations of the exploration and development wells are shown in Figure 2-1.

The Captain Sandstone Member occurs along a sand fairway oriented approximately east-west, along the south flank of the Halibut Horst (Figure 2-2). It is thought that the sand distribution is a result of deposition into a structural low by a combination of transverse locally-sourced and axial submarine mass flows and turbidites. Well 14/29a-2, which is located north of this depositional limit, encountered no Captain reservoir. The distribution of properties in the static models created for the field is controlled by four full reservoir penetrations. The subsequent development wells all partially penetrate the Captain, and are completed in the main Captain D unit.

The field commenced production in October 2004. As of December 2010 the field has ceased production: all the development wells are shut-in due to water production.

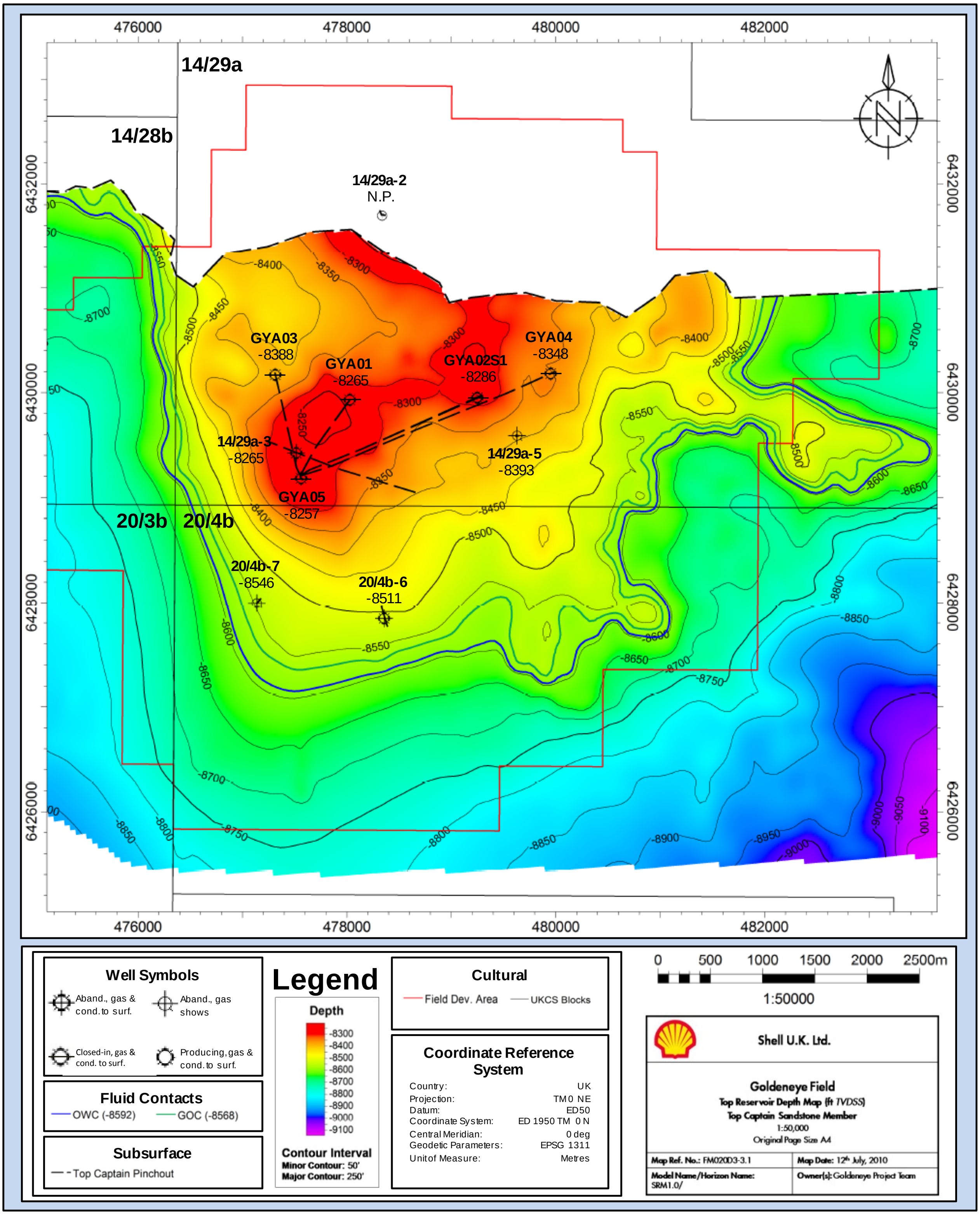


Figure 2-1: Goldeneye field top structure map, True Vertical Depth Subsea (TVDSS) – asset reference case (SRM1). Note absence of Captain sands in 14/29a-2.

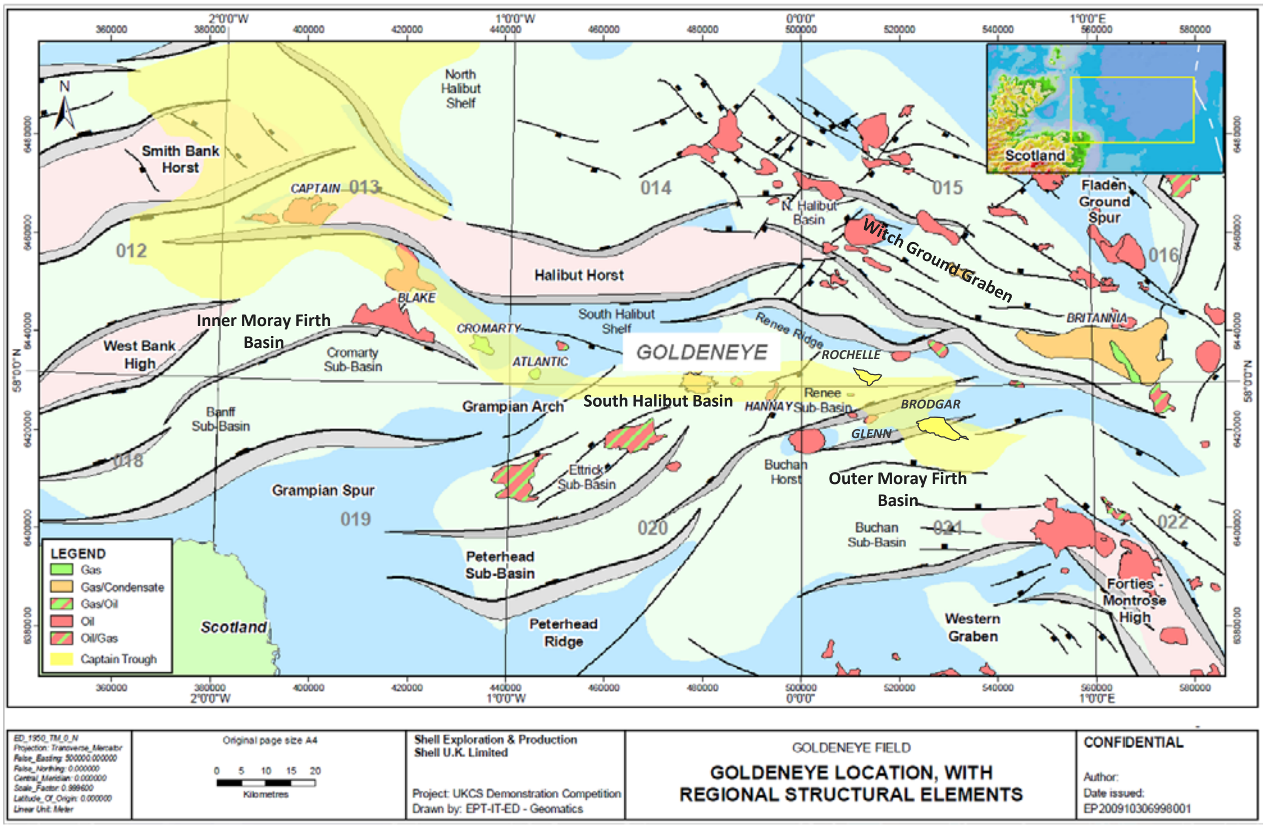


Figure 2-2: Distribution of Captain sandstones across outer Moray Firth: Captain fairway highlighted in yellow; basinal areas in pale green.

3. Model scope & objectives

The primary objective of the static modelling phase of the CCS project was to produce a set of geological realisations covering the key uncertainties that could impact the CO_2 injection into the field and which could be used to dynamically simulate CO_2 injection and storage.

At project start-up, it was decided – after an audit trail had been constructed – to use the existing asset SRM as the basis of the structural and facies model. It was also agreed to re-use the input data to these models – comprising well deviation data, log data, petrophysical interpretation, core-based geological facies interpretation, seismic depth surfaces and faults – again after a suitable audit trail had been established.

A number of issues were identified by the Goldeneye project team, which could be important for CCS but which may not be adequately represented in the asset SRM. To address these issues, the following modifications were prioritised:

- The SRMs had to be made larger than the existing asset SRM to be able to accommodate CO_2 movements down and away from injectors under differential pressure, as free CO_2, and gravitational movement of formation water made denser by CO_2 dissolution. This required re-building the asset SRM with a different grid boundary definition.
- The method for determining the robustness of any SRM for future CO_2 injection prediction was to assess how well it 'predicted' known production. Hence, it was necessary to reproduce the modifications required in the FFSM to correctly match the timing of water breakthrough in the static model domain.
- A variety of different zoning schemes (division of the Captain Sandstone Member into A, C, D and E Units) have been used to investigate uncertainty around the distribution of gas volumes in the reservoir. In addition, attention was paid to the distribution of porosity and permeability in the underburden.
- Lastly, some modification of the reservoir layering modelling was thought necessary to better model thin, buoyant CO_2 plumes.

The field scale SRM is designed to complement static models used to investigate the overburden and the regional aquifer, which are being constructed in parallel. Learning from each of the models are mutually applied. The intention is to transfer the results of the detailed dynamic simulation to the other, less detailed models as required so, for example, denser formation brine with CO_2 moving by gravity 'out' of the SRM/FFSM should be modelled regionally in the aquifer model. This means that the three subsurface models should share sufficient common features, such as field volume, reservoir fairway dimensions, *etc.*, for this to be consistent.

4. Geological setting

The Goldeneye field is a gas accumulation with a thin oil rim, located in the South Halibut Trough of the outer Moray Firth area. Its reservoir, the Captain Sandstone Unit, comprises Early Cretaceous-aged sandstones deposited in a submarine environment and the trap is formed by a combination of structure and stratigraphic trapping.

4.1. Regional stratigraphy

A regional stratigraphic column for the Outer Moray Firth is shown Figure 4-1 with detail for the Jurassic and Lower Cretaceous in Figure 4-2. The reservoir sandstones of the Goldeneye field are assigned to the Captain Sandstone Member of the Valhall Formation. The Captain Sandstone Unit (which is also called the Kopervik Formation by other operators) was deposited in a WNW – ENE oriented trough immediately to the south of the South Halibut Shelf in the Moray Firth. The trough served to channel and confine deposition, which was initiated during a phase of eustatic sea-level fall during the Aptian stage of the Early Cretaceous. This drop in mean sea level coincided with reactivation of the Halibut and other local structural highs by tectonic activity related to the opening of the proto-Atlantic Ocean to the west of the British Isles. Sediments accumulated through the action of turbidity currents and mass-wasting of locally exposed fault scarps. Heavy mineral analysis and palaeo-flow indicators suggest contributions were made by both north-south (laterally) oriented turbidite fan and debris flow systems and west-east (axially) oriented submarine channel systems. Within the central area of the Goldeneye field, up to 250 m of turbiditic and debritic sediments accumulated at this time.

Equivalent reservoir occurs along a roughly east-west fairway to the south of the South Halibut Shelf. The same reservoir is interpreted to occur in the Blake, Atlantic and Cromarty fields to the west, and in Hannay and Rochelle to the east. Models of the charge history of the Goldeneye field indicate an early oil fill, sourced from local instances of the Kimmeridge Clay Formation, which was flushed by a later and more sustained flow of gas likely to have originated from the deeper eastern end of the trough (Fisher Bank basin and Renee sub-basin) where Kimmeridge Clay is mature for gas at present. This implies a significant lateral gas migration (and continuous reservoir).

The Captain Sandstone Unit lies above mudstones of the lower Valhall Formation. These rocks also provide a lateral seal to the north. The lower Valhall Formation contains two other potential reservoir units – the Yawl and Scapa Sandstone members – which have been penetrated by wells in the area. In the wells 20/4b-6 and 20/4b-7, both units are water bearing, lying below the original oil water contact (OOWC) of the Goldeneye field. The Scapa is also encountered in 14/29a-2, up-dip of the Goldeneye field, where again it is 'tight' (as confirmed by a number of failed repeat formation tester (RFT) pressure tests) and is considered, after petrophysical analysis of wireline log information, to be water wet. Beneath the centre of the Goldeneye field, the Captain Sandstone Member sits directly on shales of the Jurassic Humber Group, comprising the Kimmeridge Clay and Heather formations. The asset static model has lumped all of the pre-Captain/post-Kimmeridge Clay stratigraphy into a unit labelled 'Scapa' and that nomenclature has been maintained in this report.

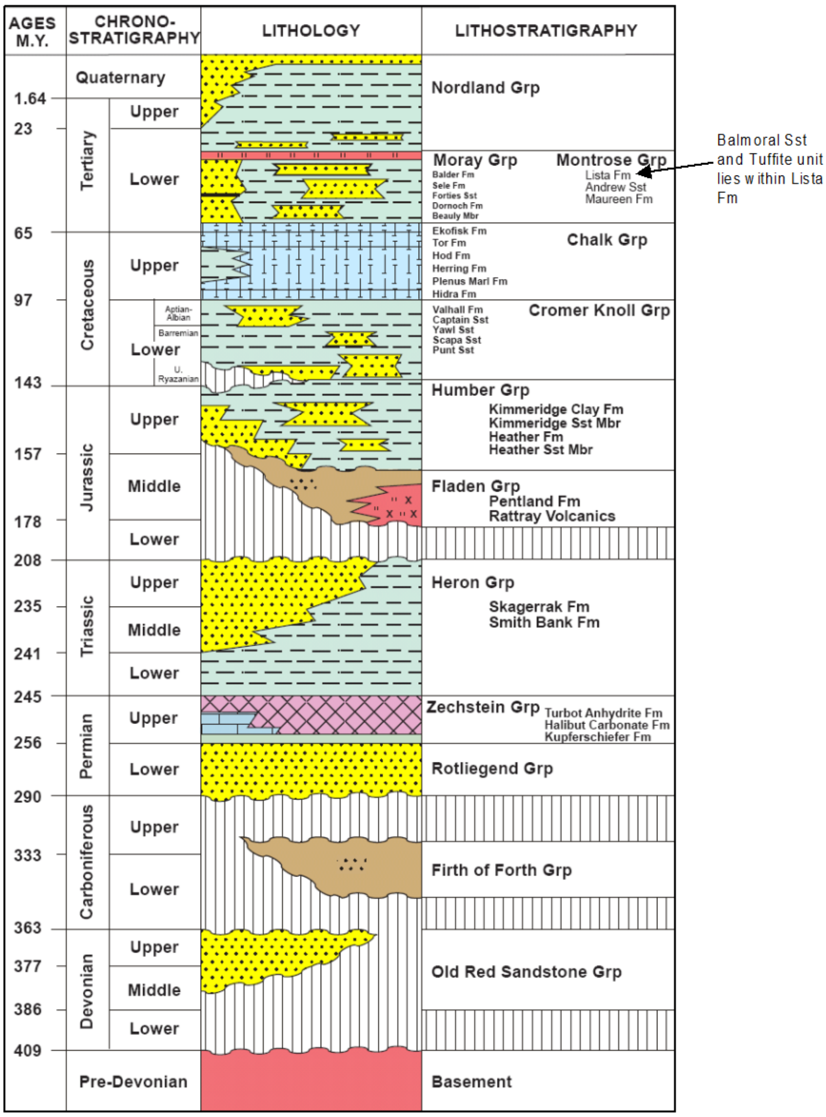


Figure 4-1: Generalised stratigraphy of the Goldeneye area

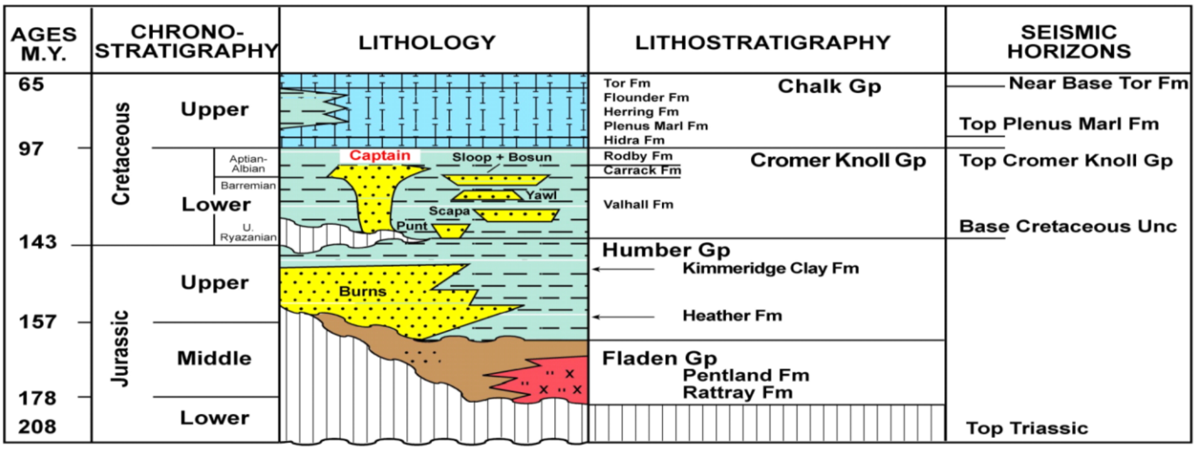


Figure 4-2: Jurassic and Lower Cretaceous stratigraphy of the outer Moray Firth

The reservoir top-seal is formed from a combination of upper Valhall Formation and Rødby Formation shales. These two units combined comprise a 190 ft to 280 ft (60 m to 85 m) thick succession of laminated, calcareous mudstones. The extent of the top-seal is significantly larger than the reservoir, and it therefore forms a regionally effective seal.

4.2. Structure

Top structure (top Captain event) is mapped seismically on Pre-Stack Depth Migrated (PreSDM) seismic data derived from a high-fold 1997 3D survey covering the Greater Ettrick region. Several depth conversion scenarios have been investigated but the current method uses interval velocity vs. interval transit time regressions. The interpreted seismic time horizons in the overburden were depth converted using a seven-layer depth conversion (Table 4-1). The shallowest layer (mean sea level-top Chalk) uses a constant velocity (linear depth/time relationship). Other intervals use well-based interval velocity vs. interval transit time regressions. A "supra-Beauly wedge" of high, constant velocity between the 14/28b-2 and 14/29a-3 wells is inserted above the top Beauly Member (Figure 4-3 & Figure 4-4), in order to compensate for complex overburden velocity effects and to achieve closure of the Goldeneye structure to the west. This is more fully explained in the accompanying Seismic Interpretation Report. A further local adjustment was made within the base Hidra-top Captain layer in the area around well GYA03, to take account of a velocity anomaly observed in the seismic at this well location. Residuals at each level are shown in Table 4-2. After depth conversion, the residuals that remained at the well locations were gridded with an influence radius of 2 km and then added to the top structure map, tying the surface explicitly to its observation point in each well (1).

There is no significant faulting at top Captain level. There are many small scale faults interpreted but these have minor throws. The Captain Sandstone has little acoustic impedance contrast with the shales that encase it. Although many small faults could be interpreted, based on lateral seismic character changes and reflector discontinuities, these faults, the base Captain and the internal reservoir divisions all carry significant uncertainty. All five production wells were completed within the main reservoir unit, the Captain D. The production history from these wells has shown no evidence of compartmentalisation, with all the wells in communication.

Table 4-1: Velocities used for depth conversion (depth in feet)

Interval	Depth/TWT Regression	Interval Velocity/Interval TWT Regression
Surface-Top Chalk	Z = 4.2387*TWT – 1369	
Supra Beauly Wedge	Constant velocity 7400 ft/s added to Top Chalk depth surface	
Top Chalk-Top Tor		V = -247.954*Chalk-Tor isochron + 17863
Top Tor-Top Hod		V = -131.08*Tor-Hod isochron + 23819
Top Hod-Top Plenus		V = -6.8924*Hod-Plenus isochron + 15332
Top Plenus-Top Rodby		V = -277.9*Plenus-Rodby isochron + 23534
Top Rodby-Top Captain		V = -93.879*Rodby-Captain isochron + 14212
Captain Reservoir	Constant velocity 11000 ft/s	
Top Rodby-BCU		V = -2.801*Rodby-BCU isochron + 11024
BCU and below	Constant velocity 10500 ft/s	

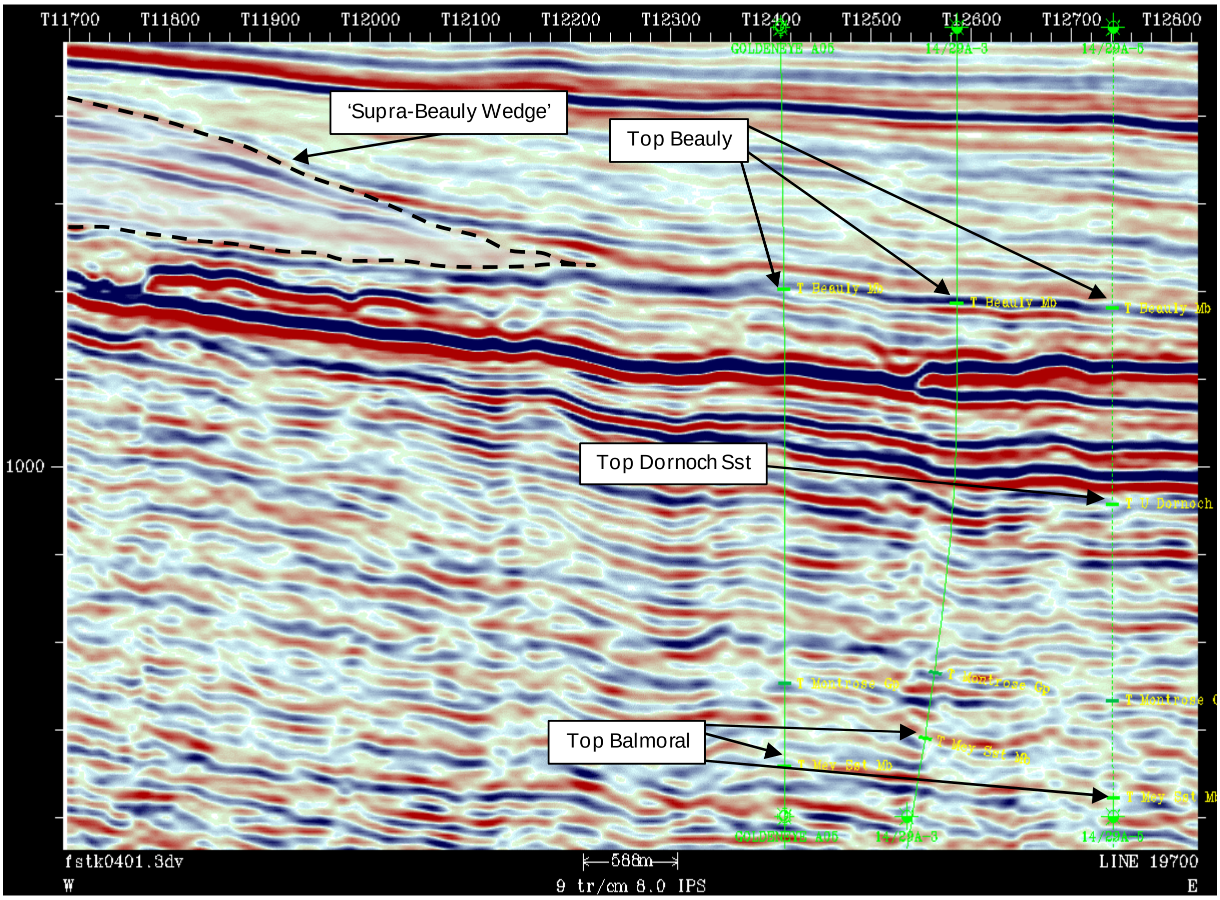


Figure 4-3: W-E reflectivity time section close to GYA05, 14/29a-3 & 14/29a-5. Top Reservoir (not shown) is at approximately 2020-2120 ms.

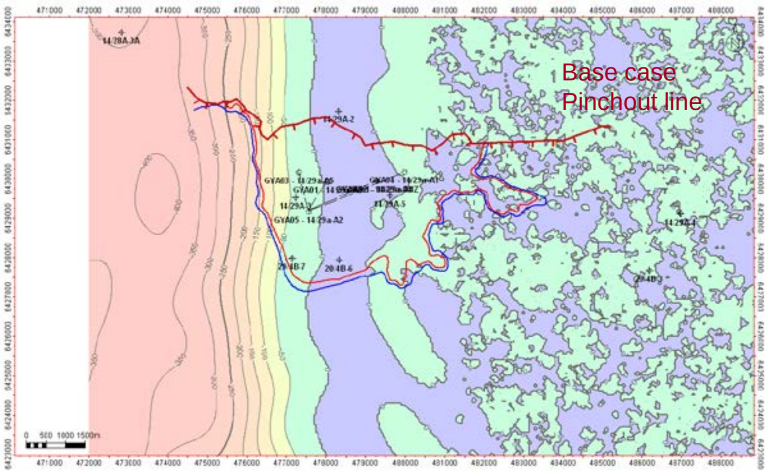


Figure 4-4: The Supra-Beauly Wedge, 50 ft depth contours

Table 4-2: Depth Conversion Residuals in feet

Depth Conversion Residuals								
Isochore Residuals							**Total Residual**	
tchlk	ttor	thod	tplen	bhid	tcap	**Well**	**tcap**	**RMS**
-12	2	-7	51	-1	-13	14/29A-2	20	400
14	-7	10	20	2	8	14/29A-3	48	2304
-14	-27	31	-3	27	-5	14/29A-4	10	100
41	-11	-21	-22	-13	16	14/29A-5	-10	100
5	27	-10	-31	-40	24	20/4B-3	-24	576
-9	-10	11	-68	44	-9	20/4B-6	-41	1681
-39	51	-35	-36	-3	2	20/4B-7	-61	3721
-8	8	-12	-3	8	-6	GYA01	-14	196
-31	-10	74	30	3	-5	GYA02	62	3844
-33	24	-4	-9	-54	17	GYA03	-58	3364
50	-11	-20	-19	-17	0	GYA04	-17	289
37	-36	-18	90	-11	3	GYA05	65	4225
							Average	**42**
							Std Dev	43.4

Studies into fault sealing potential show that the Captain sands are clean and that cataclasites identified in core do not represent significant barriers to fluid flow, which suggests any faulting should not result in fluid barriers or baffles. Geochemical investigation into recovered gas condensate samples shows a constant geochemical fingerprint across field, again suggesting no compartmentalisation. Oil samples, however, do show variations in composition and may indicate vertical compartmentalisation. The operator of the Hannay field, which also has a Captain Sandstone Unit reservoir, report that there is a pressure barrier between the lower and upper massive sand units during production. Given the shaley nature of the upper Captain C, one possible realisation is that a stratigraphic barrier or baffle exists between hydrocarbons in units D and E and in units C and A below them.

The Goldeneye field is a combined structural and stratigraphic trap (Figure 4-5). The trap is a three-way dip closed anticline to south, west and east, with a northerly up-dip pinch-out. The original hydrocarbon column is approximately 300 ft [90 m], indicating that an effective overpressure of *c*.115 psia [7.9 Bara] [792.8971 KPa] above hydrostatic at the crest is held by the caprock (Figure 4-6). The exact location of the northerly pinch-out cannot be resolved seismically, but Captain-aged sandstone is absent from Well 14/29a-2. The sandstones lap onto and thin onto the Halibut Horst high, creating a pinch-out. The geometry is therefore likely to be a thinning wedge of sandstones formed during deposition. This is consistent with a lack of net to gross deterioration to the north, and lack of evidence of erosion at top Captain. The OOWC at -8592 ft [2618 m] TVDSS proves effective closure to at least this depth. All models therefore assume a structural-stratigraphic spill point in the north-west corner of the field at the OOWC, consistent with regional models of up-dip gas migration from east to west.

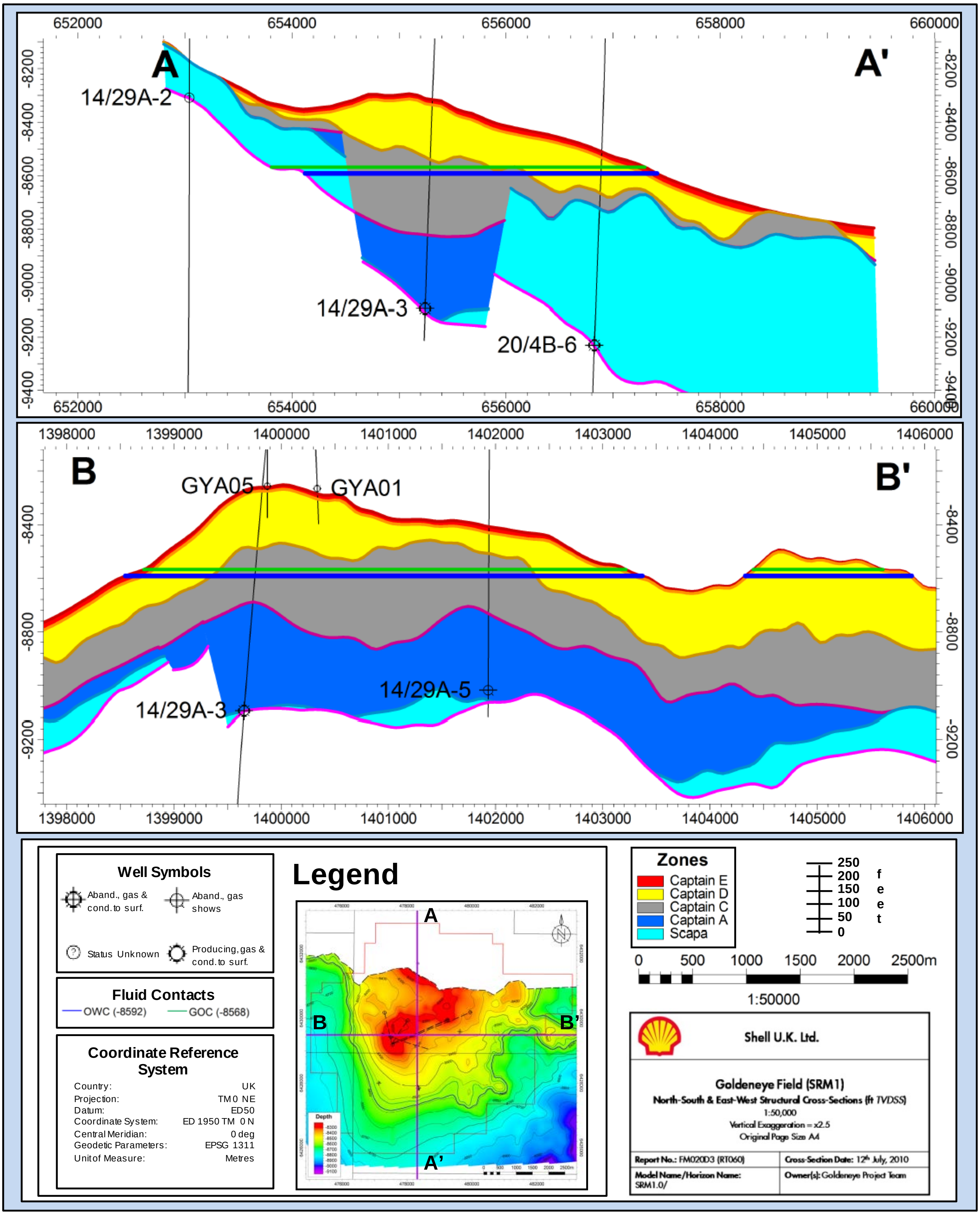
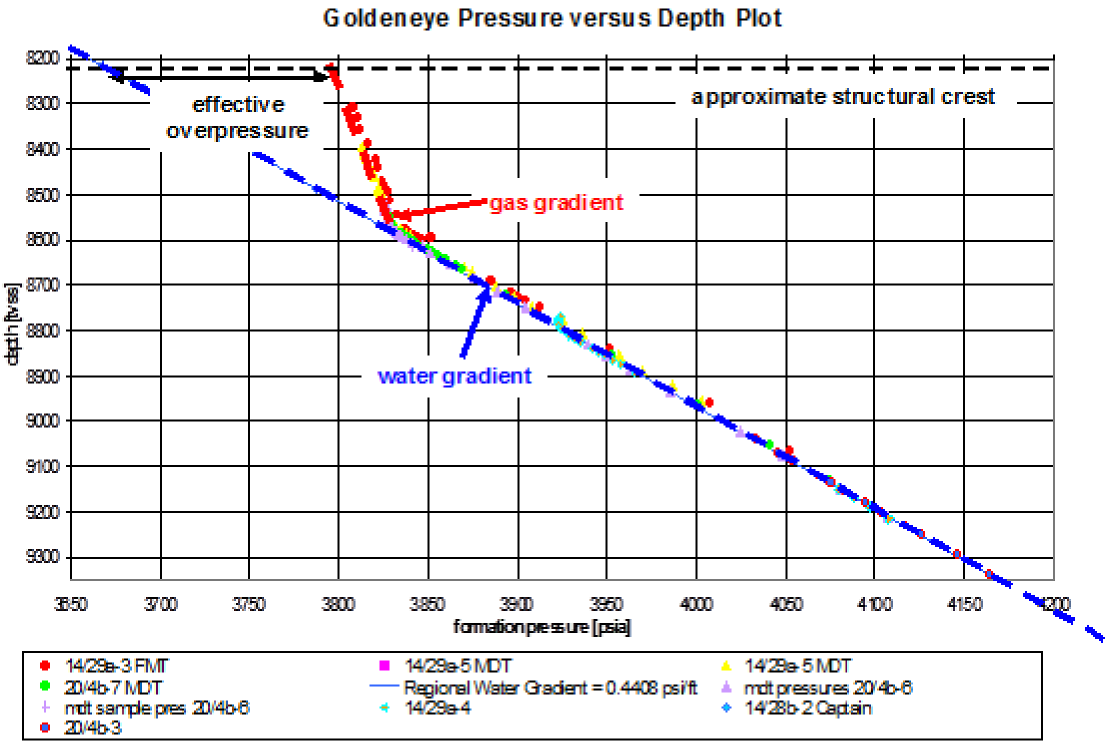


Figure 4-5: Representative structural cross-sections through Goldeneye field

The structural configuration in Goldeneye is the result of two major extensional phases during the Late Jurassic and the Cretaceous with periods of north-south directed compression. Further minor compression, combined with a period of regional eastward tilting took place in the early Tertiary.



Estimated field crest at -8225 ft [~2507 m] TVDSS gives an effective overpressure of *c.* 115 psia [7.9 Bara] [792.8971 KPa] retained by the caprock, equivalent to a total gas column of around 375 ft [114 m]. Proved gas column in 14/29a-3 (red points) is 303 ft [92 m].

Figure 4-6: Goldeneye pressure data

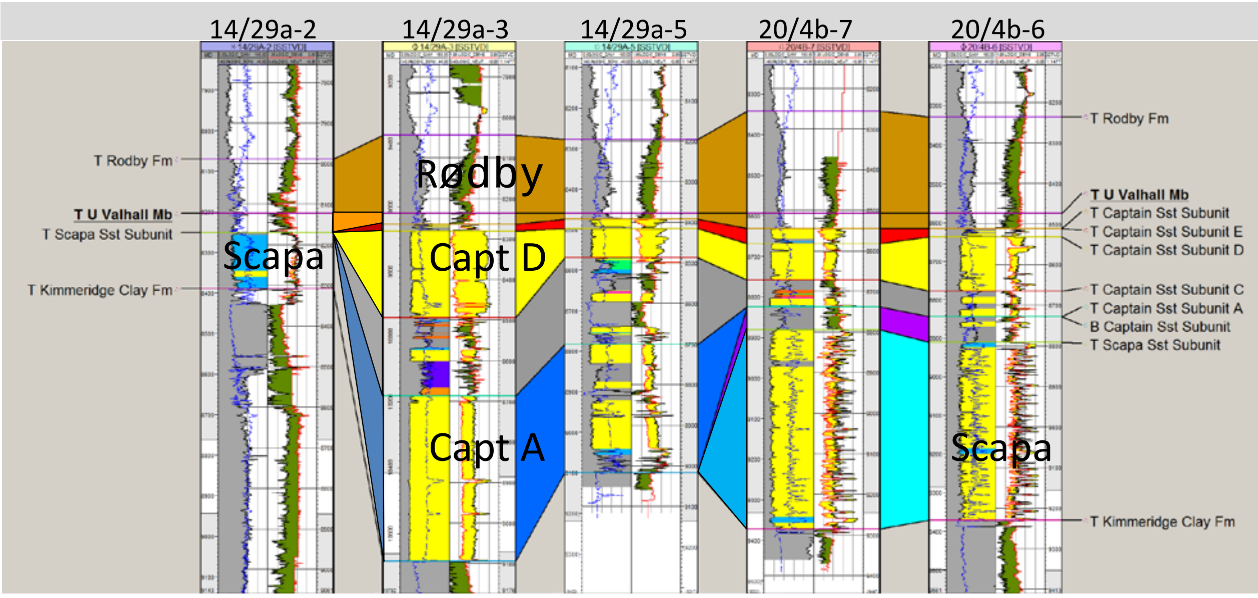
4.3. Reservoir stratigraphy

The Captain Sands were deposited in a sand-rich turbidite slope/base of slope system interpreted to trend predominantly west-east but with significant lateral sediment input from the South Halibut Shelf situated immediately to the north. Information from the four discovery/appraisal wells drilled in Goldeneye and an extensive regional database of over 200 wells in the Moray Firth area suggests that sand continuity over a large area adjacent to the regional break in slope is good. The Goldeneye reservoir can be subdivided into 4 lithostratigraphic units from top to base, as shown in Table 4-3.

Table 4-3: Subdivision of the Captain reservoir, Goldeneye area

Reservoir Unit	Description
Captain 'E' Unit	Laterally variable thin heterogeneous unit
Captain 'D' Unit	Laterally extensive massive sand unit
Captain 'C' Unit	Laterally extensive, mudstone-rich heterogeneous unit
Captain 'A' Unit	Laterally restricted sand-rich unit

Units C-E can be correlated across Goldeneye, with unit C representing a field-wide shale-rich horizon. By contrast, the 180 m to 250 m thick unit A is only locally present, occurring only in Wells 14/29a-3 and 14/29a-5 (Figure 4-7). The distribution of this unit may be fault controlled (as implemented in SRM 1-2), or by slumping or channel erosion (as in SRM 3 and SRM 3.1). Whatever the mechanism, the extent of this thick Captain is seismically defined away from the two well data points, and is limited to an east-west trough, extending from the centre of the field to the east of Goldeneye (Figure 4-9**).**



Log Tracks (from left to right): measured depth; gamma ray (black line with grey fill), sonic (dashed blue line) & facies (coloured fill from Gamma Ray to right hand edge); neutron (black line) & density (red line); true vertical depth subsea. Colour between wells shows reservoir zones. Captain is absent in well 14/29a-2, Captain A is absent in wells 20/4b-6 & 20/4b-7.

Figure 4-7: Geological correlation of Goldeneye wells, section approximately north-south. Section flattened on top U Valhall Member well picks.

The core description log from the type well (14/29a-3) of the Goldeneye field is shown in Figure 4-8, where it is compared with the gamma ray (GR) and neutron-density (N-D) logs for the whole Captain Sandstone Member interval to highlight the characteristics of each unit.

The **Captain A** Unit is a massive, medium grained sandstone. Sandstone from this unit has been recovered in core from Well 14/29a-3 only. The depositional model for this unit suggests a very localised deposition within a fault-bounded basin or erosional scour, from a turbidite fan system sourced in the Halibut Horst, directly to the north of the field location (Figure 4-9). The base of the Captain A Unit is considered to be represented by an erosive sequence boundary, though the section missing from below the reservoir contains several other sequence boundaries (2). Average net-to-gross for this unit is 84%, average net porosity is 23% and average permeability is 134 mD.

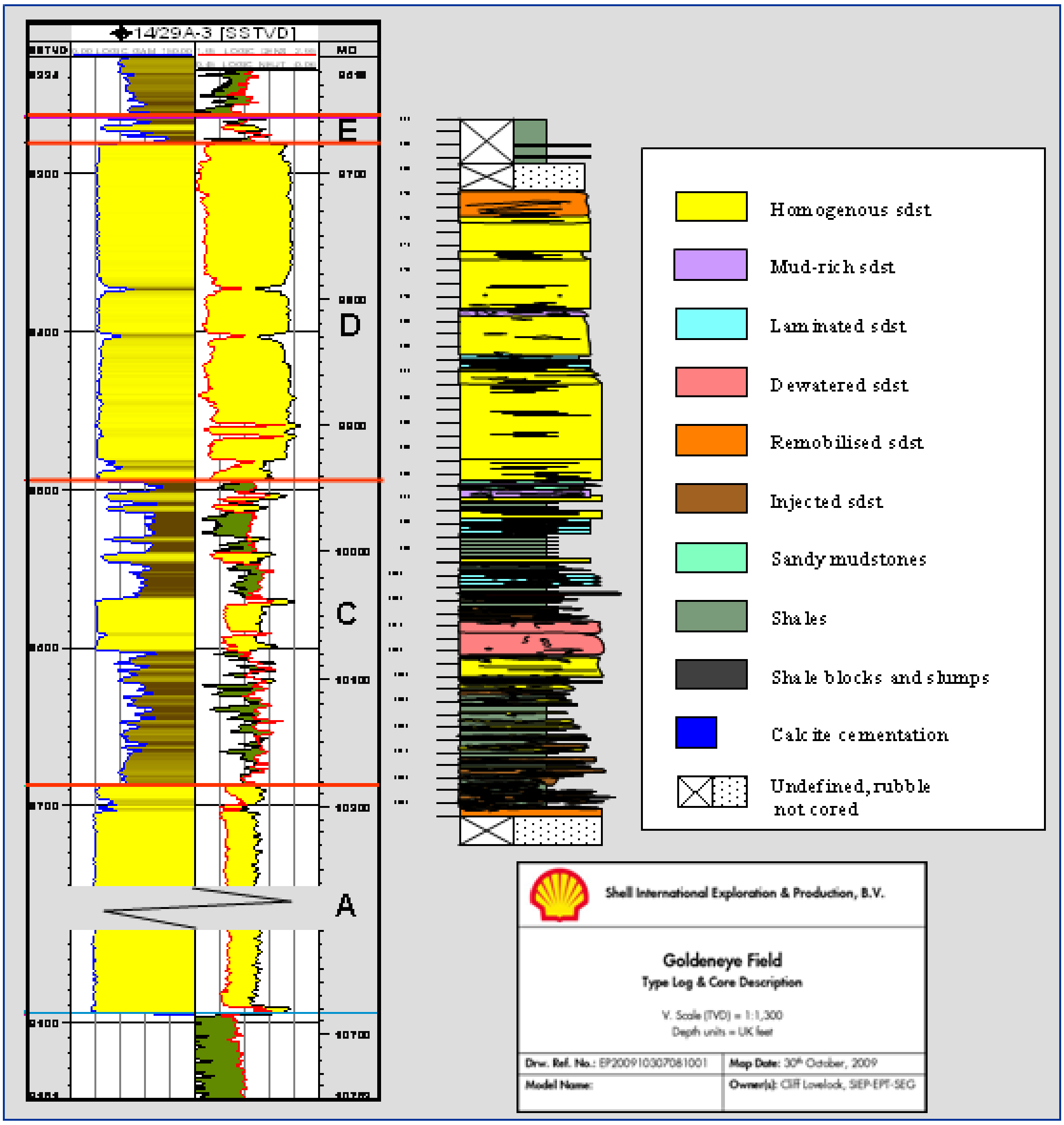


Figure 4-8: Subdivision of the Captain reservoir, Goldeneye area.

Note: log data on left with core facies log description on right. Unit A is homogenous in parts and highly variable in thickness (shown as partial log)

The **Captain C** unit is a heterogeneous clastic sequence containing a considerable proportion of extra-basinal material, presumably deposited through the action of mass wasting processes, as seen in core from Wells 14/29a-5, 14/29a-3 and 20/4b-7. The base of the Captain C Unit appears to onlap onto the underlying stratigraphy. The mixture of facies present testifies to a variety of processes being active during the period of its deposition. It is interpreted to have been dominated by the actions of debris flows sourced from the structural high to the north of the Goldeneye field. High and low-density turbidity currents also flowed through the area during Captain C times, producing reservoir sands of varying quality (Figure 4-9). Average net-to-gross for this unit is 33%, average porosity within the net intervals is 22% but average permeability (from the whole interval) is only 10 mD.

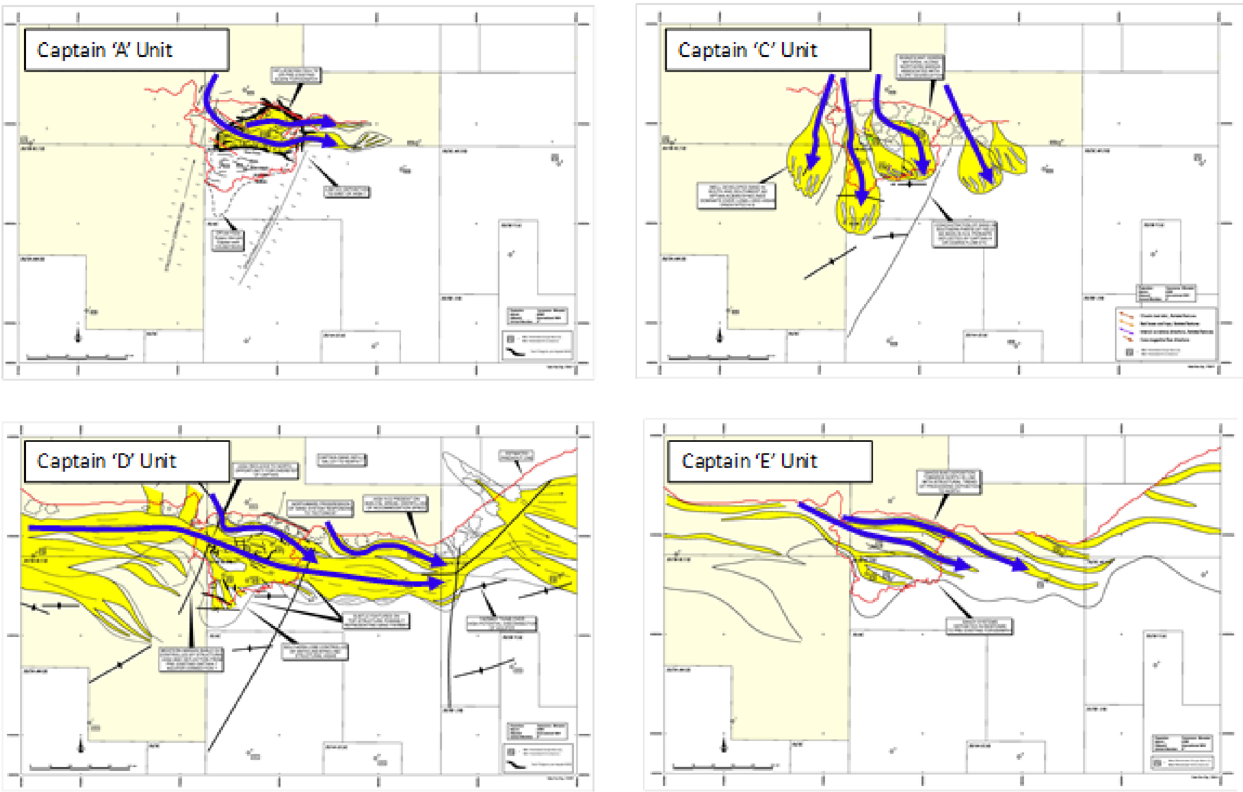


Figure 4-9: Depositional model for the Captain reservoir.

Note: A and C are more locally sourced, and C sands are less extensively distributed than the overlying D & E units. D in particular comprises amalgamated sandstones thought to have a dominantly axial source. Blue arrows indicate predominant depositional directions.

The **Captain D** is the primary reservoir unit, into which all the development wells have been completed. The D unit has been cored in all of the exploration and appraisal wells in the Goldeneye Field. As with the similarly massive Captain A Unit, the base of the Captain D Unit is deemed to be represented by an erosive sequence boundary (2). It comprises medium grained massive sandstones that, with the exception of a fining-upwards sequence at the top seen in all wells in the field, show only subtle changes in grain size. Heavy mineral analyses and palaeocurrent indicators suggest that axially oriented (west-east) turbidite systems predominantly controlled deposition (Figure 4-9). Mud clasts are dispersed throughout the massive sands, as well as locally being concentrated within individual debris flow beds. The sandstones are dominantly quartzose, with subsidiary quantities of plagioclase and alkali feldspars, glauconite, lithic fragments, clay and bioclasts. There is little cementation, and the bulk of authigenic minerals are composed of chloritic and kaolinite clays. Thin mudstone layers that are visible on wireline log and in core material, cannot be reliably correlated in adjacent wells. Occasional dish-and-pillar structures and the featureless nature of the sandstones suggest post-depositional de-watering processes. This has probably destroyed depositional fabrics, and any shaley layers are therefore likely to be disrupted. Average net-to-gross from this interval is 94%, average net porosity is 25% and average (total) permeability is 790 mD.

The uppermost division of the reservoir is the **E unit**. The base of this unit is typically marked by a thin shale bed, with no evidence of erosion or disconformity. This is cored in wells 14/29a-5 and 20/4b-7. Sandstones within this unit can appear 'dirty' due to 2% to 3% detrital clay fractions and also show evidence of dewatering. In some wells it may consist of sandstone dykes, presumably injected from the D layer below, as observed in 14/28b-2 core, west of Goldeneye. The sands in the unit have been interpreted to have been deposited from high-density turbidity currents with minor contributions from mud clast-rich debris flows. Dewatering/sandstone remobilisation occurred subsequent to deposition, as caprock and overburden sediments accumulated. Net-to-gross, on average, is 61%, average net porosity is 21% and average permeability (from the total interval) 7 mD.

4.4. Reservoir fluids

Goldeneye is a gas condensate field with a thin oil rim (which has not been produced). Pressure, volume and temperature (PVT) characteristics of the field have been described in a previous report (3). Formation multi-tester and modular formation dynamics tester (MDT) sampling shows a water gradient of 0.4408 psi/ft [9.9712 KPa/m] and that the oil-water-contact (OWC) in the field is at hydrostatic pressure. An oil rim thickness of 24-25 ft (7.3-7.6 m) is found in the Captain C Unit of the northerly Wells 14/29a-3 and 14/29a-5. The oil rim thickness is found to be 21 ft [6.4 m] in the Captain D Unit of the southerly Wells 20/4b-6 and 20/4b-7. This implies a discontinuity between the oil rims seen in the 14/29a wells and the 20/4b wells, though it is not clear if this is a vertical (between zones) or lateral discontinuity.

The Goldeneye in-situ gas gradient is 0.097 psi/ft [2.1942 KPa/m] (Figure 4-6). The oil gradients cannot be determined accurately due to the small vertical extent of the oil column. The calculated gradients vary from 0.295 psi/ft, to 0.35 psi/ft. The oil gradients cannot be determined accurately due to the small vertical extent of the oil column. The calculated gradients vary from 0.295 psi/ft, to 0.35 psi/ft. In general a reasonable agreement is found between the different methods to pick the gas/oil and oil/water fluid interfaces, with a maximum difference of 2 ft [0.6 m] between the free water level (FWL) and the OWC in a given well.

4.5. Reservoir Uncertainty

Although the Goldeneye field had been successfully managed for nearly six years, it is recognised that some uncertainties about its characteristics remain. In particular, the focus had been on predicting and managing hydrocarbon production performance. It is anticipated that some of the uncertainties thought to be unimportant for this purpose may become more significant for predicting CO_2 injection performance. For the CO_2 projects the uncertainties that have been identified as important to investigate are (Figure 4-10):

- Location of northerly stratigraphic pinch-out (which has an impact of between -13% and +6% on Gross Rock Volume (GRV))
- Top structure uncertainties particularly as expressed in the West by the use of the supra-Beauly wedge to vary spill point and local structural dip (which has a small impact of +/-0.5% on GRV)
- The presence or absence of sealing faults (which impacts fluid connectivity)
- Distribution of reservoir units (which has an impact of between -3.5% and +5.5% on In-place volume and also, potentially, has an impact on the dynamic behaviour of the reservoir).

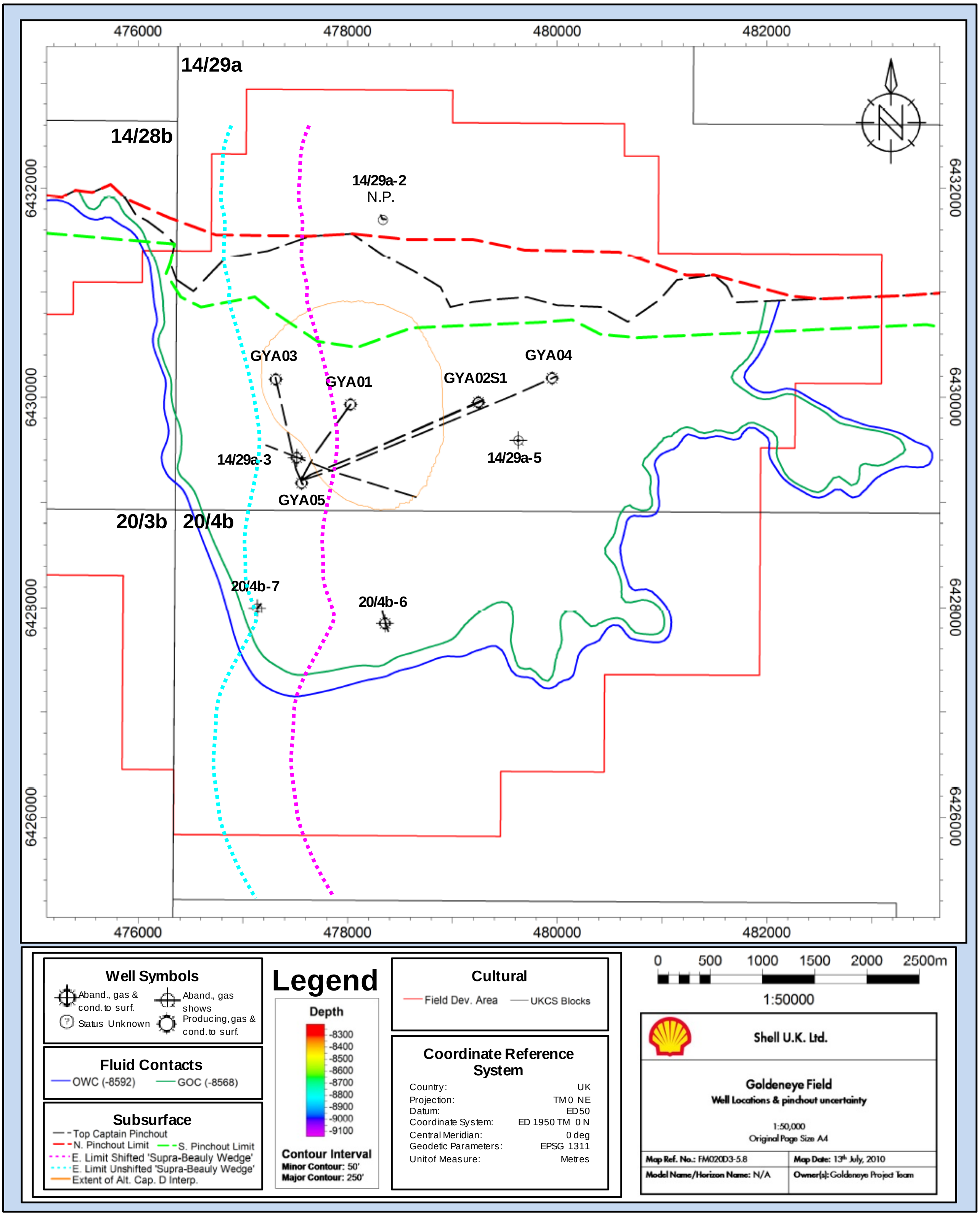


Figure 4-10: **Well locations and uncertainties.**

4.6. Impact of Production

The significant reduction in pore pressure caused by the production of gas condensate from Goldeneye could impact upon the actual in-situ volumes available for subsequent CO_2 storage. This was investigated during the companion geomechanical study (4). Compaction experiments, aimed at determining the compressibility of the reservoir rock, showed that the compaction of the Captain Sandstone is partly elastic (i.e. reversible) and partly plastic (i.e. irreversible). When loaded from 17 to 34 MPa [2500 psia to 5000 psia], the material showed minimal compaction and the porosity change was about 0.3%. As a result this effect can be considered to have negligible impact on the difference in available pore volume between the gas depletion and CO_2 injection phases.

The potential for tensile and shear failure of the Captain Sandstone was also assessed in the geomechanical study, using core data and the 3rd party modelling package GeoMec. The analysis demonstrated changes in minimum principal stress during gas condensate production, with similar changes during the injection phase but smaller in magnitude and in the opposite direction. In contrast, negligible changes are seen for the maximum horizontal stress. These changes were not beyond the strength of the reservoir rock: they did not give rise to predictions of either shear or tensile failure of the reservoir during the two phases of the reservoir development, and none has been observed for the production phase.

It was concluded that the reservoir rock strength and the relatively limited pressure decrease owing to the strong regional aquifer act to produce only relatively small production-related effects. Accordingly, no special modifications were required for the input static models.

5. Static model realisations summary

A suite of SRMs has been generated to evaluate key uncertainties impacting on CO_2 storage capacity and containment. The differences in the models have been generated by using/ignoring faults; differing seismic depth surfaces to represent the top and base of the reservoir; using seismic depth surfaces, isochores or well tops to define internal reservoir layering; varying the location of the northerly stratigraphic pinch-out; altering the zonation of the pre-reservoir stratigraphy and; adding (or ignoring) a top Captain C pick to well GYA01 (Table 5-1). In each case, the data and methodology used to construct the facies and petrophysical property models remained the same – with the exception that the vertical probability curve that controls facies distribution in each zone had to be modified to accommodate changes in zone layering.

Table 5-1: Geological realisations summary for each SRM (p/o = pinch-out).

Name		Asset equivalent, deep flank	FFSM match, deep flank	Shallow flank, simple pinch-out	New zones	New zones with tops only	Overburden Base Captain	Overburden surfaces, deep flank
		SRM1	**SRM2.0**	**SRM2.1**	**SRM2.2**	**SRM2.25**	**SRM3.0**	**SRM3.1**
Grid	AOI	~ 85 km²	~ 85 km²	~ 85 km²	~ 85 km²	~ 85 km²	~ 85 km²	~ 85 km²
	Faulting	Seismic major only	Seismic major only	Seismic major only	Seismic major only	Seismic major only	None	None
Structural Input	Depth conversion	7-layer	7-layer	7-layer	7-layer	7-layer	7-layer	7-layer
	Top surface	asset	asset	Alternate wedge	Alternate wedge	Alternate wedge	Alternate wedge	No wedge translation

Name		Asset equivalent, deep flank SRM1	FFSM match, deep flank SRM2.0	Shallow flank, simple pinch-out SRM2.1	New zones SRM2.2	New zones with tops only SRM2.25	Overburden Base Captain SRM3.0	Overburden surfaces, deep flank SRM3.1
	Base surface	asset	asset	asset	asset	asset	Overburden	Overburden no wedge translation
Stratigraphy	Internal zonation	Seismically-mapped	Seismically-mapped	Seismically-mapped	Isochore + tops	Tops	Isochore + tops	Isochore + tops
Pinch-out		Surface intersection + boundary property	Surface intersection + FFSM boundary Southerly p/o polygon	Simple line + boundary property	Simple line + boundary property	Simple line + boundary property	Simple line + boundary property	Remodelled surfaces
Underburden		Scapa	Scapa	Scapa	Scapa, layering on base	Scapa, layering on base	Separate L Valhall & Scapa	Separate L Valhall & Scapa
Top C Pick	GY01	No (thicker Capt. D)	Yes (thinner Capt. D)	No (thicker Capt. D)	No	No	No	No
	GY02	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	GY03	No	No	No	No	No	No	No

The key static modelling uncertainties for the CO_2 injection into the Goldeneye field are related to the capacity of the field (volumes that can be injected) and containment. The SRMs have been constructed to address these issues, in particular:

- Different volume scenarios;
- Unstable displacement effects (requiring finer/alternative layering);
- Increased sensitivity to heterogeneities due to fluid contrast (CO_2 vs. water);
- Focus on structural dip and spill location relative to injection wells for injection strategy planning;
- Underburden & overburden focus to investigate possible CO_2 migration pathways (mainly remodelling SRM1 'Scapa' interval);
- Alternative Captain D interpretation.

5.1. SRM1

This is a regeneration of the asset SRM (using the same seismic depth surfaces, zonation scheme, layering, facies model and petrophysical model) but extended to include a larger aquifer. The same polygon method is used to generate a pinch-out of the reservoir and for volumetric calculations. Extending the area of interest (AOI) and regridding the seismic depth input surfaces gives rise to minor differences in the gridded structural surfaces compared to the original asset SRM. SRM1 represents the asset's best geological case and, therefore, serves as the reference case. However, it failed to provide a reasonable history match for the field, which led to the asset applying some modifications to their dynamic representation of the static model. An attempt has been made to institute these dynamic modifications in the static realm in SRM2.

5.2. SRM2

As discussed above, to construct this static model, adjustments that were made in the asset FFSM to obtain a dynamic history match were reviewed. To match these, the Captain D zone has been made thinner in the western half of the field by introducing a top Captain C pick to the GYA01 well. This was considered feasible because of uncertainties in the biostratigraphic interpretation of a shale penetrated close to the bottom of this well. In addition, the northern stratigraphic pinch-out has been moved further to the south, along a line defined with reference to minor faults/discontinuities mapped at base Captain level.

5.3. SRM2.1

SRM2.1 uses the top Captain surface derived from the 'alternate supra-Beauly wedge interpretation' depth conversion. This depth conversion sees the 'supra-Beauly wedge' migrated 750m to the west. This has the effect of reducing the structural dip on the western side of the field. The reason for including such a realisation is to create a model that is likely to make CO_2 migration down-dip possibly easier. To ensure structural closure, the new seismic depth surface requires a consistent boundary (pinch-out) polygon. Opening the structure in this way also increases the volume within the structural closure.

5.4. SRM2.2 & SRM2.25

SRM2.2. As in SRM2.1, this SRM uses the 'alternate supra-Beauly wedge interpretation' depth conversion to generate the top Captain seismic depth surface that defines the top of the reservoir. Unlike SRM2.1, well tops and average isochores are employed to model internal Captain stratigraphy instead of the seismic derived top Captain C and top Captain A surfaces used in models SRM1, 2 & 2.1. A different layering scheme is also used in the under-burden to better represent the lower Valhall and Scapa intervals. In these zones (which are amalgamated, as in previous models), layers follow the base structure and, for the facies model, a vertical probability curve is used to ensure that the shallowest layers are shale-prone (equivalent to the lower Valhall Formation).

SRM2.25. This SRM is the same as SRM2.2, with the exception of using only well tops for internal zonation (i.e. the minimum possible input) instead of a combination of tops and isochores.

5.5. SRM3.0

The top Captain surface in SRM3.0 is the same as that used in SRM2.1, 2.2 & 2.25. However, the base Captain seismic depth surface is derived from the Goldeneye overburden model (5), as is the top Triassic seismic depth surface, which is used to model base Scapa. The model uses no faults. It produces cross-sectional geometries that strongly suggest channel erosional processes were the cause of the thick Captain reservoir in the centre of the Goldeneye field (although the nature of the Captain C fill points to significant mass wasting processes, so a slump scar is a viable alternative explanation). Captain internal zonation has, again, been created by the use of isochore and well tops. The lower Valhall Formation was modelled as a separate zone to the Scapa Formation. The intention of this change was to produce a continuous, shale-prone layer that is interposed between Captain Sandstone and Scapa Sandstone, representing the belief that there is no pressure or fluid communication between these two units. In this model, the division was achieved by splitting the pre-Captain/post-base Cretaceous zone proportionally along a surface defined by well picks.

5.6. SRM3.1

This is a variation on SRM3.0, where both the top and base Captain seismic depth input surfaces were taken from the Goldeneye overburden model. They were generated using the un-shifted 'supra-Beauly wedge' depth conversion previously used for SRM2.0, so with a deeper west flank than in SRM2.1-3.0. As in SRM3.0, the underburden was divided into lower Valhall Formations and Scapa Formations. In the SRM3.1 SRM, a slightly different method was used to generate top Scapa where it was made conformable to the base surface (again, along a surface defined by well tops).

5.7. Sensitivities for dynamic modelling

During dynamic modelling the SRM3.1 model was seen to provide the closest history matches to reality and was used as the reference case. Two additional sensitivities were created around it to vary three critical parameters: structural dip on the west flank of the field, the northern pinch-out of the Captain Sandstone, and its internal thickness.

SRM3.05 uses the same top Captain surface as the SRM2.1-3.0 series to reproduce a case with a shallow western flank to see if it would allow injected CO_2 egress.

SRM3.15 carries the same top Captain surface as SRM3.1 but uses the southerly pinch-out line to represent a more restricted extent of the Captain Sandstone in the north of the field. This reduces the storage capacity in the north-west of the field and again allows for testing against injected CO_2 egress.

	SRM	SRM	SRM
Structure	Steeper Flank	Shallower Flank	Steeper Flank
Pinch out	Medial	Medial	Southerly
Thickness	Log based	Log based	Log based

Figure 5-1: Final static models for dynamic uncertainty analysis

6. Model build

The model was built using Petrel 2007 and 2009 software. At the time of preparing this report, the model had been updated to Petrel 2012 for future work but no changes were made to the model build.

6.1. Model AOI (area of interest)

The existing asset static model AOI was defined roughly by the OOWC, since it only models in-place hydrocarbon and its movement to development wells. For the current study, the AOI had to be enlarged relative to the asset model for effective CO_2 simulation. This is because formation water becomes denser with dissolved CO_2 causing it to migrate down through the aquifer, and because free

CO_2 has a large density contrast with the formation water and will tend to over-ride it in thin plumes. Both effects have the potential to push CO_2 beyond the geographic limits of the field's closure. The model dimensions are approximately 12.4 x 6.8 km across x 2600 ft [~800 m] thick. All distance units are metric, depths in feet, as conventional hydrocarbon field units.

6.2. Grid and faults

The CCS Goldeneye field SRMs are all gridded at approximately 50 x 50 m. The model framework grid itself comprises irregular cells, and all models share the same grid. Models have 253 x 147 x *c*.250 (number of layers varies), giving around 9.5 million cells.

Many small seismic discontinuities can be mapped within the Goldeneye reservoir, but production and regional aquifer data indicate no compartmentalisation. Further, the clean nature of the upper reservoir (Captain D/E) suggests faults are unlikely to be sealing. No compartmentalised dynamic realisations could match the observed field performance, including timing of water breakthrough, during dynamic simulation. Intra-reservoir faults were, therefore, omitted from the existing asset models. Four major faults were retained in the asset model because these partly control the base Captain surface, but in models 3.0 and 3.1, derived from the overburden model, faults are available in the model dataset but are not used during gridding as it is assumed that the base Captain surface originates from a slump failure or channel erosion. It should be noted, however, that the resulting overall basal reservoir geometry is very similar, despite the different possible genetic interpretations.

6.3. Input surfaces

The input surfaces are all derived from the existing asset seismic interpretation and time-depth conversions (a detailed explanation of this methodology is explained in the seismic interpretation report) (1). In summary, time and depth interpreted input surfaces were available from the existing asset model as follows:

- Top Captain
- Top Captain C
- Top Captain A
- Base Cretaceous

The top Captain was derived as in **Section 4.2 Structure**.

Top Captain C, A and base Cretaceous depth surfaces were generated using time isochrons and an average interval velocity of 11,000 ft/s for the Captain section. The resultant isochores were used to generate the other input surfaces as follows:

1. Base Captain depth = top Captain depth+ base Captain to top Captain isochore
2. Top Unit C depth = top Captain depth + top Captain to top Unit C isochore
3. Top Unit A depth = base Captain - top Unit A to base Captain isochore
4. Base Cretaceous depth = top Captain + base Cretaceous to top Captain isochore

Residuals were corrected for at each surface prior to addition/subtraction by using unlimited convergent gridding of the residuals for Top Captain and by applying a radius of influence convergent gridding of 2 km for all the others. The Top Unit A depth horizon required some editing to ensure that it honoured the Base Captain Depth horizon. Top Unit D was generated from well data during the model building process (isochore down from Top Captain with well controlled Unit E).

SRM1 used the asset SRM methodology and inputs, comprising all four seismically-derived input surfaces, tied to well tops. The underburden was defined using the existing base Cretaceous seismic depth surface, and no internal sub-division was applied. The only difference in SRM1 from the asset static model is that it has a larger area, in order to better model downward migrating free and dissolved CO_2.

The precise geometry in depth of the field's western flank, and hence spill point, can be varied using different overburden velocity models. For the CCS project, it was necessary to investigate the sensitivity of CO_2 migration to dip on the western flank. An alternative interpretation of the '*supra-Beauly wedge'* was made which pinched out 750 m further to the west, which resulted in a slightly different velocity model. This impacted on the corresponding top structure definition and produced a less steeply dipping western flank. Note that each scenario requires a corresponding erosional limit in order to close the structure at the exact OOWC depth. This modified top seismic depth surface was used in SRMs SRM2.1-SRM3.0.

For SRM2.2 and SRM2.25, a slightly modified base Captain event has been generated. This seismic depth surface incorporates some additional interpretation to further refine the definition of the reservoir pinch-out to the north of the field. The position of the stratigraphic pinch-out has been varied in this way to test if its precise geometry can influence the migration and concentration of CO_2 during injection. The modified base Captain seismic depth surface was used in SRM2-2.25.

To create a slightly different structural realisation, top and base Captain surfaces were generated during the building of the overburden model (5). These were used as inputs for the base Captain and some of the under-burden modelling for SRM3.0. For SRM3.1 the overburden model surfaces were re-generated using an un-shifted '*supra-Beauly wedge'* – back to a deeper west flank than in SRM2.1-3.0 models but with a shallower crest in the GYA03 area.

6.4. Model zonation

All models sub-divide the Captain reservoir into Captain A, C, D & E. The underburden units are not differentiated (by zonation) in the models using the asset seismic input surfaces (SRM1-SRM2.25) but for SRM3.0 & 3.1 the 'Scapa' Unit of the earlier static models has been differentiated into lower Valhall Formation (shale-prone) and Scapa Formation (sand-prone). All SRMs in this report use seismically interpreted surfaces for top and base Captain Sandstone Unit, and base Cretaceous (and top Triassic in SRM3.0 & 3.1). Seismic input is also used for top Captain C Unit and top Captain A Unit, in SRM1, 2 & 2.1 (top Captain D Unit is constructed using just well pick information – conforming the resulting surface to the top Captain depth surface, as per the asset static model).

In SRM 2.0, an alternative well tie in GYA01 is used, where the top Captain C is picked, effectively transferring GRV from the (high quality) Captain D to the (low quality) Captain C. This interpretation had been implemented in the dynamic model previously, in order to improve the history match of water breakthrough in GYA01.

In SRM2.2, 3.0 & 3.1, internal zonation is generated through the use of isochore surfaces, tied to well picks. In model SRM2.25, well picks alone are used to define the reservoir zones (the surfaces are conformable to top and base of the overall reservoir package – i.e. they split the unit proportionally).

6.5. Layering by zone

Each reservoir zone is further sub-divided into layers in order to model effectively the geological heterogeneity. The Captain C Subunit, which is interpreted to comprise chaotic mass-flows or slumped sediment and the Captain E subunit, which consists of interbedded thin sandstones and mudstones, require a fine-scale layering scheme to represent them in the static model. However, the massive sandstone beds of the Captain A and Captain D subunits need only a coarse layering scheme.

The layering within the SRM zones is 'upscaled' when the modelled is imported into the dynamic modelling realm, to reduce the number of grid cells that are simulated – thus optimising simulation cycle time. The SRM1 (inherited from the asset SRM and FFSM) layering scheme is shown in Table 6-1.

To model CO_2 flow, it is also appropriate to concentrate on higher resolution towards the tops of flow units, where buoyant CO_2 will be ponded and will be most likely to migrate laterally. CO_2 tends to form thin expanding plumes below permeability barriers and spread out laterally. It is important to have sufficient resolution to allow accurate plume modelling, and to have coherent cell layers to allow stable cell-cell calculations. This means that for the important reservoir layers Captain A, C & D, layering is always made top conformable or proportional to avoid cells collapsing laterally. The 'Scapa' zone is always modelled with layers that are bottom conformable, reflecting the fact that its upper bounding surface is an erosive unconformity. Non-reservoir zones, such as Rødby and (in SRM3.0 & 3.1) lower Valhall formations are not differentiated (i.e. they have one layer).

Table 6-1: Horizons, zonation and layering in SRM1 static model (Petrel) and associated dynamic models (MoReS). Thicknesses in ft, layering strategy in thickness column.

SRM1	Petrel					MoReS	
	Zones		layers			zones	
Horizon	no	name	index	thickness	number	index	number
top Captain	1	Captain E	1-16	3 base	16	1-2	2
top subunit D	2	Captain D	17-39	15 top	23	4-7	4
top C	3	Captain C	40-168	3 top	129	8-15	8
top A	4	Captain A	169-198	15 top	30	15-18	4
base Captain base Cretaceous	5	"Scapa"	199-301	15 base	103	19-24	6
total					301		22

In SRM1, 2 & 2.1, Captain E is divided into 16 layers, 3 ft [0.9 m] in thickness, and inserted into the zone from the base upwards (i.e. they are bottom conformable). In SRM 2.2 & 2.25, 16 layers are inserted proportionally and in SRM3.0 & 3.1, this number is reduced to 15 layers. The other reservoir zones (Captain D, C and A) are layered using the same rules as seen in SRM1 (Table 6-1): all inserted conformable to the zonal top surface; Captain D and A layers are 15 ft [4.6 m] in thickness; Captain C layers are 3 ft [0.9 m] in thickness. In all models, the 'Scapa' layers are inserted from the bottom of the zone and are 15 ft [4.6 m] thick.

6.6. Facies modelling

The following wells have been used to control the facies and property modelling:

Table 6-2: Wells employed for the models

Exploration and Appraisal Wells	Development Wells
• **14/29a-2**	• GYA01
• **14/29a-3**	• GYA02
• **14/29a-5**	• GYA03
• **20/4b-6**	• GYA04
• **20/4b-7**	• GYA05

Well data from GYA02 sidetrack (GYA02S1) was not used in the property modelling, due to poor data quality across the reservoir section, caused by interference from the original hole.

The asset SRM has eight facies, and these have been retained for all models described in this report:

Table 6-3: Facies used in the asset and CCS models

Facies Number	Facies Name
0	Extensive Shale (background into which everything is modelled)
1	Amalgamated Sandstones (present in units A-E) – treated as net sand
2	Cemented Bodies (present in units A-D)
3	Discontinuous Chaotic Shales (present only in unit C)
4	Discontinuous Laminated Shales (present only in unit C)
5	Sandy Slurry (debris flow, non-net, present only in unit C)
6	Shaley Debris Flow (mass flow, non-net, present only in unit C)
7	Sheet Sands (thin overbank sands, present only in unit C) – treated as net sand

Facies curves were generated for each well using the expressions below which address the three main facies, with 0 representing extensive shale, 1 representing amalgamated sand and 2 representing cemented bodies.

- 14/29a-2 Facies 8 FACIES =If(GAMM>80,0,If(SONI<70,2,1))
- 14/29a-3 Facies 8 FACIES =If(GAMM>55,0,If(SONI<70,2,1))
- 14/29a-5 Facies 8 FACIES =If(GAMM>43.5,0,If(SONI<70,2,1))
- 20/4b-6 Facies 8 FACIES =If(GAMM>68,0,If(SONI<70,2,1))
- 20/4b-7 Facies 8 FACIES =If(GAMM>32.75,0,If(SONI<70,2,1))
- For the production wells (GYA01 – GYA05) Facies 8 FACIES =If(GAMM>60,0,1)

Each facies curve generated was then considered in turn and hand-edited over the reservoir section using extensive core data, core descriptions and other well logs to incorporate the more complex facies (Figure 6-1). Facies logs are "upscaled" into the model layers (i.e. one value per layer or cell, (Figure 6-2). This gives the dominant facies type in each cell the well bore passes through to provide a seed for the modelling of the inter-well areas. The distribution of facies types throughout the model is therefore controlled by the well data. For the Captain D and E, there are nine well penetrations including the development wells, all with similar log character, so the resulting facies models are all relatively well controlled, homogeneous intervals of amalgamated sandstones.

Figure 6-1: Facies identification in the Goldeneye Reservoir

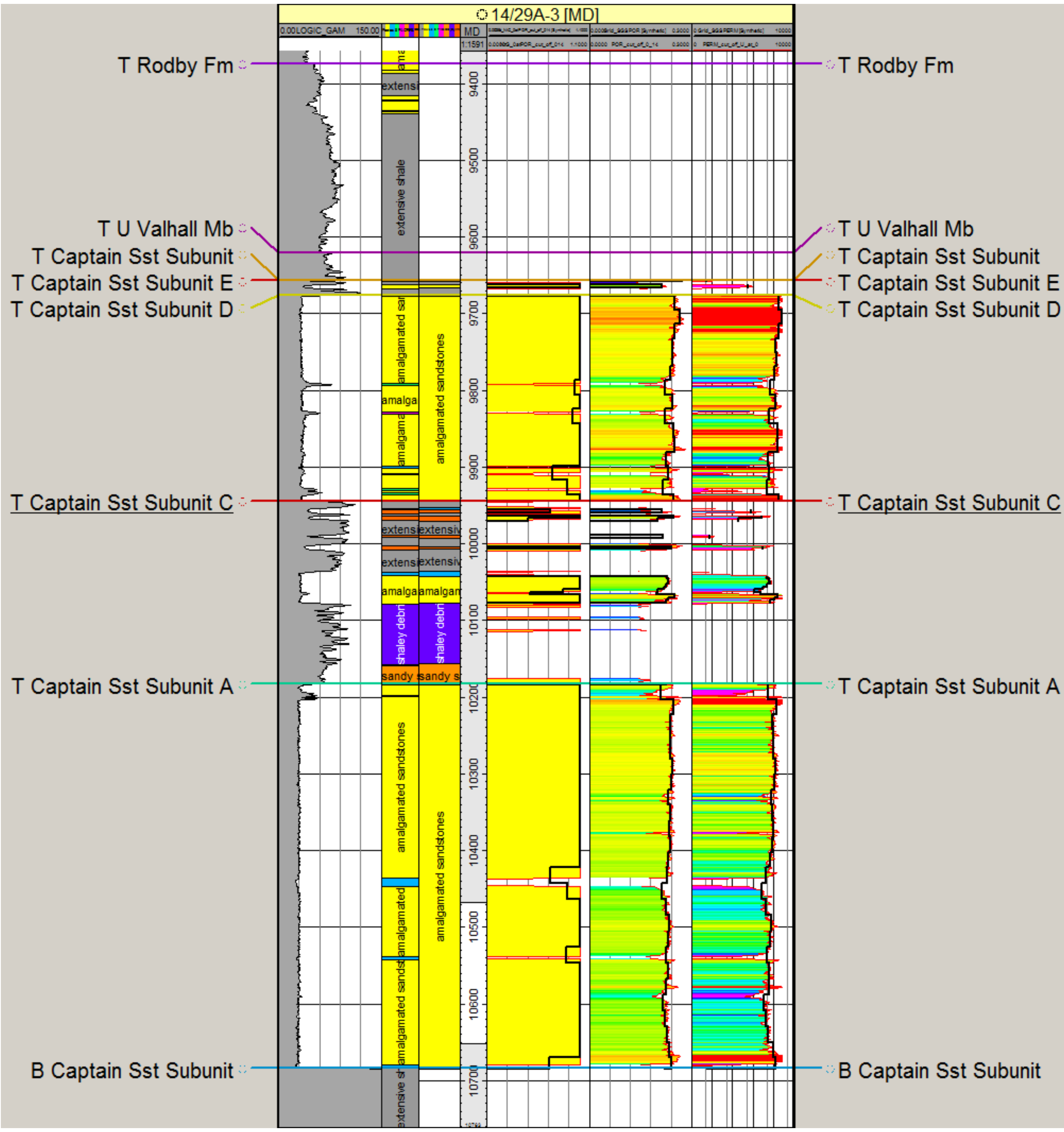


Figure 6-2: Log panel from well 14/29a-3 to show comparison between wireline logs (thin red lines with colour fill) and upscaled properties (thick black lines).

Note: Log Tracks (from left to right): gamma ray (black line with grey fill); facies (input); facies (upscaled); measured depth; net to gross (input and upscaled); porosity (set to undefined where net to gross = 0, input and upscaled); permeability (set to undefined where net to gross = 0, input and upscaled).

The facies modelling is also controlled by vertical distribution curves of facies proportions derived from well logs (Figure 6-3). This means that facies proportions within the layers of the model are also derived from log data. This, in turn, means that the layering scheme has a significant control on facies distribution, since a top-conformable layering will result in different parts of the zone being correlated than a base-conformable scheme. Since the depositional model is one of infill of negative relief (by faulting, slumping or channel erosion), layering schemes within the Captain were defined top conformable.

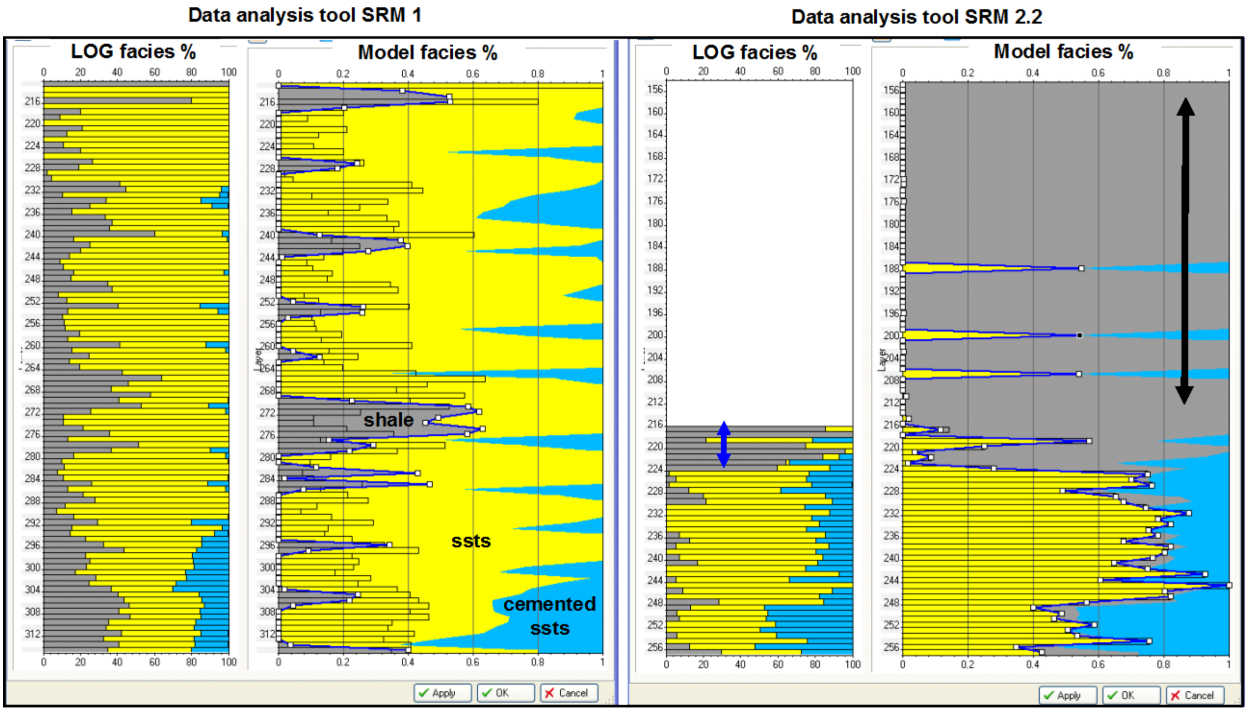


Figure 6-3: View of the Petrel Data Analysis Tool for the section beneath Captain reservoir (underburden).

Each panel shows log-derived distribution on left versus model input distribution on right, for SRM 1 and SRM 2.2. In SRM 2.2 the sampled Valhall section is arrowed blue, the unsampled layers in the model arrowed black, are manually assigned mainly shale.

As stated in section § 5, the facies modelling parameters – the objects used, their dimensions and orientation and the proportions of each facies within each zone – are kept the same for all SRMs in this suite (Table 6-4). This produces a relatively 'tank-like', homogenous distribution of amalgamated sandstone facies in **Captain A & D subunits**, with a minor volumes of cemented bodies (1% to 3%) and a background of extensive shale (20% in Captain A, <0.5% in Captain D). This homogenous distribution is in accordance with evidence from well performance (which shows that all production wells – all completed within the Captain D Subunit – interfered with each other during clean up) and with fine-scale geological models (using Geomodelling Technology's SBED™ software) that suggest any shale drapes that do exist are of limited extent. This gives confidence that the reservoir continuity of the Captain D sand is good in both lateral and vertical directions.

Table 6-4: Facies modelling parameters for Captain E & D

Amalgamated Sandstone Facies	%/N	Orientation	Amplitude	Wavelength	Channel width	Thickness
Captain E						
W-E fluvial channels	36%	Triangular: 270,290,300	Deterministic: 300	Deterministic: 2000	Triangular: 100,300,500	Triangular: 10,30,50
N-S fluvial channels	18%	Triangular: -10,0,10	Deterministic: 160	Deterministic: 800	Triangular: 150,200,300	Deterministic: 20
Captain D						
W-E fluvial channels	66%	Triangular: 270,290,300	Deterministic: 300	Deterministic: 2000	Triangular: 100,300,500	Triangular: 10,30,50
N-S fluvial channels	33%	Triangular: -10,0,10	Deterministic: 160	Deterministic: 800	Triangular: 100,200,300	Deterministic: 20
Cemented Bodies Facies				**Major/Minor**	**Minor width**	
Captain D						
Cemented sst ellipses	1%	Triangular: 300,320,340		Triangular: 0.8,1,1.2	Triangular: 200,400,600	Triangular: 10,15,20

In contrast, the **Captain C** is very heterogeneous, with significant sections comprising non-net reservoir shales and mass flow deposits. In this case all seven facies types are modelled. The Captain C is shaley towards the top, so using a top-conformable layering scheme and a suitable vertical facies distribution curve, these shaley intervals are correlated across the field producing a possible barrier to fluid migration. A trend grid is also used to control the areal distribution of shaley debris flow facies in unit C to ensure that more of the debris flow facies is found in the north than south, consistent with a Halibut Horst source. The **Captain E** facies model comprises two sets of narrow amalgamated sandstone channel bodies (one oriented approximately north-south and the other east-west) in a background of extensive shale (45%).

For the section below the Captain, the existing asset static model has a single 'Scapa' unit, which also includes Lower Valhall Formation shales. In this model (and hence also SRM1) the vertical facies distribution is the result of a proportional layering scheme (though the actual model layering is bottom conformable) and approximates an average proportion throughout the section. In contrast, SRM 2.1 & 2.2 use a conform-base derived vertical distribution (Figure 6-3). The Lower Valhall Formation occurs above the Scapa in wells 20/4b-6 & 7 and is a distinct, shale-prone section. Data from regional exploration wells suggests that it is a widely distributed mudstone unit and so we have endeavoured to produce a shaley interval at the top of the 'Scapa' in SRM 2.0-2.25 (Figure 6-4). In SRM3.0 and SRM3.1 a similar effect is achieved by explicitly modelling separate Scapa and Valhall Formations.

All facies modelling is performed using stochastic object modelling. The object dimensions and geometries for each zone were defined by the asset using core data, the conceptual model for the deposition of the reservoir and discussion with Shell's turbidite research team. The orientations reflect the regional understanding of predominant eastwards flow along the South Halibut basin with subordinate flow from the Halibut Horst to the north.

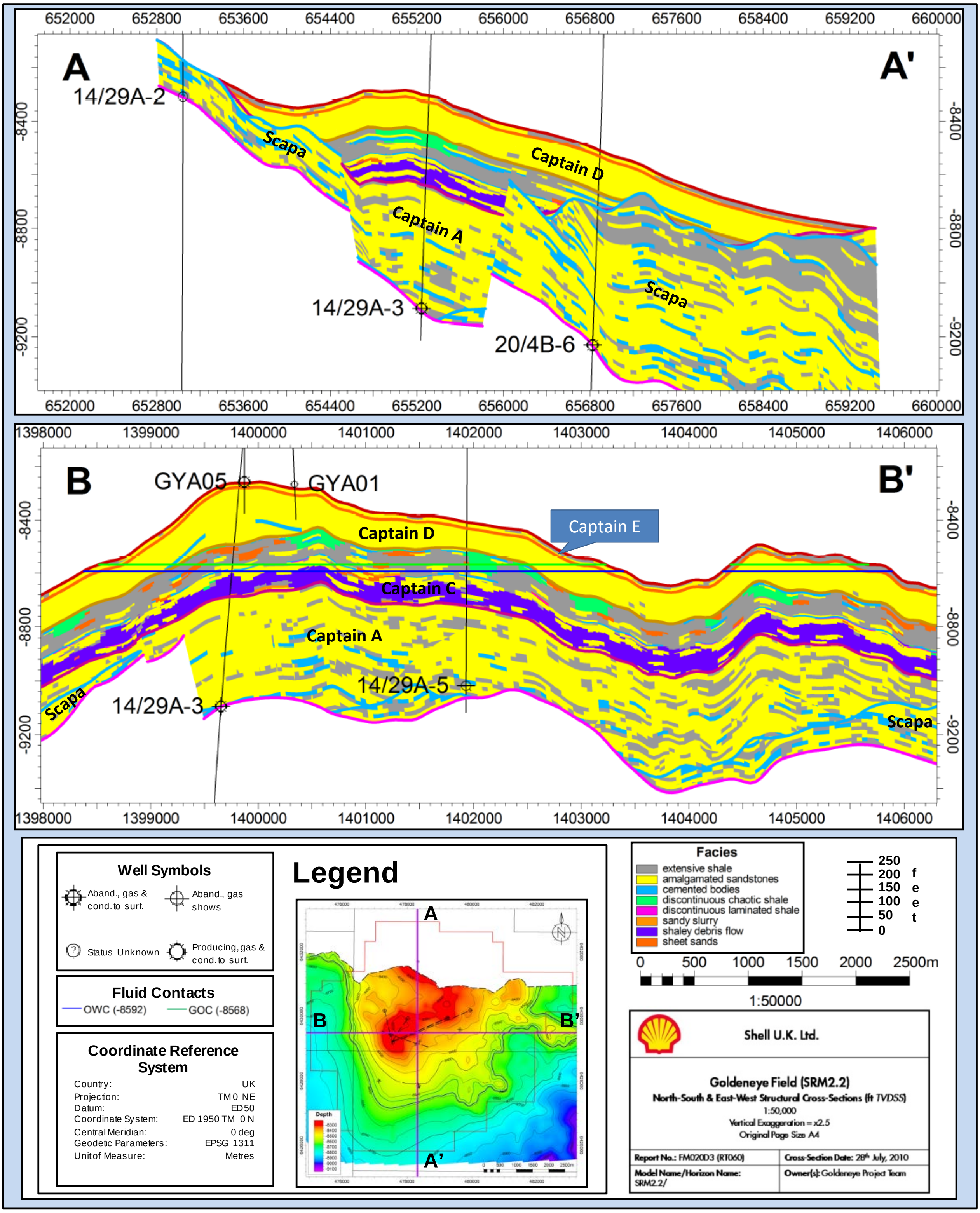


Figure 6-4: **Well section showing facies. Note coherent shaley & slumped intervals in Captain C and above Scapa Sst (Valhall equivalent).**

6.7. Property modelling

Property modelling follows a similar methodology to the facies modelling. Input log data derived from petrophysical evaluations are upscaled into the model layers by arithmetic averaging, and then a Sequential Gaussian Simulation (SGS) algorithm was used to populate the model.

6.7.1. Petrophysical input data

Net to gross, porosity and permeability were all modelled using petrophysical evaluation logs as input. Comprehensive data is available for the exploration and appraisal wells whereas, in the development wells, standard GR and resistivity are the only formation evaluation data available. Data availability is summarized in Table 6-5. Each of these wells is individually evaluated, using a similar methodology: the procedures are given in the accompanying Petrophysical Modelling Report.

Table 6-5: Petrophysical data available, Goldeneye area wells.

Well	Year	Contractor	Wireline/LWD	Routine Core	SCAL	MDT	Image data	Drilling fluid
14/29a-2	1980	Schlumberger	Y	N (MCT)	N	N	N	WBM
14/29a-3	1996	Atlas Wireline	Y	Y	Y	Y	Y	OBM
14/29a-5	1999	Schlumberger	Y	Y	Limited	Y	Y	OBM
20/4b-6	1998	Schlumberger	Y	Y	Y	Y	Y	WBM
20/4b-7	2000	Schlumberger	Y	Y	N	Y	Y	OBM
GYA01	2004	Schlumberger	Y	N	N	N	N	OBM
GYA02	2004	Schlumberger	Y	N	N	N	N	OBM
GYA03	2004	Schlumberger	Y	N	N	N	N	OBM
GYA04	2004	Schlumberger	Y	N	N	N	N	OBM
GYA05	2004	Schlumberger	Y	N	N	N	N	OBM

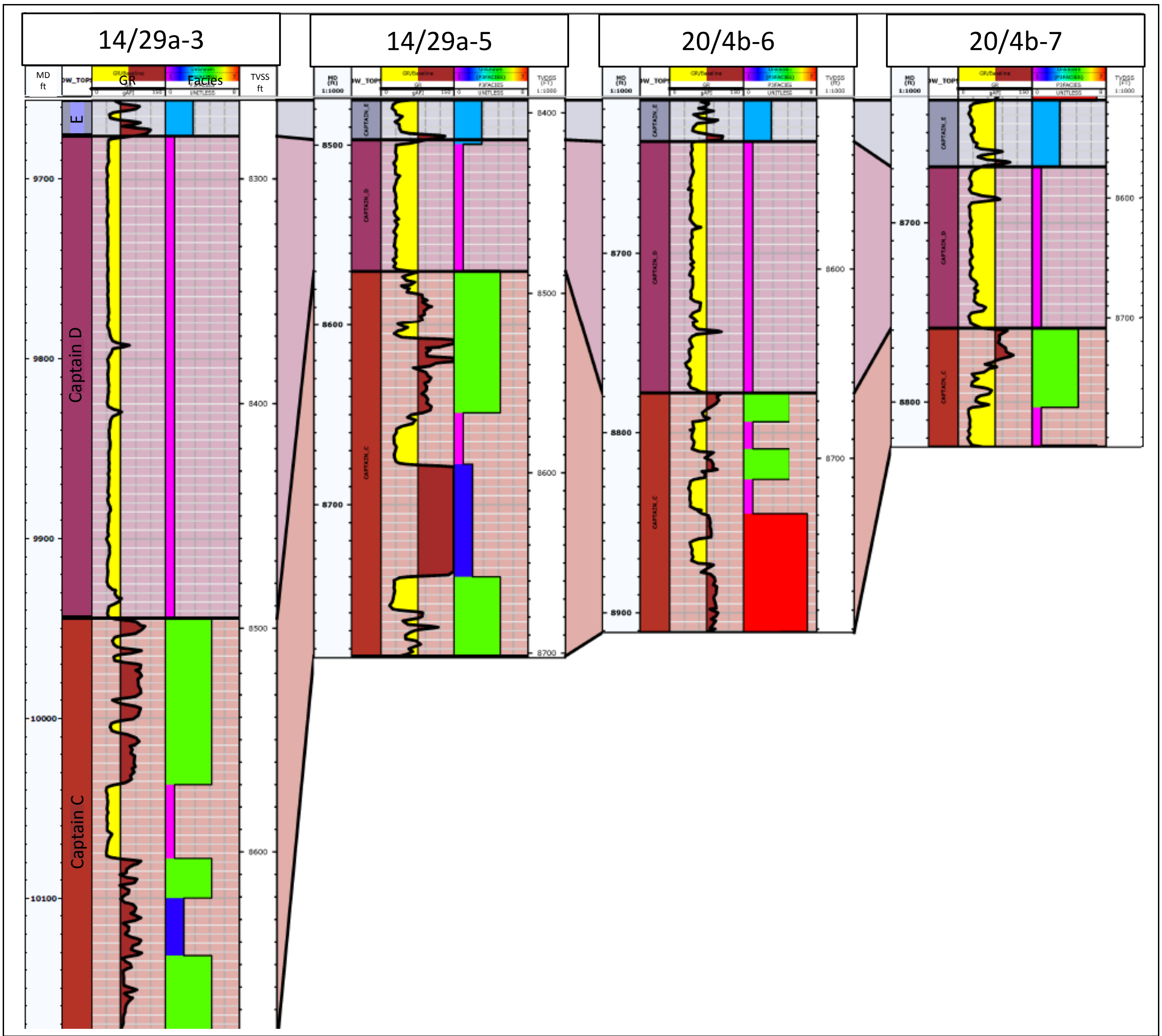
Note: special core analysis (SCAL), water based mud (WBM), oil based mud (OBM)

Net cut-offs use GR-derived Shale Volume less than 0.5 and porosity more than 0.14 to ensure that clay rich intervals and tight sandstone are excluded. Total Porosity is used in Goldeneye.

Core permeability data in the Goldeneye field shows a strong relationship to facies which were built based on geological understanding. For the Static Field Model input, these were simplified into three classes each allowing the derivation of permeability from porosity using a different regression. The classes were assigned by hand to the Goldeneye exploration wells:

- Class 1. Clean sandstones, predominantly represented in the Captain A and Captain D subunits in their entirety. A prominent medial sand in the Captain C interval is also assigned to this class.
- Class 2. Bioturbated sands and shaley sands of the Captain E.
- Class 3. Shales and interbedded sand-shale intervals, representing most of the Captain C.

The distribution of these classes is shown in Figure 6-5.



Class 1: Purple. Class 2: light blue. Class 3: green. Shale: dark blue. Other non-net: red.

Figure 6-5: Permeability classes in the Goldeneye Exploration wells

The well-derived property averages per Captain unit are given in Table 6-6.

Table 6-6: Average reservoir properties per unit (from asset evaluations of wells 14/29a-3, 14/29a-5 & 20/4b-6)

Reservoir Unit	Net to gross (v/v)	Total Por (v/v)	Net Por. (v/v)	Total K (mD)
Captain E	0.61	0.13	0.21	7
Captain D	0.94	0.23	0.25	790
Captain C	0.33	0.07	0.22	10
Captain A	0.84	0.19	0.23	134

Note: Por = Porosity, K = permeability

6.7.2. Net to Gross, porosity & permeability modelling

The original input porosity curve had a cut-off applied at 0.14 pu, to ensures there are no zero values for porosity (they are set to undefined). The cut-off prevents net reservoir appearing in shale sections of the log data, and it is also noted that 0.14 gives the right thickness of cements compared to core (using 0.1 instead has virtually no impact on net-to-gross, Figure 6-6). The permeability curve was also cut to ensure no zero values were present.

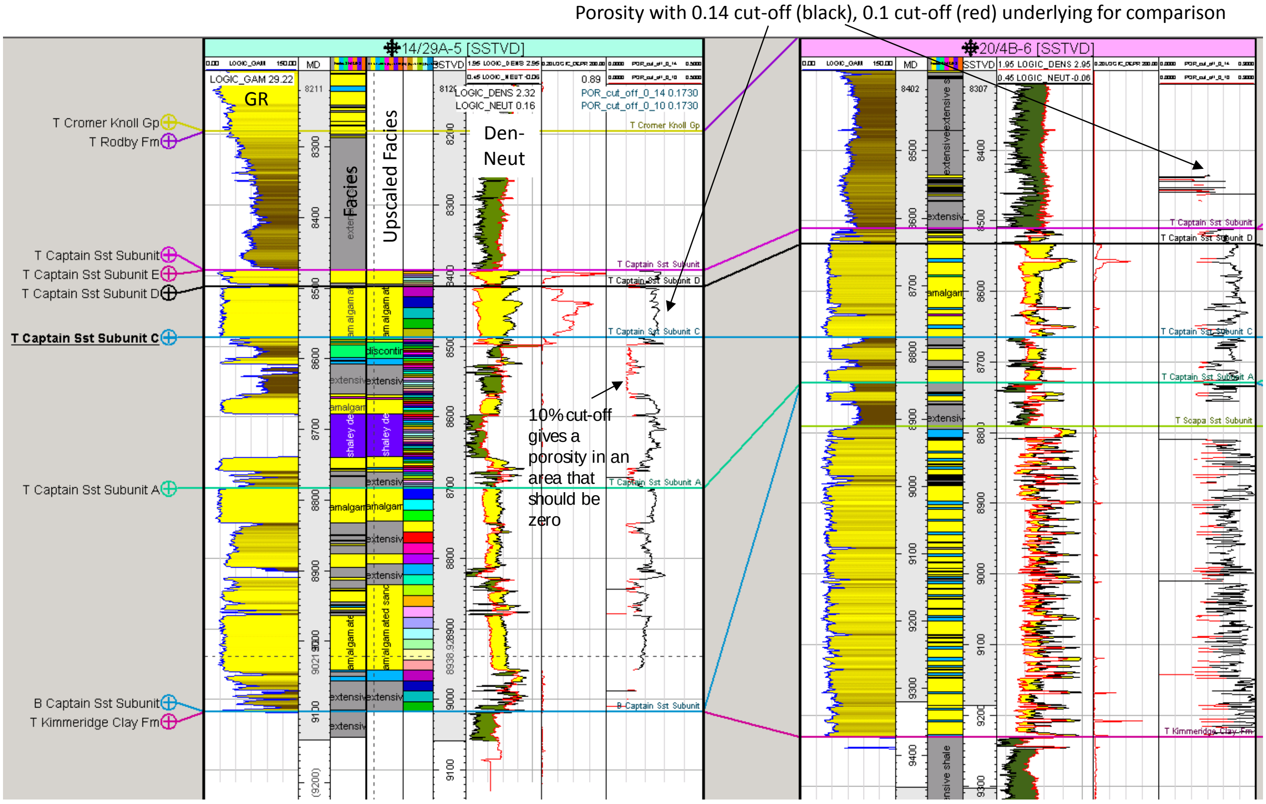


Figure 6-6: Comparison of Porosity curves with 14% & 10% cut off: wells 14/29a-5 and 20/4b-6

A net to gross curve was then generated which is 1 where the porosity curve is set to 'defined' or 'zero' where it is undefined.

Property modelling was performed separately for each individual zone. The porosity, permeability and net/gross curves were upscaled into the model layers using arithmetic averages. The three properties were distributed between wells using SGS with the same settings for all intervals (Table 6-7) and constrained via the facies model. This means that property distributions derived from the log data are maintained in the populated model. Non-net facies are assigned values of 0 for all three properties, and the two net reservoir facies (amalgamated sandstones and sheet sands) have individual proportions generated from their logged intervals in each zone. Spatial occurrence is controlled by the wells, and no trends (spatial or depth) are used, except in the Scapa Sandstones.

Table 6-7: Reservoir Property variogram settings – Amalgamated and Sheet Sand Facies

Type	Major Axis	Minor Axis	Vertical	Azimuth
Exponential	2000 m	1000 m	20 ft	-80°

Permeability is co-kriged with the porosity model, to ensure that if a cell has a high porosity value, it is more likely to have a high permeability.

The stochastic distribution of the properties is taken from the distribution seen in the upscaled well logs for Unit E and Unit D. For the other zones the number of well penetrations is very limited and the distribution found from the upscaled well logs is not a statistically meaningful sample. In these cases a normal distribution using the mean and standard deviation taken from the upscaled well logs is enforced upon the properties. The net-to-gross modelling within the Scapa cemented bodies uses a trend grid to decrease the net to gross seen in the wells from south to north.

The permeability model created as part of this suite of SRMs is representative of horizontal permeability (K_h) only. A vertical permeability (K_v) model is created in the dynamic simulator through the application of a K_v/K_h ratio.

6.7.3. Water saturation modelling

The basis of the saturation function work is discussed in § 6.7.2 above. These functions are applied using the following equations (8 & 9):

$$Sw_{Oil} = 0.02 + 0.72 \cdot \left[0.0074675 \cdot hafwl_{Oil} \cdot \sqrt{k_{Model} / \phi_{Model}} \right]^{-0.54} \qquad (8)$$

$$Sw_{Gas} = 0.02 + 0.6 \cdot \left[0.01087 \cdot hafwl_{Gas} \cdot \sqrt{k_{Model} / \phi_{Model}} \right]^{-0.52} \qquad (9)$$

Where: Sw_{Oil}= Water saturation in oil leg (v/v)

Sw_{Gas}= Water saturation in gas leg (v/v)

hafwl= Height Above Free Water Level (ft)

K_{Model} = Upscaled & gridded permeability (mD)

ϕ_{Model} = Upscaled & gridded porosity (v/v)

Both the resulting water saturations have their higher values clipped and set to 1. The resulting saturation properties are used directly in the volumetric calculations.

6.8. Fluid contacts

Initial in-place fluid contacts are discussed briefly. Hydrocarbon volumes are not reported here, but a discussion of the in-place hydrocarbon occurrence is relevant for analysis of connectivity, charge history and later history matching during dynamic simulation. It is important to understand the initial distribution of hydrocarbons so that relative permeabilities and hysteresis effects are modelled correctly. In addition, the OOWC defines the minimum depth of closure for the field, which in turn defines the minimum CO_2 storage volume available.

A number of data constrain the fluid contacts. These are a mix of direct samples (MDT & core) and fluid interpretation from wireline logs and pressure data. The (oil) free water level is defined by the intersection of hydrocarbon and water pressure gradient at 8,592 ft TVDSS [2,619 m]. This data is summarised in Table 6-8 below.

Table 6-8: Summary of fluid distribution data for Goldeneye wells

Well	Source	GUT	GDT	GOC	OUT	FOL	OWC	FWL
14/29a-3	Log	8,265	8,547	N/L	8,570		8,590	
	MDT					8,567		8,592
	Core	N/L.	8,547	N/L	8,569		8,588	
14/29a-5	Log	8,393	8,498	N/L	8,567		8,589	
	MDT					8,564		8,588*
	Core	8,394	8,498	N/L	8,566		8,593.5	
20/4b-6	Log	8,523	N/A	8,571	N/A		8,591	
	MDT					8,575		8,593
	Core	N/L	N/A	8,570	N/A		8,592	
20/4b-7	Log	8,546.5	N/A	8,567.5	N/A		8,593.5	
	MDT					8,572		8,593
	Core	N/L	N/A	8,569.5	N/A		8,595	

*possible depth control issue. GUT= gas up to; GDT = gas down to, GOC = gas-oil contact, OUT = oil up to, FOL = free oil level, OWC = oil-water contact, FWL = free water level, N/L = Not Logged. Units are ft TVDSS.

There remains some uncertainty about the oil rim across the field. The oil rim is a few feet thicker in the central part of the field than in the south. In the central area the oil rim is penetrated in the Captain D with 24 ft to 25 ft [7.5 m] in 14/29a-3 and 14/29a-5; in the south the rim is penetrated in the Captain C with 18 ft to 20 ft [5.5 m to 6 m]; in 20/4b-6 and 20/4b-7 (Figure 6-7). This is probably due to the less efficient displacement of oil by gas in the poorly-connected Captain C relative to the Captain D. For the SRM, a simplification to a mid-value gas-oil contact at 8568 ft TVDSS [2611.5 m] and a mid-value oil-water contact at 8592 ft TVDSS [2619 m] is used.

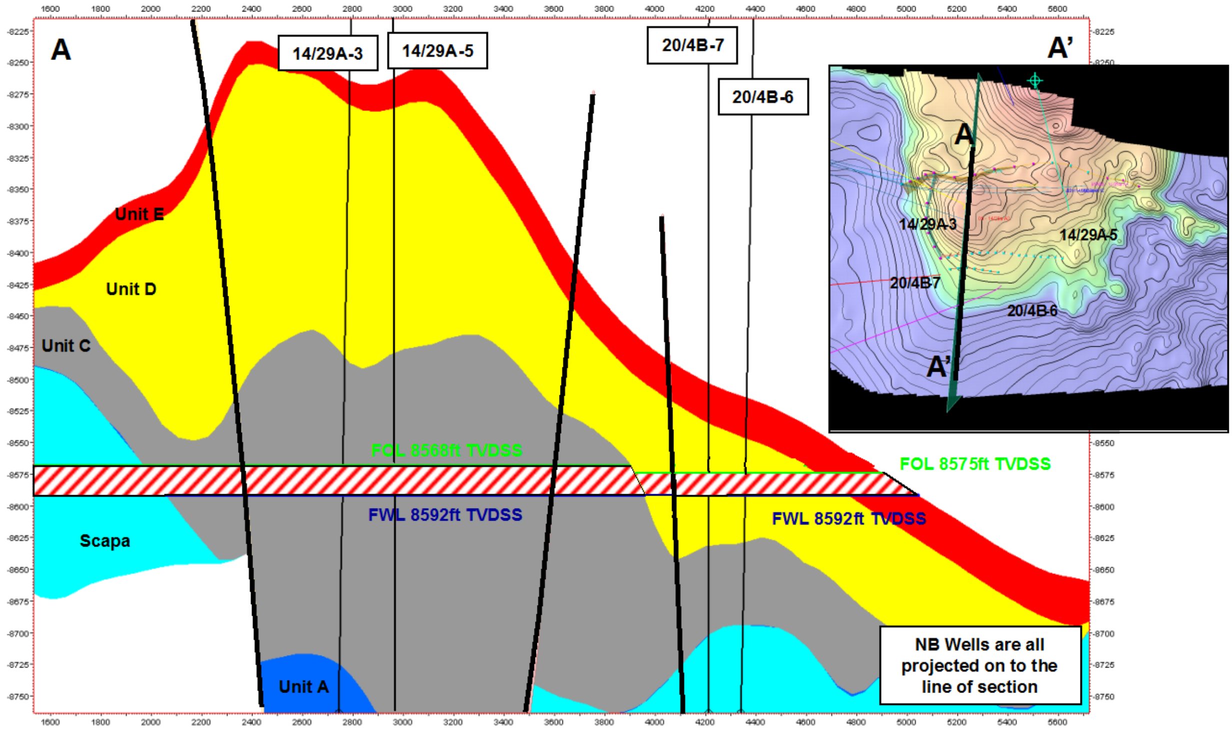


Figure 6-7: North-south cross-section of oil rim

7. Conclusions/Observations

A suite of SRMs have been built for the Goldeneye CCS project and realisations designed to test issues pertaining to CO_2 displacement and containment have been upscaled to the dynamic simulator. The SRM that best reflected the one built by the asset for field management – SRM1 – was used as an initial case. However, this model had already failed to provide an adequate history match and so further models were built to address this issue (SRM2-SRM3.15).

The models allow the investigation of uncertainties and the robustness of the CO_2 injection development to different possible geological realisations. Specific elements of modelling have been included for CO_2 injection dynamic simulation, such as the geometry of the top seal, layering refinements, alternative internal zonation schemes. Since the facies and property modelling elements were kept the same for all models, the differences between them result from changes to the structural envelope and internal zonation and so can best be illustrated by comparison of their GRV values, as shown in Table 7-1, and representative structural cross sections of the end-member models (Figure 7-1). The range in overall GRVs is narrow due to the fact that the same structural interpretations for the top and base of the reservoir were used in the SRM1-SMR2.25 cases. SRM3 and SRM3.1 use slightly different realisations but one that are still derived from the same depth conversion techniques as the others. However, the GRV of the main reservoir unit (Captain D) does vary more widely, due to the different methods for subdivision meaning that the in-place volumes for the field (which are not quoted here) also have a greater variation.

Table 7-1: Comparison of GRV (x10^6 m^3) in original suite of SRM cases for Goldeneye Field

	SRM1	SRM2.0	SRM2.1	SRM2.2	SRM2.25	SRM3	SRM3.1
Full Model	810	701	871	871	871	865	1055
Captain E	102	94	106	140	108	135	141
Captain D	409	368	437	378	442	382	394
Captain C	187	202	186	170	180	185	204
Captain A	5	5	5	42	0	0	1
Scapa	107	32	136	140	140	163	315
Captain D + E	511	462	543	518	550	517	535
Captain (no Scapa)	**703**	**669**	**734**	**730**	**730**	**702**	**740**

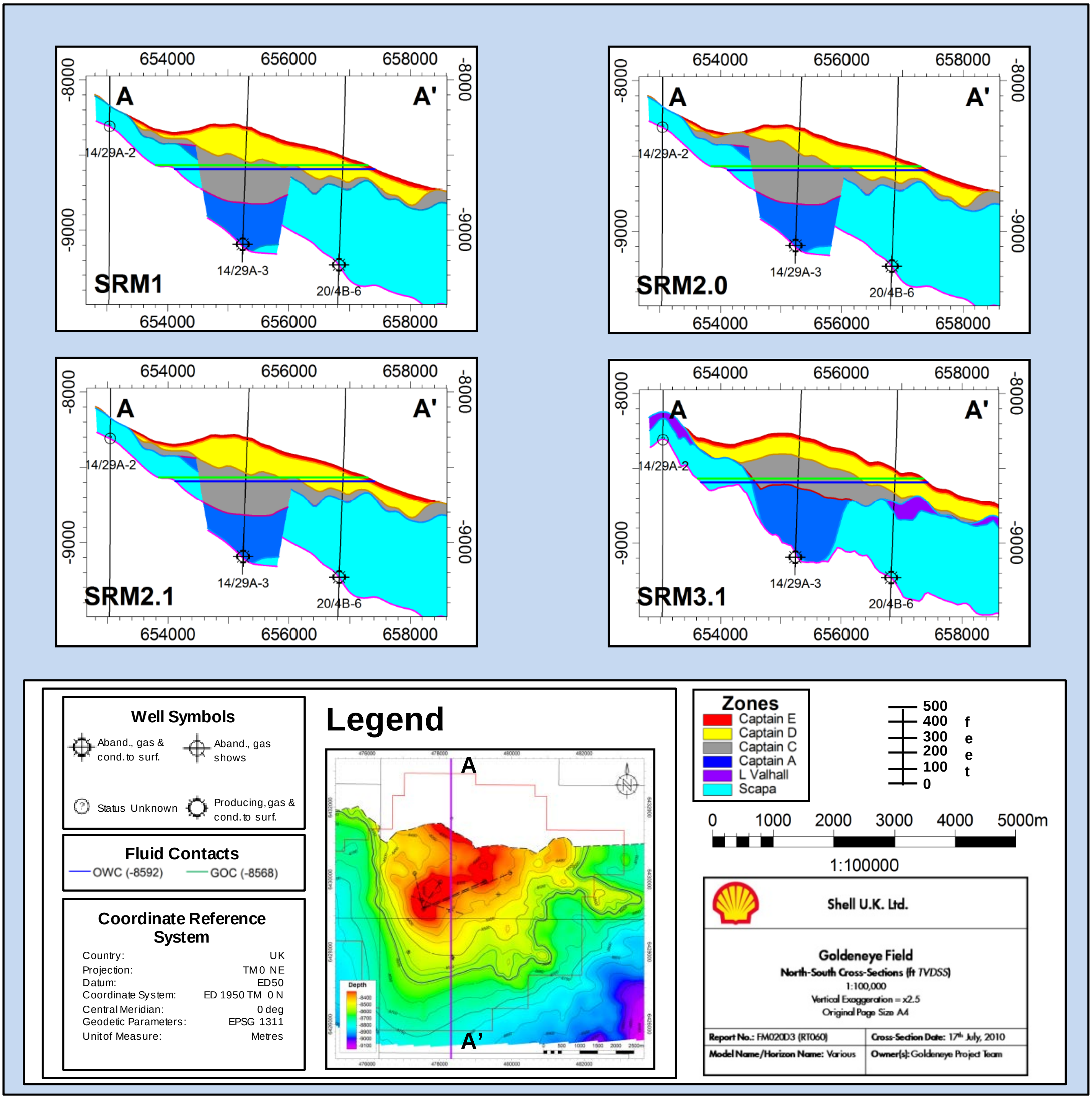


Figure 7-1: **Representative north-south cross sections from the 'end-member' SRMs built for dynamic simulation.**

End members of the realisations were exported to the Shell dynamic simulation software (MoReS). The dynamically simulated models are used as input for decisions on injection strategy, field monitoring and to focus further investigation into the likelihood and direction of any egression from the primary container. The simulation work has resulted in the creation of two final sensitivities, SRM3.05 to test for shallow flank and SRM 3.15 to test for a more southern truncation of the Captain Sandstone (Table 7-2).

Table 7-2: Comparison of GRV (x10^6 m^3) in final models for dynamic CO_2 sensitivity work

	SRM3.1	**SRM3.05**	**SRM3.15**
GRV	1055	1012	1055
Captain E	141	141	141
Captain D	394	400	394
Captain C	204	167	197
Captain A	1	8	8
Scapa	315	296	315
Captain D + E	535	541	535
Captain (no Scapa)	**740**	**716**	**740**

8. References - Bibliography

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3. Shell, 2014. PVT Modelling Report for CO_2 in Goldeneye Project – OP200D3 (RT082), PCCS-05-PT-ZR-0580-00001Key Knowledge Deliverable 11.106
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5. Shell 2013. Static Model (overburden) Report, PCCS-05-PT-ZG-0580-00005, Key Knowledge Deliverable 11.108

9. Glossary of Terms

Term	Definition
AOI	Area of Interest
CCGT	Combined cycle gas turbine
CCS	Carbon Capture & Storage
CO_2	Carbon Dioxide
ENE	East-Northeast
E-W	East-West
FDP	Field Development Plan
FEED	Front End Engineering Design
FFSM	Full Field Simulation Model
FMT	Formation Multi-Tester
FOL	Free Oil Level
FWL	Free Water Level
GDT	Gas down to
GOC	Gas Oil Contact
GR	Gamma ray
GRV	Gross Rock Volume
GUT	Gas up to
K	Permeability
LWD	Logging Whilst Drilling
MCT	Mechanical Coring Tool
MDT	Modular Formation Dynamics Tester
N/L	Not Logged
N:G	Net-to-Gross
NW	Northwest
OBM	Oil-Based Mud
OGOC	Original Gas Oil Contact
OOWC	Original Oil Water Contact
OUT	Oil up to
OWC	Oil Water Contact
Por	Porosity
PSDM	Pre-Stack Depth Migrated
PVT	Pressure, Volume, Temperature
RFT	Repeat Formation Tester
SCAL	Special core analysis
SGS	Sequential Gaussian Simulation
SRM	Static Reservoir Model
TVDSS	True Vertical Depth Subsea (i.e. relative to Mean Sea Level)
WBM	Water-Based Mud
WNW	West-Northwest

In the text well names have been abbreviated to their operational form. The full well names are given in Table 9-1.

Table 9-1: Well name abbreviations

Full well name	Abbreviated well name
DTI 14/29a-A3	GYA01
DTI 14/29a-A4Z	GYA02S1
DTI 14/29a-A4	GYA02
DTI 14/29a-A5	GYA03
DTI 14/29a-A1	GYA04
DTI 14/29a-A2	GYA05

10. Glossary of Unit Conversions

Table 10-1: Unit Conversion Table

Function	Unit - Imperial to Metric conversion Factor
Length	1 Foot = 0.3048 metres
Pressure	1 Bara = 14.5psia 1 MPa = 145.04 psia

APPENDIX 3. Static Model Overburden Report

C.1. 11.108, Static Model (Overburden) Report, PCCS-05-PT-ZG-0580-00005

Peterhead CCS Project

Doc Title: Static Model (Overburden)

Doc No. **PCCS-05-PT-ZG-0580-00005**

Date of issue: **19/03/2015**

Revision: **K03**

DECC Ref No: **11.108**

Knowledge Cat: **KKD - Subsurface**

KEYWORDS

Goldeneye, CO_2, Overburden, Static Model, Seismic, Faults, Petrel, Rødby, Lista, Captain Sandstone.

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Executive Summary

In support of the Peterhead Carbon Capture and Storage (CCS) Project an overburden assessment has been conducted above and adjacent to the planned storage site, the Goldeneye field, to identify possible secondary containment horizons and potential migration pathways out of the field and associated storage complex in the unlikely event of seal or fault leakage of the sequestered CO_2. As a part of the assessment, a 3D static model was constructed to capture the relevant data: this formed input to subsequent geomechanical modelling. This report is an update of the Overburden Model Report issued for the earlier Longannet CCS Project. It contains minor edits for Cessation of Production, grammar and clarity.

The 3D geological model was constructed in the third-part software Petrel™ and depicts the overburden and underburden lithologies, covering an area approximately 17 km by 8 km around the Goldeneye field. The model extends from the sea floor (~2400 m above the Captain reservoir) down to the Top Triassic Heron Group (~900 m below the Captain reservoir).

The primary seal to sequestered CO_2 in the Goldeneye field is provided by the calcareous and chalky mudstones of the Rødby Formation. CO_2 is not expected to leak through the Top Rødby seal which has already trapped the Goldeneye gas over geological time, or via reservoir level faults as they do not offset the sealing caprock. At least two different fault sets are present in the overburden, but these faults are considered to be decoupled from the Captain reservoir faults.

The Lista Formation is identified as a secondary sealing interval in the overburden above the Goldeneye field. The Lista mudstone comprises non-calcareous, bioturbated, non-carbonaceous and non-pyritic mudstones, and is a proven hydrocarbon seal in the Central North Sea. CO_2 could also potentially be constrained by the shallower Dornoch Mudstone. There are, however, no additional structural closures identified in the overburden stratigraphy.

Overall it is anticipated that migrating CO_2 from the Goldeneye field is unlikely to reach the surface via pathways originating in deeper parts of the overburden.

1. Introduction

The Peterhead CCS Project aims to capture around one million tonnes of CO_2 per annum, over a period of 10 to 15 years, from an existing combined cycle gas turbine (CCGT) located at SSE's Peterhead Power Station in Aberdeenshire, Scotland. This would be the world's first commercial scale demonstration of CO_2 capture, transport and offshore geological storage from a (post combustion) gas-fired power station.

Post cessation of production, the Goldeneye gas-condensate production facility will be modified to allow the injection of dense phase CO_2 captured from the post-combustion gases of Peterhead Power Station into the depleted Goldeneye reservoir.

The CO_2 will be captured from the flue gas produced by one of the gas turbines at Peterhead Power Station (GT-13) using amine based technology provided by CanSolv (a wholly owned subsidiary of Shell). After capture the CO_2 will be routed to a compression facility, where it will be compressed, cooled and conditioned for water and oxygen removal to meet suitable transportation and storage specifications. The resulting dense phase CO_2 stream will be transported direct offshore to the wellhead platform via a new offshore pipeline which will tie-in subsea to the existing Goldeneye pipeline.

Once at the platform the CO_2 will be injected into the Goldeneye CO_2 Store (a depleted hydrocarbon gas reservoir), more than 2 km under the seabed of the North Sea. The project layout is depicted in Figure 1-1 below:

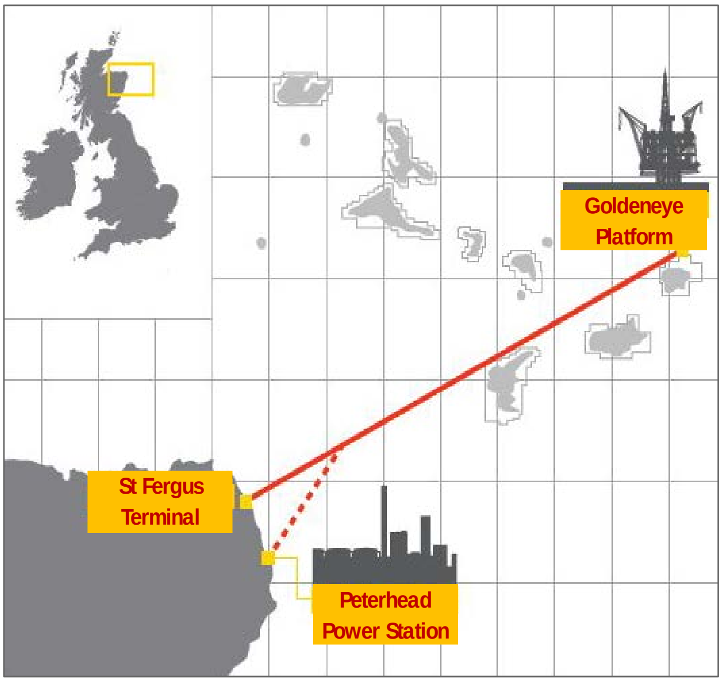

Figure 1-1: Project Location

1.1. Summary

This report documents the construction of the Goldeneye overburden static model in Petrel. It is important to consider not only the stratigraphy directly above the storage site, but also to document all stratigraphic units that could possibly have a direct connection to the reservoir sands. This is because CO_2 can potentially egress not only vertically out of the structure, but also potentially laterally through juxtapositions with the underburden stratigraphy. Thus, an overburden and underburden assessment has been conducted around the Goldeneye field, examining the lithology, stratigraphy and structure of the overburden and underburden, to identify possible secondary containment and potential migration pathways.

This is only a static assessment of the overburden stratigraphy and migration pathways. The containment risking, and geomechanical and dynamic aspects of CO_2 sequestration are covered in the Storage Development Plan.

2. Model Scope & Objectives

The overburden static geological model is designed to complement the detailed 3D full field static model (FFSM) and the 3D aquifer static model which were constructed in parallel. Learnings from the construction of each model have been mutually applied. The FFSM is designed to model detailed geological features in the Goldeneye field, and enable dynamic simulation to predict fluid interactions and movements during the injection and post injection periods. The aquifer 3D static model is used for dynamic modelling of the Captain Sandstone aquifer in order to simulate any potential lateral discharge of CO_2 out of the Goldeneye containment structure.

The overburden static geological model facilitates the visualization of the overburden and underburden stratigraphy above and below the Captain Sandstone of the Goldeneye field, from the seabed down to the top Triassic, and allows assessment of possible secondary containment horizons and static assessment of migration pathways for the injected CO_2.

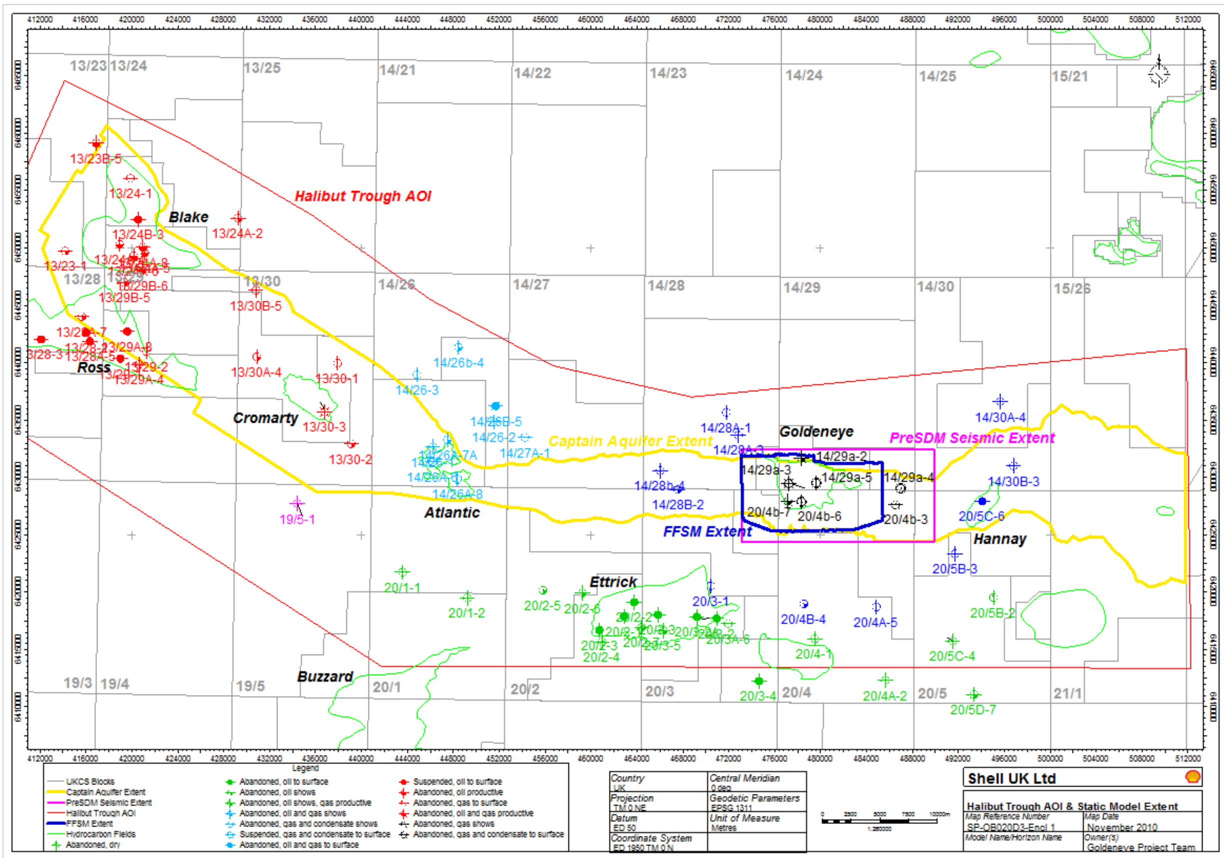

Figure 2-1: Areal extent of the Petrel static models for the Goldeneye CO_2 sequestration studies.

Note: The coverage of the PSDM seismic data cube (shown in pink) determined the extent of the overburden static model. The extent of the regional aquifer model is shown in yellow, and the FFSM in dark blue.

3. The Goldeneye Field

3.1. Geological Setting

The Goldeneye field is located in the Outer Moray Firth region of the UKCS Central North Sea. The region is dominated by the Halibut Horst, an area that remained emergent throughout most of the Jurassic and Lower Cretaceous periods. The Goldeneye accumulation is situated on the northern edge of the South Halibut Basin adjacent to the southern margin of the South Halibut shelf. The shelf edge depositional setting of the Lower Cretaceous (latest Aptian–earliest Albian) resulted in the ribbon like deposition of the Captain Sandstones along the southern margins of the Halibut Horst and South Halibut Shelf (see Figure 3-1).

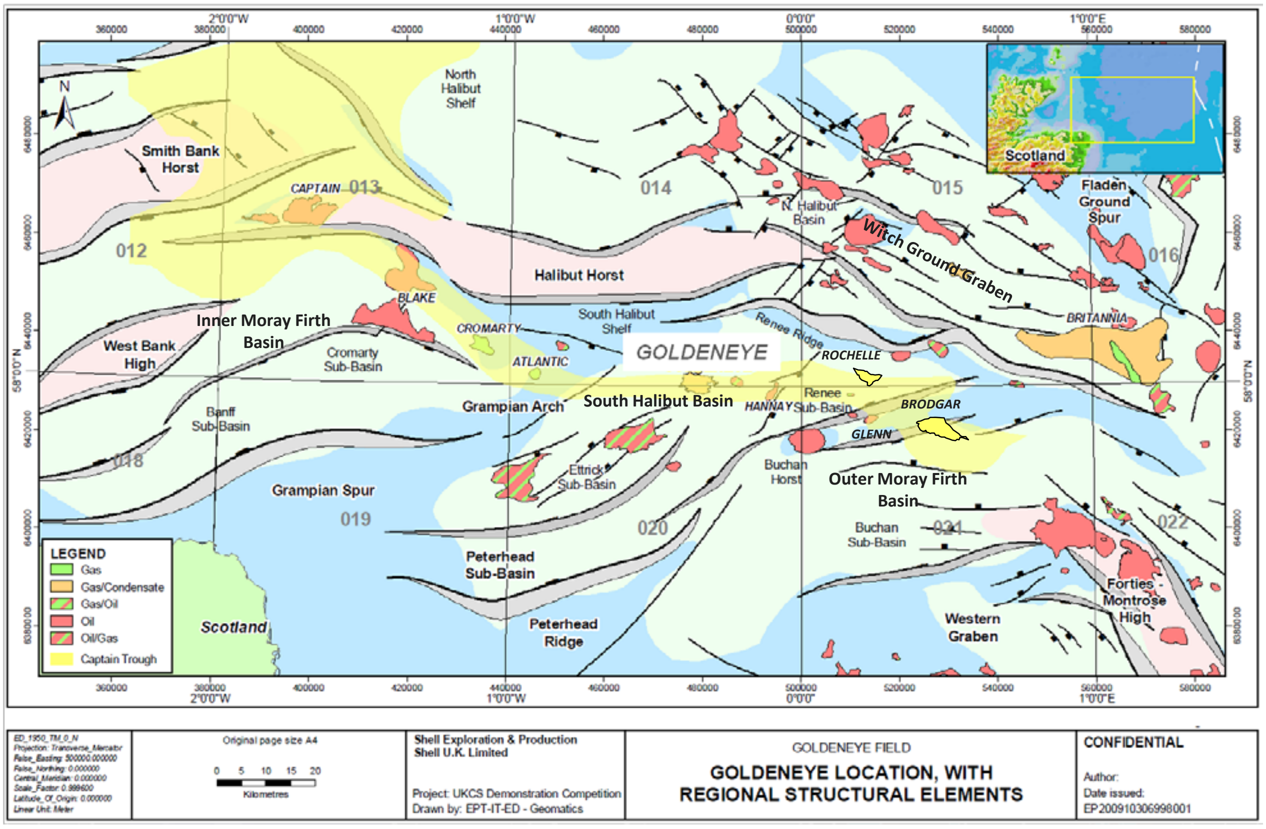

Figure 3-1: Distribution of Captain Sandstones across the Outer Moray Firth

Note: Captain fairway highlighted in yellow; basinal areas in pale green.

3.2. Structural history

The Moray Firth Basin is the name given to the complex series of tilted fault blocks and grabens that extend eastward offshore from the Moray Firth, Scotland. The present day structural fabric is the result of at least five orogenic episodes along with a failed attempt as a spreading centre that span nearly 400 Ma.

The Outer Moray Firth basin exhibits several structural compartments, of which the most significant are the Halibut Horst, the Witch Ground Graben, and the Halibut Basin (see Figure 3-1). Northwest-trending faults in the Witch Ground Graben and north of the Halibut Horst are likely to be Hercynian age structures which extend from the Central Graben, whereas faults running approximately east to west that fall between the Halibut Horst and Peterhead Ridge result from a complex interaction between Caledonian and Hercynian structures.

The Grampian Highlands extend north-eastward to form the Grampian Spur and Grampian Arch (sometimes termed the Grampian High), that subdivide the Moray Firth into the inner and outer basins. The Grampian Arch and portions of the Halibut Horst probably owe their existence to the buoyancy of an underlying Caledonian-age granitic pluton that has provided a broad northeast trending high during several phases of the basin's history. The buoyant effect of the granite was evident as early as the late Devonian, but more significant was uplift during the Middle Jurassic when it separated the inner Moray Firth from the Halibut Basin, and erosion of the sedimentary cover of the Arch occurred. Basin subsidence together with a eustatic rise in sea level during the Late Jurassic and Cretaceous times resulted in thick sediments being deposited fairly continuously across the basinal areas, which thin or become condensed across the Grampian Arch.

A major change in structural regime and sedimentation occurred in the Palaeogene due to ca. 1 km of uplift of the inner Moray Firth, Scottish Highlands and the East Shetland Platform areas which resulted in a regional eastward tilting of the area. During this period large quantities of clastic sediments were deposited in the Outer Moray Firth and Central Graben areas. There was also a continuation of the mild north-south compressive regime which warped the top chalk surface and funnelled the Captain Sandstones west-east through the basin.

3.3. Exploration history

The Captain fairway (also known as the Kopervik fairway by some operators) has a history of exploration dating back to the mid-1970's. Despite one or two early successes (the undeveloped North Glenn accumulation in 1975 and the Captain field in 1977) production did not commence in the area until the late 1990s (1). To date, nine fields have received development approval, combining to provide estimated ultimate recovery (EUR) of 437MMbbl oil, 51MMbbl condensate and 1.1 Tcf gas (2). The Captain oil field saw the first production from the Captain Sandstone in 1997, followed by the Blake oil field in 2001, and the Hannay oil field in 2002. The Goldeneye condensate field commenced production in October 2004 and was followed by the Atlantic and Cromarty fields (a joint development) in June 2006 and the Brodgar field in July 2008. Most recently, the Rochelle field came on production, in 2013.

The Goldeneye field is a gas condensate accumulation with a thin oil rim. The reservoir properties are very favourable for hydrocarbon production (average porosity is 25% and average permeability is 760 mD) and the hydrocarbons are contained at normal pressure and temperature. The field was discovered in 1996 by Shell/Esso Well 14/29a-3, which encountered a gas column of 92 m. In the following years three appraisal wells were drilled: 1998 Amerada 20/4b-6 (south), 1999 Shell/Esso 14/29a-5 (south-east) and 2000 Amerada 20/4b-7 (south-west). In 2004 five development wells were drilled. The locations of the exploration and development wells are shown in Figure 3-2. Well 14/29a-2, is located north of the depositional limit of the fairway, and did not encounter any Captain Sandstones. The Goldeneye field commenced production in October 2004. As of December 2010, all five development wells are shut-in due to water production.

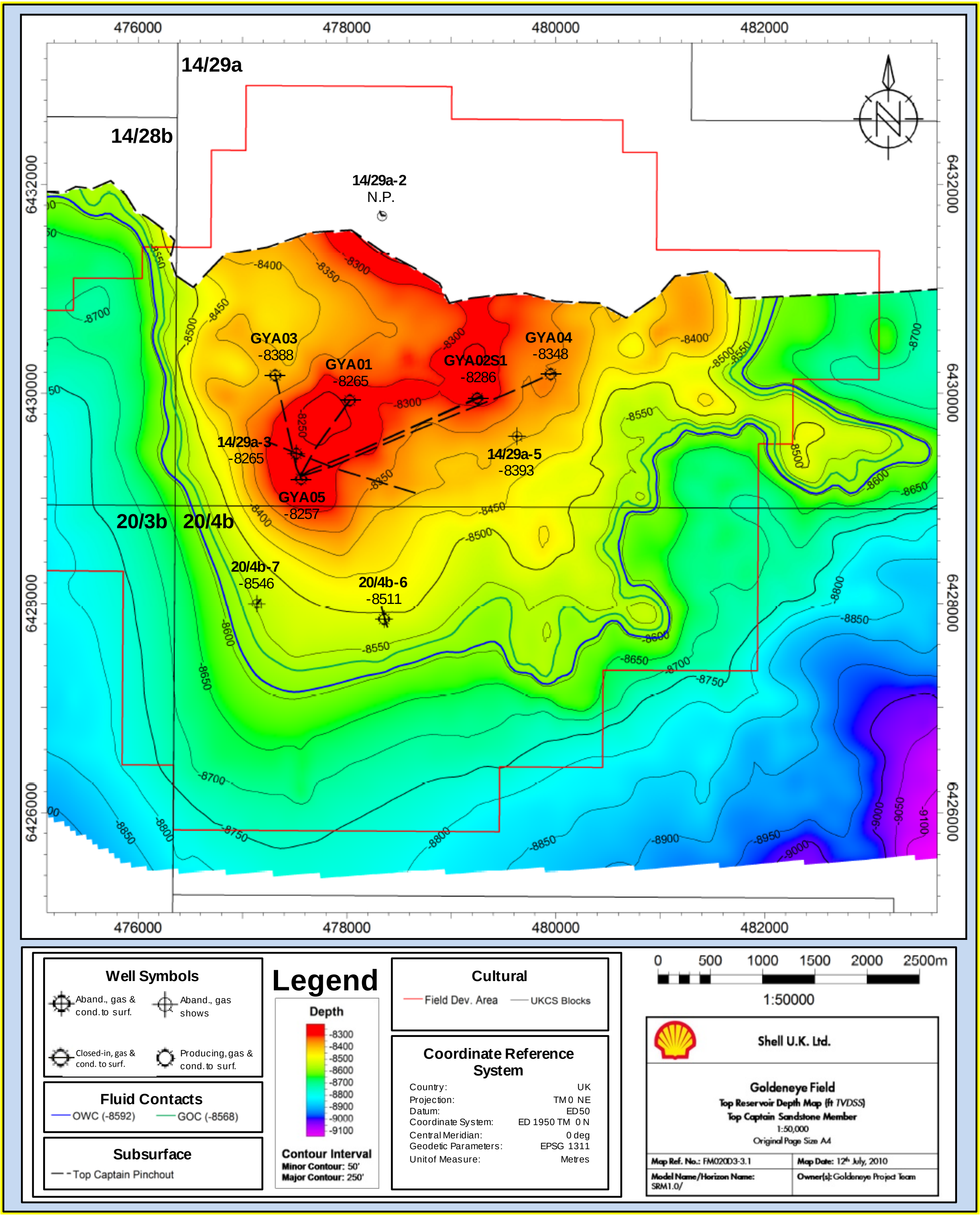

Figure 3-2: **Goldeneye field top structure map, True Vertical Depth Subsea (TVDSS) – Reference Case.**

Note: Absence of Captain Sandstone in 14/29a-2.

4. Stratigraphy in the Goldeneye area

4.1. Overview

The regional stratigraphic column for the Outer Moray Firth is shown in Figure 4-1. The stratigraphy consists of an upper interval of Quaternary age sediments and a thick interval of Tertiary age deposits comprising interbedded sands, shales, claystones and lignites.

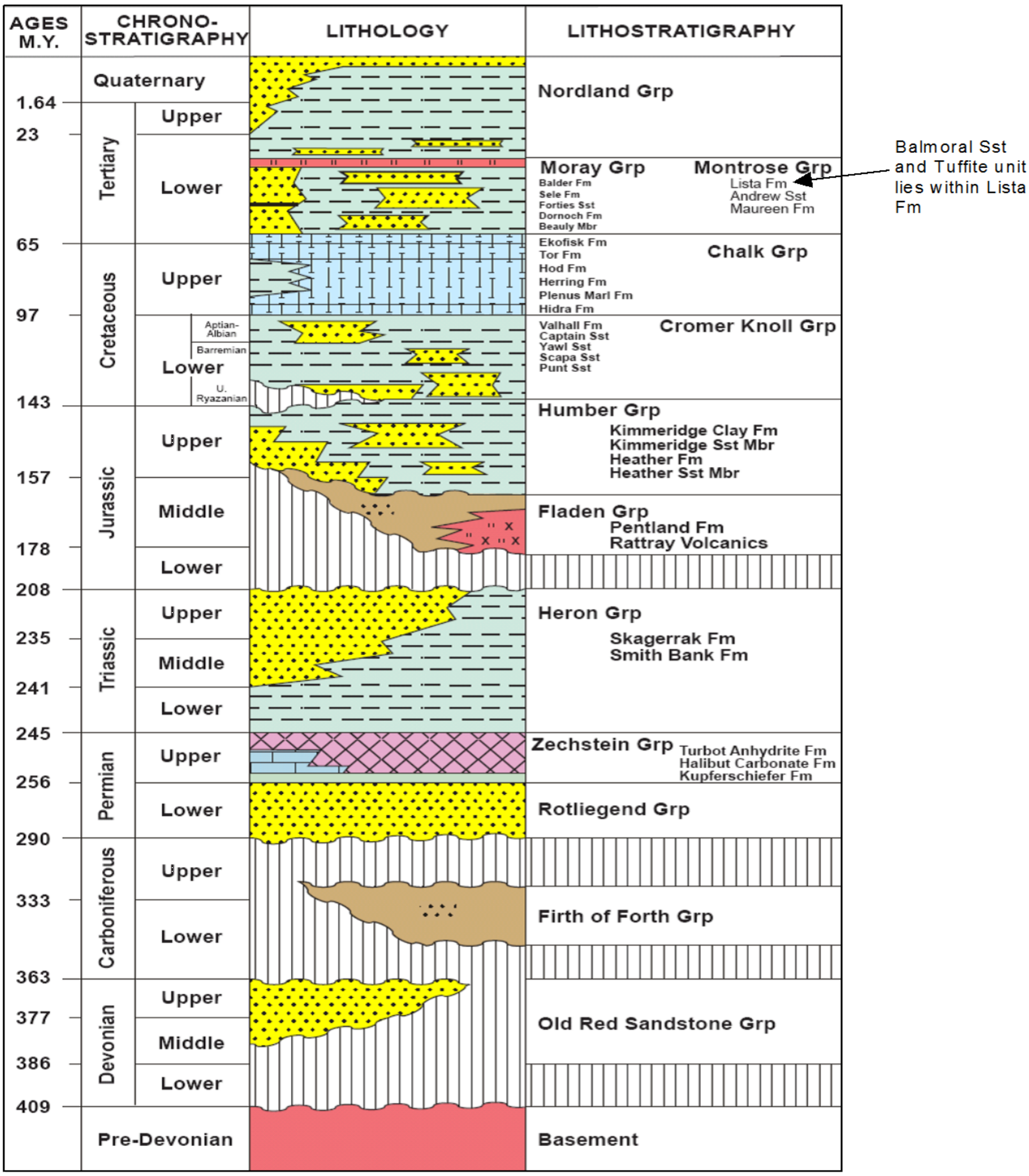

Figure 4-1: Generalised stratigraphy of the Goldeneye area.

Below the Tertiary clastics, the chalk is of fairly uniform thickness across the area. The Upper Cretaceous Chalk Group is the oldest formation to have been deposited over the entire Halibut Horst. Prior to this the Halibut Horst is believed to have been emergent. The erosion of the Halibut Horst, and storage of the resultant clastic sediments in both the north and south Halibut shelfal areas, is believed to have contributed significantly to the deposition of turbidites throughout the Lower Cretaceous and Jurassic in the Outer Moray Firth. The periodic deposition of the sand rich turbidites took place within the background deposition of hemipelagic shales, marls and occasional limestones.

The sands of Albian–Aptian age (Figure 4-2, dominantly the Captain Sandstone) are generally more sand rich and massive than those of Barremian–Ryazanian ages. The latter appear from log signatures and seismic expression to be of more classical low density fan-type turbidites as opposed to the massive, blocky, sandy debrite/high density turbidites of the Captain Sandstones.

Good reservoir quality turbidite sands are also found within the Upper Jurassic Kimmeridge Clay Formation. Underlying the Kimmeridge Clay Formation, paralic sediments were deposited (e.g. Heather/Pentland Formations).

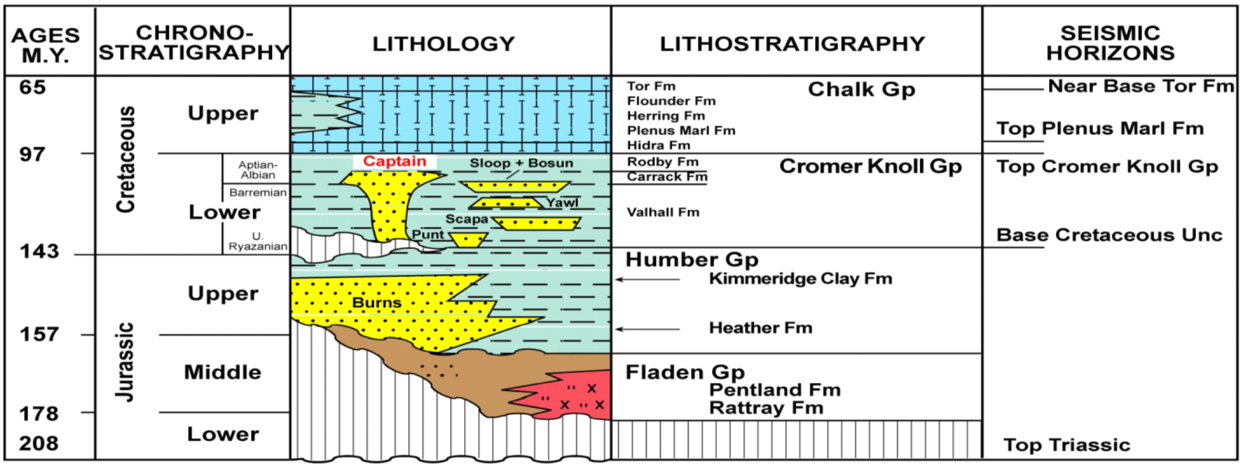

Figure 4-2: Jurassic - Cretaceous stratigraphy of the outer Moray Firth

The economic basement comprises Triassic age siltstones and shales of the Smith Bank Formation, Permian Zechstein and Rotliegend Formations and the deeper sand rich clastics of Carboniferous and Devonian age. Below the Devonian sediments, basement granites that form the core of the Halibut Horst are present.

A sedimentological and lithological description of all of the overburden stratigraphic units, and a summary of their distribution across the overburden model area of interest (AOI) can be found in Appendix A.

4.2. Significant Overburden Stratigraphy

There is approximately 2400 m of overburden stratigraphy overlying the Goldeneye field. This stratigraphy is divided into seven lithostratigraphic groups – Nordland, Westray, Stronsay, Moray, Montrose and Chalk groups. Within the overburden sediments, there are four possible aquicludes identified which could potentially restrict the migration of the CO_2 plume to the seabed should it egress from the Captain reservoir storage site. These are:

- Nordland Group
- Dornoch Mudstone Unit
- Lista Formation (secondary seal)
- Plenus Marl & Hidra Formations – these directly overly the primary seal and along with the primary seal can act as containment against lateral egress

The Primary Seal is the Rødby Formation.

4.2.1. Nordland Group

The Nordland Group consists of an undifferentiated interval of grey to brown coloured poorly bedded, soft, silty mudstones and siltstones with subordinate sands. Although lithologically this is a potential aquitard, if a migrating CO_2 plume reached such a shallow depth it would no longer be in a supercritical phase at these temperatures and pressures, and as such would be extremely difficult to contain in its gaseous state. It would however slow the upward migration and allow opportunities for dissolution and capillary trapping.

4.2.2. Dornoch Mudstone Unit

The Lower Dornoch Mudstone unit is proposed as a tertiary seal to the upwards migration of CO_2. It comprises a subtle upwards coarsening sequence from silty mudstone to muddy siltstone with a gamma ray (GR) maximum at the base of the unit. The mudstone is consistently present in the overburden model AOI and closest offset wells; it is not widely developed within the Halibut trough area. There is no structural closure at this level in the Goldeneye area. Aquifer storage below this aquiclude would exist in the Lower Dornoch sandstone although the regional distribution of this sandstone is also constrained, being only present in the overburden model wells and closest offset wells. The Dornoch Mudstone Unit appears to merge with the Lista mudstone to the west (up dip) of the area being studied.

4.2.3. Lista Formation

The Lista Formation is proposed as a secondary seal to sequestered CO_2 in the Goldeneye field. There are several Paleocene fields in the central North Sea that have Andrew or Mey sandstone reservoirs capped by a Lista Formation seal. The closest to the Goldeneye field is the Rubie field (40 km) and the MacCulloch cluster fields (50 km: MacCulloch Donan, Nicol, Lochranza, Blenheim, Blair, Beauly, Burghley and Andrew fields).

The Lista Mudstone comprises non-calcareous, bioturbated, non-carbonaceous and non-pyritic mudstones, grading into claystones in places. The dominant colour is pale green-grey to grey-green. The lower boundary is marked by a GR decrease and sonic velocity increase associated with the development of massive well developed sand facies. The Lista Mudstone facies is widely present in the Halibut Trough area (60 out of 72 wells) and is present in all overburden model AOI and closest offset wells. It is 60 m to 120 m thick in the Goldeneye area, and appears to thin slightly to the west (see Figure 4-3). The Lista mudstone facies overlies approximately 1200 m of stratigraphy believed to be of aquifer quality: the Mey Sandstone Member, Upper and Lower Balmoral Units, Marueen, Ekofisk, Tor, Hod and Herring Formations. These intervals, together with the Lista Formation as their seal, offer the main possibility for secondary containment of CO_2 above the Goldeneye field. However, there is no structural closure within the Goldeneye AOI at the base of the Lista Formation (see Figure 4-4). The base Lista Formation/top Mey Sandstone Member surface dips regionally from west to east along the Halibut Trough at approximately 1° to 1.5° to the east. Any CO_2 reaching the base of the Lista Formation is expected to migrate in a west to north-westerly direction. The Lista Formation is believed to crop out at seabed about 150 km to the west of Goldeneye, in the Inner Moray Firth, but this is uncertain due to the poor quality of the regional seismic data available to the project. Figure 4-3 and Figure 4-4 have the Goldeneye oil water contact (OWC) in red and gas oil contact (GOC) in green polygons and the Captain Sandstone fairway outline (blue) superimposed on them.

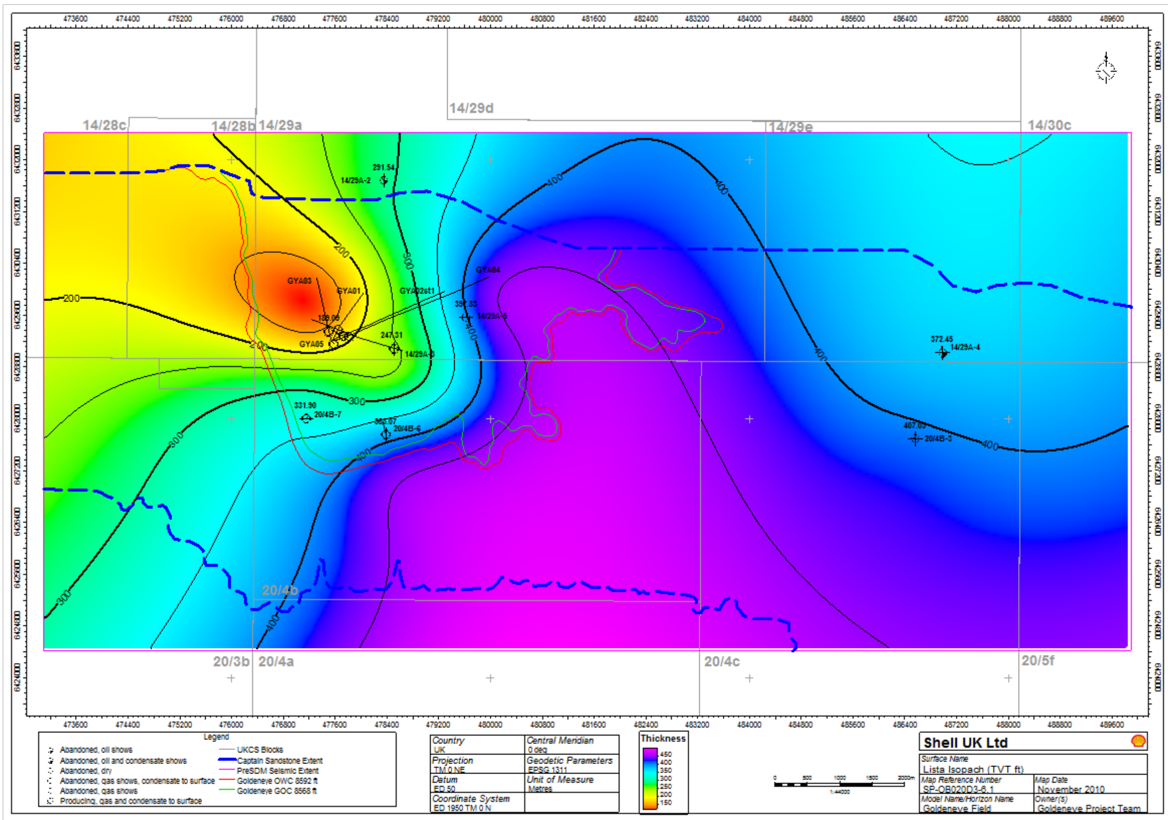

Figure 4-3: Thickness of Lista mudstone facies over the Goldeneye field (ft)

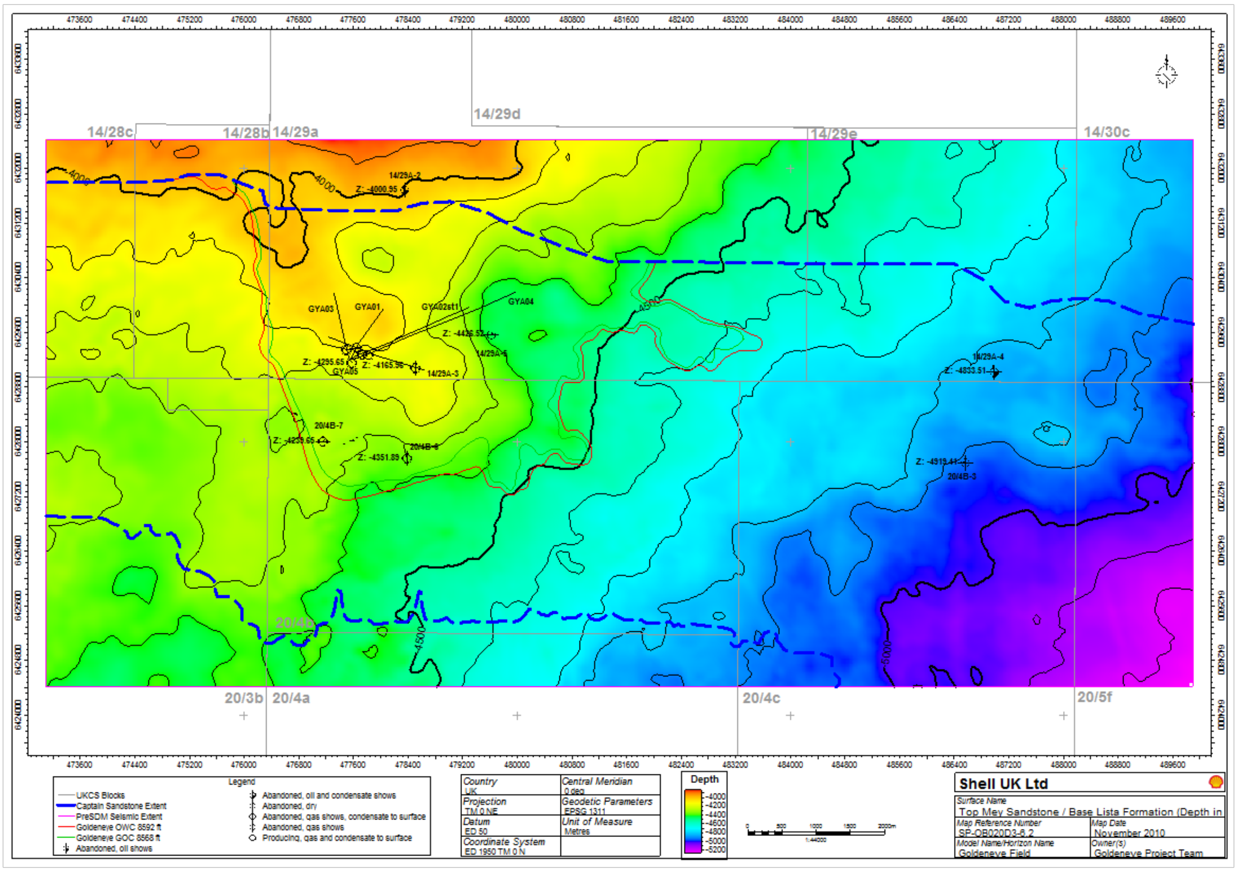

Figure 4-4: Base Lista Formation / Top Mey Sandstone Member depth map (ft)

4.2.4. Plenus Marl & Hidra formations

The Plenus Marl Formation consists of black mudstones which were deposited during a phase of stagnant and partly anoxic conditions. It is on average 90 ft [30 m] thick across the Goldeneye AOI. The underlying Hidra Formation (bioturbated limestones with interbedded mudstones) is on average 260 ft [80 m] thick across the Goldeneye AOI. Together with the Plenus Marl Formation, these are considered to be lithologically good aquicludes. They sit directly above the top seal (the Rødby Formation) of the Goldeneye field. Thus, they offer an extension to the Rødby seal but as they have no aquifer between them and the Captain sandstones, they do not offer any separate secondary containment for migrating CO_2.

4.2.5. Rødby Formation

The Rødby Formation is the primary top seal to the Goldeneye field. It has proven over geological time to be a competent seal, resulting in the trapping of hydrocarbons in the Goldeneye field. The Rødby Formation directly underlies the Late Cretaceous Hidra Formation and ranges in age from Middle to Late Albian. It consists of calcareous and chalky mudstones with sporadic thin beds of argillaceous limestone. The mudstones are mainly pale to dark grey but are often red-brown, brick red, olive grey and dark brown. The red mudstones are most commonly seen in the uppermost and lowermost units of the formation. Its upper boundary is characterised by a subtle downward increase in GR values and a decrease in velocity. Lithologically the top of the Rødby Formation is marked by a change from the interbedded grey and pink limestones, chalks and calcareous mudstones of the Hidra Formation (often with a basal limestone) to less calcareous mudstones and chalky mudstones. Its lower boundary is marked by a downward increase in GR values and a decrease in velocity. It is present over much of the Halibut Trough area (42 wells) and all of the Goldeneye overburden AOI and closest offset wells.

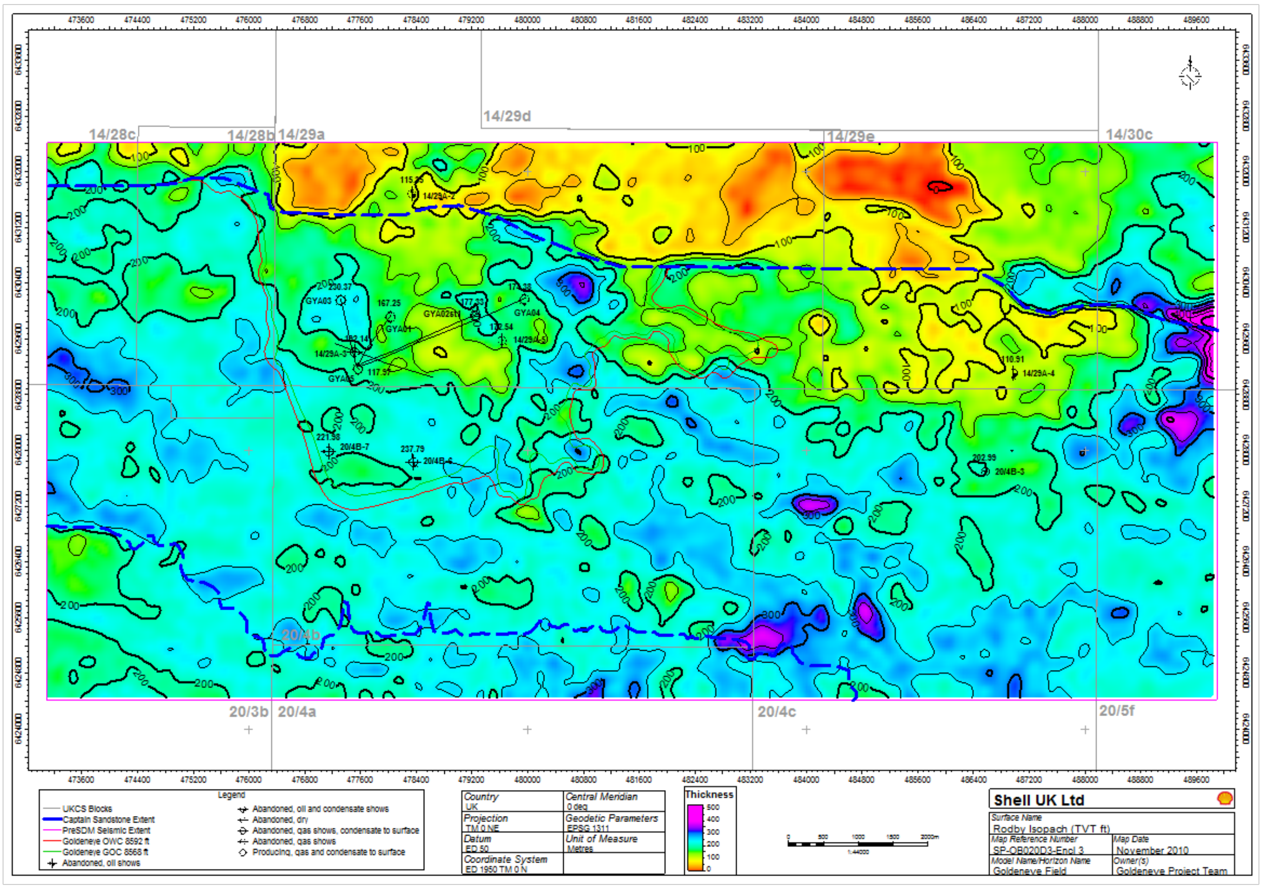

Figure 4-5: Thickness of the Rødby Formation over the Goldeneye field (in ft)

Note: The outline of the Goldeneye OWC (red) and GOC (green) and Captain aquifer extent (dashed blue) are superimposed onto the surface.

As can be seen in Figure 4-5, the Rødby Formation is on average 180 ft [60 m] thick over the Goldeneye AOI. It thins to less than 90 ft [30 m] to the north of the Goldeneye field, and to the north east may locally disappear altogether (drops below seismic resolution). However, it is important to note that this only occurs over the structural high to the north, beyond the Captain Sandstone pinchout line. In these areas seismic picks indicate continuity of the overlying and sealing Hidra and Plenus Marls. Within the depositional limits of the Captain Sandstone fairway in the overburden AOI, the Rødby Formation can be confidently mapped.

4.2.6. Upper Valhall Member

In the vicinity of the Goldeneye field immediately below the Rødby Formation lies the Upper Valhall Member which is the uppermost member of the Valhall Formation. This member is not further subdivided and is essentially a lithological extension of the Rødby Formation, in that it is a 0-39 ft [0-12 m] thick, pale to dark grey, mudstone, thickest in the south of the field and thinning to zero north of a line from GYA03 to 14/29a-5. This acts as an additional sealing interval directly above the Captain Sandstones. It is present over much of the Halibut Trough area (40 wells) and all of the Goldeneye overburden AOI and closest offset wells.

4.3. Significant underburden stratigraphy

It is important to consider not only the stratigraphy directly above the Captain Sandstone, but also to document all stratigraphic units that could possibly have a direct connection to the Captain sands. CO_2 cannot only egress vertically out of the Goldeneye field, but also laterally through juxtapositions with the underburden stratigraphy. Along the northern edge of the Goldeneye field the Captain Sandstones (both hydrocarbon and water leg) are (probably fault) juxtaposed against older members of the stratigraphic column, predominantly the Lower Valhall Members and the Humber Group but also the Fladen and Heron Groups (Figure 4-9). The magnitude of age differential across this juxtaposition increases to the east towards the Jurassic structural high that dominates the north-eastern corner of the overburden model AOI. At no point are stratigraphic units deeper than the Triassic (Heron Group) juxtaposed against the Captain Sandstones, and thus, the Zechstein, Rotliegend, Firth of Forth, Old Red Sandstone and Basement Groups are considered true underburden stratigraphies in the overburden model.

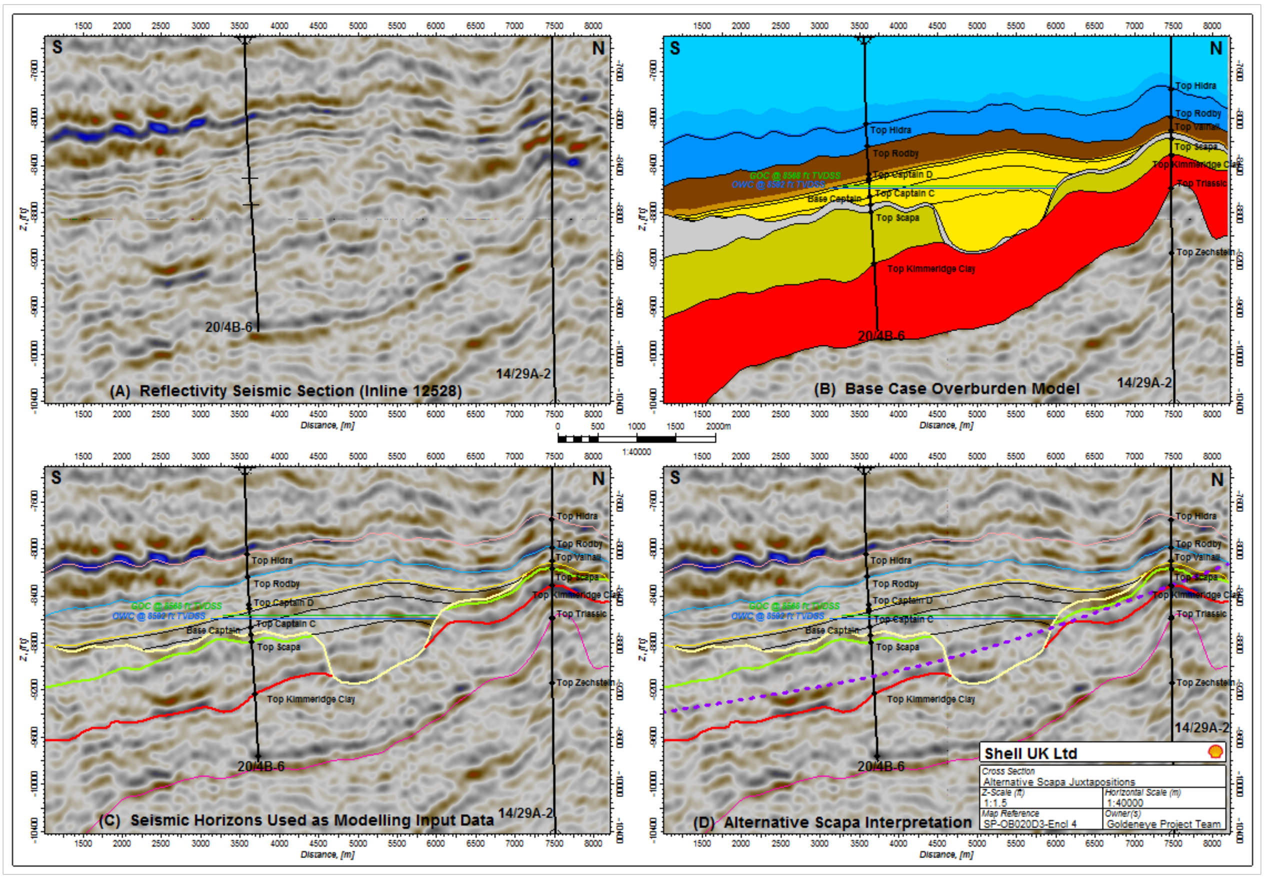

Figure 4-6: Potential juxtapositions with the Scapa Formation (see map in Figure 4-9 for line of section).

Figure 4-6 shows as north-south seismic section (Inline 12528) through the Goldeneye field between Wells 14/29a-2 and 20/4b-6. The upper left image **(A)** shows an uninterpreted seismic section between the two wells, with ticks marking the top and base Captain in Well 20/4b-6. No Captain Sandstones were present in Well 14/29a-2, so the northern pinchout of the Goldeneye field must be located to the south of this well. As can be seen in the seismic section, the data quality is not good, and there is not a consistent top Captain seismic reflector to follow due to the poor impedance contrast between the top reservoir and the overlying Rødby shales.

The upper right image **(B)** shows the base case overburden model overlain on the seismic section. The Captain Sandstone is highlighted in yellow, the Lower Valhall in light grey, the Scapa Formation in olive, and the Humber Group in red. The Captain Sandstone is interpreted to be an erosive feature, which has cut down through the Lower Valhall and Scapa sediments and into the upper section of the Kimmeridge Clay Formation, possibly exploiting a prior fault-related topography. Wells 14/29a-3 and 14/29a-5 both drilled into this central trough and observed Captain A sands lying directly on Kimmeridge Clay sediments. Note the extension of the Lower Valhall below the erosional cut of the Captain Sandstones in Figure 4-6 **(B)** is an artefact of the modelling surfaces in Petrel.

The lower left image **(C)** shows the input seismic horizons used for modelling, where the Captain sands have eroded down into the Kimmeridge Clay Formation, and there are no Lower Valhall sediments in the centre of the field. This interpretation assumes juxtaposition of the hydrocarbon bearing Captain Sandstone against the Lower Valhall and the Scapa Sands (green reflector), above the hydrocarbon-water contact on the northern flank of the field.

The lower right image **(D)** in Figure 4-6 shows an alternative interpretation of the Scapa Sands. The uncertainty on the seismic pick of the Scapa to the north of the field means a slightly deeper seismic pick for the Scapa could juxtapose the Scapa against the Captain Sandstones below the hydrocarbon contact which also would occur with a more northerly pinch-out of the Captain Sandstones onto the 14/29a-2 high.

Figure 4-7 shows three images (looking from the southwest) of the Goldeneye field with various model zones of the overburden model displayed. The upper image **(E)** shows the areal extent of the modelled Scapa Sandstone Member (olive) overlying the Top Triassic surface. Around the Goldeneye field, the Scapa is comparatively localised in extent, being only present in three wells (14/29a-2, 20/4b-6 & 20/4b-7). The Scapa is not present in the palaeotopographic low penetrated by the 14/29a-3 and 14/29a-5 wells, and is also absent in Wells 14/29a-4 and 20/4b-3 further to the east of the Goldeneye field. The middle image **(F)** shows the same view, but with a horizontal plane (blue surface), representing the Goldeneye OWC at 2619 m [8592 ft] TVDSS superimposed on it. This illustrates the extent of the Scapa Sands that are present above the OWC, to the north of the Goldeneye field. However, given the fact that Well 14/29a-2 drilled into this high and found no hydrocarbons in this condensed Scapa interval, it appears that there is no communication between the Captain and the Scapa Sands. It should be noted that there is no mapped Scapa structural closure within the PSDM seismic coverage. The lower image **(G)** additionally displays the Captain Sands (orange) protruding above the OWC, with the northern pinchout clearly shown.

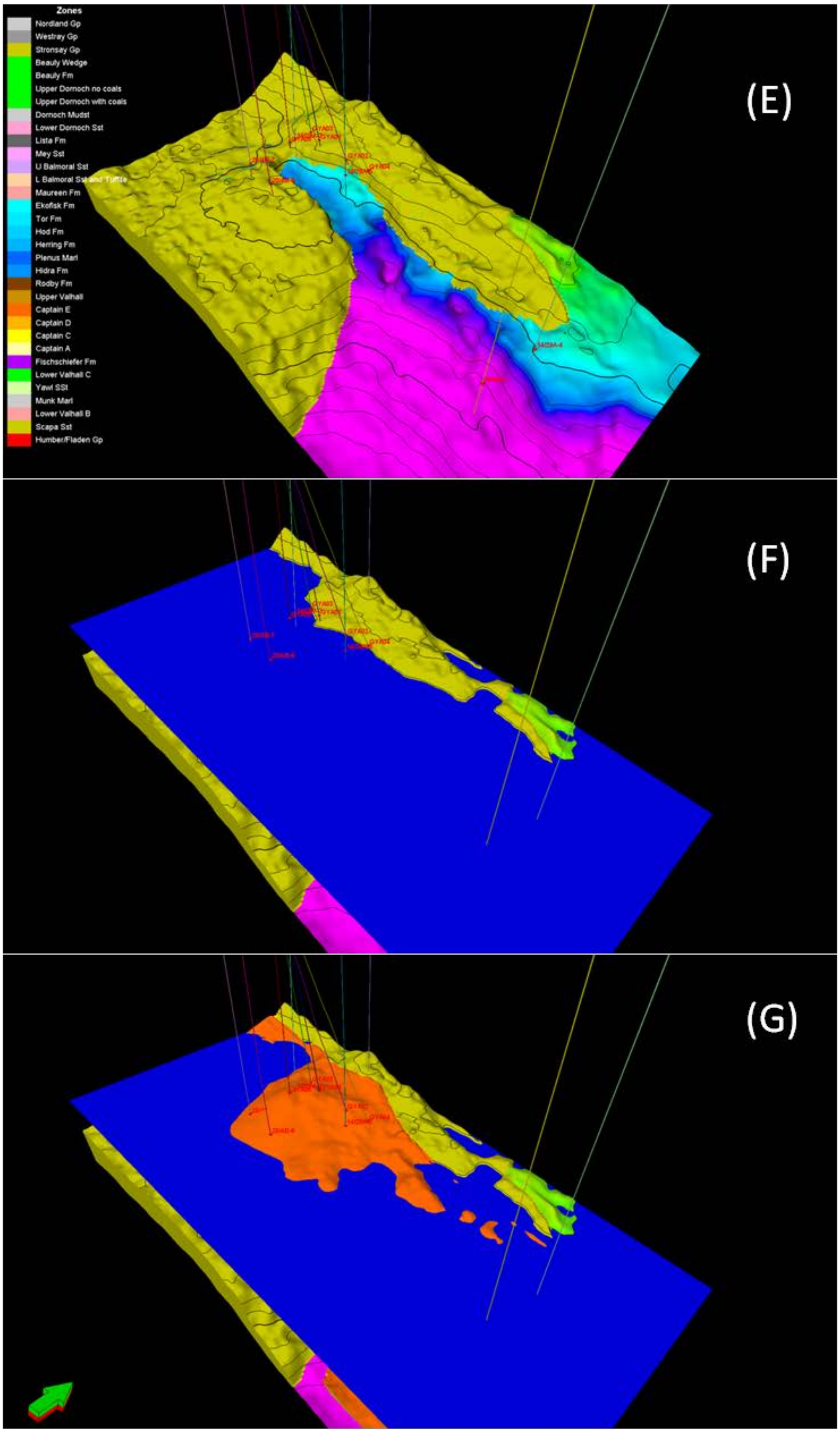

Figure 4-7: 3D view of modelled Scapa distribution around the Goldeneye field (vertical exaggeration x5).

No hydrocarbons were found in the Scapa sands in Well 14/29a-2. In this well, the Scapa sands are 41 m thick, and are well-cemented with a net to gross of 46%, average porosity of 11%, and an average permeability of 5 mD. Three repeat formation tester (RFT) pressure samples were attempted in the best developed sands, but all failed, indicating that the sands are very tight. A much thicker section of Lower Cretaceous Scapa Sands were encountered in Wells 20/4b-6 and 20/4b-7 (133 m and 151 m respectively) on the southern side of the field. These water-bearing wells had much better reservoir properties than the 14/29a-2 well, with a net to gross of 75% to 80% and average porosity of 22%. Figure 4-8 shows the petrophysical logs through the Scapa sands in Wells 20/4b-6 and 14/29a-2.

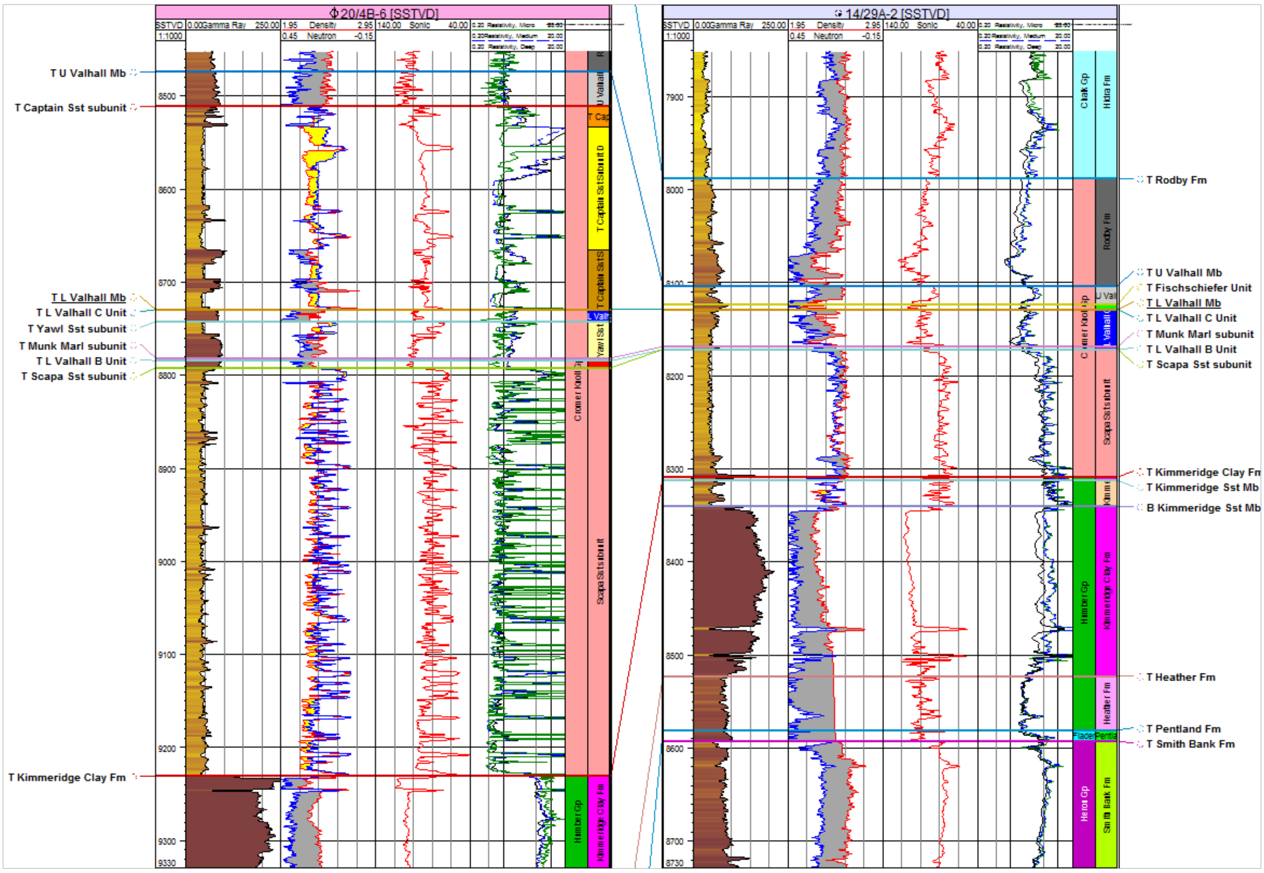

Figure 4-8: Well log from Wells 20/4b-6 and 14/29a-2 showing the Scapa sands.

Note: The display has been flattened on the Lower Valhall Member pick. Notethe absence of the Captain sandstones in Well 14/29a-2.

The lack of hydrocarbons in the Scapa Sands in Well 14/29a-2 can be explained by either:

- Cementation of the Scapa Sands on the northern flank of the field. The areal extent of the cementation of the Scapa Sands however is uncertain.
- The potential sand-on-sand juxtaposition may occur between the poorer quality Captain C unit, and not the Captain D unit which contains the majority of the hydrocarbons (and into which the CO_2 will be injected) – i.e. the Captain C is acting as a barrier.
- The presence of a thin drape of Lower Valhall Shale that ensures there is no direct connection between the Captain Sands and the Scapa Sands.
- The key evidence however, is the presence of the Goldeneye field itself. If there is communication with the Scapa Sands then one would not expect to find a large hydrocarbon accumulation contained in the Captain Sandstone reservoir. The field dynamic data also

supports the hydrocarbon initially in-place (HCIIP) volumes estimated for the Captain Sandstones.

Although the Scapa Sands were water-bearing in Well 14/29a-2, a 10 m gas condensate column was interpreted deeper in the section in the Upper Jurassic Burns Sandstone (Kimmeridge Sandstone Member) of the Kimmeridge Clay Formation. A gas-down-to was observed at 2544 m [8345 ft] TVDSS at the base of the Kimmeridge sands. A compound specific isotopic analysis (CSIA) profile obtained from fluid inclusions in cuttings from the Burns Sandstone in Well 14/29a-2 indicated that the hydrocarbons had a different signature to the gases found in the Goldeneye field. The differences are large enough to suggest that the 14/29a-2 well is not connected to the Goldeneye field. The CSIA profile also suggests that the gas in the 14/29a-2 well is less mature compared to the Goldeneye field. The Burns Sandstone has only been identified in Well 14/29a-2 in the Goldeneye area. However, it is below seismic resolution and its potential areal extent cannot be seismically mapped. The Burns Sandstone is dipping 4.5° at an azimuth of 160° in Well 14/29a-2. A plane was generated dipping at this angle (dashed purple line) as shown in the lower right image **(D)** in Figure 4-6. It suggests that any intersection with the Captain Sandstones is likely to occur in the water leg against the Captain A unit. Finally, a single reliable pressure RFT sample was obtained in the Burns Sandstone at 8406 ft (2562 m) MD which indicated that the Burns Sandstone was not on the same pressure trend as the Captain Sandstones. Overall, the evidence suggests that the Burns Sandstone and the Captain Sandstones are not in communication.

Figure 4-9 shows further cross sections through the reservoir section of the overburden model. The upper right image (**I**) shows a west-east cross section though the model. There is potential contact between the Captain A Sands and the Scapa at the western edge of the field. However, this is always below the OWC.

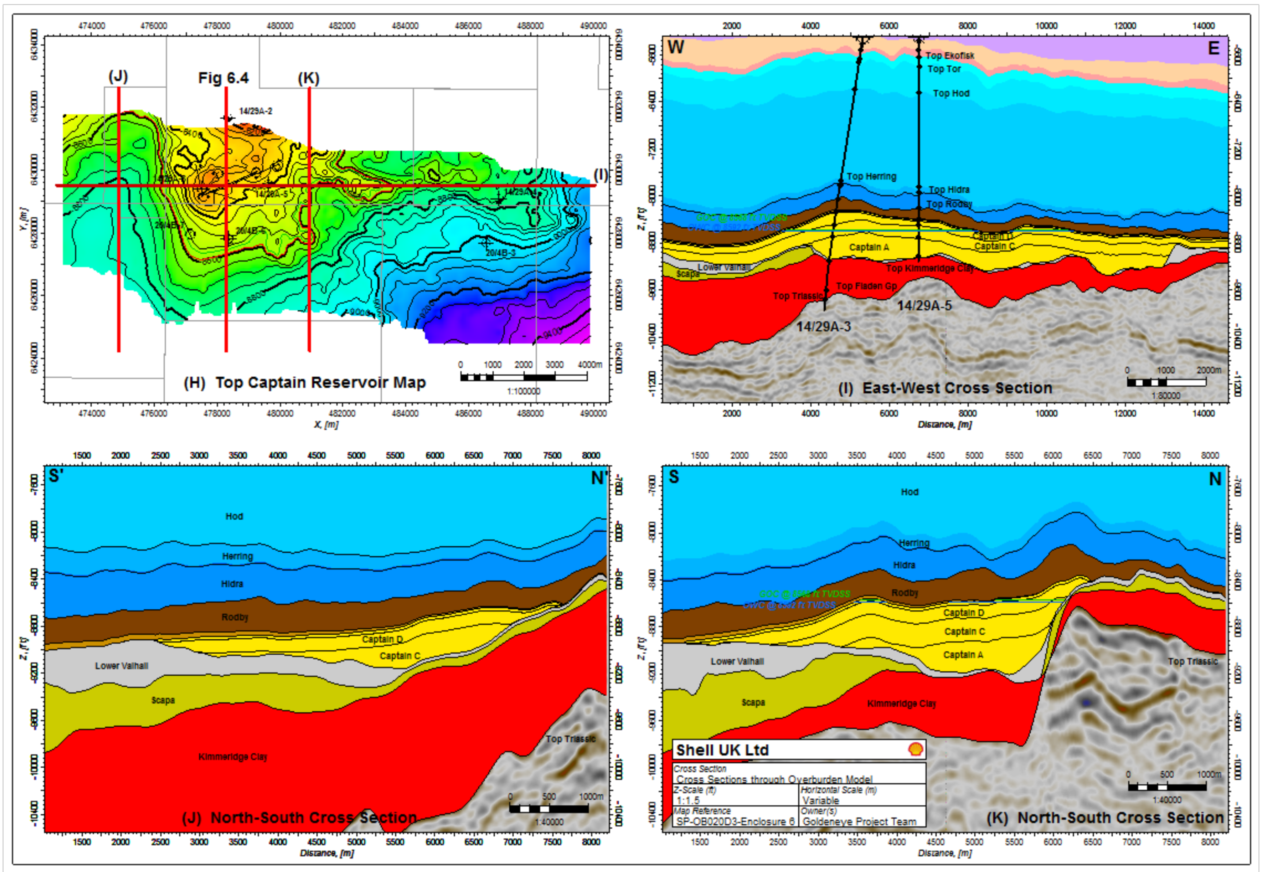

Figure 4-9: Cross sections through the reservoir section of the overburden model.

The lower images **(J & K)** both show north-south orientated cross sections similar to Figure 4-6. The lower left image (J) bisects the spill point on the western edge of the field. In this line of section to the west of the field, the Captain A Sand is not present (being confined to the palaeotopographic trough in the centre of the field). Where the erosive Captain A is not present, it is interpreted that the Captain C Sand overlies a thin 10 m zone of Lower Valhall, separating the Captain and Scapa Sands.

The lower right image **(K)** is a north-south orientated cross section through the eastern flank of the field. On the northern flank, the throw on the fault increases to the east of the field towards the Jurassic structural high that dominates the north-eastern corner of the overburden model AOI. Here there is potential juxtaposition between the Captain Sands and Jurassic (Fladen Group) and Triassic (Heron Group). However, this is most likely to be only within the water leg, and there are limited reservoir lithologies in the predominantly silty and shaley Fladen and Heron groups.

5. Overburden static modelling

The overburden static model was built using Petrel 2009.2.0.3 software. All distance units are metric, with depths measured in feet.

5.1. Model AOI

A geological Petrel model comprising an area approximately 17 km by 8 km around the Goldeneye field was constructed. The AOI was determined by the extent of the PSDM seismic data coverage. In the vertical direction the model extends from the seafloor (~2400 m above the Captain Sandstone reservoir) to the Top Triassic Heron Group (~900 m below the Captain Sandstone reservoir). The overburden model was gridded at a 50 x 50 m resolution, resulting in a total of 1.8 million cells (336 x 160 x 34).

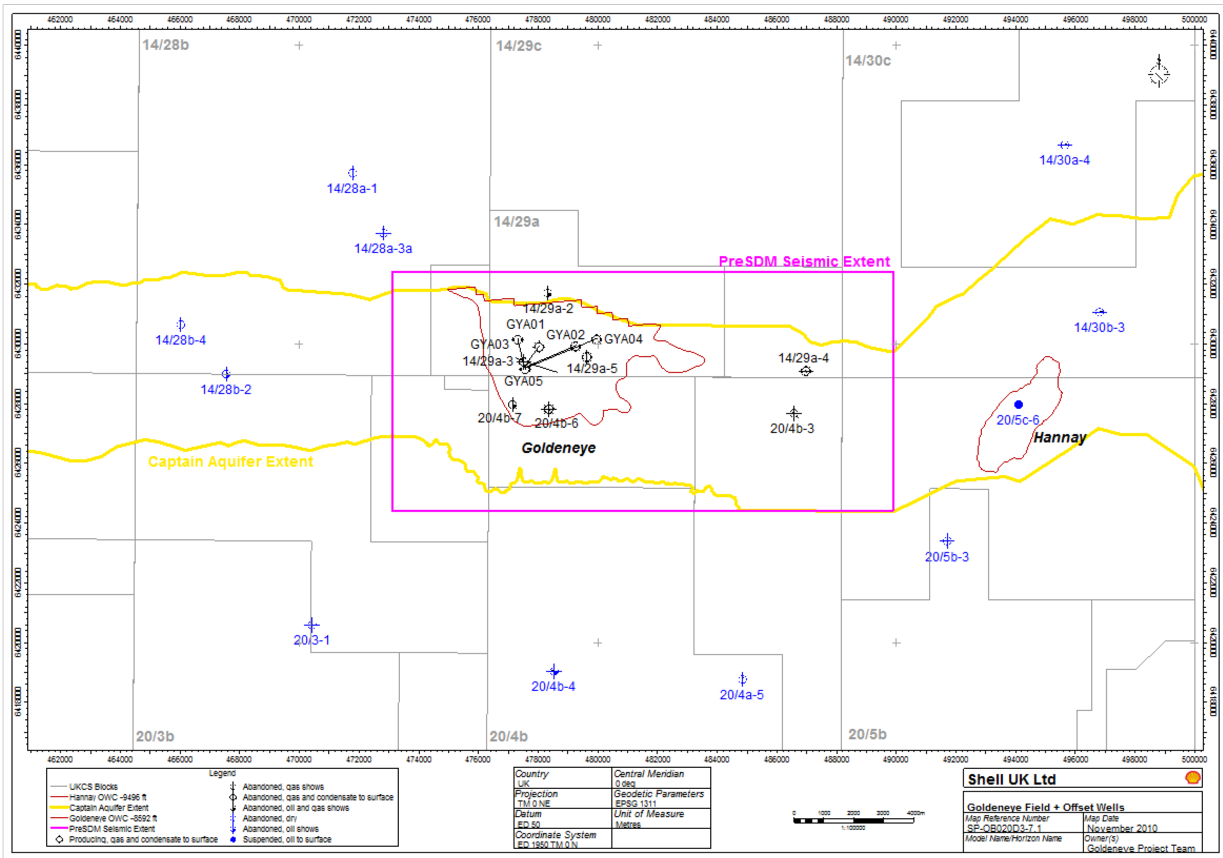

Figure 5-1: Goldeneye field and nearby offset wells.

Note: Extent of PSDM seismic data cube (and consequently of the overburden model) is shown in pink.

5.2. Model build workflow

Of the approximately 72 wells in the Halibut Trough area from the Blake to Hannay fields, twelve wells are used in the overburden model, and a further eleven wells are identified as closest offset to the overburden model (see Figure 5-1). The model was constructed using lithostratigraphic data only; faulting has not been included in the model build process. This is due to the occurrence of several fault sets within the stratigraphy (see section 6) and the practical limitations of the modelling software that requires faulting to extend through all zones in the model i.e. from top to bottom.

Within this AOI, eighteen seismic horizons were interpreted and imported into Petrel. These horizons were used to create the structural framework of the overburden model. The raw imported seismic data was gridded, edited and smoothed (where required) and tied to the well tops in Petrel prior to the model build.

A review of the lithostratigraphic correlation of the overburden in the AOI was undertaken. From this, fifteen additional correlatable stratigraphic horizons (that were not seismically resolvable), were defined and used along with the seismic horizons to create a 34 zone model extending ~4000 m down from the seabed to the top Triassic (Heron Group) (see Figure 5-2, Figure 5-3 & Table 5-1**)**. Each stratigraphic interval in the model is represented as one zone. The zones were assigned properties to indicate:

- The zonation between seismic mapped horizons.
- The detailed log stratigraphic zones.
- The stratigraphic units identified as aquifers and aquicludes.
- The average net to gross for each zone.
- The average net porosity for each zone.
- The average permeability for each zone.

A small number of minor inaccuracies are present in the model, most of which are the result of the difficulties in modelling some of the non-seismic horizons across the model. These are considered minor issues but are listed below for rectification if required in future updates of the model:

- The Lista Formation and Mey Sandstone stratigraphic horizons were isochored down from the Lower Dornoch Mudstone seismic pick. As a result, in places the surfaces do not correctly follow the approximate seismic dip, particularly to the south of the overburden AOI. Unfortunately, it is not possible to directly interpret the top Lista horizon on seismic due to the lack of contrast (acoustic transparency) in the thick sequence of Montrose Group sands and shales. The large thickness of lignites above generates considerable multiples and absorption losses.
- The Top Chalk (and Tor and Hod) horizons required significant smoothing, but still remain relatively uneven. The Top Chalk is naturally rugose due to sub-aerial weathering after deposition, but also the seismic has an undulating "ringing" effect generated by the near surface topography that was not removed during the seismic processing.
- The Upper Valhall should be continuous over the entire AOI but it is absent in a small area to the north of the field. The Upper Valhall is not an important zone, it is essentially just an extension to the Rødby and therefore this is not considered an issue.
- The Lower Valhall A should be modelled in the south east corner of the field as indicated by Well 20/4b-3. The Lower Valhall A occurs stratigraphically below the Scapa which is not present in the south east or in 20/4b-3. Without the base Scapa/Top Lower Valhall A being seismically mappable, the Lower Valhall A package becomes impossible to independently model. Hence the Lower Valhall A below the Scapa hiatus in the south east area is modelled

as part of the Lower Valhall B. As both intervals have similar properties and are both underburden stratigraphies this is not considered an issue.

- Due to modelling limitations the Yawl Sandstone is currently modelled in 14/29a-2 but is not seen in that well. Furthermore the presence of the Yawl to the north of the field is uncertain. In order to rectify this, a top and base Yawl Sandstone seismic interpretation or isochore map incorporating the pinchout is required as input to the modelling.
- Thin pockets of Lower Valhall B and A packages are modelled in the central trough where Captain Sands are interpreted to have eroded all Lower Valhall sediments, and cut down into the underlying Kimmeridge Clay Formation. This is due to modelling limitations forcing thin zones between seismic horizons. Editing of these anomalies has not been undertaken.

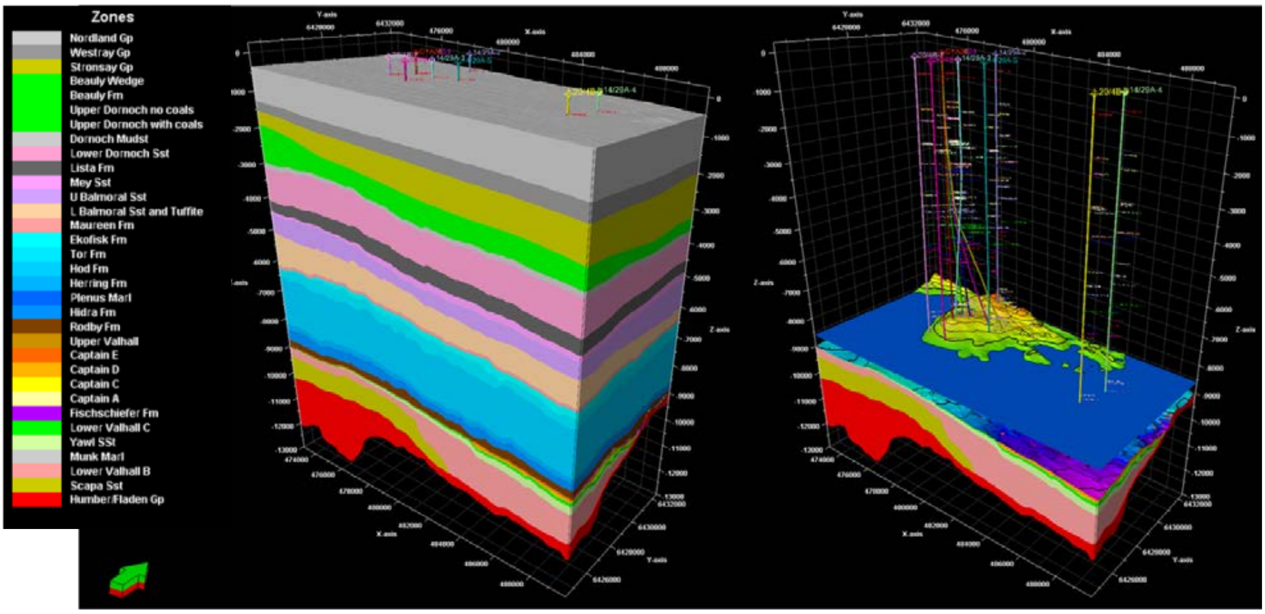

Figure 5-2: 3D view of the overburden model (5x vertical exaggeration).

Note: Right hand figure shows the Top Captain surface above the OWC at 2619 m [8,592 ft] TVDSS.

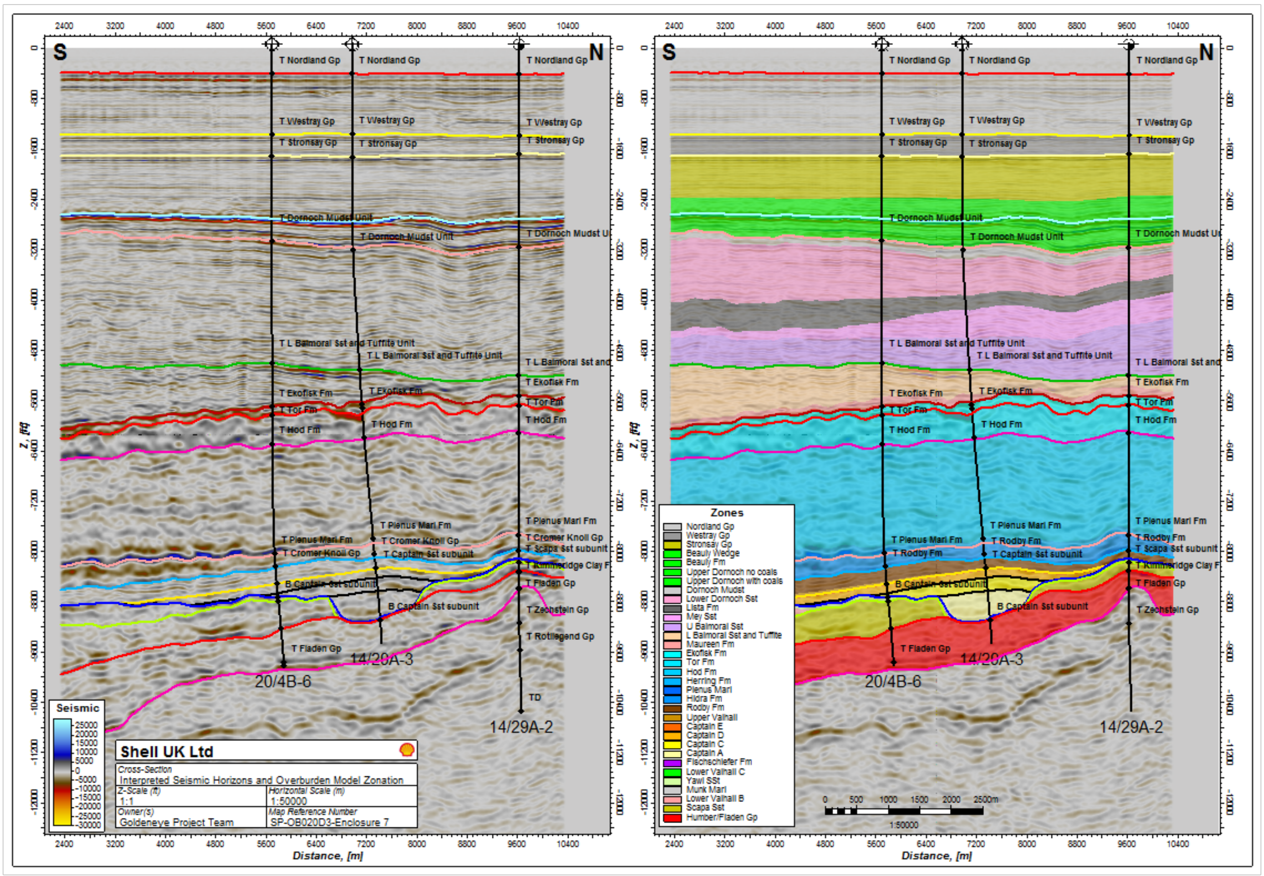

Figure 5-3: Cross section showing the interpreted seismic horizons in the overburden, and the resulting overburden model zonation.

Table 5-1: Interpreted seismic horizons and resulting modelled stratigraphy. Zones incorporating multiple tops are italicised.

Group	Stratigraphic Zone: Halibut Trough Logs	Seismic Horizon	Stratigraphic Zone: Petrel Model	
Nordland Group	**T Nordland Gp**	**y**	T Nordland Gp	1
Westray Group	**T Westray Gp**	**y**	T Westray Gp	2
Stronsay Group	**T Stronsay Gp**	**y**	T Stronsay Gp	3
Moray Group	**T Moray Gp**		supra beauly w edge*	4
	T Balder Fm / T Dornoch Fm / T Beauly Mb	**y**	T Beauly Mb	5
	T U Dornoch Sst Unit		T U Dornoch Sst Unit	6
		y (top coals)	Top coals	7
	T L Dornoch Mudst Unit	**y (base coals)**	T L Dornoch Mudst Unit	8
	T L Dornoch Sandst Unit		T L Dornoch Sandst Unit	9
Montrose Group	**T Montrose Gp**			
	T Lista Fm		T Lista Fm	10
	T Mey Sst Mb		T Mey Sst Mb	11
	T U Balmoral Sst Unit		T U Balmoral Sst Unit	12
	T L Balmoral Sst and Tuffite Unit	**y**	T L Balmoral Sst and Tuffite Unit	13
	T Andrew Sst		*only present outside the overburden model AOI*	
	T Maureen Fm		T Maureen Fm	14
Chalk Group	**T Chalk Gp**			
	T Ekofisk Fm	**y**	T Ekofisk Fm	15
	T Tor Fm	**y**	T Tor Fm	16
	T Hod Fm	**y**	T Hod Fm	17
	T Herring Fm		T Herring Fm	18
	T Plenus Marl Fm	**y**	T Plenus Marl Fm	19
	T Hidra Fm		T Hidra Fm	20
Cromer Knoll Group	**T Cromer Knoll Gp**			
	T Rodby Fm	**y**	T Rodby Fm	21
	T Valhall Fm / T U Valhall Mb		T U Valhall Mb	22
	T Valhall Sst Mb / T Kopervik Sst Unit / T Captain Sst subunit / T Captain Sst Subunit E	**y**	T Captain Sst Subunit (E)	23
	T Captain Sst Subunit D		T Captain Sst Subunit D	24
	T Captain Sst Subunit C		T Captain Sst Subunit C	25
	T Captain Sst Subunit A		T Captain Sst Subunit A	26
	B Kopervik Sst Unit	**y**	B Kopervik Sst Unit	
	T Fischschiefer Unit		T Fischschiefer Unit	27
	T U Valhall B Unit		*only present outside the overburden model AOI*	
	T U Valhall A Unit		*only present outside the overburden model AOI*	
	T L Valhall Mb / T L Valhall C Unit		T L Valhall C Unit	28
	T Yaw I Sst subunit		T Yaw I Sst subunit	29
	T Munk Marl subunit		T Munk Marl subunit	30
	T L Valhall B Unit		T L Valhall B Unit	31
	T Scapa Sst subunit	**y**	T Scapa Sst subunit	32
	T L Valhall A Unit		*combined with Valhall B where Scapa not present*	
	T Punt Sst subunit		*only present outside the overburden model AOI*	
	T Devils Hole		*only present outside the overburden model AOI*	
Humber Group	**T Humber Gp**	**y**	T Humber Gp	33
	T Kimmeridge Clay Fm			
	T Kimmeridge Sst Mb			
	T Heather Fm			
	T Heather SSt Mbr			
Fladen Group	**T Fladen Gp**		*only present outside the overburden model AOI*	
	T Piper FM			
	T Pentland Fm			
Heron Group	**T Heron Gp**	**y**	T Heron Gp **N.B. base of model**	
	T Skagerrak Fm			
	T Rattray Volcs			
	T Smith Bank Fm			
Zechstein Group	**T Zechstein Gp**	**y**		
	T Kupferschiefer Fm			
Rotliegend Group	**T Rotliegend Gp**			
	T ROTL			

5.3. Petrophysical modelling

A full petrophysical evaluation of the overburden lithology was carried out on the seven exploration/appraisal and five development wells in the Goldeneye area wherever data availability made this possible (3). A full set of overburden data acquisition was only obtained from the exploration/appraisal wells. In the development wells, standard log suites were only obtained across the reservoir interval. From the available log data, only porosity and net sand were evaluated using a unified method. Where not available from core study, permeability data was taken from analogue data from adjacent/other fields.

Total porosity for the overburden formations was computed from the bulk density, and then matched with in-situ (stress) corrected core porosity by applying a suitable fluid density. The total porosity was calculated using the following equation:

$$\varphi = \frac{(\rho_{ma} - \rho_b)}{(\rho_{ma} - \rho_{fluid})}$$

Where: ϕ = Total porosity (v/v)

ρ_{ma} = Matrix density (g/ cm^3)

ρ_b = Bulk density (g/ cm^3)

ρ_{fluid} = Fluid density (g/ cm^3)

A generic matrix density of 2.65 g/cm^3 for sandstone and 2.71 for limestone (chalk) was applied to the overburden wells. Fluid density depends on mud type assuming moderate mud filtrate invasion during drilling. The respective values for water-based-mud and oil-based-mud are 1.1 g/cm^3 and 0.9 g/cm^3.

Net-to-gross for the overburden formations (except the upper Chalk Group) was defined using GR derived shale volume cut-off ($V_{shale} < 0.5$) and porosity cut-off ($\phi > 0.1$). The GR shale volume was calculated using following equation:

$$V_{shale} = \frac{GR - GR_{sand}}{GR_{shale} - GR_{sand}}$$

Where: V_{shale} = Shale Volume (v/v)

GR = Measured gamma ray (API)

GR_{sand} = Sand baseline gamma ray (API)

GR_{shale} = Shale baseline gamma ray (API)

The resultant shale volume is consistent with the shale volume that is derived from the neutron-density method, and is therefore considered robust for net sand calculation. It was not applicable to use the same criteria for the upper Chalk Group. The Ekofisk, Tor and Hod formations, based on the log readings, have clean properties throughout resulting in a net-to-gross equal to 1.

Given the limited permeability data available for the overburden lithologies, analogue data was sought from neighbouring fields. For the Montrose Group, the permeability data was taken from published literature from various fields in the Halibut Trough. The permeability data was then adjusted using normalised GR data from the Goldeneye overburden wells. An average permeability of 0.001 mD was identified from analogues for the Chalk Group. The Chalk Group is water bearing and based on current analysis does not contain any geological features which may suggest property enhancement.

Average porosity, permeability and net-to-gross were calculated for each of the zones in the model. Using these averages and what is known of the lithology and stratigraphy as described in Appendix A, an interpretation was made on whether the zone would act as a storage unit for CO_2 i.e. act as an "aquifer", or act as an "aquiclude".

The following properties listed in Table 5-3 were assigned to each zone (stratigraphic unit) in the model (see Figure 5-4).

Table 5-2: Petrophysical properties assigned to zones in the overburden model.

Model Zone	Aquifer?	NTG	POR	Perm (mD)	
Nordland	Aquiclude	0.45	0.30	100	Overburden
Westray	Aquifer	0.40	0.33	500	
Horda	Aquifer	0.60	0.34	500	
Supra_Beauly_Wedge_d	Aquifer	0.47	0.33	470	
Beauly	Aquifer	0.47	0.33	470	
Upper Dornoch no coals	Aquifer	0.47	0.34	370	
Upper Dornoch SST with coals	Aquifer	0.47	0.34	370	
Lower Dornoch Mudst	Aquiclude	0.27	0.34	80	
Lower Dornoch SST	Aquifer	0.39	0.32	290	
Lista	Aquiclude	0.06	0.24	0.08	
Mey SST	Aquifer	0.46	0.34	210	
Upper Balmoral Tuffite	Aquifer	0.61	0.30	350	
L Balmoral Tuffite	Aquifer	0.81	0.27	350	
Maureen	Aquifer	0.83	0.24	370	
Ekofisk	Aquifer	1.00	0.11	0.001	
Tor	Aquifer	1.00	0.04	0.001	
Hod	Aquifer	1.00	0.06	0.001	
Herring	Aquifer	0.99	0.05	0.001	
Plenus Marl	Aquiclude	0.40	0.07	0	
Hidra	Aquiclude	0.99	0.05	0	
Rodby	Aquiclude	0.00	0.00	0	
Upper Valhall	Aquiclude	0.05	0.11	0.01	
Captain E	Aquifer	0.63	0.24	150	
Captain D	Aquifer	0.94	0.25	1000	
Captain C	Aquifer	0.33	0.22	500	
Captain A	Aquifer	0.86	0.23	450	
Fisch	Aquiclude	0.00	0.00	0.00	Underburden
LVH C	Aquiclude	0.05	0.11	0.01	
Yawl SST	Aquifer	0.86	0.18	100	
Munk Marl	Aquiclude	0.00	0.00	0	
LVHB (A)	Aquiclude	0.00	0.00	0.01	
Scapa	Aquifer	0.75	0.22	100	
Kimm,Heather,Fladen	Aquiclude	0.20	0.20	20	

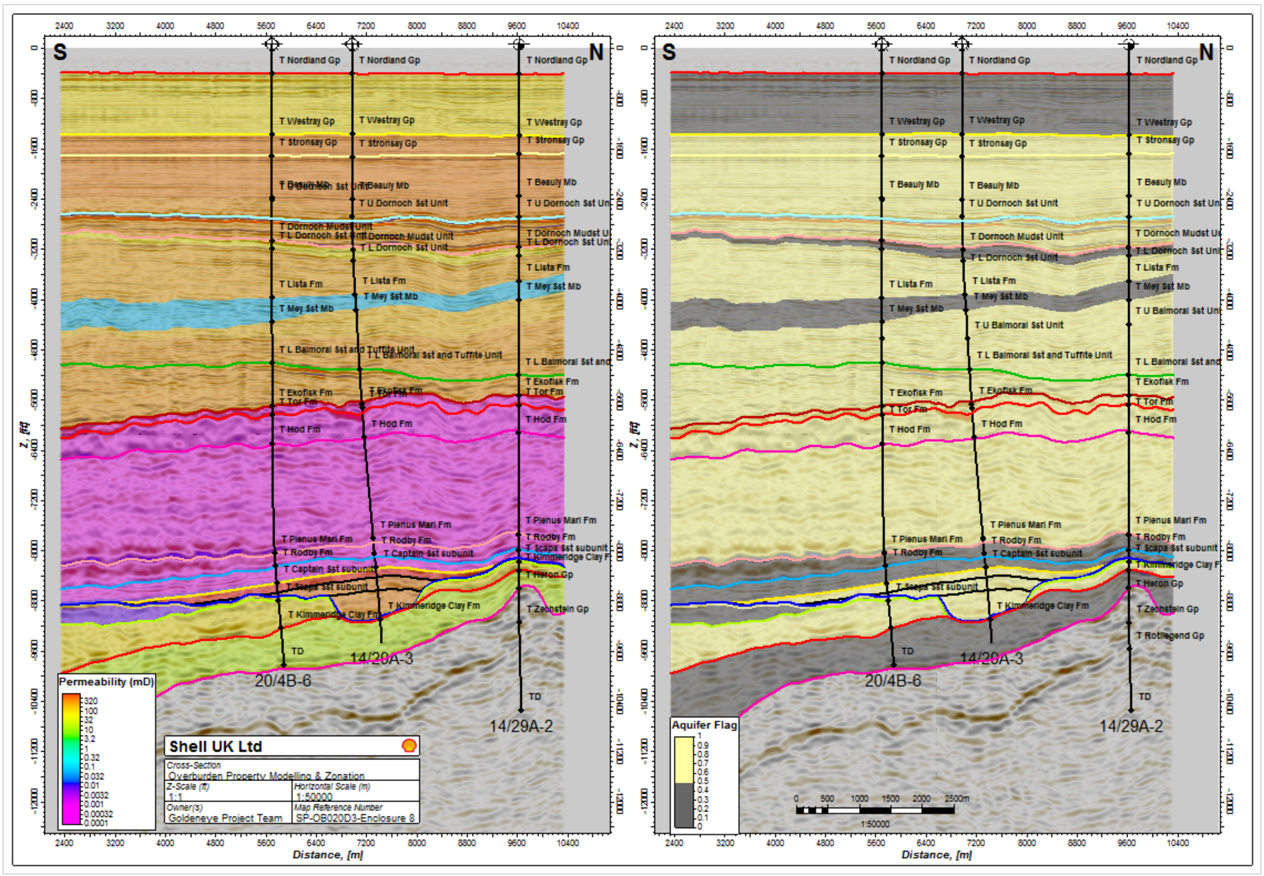

Figure 5-4: **Left hand cross section through model shows average permeability. Cross section on the right highlights the aquifer / aquiclude lithologies in the overburden.**

6. Faulting in the overburden model

A detailed study was undertaken to review the extent of faulting in the overburden interval above the Goldeneye field. For the Goldeneye full field model the initial fault interpretations were focused at reservoir level only. For the overburden model, a full review of the reservoir level and overburden faulting was undertaken to ensure that the full extent of faults penetrating the caprock were mapped.

On a regional scale the Moray Firth has undergone a complex structural evolution. The basic structural trends align WNW, ENE and east-west. There is also an important cross-cutting NE to NNE trend, seen as structural highs and fault zones which were important in subdividing the basins and acting as zones of intermittent uplift such as the Grampian Arch (see Figure 3-1).

During the Late Jurassic, extension resulted in the development of ENE and east-west trending tilted fault blocks and associated half-grabens. The imprint of older lineaments, including the NE-SW Caledonian trend is apparent throughout the basin's history. Jurassic rifting was followed by Early Cretaceous subsidence with minor compression. There was also a fundamental change in the tectonic regime at Aptian-Albian level, which significantly is the period when the Captain Sandstone was deposited. During this time there was a lessening of the influence of basin subsidence and the start of greater influence on the basin by a north-south compressive regime.

A major change in structural regime and sedimentation also occurred in the Early Tertiary due to ca.1 km of uplift of the Inner Moray Firth, Scottish Highlands and the East Shetland Platform areas. During this period large quantities of clastics, derived from the uplifted areas to the west, were deposited in the Outer Moray Firth and Central Graben areas. There was also a continuation of the mild north-south compressive regime which warped the top Chalk surface and funnelled the Captain Sandstone east-west through the basin.

The main development of the Goldeneye structure began in the Late Cretaceous and culminated in the Early Tertiary. The Early Tertiary uplift of the Inner Moray Firth and continued subsidence of the Outer Moray Firth and Central Graben resulted in strong eastward tilting of the area which enabled hydrocarbons to migrate updip, through the Captain Sandstone fairway and into the Goldeneye structure.

The Goldeneye faults were interpreted using the 2001 PSDM reflectivity data (4). A semblance volume (which highlights lateral changes in amplitude) was also used extensively to help to highlight structural trends and lineaments. Figure 6-1 summarises the extent of faulting in the overburden. Different faults types have developed at different stratigraphic levels clearly controlled by the mechanical characteristics of the different lithologies. The following section describes the fault geometry at the key stages of the basin evolution.

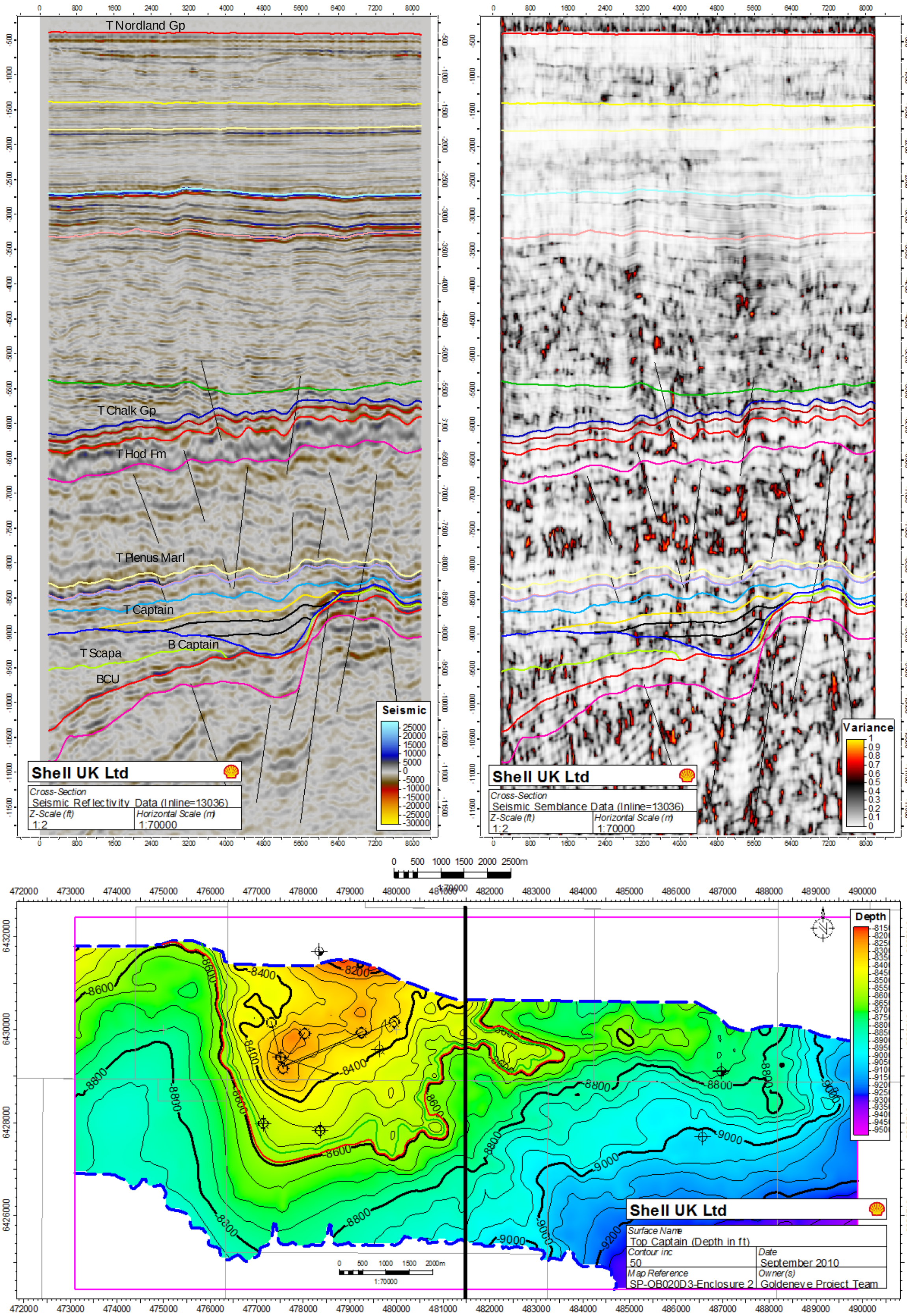

Figure 6-1: North-south TWT reflectivity and equivalent semblance seismic sections.

Note: Fault decoupling due to mechanical stratigraphy (e.g. ductile Rødby/Plenus).

6.1. Underburden faulting

The long lived WNW-ESE and east-west structural lineaments influenced sedimentation from the Triassic through to the Tertiary. Figure 6-2 shows the mapped faults at Top Triassic, Heron Group. The structural high to the north of the Goldeneye field (drilled by Well 14/29a-2) is clearly evident at this time, and remained a dominant feature defining the available accommodation space for Jurassic and Cretaceous deposition.

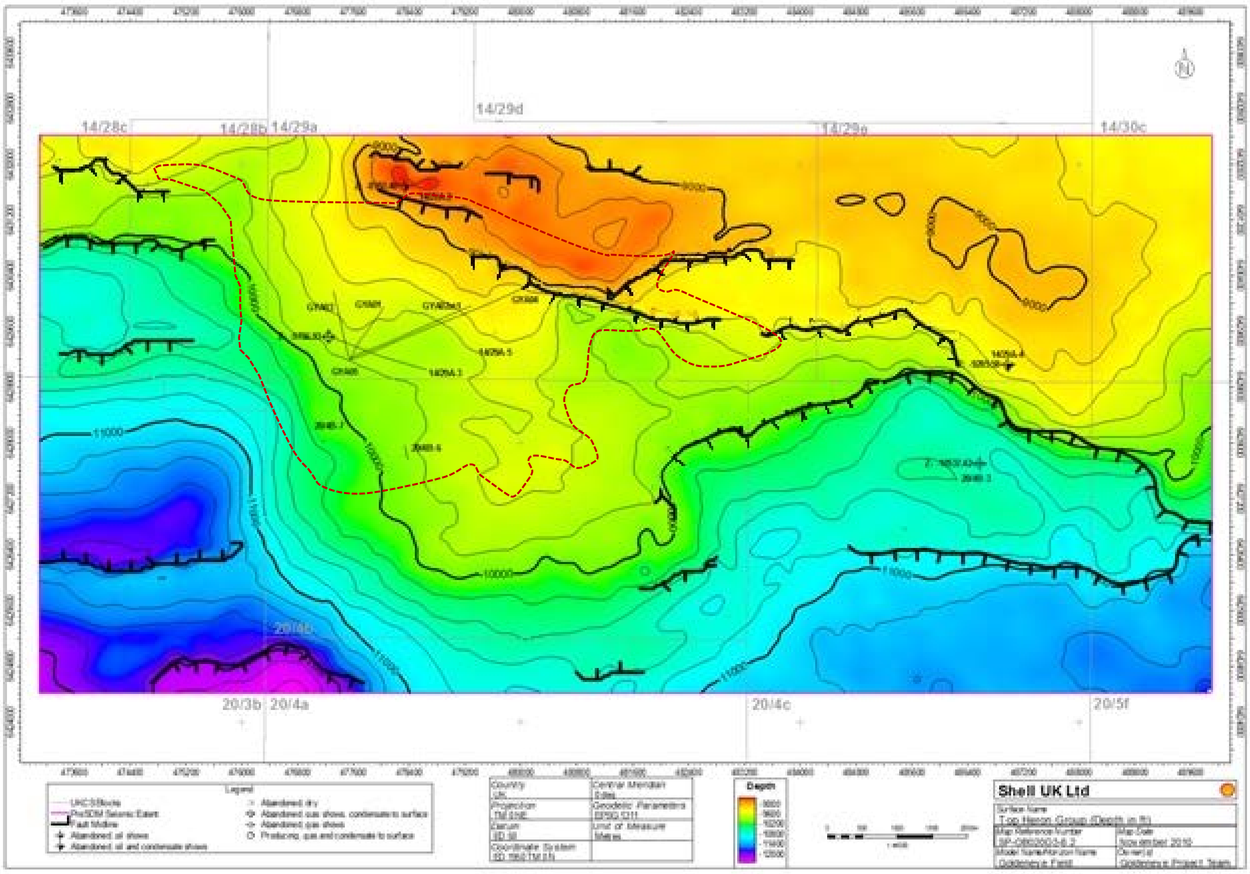

Figure 6-2: Faulting at top Heron Group (depth in feet, 100 ft contour intervals, Goldeneye outline stippled)

The faults at the Base Cretaceous Unconformity (BCU) level trend predominantly east-west, parallel to the regional structural trend (see Figure 6-3). There are three main fault zones that influence the overall reservoir geometry of the Goldeneye field which act to limit the distribution of the basal Captain A Sandstones. To the north of the field, there is a zone of east-west southerly dipping faults that mark the northern limit of the thickest Captain Sandstone accumulation. This northern bounding fault marks the transition from the thickest reservoir accumulation to the thin drape of sediments that extends to the north of the fault. At BCU level it has a maximum throw of approximately 120 m and generally increases in throw from west to east across the field. In the west of the field and north of the 14/29a-3 well, this fault tips out and another en-echelon fault takes up the throw. This second fault has a small SW-NE transfer or relay fault linking the two that makes the northern bounding fault a continuous feature in this area of the field. To the south of the field, there is a zone of northerly dipping east-west faults. There are a series of fault linkages and relay zones running to the east from the southern edge of this zone. At the western edge of the Goldeneye mini-basin, there is a terrace consisting of two north-south sub-parallel easterly dipping faults. The throws on these faults are approximately 20 m. This zone appears to act as a transfer zone at the western extent of both the northern and southern fault zones.

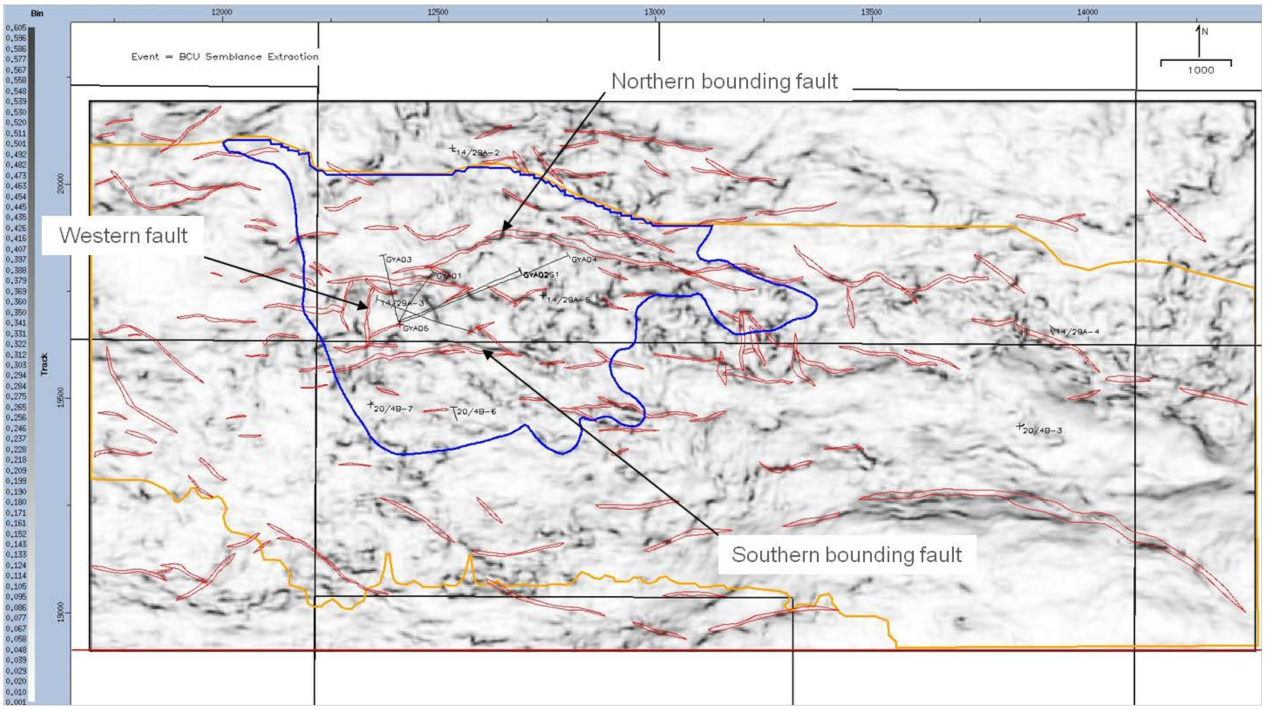

Figure 6-3: BCU fault polygons overlain on BCU semblance horizon.

6.2. Reservoir faulting

The fault pattern at Top Captain (Figure 6-4) also parallels the observed regional structural trends orientated WNW-ESE to east-west. The mapped faults are of limited vertical and lateral extent with small throws (20 m). The greatest fault density is evident around the subsurface location of Well 14/29a-3 where fracture zones have been identified in core from the Captain Unit D reservoir interval. By contrast, few fracture zones have been identified in core from Well 14/29a-5 which is located in an area with fewer mapped faults.

There is little evidence for intra-reservoir compartmentalisation based on the current seismic resolution. Any faults propagating up through the reservoir from deeper horizons appear to have little or no throw, therefore juxtaposition in the upper Captain Sandstone units will be sand-on-sand and are not expected to present any barriers to CO_2 flow. Studies into fault sealing potential show that the Captain Sandstones are clean and that cataclasites identified in core do not represent significant barriers to fluid flow, which suggests any faulting should not result in fluid barriers or baffles. The production history from the five production wells completed in the Captain D has also not shown any evidence of compartmentalisation.

Fractures are not interpreted to be pervasive through the reservoir section. Detailed analysis of two borehole images (BHI) from Wells 14/29a-4 and 14/29a-5 showed that fracture systems are most likely, associated with faults. The fractures do not appear to create systems that interconnect vertically.

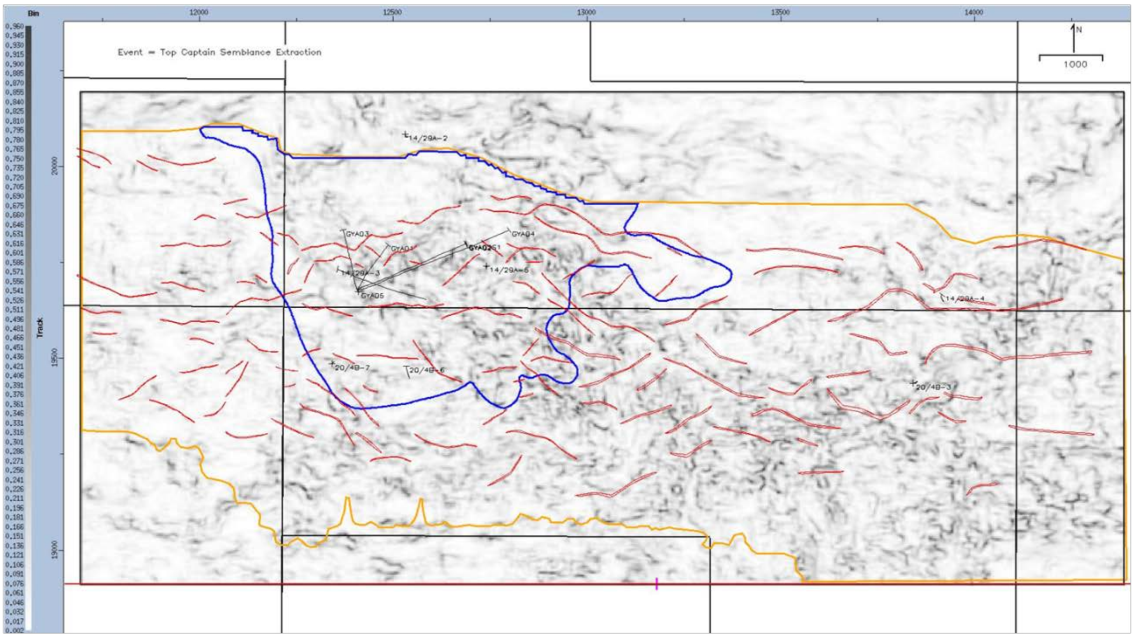

Figure 6-4: Top Captain fault polygons overlain on Top Captain semblance horizon.

6.3. Chalk Faulting

The Chalk faults trend north-west to south-east and are mainly developed over the eastern and south-eastern flank of the field (see Figure 6-5). These Chalk faults are generally decoupled from the WNW-ESE to east-west trending reservoir level faults and also do not extend far into the overlying Montrose Group. This suggests that the faults that offset the Chalk and Montrose groups are most likely not related to the syn-rift to late rift reservoir faults and have developed in a different phase within the structural evolution of the region (late thermal subsidence phase).

The fault interpretation in the Chalk section, however, is complicated by the variable seismic character of the Chalk as a result of prolonged sub-aerial weathering and intense karstification following deposition, which has caused strong variability in the seismic reflectivity.

An analysis of fracture density and patterns in the Chalk Group suggests the Hod Formation shows a relatively higher density of fractures than seen at reservoir level. However, fracture growth and distribution is still controlled by the internal mechanical variability within the formations in the Chalk Group and are “disconnected” along the vertical path of the fault system. It is considered, therefore, that fractures do not pose a risk for containment in the Chalk or within the top reservoir seal.

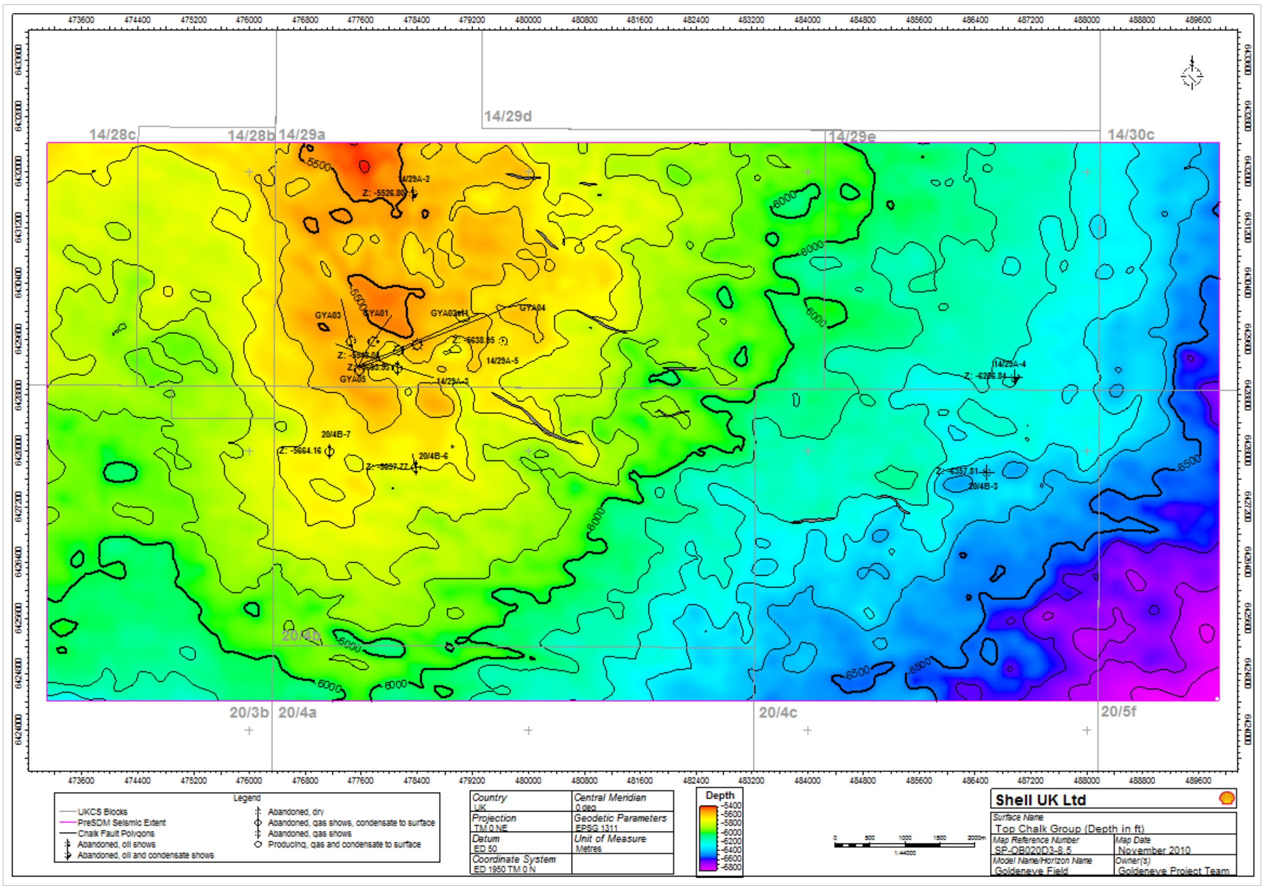

Figure 6-5: Fault polygons at top Chalk Group (ft).

6.4. Tertiary faulting

Above the Chalk Group, there is little evidence of significant faulting. The seismic imaging is hindered in the Montrose Group by the presence above of thick, laterally variable coal packages. The coals generate considerable multiples and cause absorption losses. Some obvious vertical discontinuities are also visible at shallower depths, particularly around the bright amplitudes of the Eocene coal interval (see Figure 6-1). This vertical striping is not interpreted as faulting, but is likely to be a geophysical artefact generated by the "edge effects" (velocity contrasts) from the overlying coals. Where individual coal events die out, it generates a zone of seismic disturbance that "echoes-on" for a further 900 ms below. These (coal) paleo-shorelines create very sharp north-south lineaments over the Goldeneye field. The paleo-shoreline is clearly observed in semblance time slices and shows the shoreline retreating westwards, marked by the outlets of subaerial channels and estuaries (see Figure 6-6).

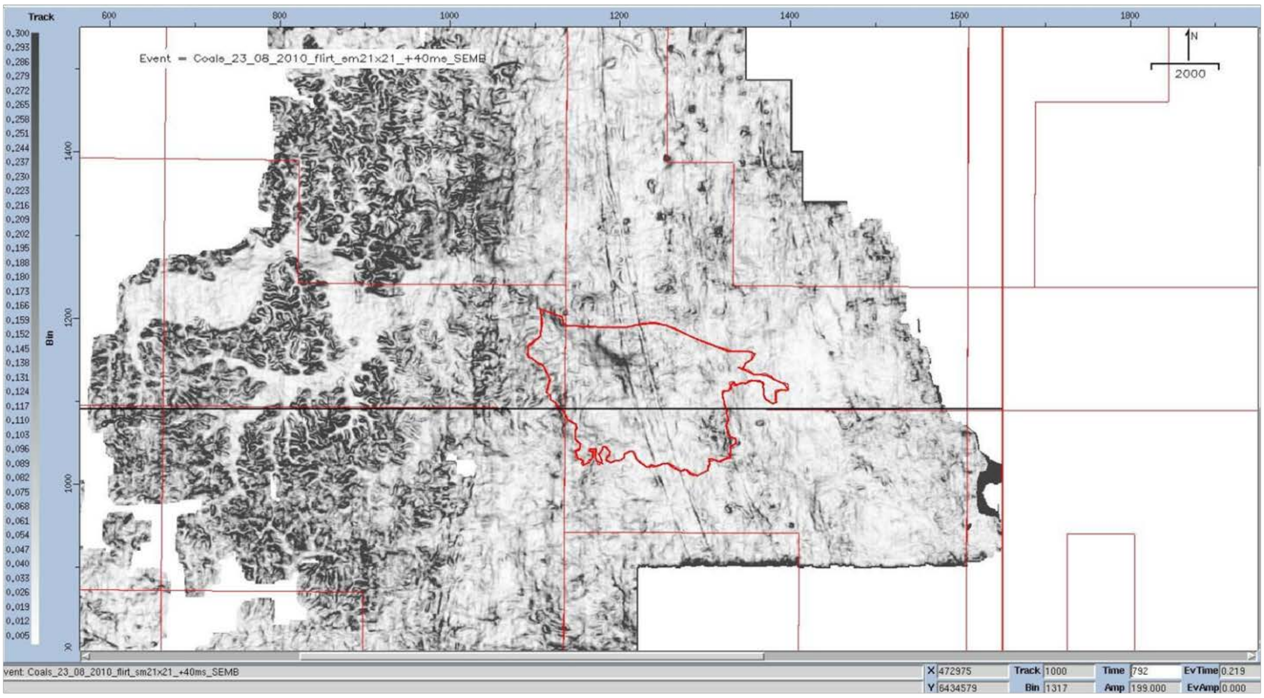

Figure 6-6: Paleo-shoreline and drainage network as observed in the semblance map (from the Greater Ettrick 3D survey) through the Eocene Coals

Note: Semblance extracted from interpreted coal event at approximately 760 m to 970 m. Field outline – OWC at 2619 m [8592 ft] is superimposed.

7. Conclusions

A study of the Goldeneye overburden has been undertaken to understand the location and distribution of secondary containment horizons and potential migration pathways in the overburden in the event that CO_2 migrates out of the structural closure of the Goldeneye field. To address and visualise the issues, a 3D static model was constructed in Petrel, and the lithology, stratigraphy and structure of the over and underburden was evaluated.

The calcareous and chalky mudstones of the Rødby Formation are the primary seal to the Goldeneye field, supplemented by the immediately overlying Hidra and Plenus Marl Formations. The main conclusion from this study is that CO_2 is not expected to leak through the top Rødby seal which has already proven to be a competent seal over geological time, or via reservoir level faults as they do not offset the sealing caprock.

Any migration of CO_2 vertically out of the Captain reservoir could potentially be contained above the Goldeneye field within a number of overlying aquifers bounded by the Lista Formation. The Lista Formation is identified as a secondary sealing interval in the overburden above the Goldeneye field. It comprises non-calcareous, bioturbated, non-carbonaceous and non-pyritic mudstones, and is a proven hydrocarbon seal in the central North Sea. CO_2 could also potentially be constrained by the Dornoch Mudstone. There are, however, no secondary structural closures identified in the overburden above the Goldeneye field. The potential migration of CO_2 in the Mey Sandstone Member (below Lista mudstone) will be addressed in the Storage Development Plan.

At least two different fault sets are present in the overburden, but these faults are considered to be decoupled from the Captain reservoir faults by the ductile Rødby/Hidra/Plenus Marl sediments.

In summary it is concluded that any migrating CO_2 from the reservoir is not expected to reach the surface via pathways originating within the deeper parts of the overburden.

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9. Glossary of Terms

Term	Definition
AOI	Area of Interest
BCU	Base Cretaceous Unconformity
BHI	Borehole image
CCGT	Combined cycle gas turbine
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
CSIA	Compound Specific Isotopic Analysis
E&A	Exploration and Appraisal
ENE	East-Northeast
ESE	East-Southeast
EUR	Estimated Ultimate Recovery
FFSM	Full Field Static Model
GOC	Gas-Oil Contact
GR	Gamma Ray (wireline log)
HCIIP	Hydrocarbons Initially In Place
MD	Measured Depth
NE	Northeast
NNE	North-Northeast
OWC	Oil-Water Contact
PSDM	Pre-Stack Depth Migrated
RFT	Repeat Formation Tester
SRM	Static Reservoir Model
SW	Southwest
TVDSS	True Vertical Depth Subsea
TWT	Two-Way Time
UKCS	United Kingdom Continental Shelf
UKOOA	United Kingdom Offshore Operators Association
WNW	West-Northwest

In the text well names have been abbreviated to their operational form. The full well names are given in Table 9-1 below.

Table 9-1: Well name abbreviations

Full well name	Abbreviated well name
DTI 14/29a-A3	GYA01
DTI 14/29a-A4Z	GYA02S1
DTI 14/29a-A4	GYA02
DTI 14/29a-A5	GYA03
DTI 14/29a-A1	GYA04
DTI 14/29a-A2	GYA05

10. Glossary of Unit Conversions

Table 10-1: Unit Conversion Table

Function	Unit - Imperial to Metric conversion Factor
Length	1 Foot = 0.3048 metres

11. Appendix A

The following section gives a sedimentological and lithological description of all of the overburden stratigraphic units, and a summary of their distribution across the overburden model AOI. The following lithostratigraphic descriptions are taken from the UKOOA, 1992 definitions (5).

11.1. Nordland Group

The Nordland Group consists of an undifferentiated interval of grey to brown coloured poorly bedded, soft, silty mudstones and siltstones with subordinate sands. Its upper boundary is the seabed, and its lower boundary is marked by a sharp downward decrease in the GR wireline log often corresponding to the base of a high GR peak. It is present everywhere across the model AOI.

11.2. Westray Group

The Westray Group consists of two formations, an upper shelfal sand section, the Skade Formation, and a lower basin mudstone section, the Lark Formation. In a regional context the Skade Formation dominates to the west, and the Lark in the east. It is the Skade Formation that is present over the Goldeneye field.

11.2.1. Skade Formation

The Skade Formation is made up of fine to coarse grained shelly sandstones with minor brown muds and silts. It is marked by a sharp downward decrease in GR often corresponding to the base of a high GR peak.

11.3. Stronsay Group

Within the Moray Firth area one division, the Mousa Formation, is present. The lateral equivalent towards the Central Graben area, is termed the Horda Formation. This transition occurs in areas east of Block 15/21 (in Goldeneye context Renee sub-basin blocks 15/26 to 21/1 area). The Mousa Formation consists of a basal mudstone unit overlain by an upward coarsening sequence of siltstones and sandstones and represents deposition in an inner to outer shelf setting. The Mousa Formation overlies the Moray Group (Beauly Member) in the Goldeneye area, and Balder Formation to the east. In both cases units comprising high GR glauconitic mudstone mark the lower boundary. The underlying sands, lignites or non-glauconitic mudstones lie outside the Mousa Formation.

11.4. Moray Group

The Shelfal Succession of the Moray Group comprises the Dornoch Formation, and the Sele and Balder Formations. The relationship between the Dornoch and Balder Formations is complex and variable but the Dornoch essentially represents the eastward progradation of a major deltaic/coastal plain system.

11.5. Dornoch Formation

The Dornoch Formation is regionally subdivided into four members although these are rarely all developed in a single well. The uppermost unit is the Beauly Member, characterised by the presence of lignites and distinctive pale grey or variegated mudstones. This overlies three informal lithostratigraphic units, the Upper Dornoch Sandstone, Dornoch Mudstone and the Lower Dornoch Sandstone. The Dornoch Formation represents a progressive change from shelf sand sedimentation (Lower Dornoch Sandstone), through prograding delta front mudstone and sandstone sedimentation (Dornoch Mudstone and Upper Dornoch Sandstone), to paralic delta top sedimentation (Beauly Member). The internal subdivisions of the Dornoch Formation are not clearly marked by log signatures and miss-picking is common. In the Goldeneye area the Top Lower Dornoch Mudstone is taken as approximately the equivalent to the base of the lowest coal package that is seismically interpretable.

11.5.1. Beauly Member

The Beauly Member comprises a complex association of sandstones, siltstones, mudstones and lignites and represents fresh to brackish water sedimentation in a paralic, coastal plain environment. The upper boundary is generally marked by a downward decrease in GR with a marked increase in sonic velocity seen at the boundary, except where lignites are found at the top of the section. The base of the Beauly Member is taken either at the base of the lowermost lignite, or at the base of the persistent claystone that locally underlies this. The Beauly Member is present within the overburden model AOI.

11.5.2. Upper Dornoch Sandstone Unit

The Upper Dornoch Sandstone Unit is a series of upward coarsening siltstone-sandstone cycles representing a prograding delta front. The top is marked either at the base of the lowermost lignite of the Beauly Member, or at the base of the persistent claystone interval that locally underlies this lignite. The lower boundary is a gradational change between sand and the underlying Dornoch Mudstone and is taken where mudstone becomes predominant. It is only present in the overburden model AOI and closest offset wells, not in the regional Halibut Trough area.

11.5.3. Lower Dornoch Mudstone Unit

The Lower Dornoch Mudstone comprises a subtle upwards coarsening sequence from silty mudstone to muddy siltstone with a GR maximum at the base of the unit. The Lower Dornoch Mudstone is only consistently present in the overburden model AOI and closest offset wells, and is not widely present in the regional Halibut Trough area.

11.5.4. Lower Dornoch Sandstone Unit

The shelf sands of the Lower Dornoch Sandstone are presumed to have sourced turbidite fans (e.g. Forties) to the Central Graben area. These single or multiple sandstones are interbedded with silty mudstones. The upper boundary is noted by a GR deflection associated with the switch from the dominantly siltstone/mudstone intervals of the overlying Dornoch Mudstone to the sand rich sections of the Lower Dornoch Sandstone. The Lower Dornoch Sandstone rests directly on the green-grey or olive-grey poorly bedded mudstones of the Lista Formation. It is only present in the overburden model AOI and closest offset wells, not in the regional Halibut Trough area.

11.6. Montrose Group

The Montrose Group comprises two formations, the upper Lista Formation characterised by the presence of interbedded sandstones and mudstones deposited in a well oxygenated basin, and the lower Maureen Formation which comprises a mudstone dominated succession. The sandstones of the Montrose Group were deposited as submarine fans. The characteristic mudstone successions differ from those of the overlying Moray Group in that they contain abundant microfauna and are poorly bedded, non-pyritic and for the most part non carbonaceous.

11.6.1. Lista Formation

A four-fold subdivision of this formation has been defined. It comprises an uppermost un-named mudstone facies dominated unit which is underlain by the Mey Sandstone Member which itself is divided into an Upper Balmoral Sandstone Unit, Balmoral Tuffite Unit and Lower Balmoral Sandstone Unit. The Lista Formation represents a range of environments from outer shelf to basin with shelf sands being redistributed to form slope aprons of superimposed and laterally coalescing fans. The sandstones and tuffite represent outer slope, shelf and basin environments. The tuffite itself is derived from air fall deposits associated with Hebridean province volcanism.

The Lista mudstone facies is characterised by non-calcareous, bioturbated, non-carbonaceous and non-pyritic mudstones and grading to claystone in places. The dominant colour is pale green-grey to grey-green. The lower boundary is marked by a GR decrease and sonic velocity increase associated with the development of massive well developed sand facies. The Lista mudstone facies is widely present in the Halibut Trough area (60 out of 72 wells) and is present in all the overburden model AOI and closest offset wells.

11.6.1.1. Mey Sandstone Member

This is equivalent to the Andrew Formation outside of the Goldeneye area. The Mey Sandstone Member itself is subdivided into an Upper Balmoral Sandstone Unit and a Lower Balmoral Sandstone Unit based on the presence of a mid tuffaceous sand (the Balmoral Tuffite Unit). It consists of variable sandstones, mostly ranging from fine to medium grade and displaying more pervasive cementation than the Balmoral Sandstones. Its upper boundary marks the start of stacked sequences of interbedded massive sands and shales. Its lower boundary corresponds to a sharp downward change from sandstone to green-grey mudstone associated with an increase in GR values and a corresponding decrease in sonic velocity. It is present in all overburden model wells and closest offset wells but is not widely distributed elsewhere in the Halibut Trough area.

11.6.1.2. Upper Balmoral Sandstone Unit

The Upper Balmoral Sandstone Unit consists of sandstones, mostly ranging from fine to medium grained and displaying variable cementation. Its upper boundary is typically defined by a downward change from green grey to grey green mudstone and sandstone associated with a decrease in GR and an increase in sonic velocity. In the Goldeneye area, the base of the Upper Balmoral Sandstone Unit coincides with the Balmoral Tuffite unit. It is present in all overburden model wells and closest offset wells, but is not elsewhere in Halibut Trough area.

11.6.1.3. Lower Balmoral Sandstone and Tuffite Unit

The Tuffite Unit is commonly associated with a regional shale interval and is identified by a distinct resistivity peak and exceptionally low GR values. It consists of well sorted silt to sand grade basaltic tuff particles, generally medium to dark grey green or brown in colour. Its lower boundary is marked by an increase in GR from exceptionally low values to background ‘sand’ values, and a decrease in resistivity and return to the interbedded massive sands and shales in stacked sequences. It is present in all overburden model wells and closest offset wells but is not elsewhere in Halibut Trough area.

11.6.2. Maureen Formation

The Maureen Formation is lithologically heterogeneous and includes mudstones, siltstones, sandstones and reworked limestones (chalk). In the Goldeneye area both sands and mudstones are present – the latter being predominant and easier to correlate in well data. The mudstone is light to medium grey with a gradational change becoming increasingly calcareous (marly) down section. There are also some subordinate fine to medium grained sandstones often with a chalky matrix present. The upper boundary is characterised by a sharp change from sandstone to green grey mudstone associated with an increase in GR values and a corresponding decrease in sonic velocity. The lower boundary is generally characterised by a rapid downward transition from marl to the limestones of the Ekofisk Formation. On wireline logs the base Maureen / top Ekofisk is taken at the top of the consistent low GR Ekofisk limestone which also corresponds to a shoulder on the sonic log marking the top of the high velocity chalk section. It is present over much of the Halibut Trough area (50 wells) and all of the overburden AOI and closest offset wells.

11.7. Chalk Group

The Chalk Group is widely distributed over the central North Sea and is seen in all wells in the Halibut Trough area. The North Sea chalk exhibits hairline, stylolite-associated, and tectonic fractures (6). The latter two may be open to fluids whereas hairline fractures have little influence on permeability. Without a way of sampling the fracture matrix over the overburden model AOI, it is hard to accurately assess whether the chalk would behave as a strong or weak aquifer (or even as an aquitard).

11.7.1. Ekofisk Formation

The Ekofisk Formation consists of hard white pale grey to beige limestones and chalks as well as argillaceous chalky limestone units. It is present everywhere in the overburden model AOI but thins towards the southwest.

11.7.2. Tor Formation

The Tor Formation consists of white or pale grey chalk. The lithologically uniform lower part consists of bioturbated pelagic chalk showing an upward transition into laminated bioturbated chalk cycles. It is present everywhere in the Halibut Trough.

11.7.3. Hod Formation

The Hod Formation comprises a white to pale grey argillaceous chalky limestone. It is heterogeneous and contains a relatively high clay content although there are also intervals of pure chalk. Bioturbation is common. It is present everywhere in the Halibut Trough.

11.7.4. Herring Formation

The Herring Formation consists of white to pale grey hard dense limestone with interbedded argillaceous chalky limestone and dark grey to red mudstone. It is present everywhere in the Halibut Trough.

11.7.5. Plenus Marl Formation

The Plenus Marl Formation comprises black mudstones which were deposited during a phase of stagnant and partly anoxic conditions. It is present everywhere across the Halibut Trough.

11.7.6. Hidra Formation

The Hidra Formation consists of fine grained white-grey strongly bioturbated limestones with interbedded dark grey to red brown mudstones, which were typically deposited in an open marine environment as pelagic coccolith oozes. It is present everywhere across the Halibut Trough.

11.8. Cromer Knoll Group

The limits of the Lower Cretaceous are taken at the top and base of the Cromer Knoll Group. The base of this group corresponds to a marked upward change in facies from dark organic rich claystones of the Kimmeridge Clay and equivalent to claystones, and carbonates deposited under oxidated bottom water condition (7). The top of the Cromer Knoll Group lies within a depositional sequence of latest Albian to earliest Cenomanian age. Most hydrocarbons found in the Lower Cretaceous are in sandstone reservoirs which are interpreted as deep water mass flow deposits. Both the areal and age distributions of these sandstones is complex and not easily understood because of the biased and widely spaced well penetrations. Most wells (particularly in the northern North Sea) are drilled on Mesozoic highs across where only condensed Lower Cretaceous intervals were deposited, the off structure Lower Cretaceous depocentres recognised on seismic data remain mostly undrilled. Much of the clastic material shed into the basin during this time was preferentially transported by gravity flows into the bathymetric lows. Sub-basins adjacent to sediment entry points developed thick packages of submarine fan sandstones such as the Scapa, Punt and Yawl. The regional litho-stratigraphic description and understanding of the Lower Cretaceous of the North Sea has been compromised however by the use of numerous localised nomenclatures. Sandstones in particular have many informal names e.g. Aptian sandstones in the Britannia field are named Britannia sands, Kopervik sands, Bosun sands, and Shirley sands on well logs (7).

11.8.1. Rødby Formation

The Rødby Formation directly underlies the Late Cretaceous Hidra Formation and ranges in age from Middle to Late Albian. It consists of calcareous and chalky mudstones with sporadic thin beds of argillaceous limestone. The mudstones are mainly pale to dark grey but are often red-brown, brick red, olive grey and dark brown. The red mudstones are most commonly seen in the uppermost and lowermost units of the formation. Its upper boundary is characterised by a subtle downward increase in GR values and a decrease in velocity. Lithologically the top of the Rødby Formation is marked by a change from the interbedded grey and pink limestones, chalks and calcareous mudstones of the Hidra Formation (often with a basal limestone) to less calcareous mudstones and chalky mudstones. Its lower boundary is marked by a downward increase in GR values and a decrease in velocity. It is present over much of the Halibut Trough area (42 wells) and all of the Goldeneye overburden AOI and closest offset wells.

11.8.2. Valhall Formation

The Valhall Formation ranges in age from intra-Late Rhyazanian to intra-Late Aptian. It consists of a thick sequence of interbedded calcareous mudstones, chalky mudstones and thin limestones with thick localized mass flow sandstones. The mudstones are generally pale to dark grey in colour and less commonly grey-green and red-brown and are micro-micaceous, pyritic, glauconitic and carbonaceous. Thin but regionally extensive units of black, laminated, non-calcareous mudstones are also present. The limestone units contained within the Valhall Formation are usually white to pale grey, but locally tan and yellow-orange to red-brown. They tend to be microcrystalline or argillaceous, and locally micro-laminated or sandy. Where the formation is condensed over palaeo-highs it often contains a higher proportion of limestones. Its upper boundary is marked by a downward increase in both velocity and density which is commonly very rapid. Locally, the boundary is also marked by a small downward decrease in average GR values. The base of the Valhall Formation is seen as a sharp downward increase in GR values and a decrease in velocity where the Kimmeridge Clay Formation underlies the Valhall. However, locally, where deep water sands directly overlie the Kimmeridge Clay Formation, the contact is highly erosive. Lithologically the boundary is taken at a sharp downward change from pale grey and grey calcareous mudstones, chalky mudstones and limestones to dark brownish grey or black, non-calcareous, organic-rich mudstones. The Valhall Formation is widely distributed over the central North Sea where it reaches maximum thicknesses in the grabens and thins onto the basin margins and over intra-basinal highs. In the Goldeneye area the thickness variation of the Valhall Formation is somewhat confused by the presence of the Captain and Scapa sandstones which locally erode into the underlying Kimmeridge Clay Formation. However, in the Basinal Area to the south of Goldeneye, beyond the Captain Sandstone pinchout, the Valhall reaches thicknesses of over 300 m (e.g. Well 20/4b-4).

11.8.2.1. Upper Valhall Member

In the vicinity of the Goldeneye field immediately below the Rødby Formation lies the Upper Valhall Member which is the first member of the Valhall Formation. This member is not further subdivided and is essentially a lithological extension of the Rødby Formation, in that it is a 6-12 m thick pale to dark grey mudstone. The Upper Valhall Member is present over much of the Halibut Trough area (40 wells) and all of the Goldeneye overburden AOI and closest offset wells.

11.8.2.2. Valhall Sandstone Unit / Kopervik Sandstone Unit / Captain Sandstone Unit

At Goldeneye the sandstone package below the Upper Valhall Member has three equivalent names, Valhall Sandstone Unit Kopervik Sandstone Unit, and the Captain Sandstone. Within the Goldeneye field, it is referred to as the Captain Sandstone, and the reservoir can be sub-divided into four litho-stratigraphic units; Captain E, Captain D, Captain C and Captain A. Units C-E can be correlated across Goldeneye, with Unit C representing a field-wide shale-dominated horizon. By contrast, Unit A occurs only in Wells 14/29a-3 and 14/29a-5 and appears to be controlled by the fault geometry or erosional scour at base Captain Sandstone.

11.8.2.2.1. Captain Sandstone Subunit E

The Captain E unit comprises an interbedded marginal net to gross interval present at the top of the Captain Sandstone reservoir. Sediments from this unit have been recovered in core from Wells 14/29a-5 and 20/4b-7. The sandstones within this unit can appear ‘dirty’ due to 2-3% detrital clay fractions and also show evidence of dewatering. They are interpreted to have been deposited from high-density turbidity currents with minor contributions from mudclast-rich debris flows. Dewatering/sandstone remobilisation occurred subsequent to deposition, as caprock and overburden sediments accumulated. It has a laterally variable thickness across overburden AOI. The Captain E is hydrocarbon bearing in Goldeneye field.

11.8.2.2.2. Captain Sandstone Subunit D

The Captain D unit has traditionally been referred to as the uppermost well-developed Captain Sandstone in the area. Reservoir quality is generally very good to excellent. The Captain D Unit is the primary reservoir unit of the Goldeneye field, containing 78% of the HCIIP, in which all of the development wells within the Goldeneye field have been completed. The D Unit, has been extensively cored in all the exploration and appraisal wells in the Goldeneye field. It comprises medium grained sandstones, that are massive bedded and, (with the exception of a fining-upwards sequence at the top of the unit seen in all wells in the field), show only subtle changes in grain size. Heavy mineral analyses and palaeocurrent indicators suggest that both laterally (north-south) and axially oriented (west-east) turbidite systems contributed to deposition. Mudclasts are dispersed throughout the massive sands, as well as locally being concentrated within individual debris flow beds. The Captain D Sandstone is laterally extensive across the Halibut Trough area.

11.8.2.2.3. Captain Sandstone Subunit C

The Captain C unit comprises a heterogeneous clastic sequence containing a considerable proportion of extra basinal material, presumably deposited through the action of mass wasting processes. This is seen in the cores taken in Wells 14/29a-3, 14/29a-5 and 20/4b-7. The facies present in this interval point to a variety of processes being active during the period of its deposition. It is interpreted to have been dominated by deposition by debris flows sourced from the structural high to the north of the Goldeneye field, during a time of relative quiescence in the basin, perhaps related to eustatic sea-level rise. Both high and low-density turbidity currents flowed through the area of the Goldeneye field during Captain C times, producing reservoir sands of varying quality. The Captain C is laterally extensive across the Halibut Trough area.

11.8.2.2.4. Captain Sandstone Subunit A

The Captain A unit comprises the lowermost unit in the Captain Sandstone and consists of massive, medium grained sandstones. It was cored in Well 14/29a-3 only. This sandstone is typically of lower reservoir quality which may be associated with basal erosion of the Captain sand system into the underlying strata (Lower Valhall and Kimmeridge Clay) and/or a possible alternative provenance. The depositional model for this unit points to a localized deposition within a fault bounded or erosively scoured basin, from a turbidite fan system sourced in the Halibut Horst, directly to the north of the Goldeneye field. The Captain A is marginally hydrocarbon bearing in the Goldeneye field (<1% HCIIP).

N.B. The Captain B interval is not recognised as a regionally extensive unit. This unit has been previously identified in the Goldeneye area but is not used in regional correlation work.

11.8.2.2.5. Fischschiefer Unit

The Fischiefer unit is an Early Aptian, black, laminated, noncalcaeous mudstone. It has a distinctive high GR log character and biostratigraphic assemblage. It is thin, but regionally extensive.

11.8.2.2.6. Upper Valhall B Unit

The Upper Valhall B unit consists of a sequence of interbedded calcareous mudstones and chalky mudstones.

11.8.2.2.7. Upper Valhall A Unit

The Upper Valhall A comprises a mud prone interval of the Valhall Formation, containing mudstones that are generally pale to dark grey in colour and less commonly grey-green and red-brown and are micro-micaceous, pyritic, glauconitic and carbonaceous.

11.8.2.3. Lower Valhall Member

The Lower Valhall Member consists of a sequence of interbedded calcareous mudstones, chalky mudstones and thin limestones with thick localized mass flow sandstones such as the Yawl and Scapa Sandstones.

11.8.2.3.1. Lower Valhall C Unit

The Lower Valhall C unit is a more mud prone section of the Valhall Formation, containing mudstones that are generally pale to dark grey in colour and less commonly grey-green and red-brown and are micro-micaceous, pyritic, glauconitic and carbonaceous.

11.8.2.3.2. Yawl Sandstone Subunit

The Yawl Sandstone is of Late Barremian to Earliest Aptian in age. It consists of very fine to coarse grained sandstones with minor interbedded calcareous mudstones. The sandstones are mainly quartzose with traces of pyrite and glauconite. Sorting varies from poor to good. The sands generally have a blocky GR signature. Thin calcite cemented doggers are also commonly seen and marked by high velocity spikes. The Yawl sands usually comprise comparatively thin sandstones interbedded with Valhall mudstones, which rapidly shale out eastwards into the Renee Sub-Basin and also southwards from the Halibut Shelf into the South Halibut Basin.

11.8.2.3.3. Munk Marl Subunit

The Early Barremian Munk Marl subunit consists of black, laminated, non-calcareous mudstones. It has a distinctive high GR log character and biostratigraphic assemblages. It is thin, but regionally extensive.

11.8.2.3.4. Lower Valhall B Unit

The Lower Valhall B comprises a mud prone interval of the Valhall Formation, containing mudstones that are generally pale to dark grey in colour and less commonly grey-green and red-brown and are micro-micaceous, pyritic, glauconitic and carbonaceous.

11.8.2.3.5. Scapa Sandstone Subunit

The Scapa Sandstone subunit is Early Hauterivian to Earliest Barremian in age. It consists of interbedded calcareous sandstones, conglomerates, mudstones and chalky mudstones. The sandstones are fine to medium grained and mainly massive to poorly laminated. Clasts of micrite and mudstone, together with carbonaceous debris and broken shelly material are dispersed throughout the sandstones. Laminated sandstones, very fine to very coarse grained pebbly sandstones and thin, bioturbated, well sorted sandstones are also relatively common. The sandstones generally have sharp bases and bed thickness varies between 0.2 and 2 metres. The conglomeratic beds are matrix-supported with poorly sorted pebble to boulder sized clasts. Matrix composition varies from grey-green sandy mudstone to coarse sandstone. Slump structures and deformed clasts are common within the conglomerates.

The Scapa Sandstone is widely distributed around the Halibut Horst and is also found within the East Orkney Basin (see Figure 11-1). Scapa sands are also present in the western Witch Ground Graben. The main provenance areas for the Scapa sands are thought to be the Halibut Horst and the East Orkney High. Around the Goldeneye field, the Scapa Sandstone Member is comparatively localised in extent, being only present in three wells (14/29a-2, 20/4b-6 & 20/4b-7), and absent in the palaeotopographic low penetrated by the 14/29a-3 and 14/29a-5 wells. It appears to be a localised sand fairway sourced from the Halibut Horst (whilst the main clastic flow is to the north of the Halibut Horst into the Scapa field). Scapa sands are next seen along the Halibut Trough in Well 13/30-1 in the Cromarty Sub-basin.

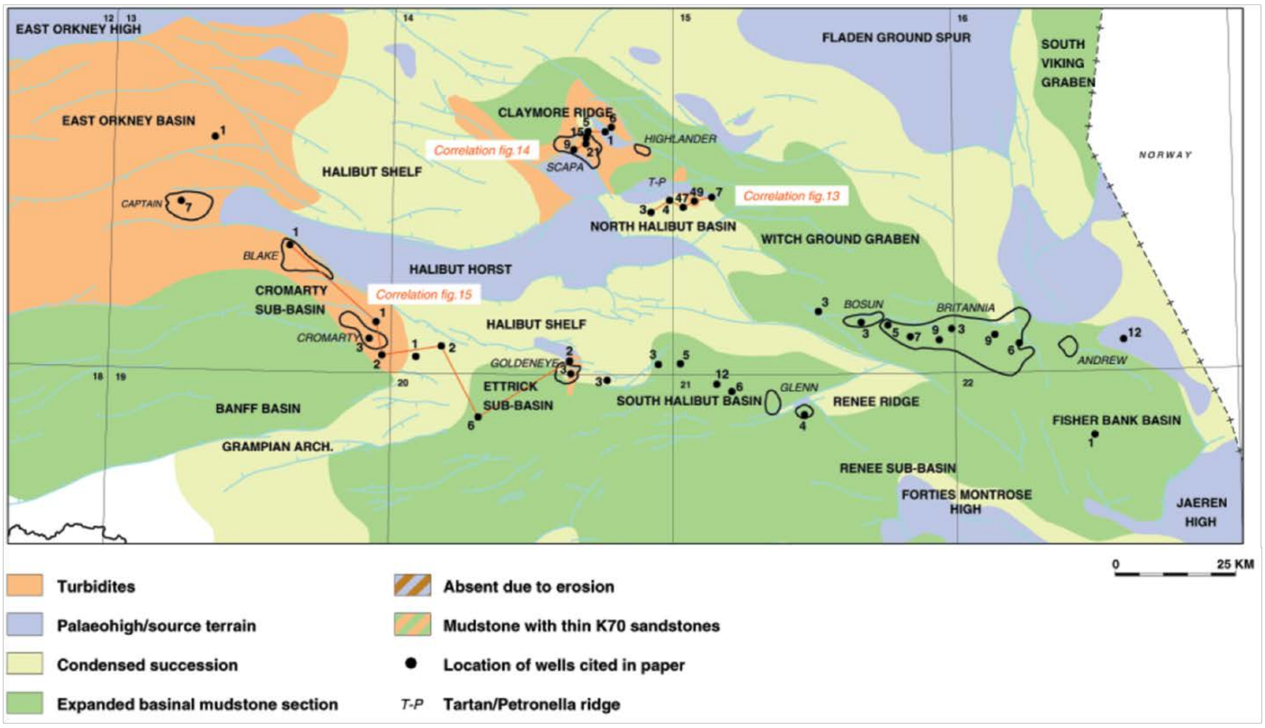

Figure 11-1: Regional facies map for the K30/K40 sequences: Scapa Sandstone Member (Early Hauterivian to earliest Barremian) (after Jeremiah 2000) (8).

11.8.2.3.6. Lower Valhall A Unit

The Lower Valhall A unit is a more mud prone section of the Valhall Formation, containing mudstones that are generally pale to dark grey in colour and less commonly grey-green and red-brown and are micro-micaceous, pyritic, glauconitic and carbonaceous.

11.8.2.3.7. Punt Sandstone Subunit

The Punt Sandstone subunit consists of a series of Intra-Late Ryazanian to Late Valanginian sandstones with interbedded siltstones and mudstones. The sandstones are very fine to very coarse grained and poorly sorted. They are quartzose, contain minor amounts of glauconite, carbonaceous debris and mica and white to pale grey in colour. The interbedded mudstones and siltstones are pale to dark grey or tan, micromicaceous, variably calcareous and blocky to fissile. Sporadic, thin, off-white argillaceous and sandy limestones are also locally present. The upper boundary is defined by a downward change from grey, calcareous and micromicaceous Valhall Formation mudstones to sandstones and interbedded mudstones. The lower boundary is marked by a downward change from sandstone dominated lithologies to grey, red-brown or varicoloured mudstones with thin-bedded limestones and chalky mudstones of the Valhall Formation. It is widely distributed around the Halibut Horst and is also present in the Ettrick and Cromarty sub-basins.

11.9. Humber Group

11.9.1. Kimmeridge Clay Formation

The Base Cretaceous Unconformity surface is thought to be the result of major tectonic events related to the opening of the proto-Atlantic. The Kimmeridge Clay Formation claystones have a high total organic carbon content and were deposited in relatively deep water within a marine basin with restricted circulation. These sediments have been shown to be the source of most (if not all) of the central and northern North Sea's hydrocarbon reserves and, where buried to sufficient depth in the Fisher Bank Basin at the eastern end of the Halibut Trough, are thought to be the source of the of the gas condensate in the Goldeneye field. The Kimmeridge Clay Formation is Uppermost Ryazanian in age, and consists of dark brownish grey or black, non-calcareous, organic-rich mudstones. It is usually very easy to distinguish as a sharp downward increase in API values of the GR log between the lowermost Valhall Formation and the Kimmeridge Clay Formation. However, where a sandstone member (e.g. the Captain Sandstone in Well 14/29a-3) rests directly upon the Kimmeridge Clay, it can be more difficult to identify.

The Kimmeridge Clay Formation also contains isolated mass flow sands such as the Burns Sandstone Member which was only encountered in Well 14/29a-2 in the Goldeneye area. The sandstones were interpreted to be hydrocarbon bearing in this well.

11.9.2. Heather Formation

The Heather Formation consists of Late Callovian to Middle Oxfordian open marine mudstones with some siltstones.

11.10. Fladen Group

11.10.1. Pentland Formation

The Pentland Formation was deposited in alluvial plain and deltaic environments and consists of sandstones, siltstones and shales with some interbedded coals. The Lower to Middle Jurassic has a discontinuous distribution in the Moray Firth. It was initially widespread, but subsequently was eroded back to a limited area around the Renee Sub-Basin.

11.11. Heron Group

The Triassic Heron Group in this area is dominated by the deposition of red mudstone facies of the Smith Bank Formation, with thick coarse-grained, often conglomeratic sandstones of the Skagerrak Formation occurring to the east. The top of the Group is often eroded and unconformably overlain by the Middle Jurassic Fladen Group.

11.11.1. Smith Bank Formation

The Smith Bank Formation comprises a reddish brown, argillaceous sequence. In parts it contains some thin sandstones and traces of dolomite and anhydrite. Most of the sediments comprise extensive, shallow, playa lakes with minor sediment input from distal ephemeral streams.

11.12. Zechstein Group.

The Zechstein Group is a readily recognisable unit in the area characterised by the occurrence of predominantly anhydrite and dolomite with some shale intercalations. The Late Permian was marked by a rapid widespread marine transgression which led to the deposition of the Kupferschiefer Formation – a thin dark grey, laminated, silty, sapropelic, shaley mudstone deposited under anoxic conditions.

11.13. Rotliegend Group

The Rotliegend Group comprises a reddened clastic sequence of aeolian sandstones up to the Grampian Arch. Alluvial sandstones and shaly mudstones tend to dominate the Halibut Basin area, and anhydritic shaley mudstones occur over much of the Western Platform area.

11.14. Firth of Forth Group

The Carboniferous Firth of Forth Group consists mainly of non-marine fluviodeltaic sands with interbedded siltstones. Interbedded coals increase towards the Witch Ground Graben to the north, and to the south of the Peterhead Ridge.

11.15. Old Red Sandstone Group

In the Halibut Basin, the Devonian deposits of the Old Red Sandstone Group vary significantly in thickness, and have been eroded from areas that were buoyed up by the granitic basement (e.g. Halibut Horst and Grampian Arch) as well as along the footwalls of major faults. Sedimentation was dominated by shallow, partly evaporitic lakes, aeolian dunes and alluvial systems.

11.16. Basement

The Caledonian basement consists of granites which form the core of the Halibut Horst. It is a fine to coarse grained equigranular granite that is typically fractured, with some fractures infilled by calcite.

3. Glossary of Terms

Term	Definition
AOI	Area of Interest
BCU	Base Cretaceous Unconformity
CCS	Carbon Capture & Storage
CO_2	Carbon Dioxide
CSIA	Compound Specific Isotopic Analysis
E&A	Exploration and Appraisal
EUR	Estimated Ultimate Recovery
FDP	Field Development Plan
FEED	Front End Engineering Design
FFSM	Full Field Static Model
FMT	Formation Multi-Tester
FOL	Free Oil Level
FWL	Free Water Level
GIIP	Gas initially in-place
GOC	Gas Oil Contact
GR	Gamma Ray (wireline log)
GRV	Gross Rock Volume
HCIIP	HydroCarbons Initially In Place
IRM	Integrated Reservoir Modelling
MDT	Modular Formation Dynamics Tester
N:G	Net-to-Gross
OGOC	Original Gas Oil Contact
OOWC	Original Oil Water Contact
OWC	Oil Water Contact
PSDM	Pre stack depth migration
RFT	Repeat Formation Tester
SGS	Sequential Gaussian Simulation
SRM	Static Reservoir Model
TVDSS	True Vertical Depth Subsea (i.e. relative to Mean Sea Level)
UKCS	United Kingdom Continental Shelf

4. Glossary of Unit Conversions

For the provision of the SI metric conversion factor as applicable to all imperial units in the Key Knowledge Deliverable.

Table 5-1: Unit Conversion Table

Function	Unit - Imperial to SI Metric conversion Factor
Length	1 Foot = 0.3048m Metres 1 Inch = 2.54cm Centimetres 1 Inch = 254mm millimetres
Pressure	1 Psia = 0.0690 Bara
Temperature	1°F Fahrenheit = -17.22°C Centigrade
Weight	1lb Pound = 0.45kg Kilogram