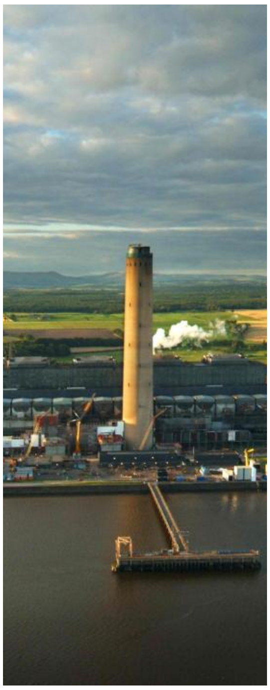

UK Carbon Capture and Storage Demonstration Competition

UKCCS - KT - S7.19 - Shell - 007
Petrophysical Modelling Report

April 2011
ScottishPower CCS Consortium

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1. Introduction

Editor's note:- This document was previously issued at Revision K01. It has been revised to Rev K02 following an Integrated Technical Review held within Shell in early March. The resulting changes between the revisions are marked in yellow. The revisions generally comprise minor corrections to improve clarity and meaning in sentences, improvements to calculation methods, and the removal of porosity and permeability equations for development wells.

This document compiles petrophysical input, the methods and interpretation results, which were used to populate the reservoir properties in the Goldeneye Static and the Dynamic models: Full Field, Overburden and Aquifer model. The comprehensive evaluation is based on datasets which were acquired from exploration and development wells in the Goldeneye field, the location where routine and special core data are mainly concentrated. For the aquifer model the scope of interpretation is extended to cover a wider area, including surrounding fields such as Atlantic, Hannay, Hoylake, and Cromarty. Key deliverables are porosity, permeability, net to gross, fluid contacts and the saturation height model for the FFM, and porosity, permeability, net to gross and Chalk capillary entry pressure for overburden and aquifer models. It is necessary to use analogue data to represent the properties, primarily permeability and capillary entry pressure, because of limited data acquisition in Goldeneye overburden formations and in the Fairway Trough Kopervik sand near the Goldeneye field.

2. Data Availability and Quality Control

Well data availability, data type and contribution are listed in Table 1.

Table 1. Well Input Data Summary

Well	Year	Wireline/LWD	Routine Core	SCAL	RFT/MDT	Image data	Drilling fluid	Input to Model
14/29a-2	1980	Y	N (MCT)	N	Y	N	WBM	FFM, Overburden
14/29a-3	1996	Y	Y	Y	Y	Y	OBM	FFM, Overburden, Aquifer
14/29a-5	1999	Y	Y	Limited	Y	Y	OBM	FFM, Overburden, Aquifer
20/4b-6	1998	Y	Y	Y	Y	Y	WBM	FFM, Overburden, Aquifer
20/4b-7	2000	Y	Y	N	Y	Y	OBM	FFM, Overburden, Aquifer
GYA01	2004	Y	N	N	N	N	OBM	Trajectory
GYA02	2004	Y	N	N	N	N	OBM	Trajectory

GYA03	2004	Y	N	N	N	N	OBM	Trajectory
GYA04	2004	Y	N	N	N	N	OBM	Trajectory
GYA05	2004	Y	N	N	N	N	OBM	Trajectory
Surrounding Goldeneye structure								
14/29a-4	1998	Y	Y	N	Y	Y	WBM	Aquifer
20/4b-3	1989	Y	N	N	Y	N	OBM	Aquifer
20/5c-6	1997	Y	Y		Y	N	WBM	Aquifer
14/30b-3	1991	Y	N	N	N	N	OBM	Overburden, Aquifer
14/28b-2	1997	Y	Y	N	Y	N	WBM	Aquifer
14/26a-6	1997	Y	Y	N	N	N	WBM	Aquifer
14/26a-8	2000	Y	N	N	N	N	OBM	Aquifer
14/26-1	1988	Y	N	N	Y	N	WBM	Aquifer
14/26a-7a	1999	Y	Y	N	Y	N	OBM	Aquifer
13/30-2	1984	Y	N	N	Y	N	WBM	Aquifer
13/30-1	1981	Y	N	N	Y	N	WBM	Aquifer
13/30a-4	1998	Y	N	N	Y	N	WBM	Aquifer
13/30-3	1986	Y	N	N	Y	N	OBM	Aquifer
13/24-1	1974	Y	N	N	N	N	WBM	Overburden
14/28a-1	1990	Y	N	N	N	N	WBM	Overburden
20/1-1	1979	Y	N	N	N	N	WBM	Overburden

2.1. Quality Control

Each Goldeneye well is evaluated individually to ensure that the effects of different logging tools and backgrounds are addressed properly. Environmental corrections were performed on bulk density and neutron porosity to correct for hole-size effect. There is no need for other neutron corrections because porosity is calculated solely from bulk density. The Resistivity curve is borehole size corrected in all wells and invasion corrected in 20/4b-6 where water-based mud (WBM) was used.

For the overburden and aquifer models Gamma Ray (GR) normalization was performed to generate shale volume consistency for the net to gross calculation. Based on observation (Figure 1), the resulting distribution in Captain Sandstones is relatively uniform, sharing a similar data density distribution profile. The GR based shale volume is chosen over Neutron–density due to missing bulk density data in the older wells.

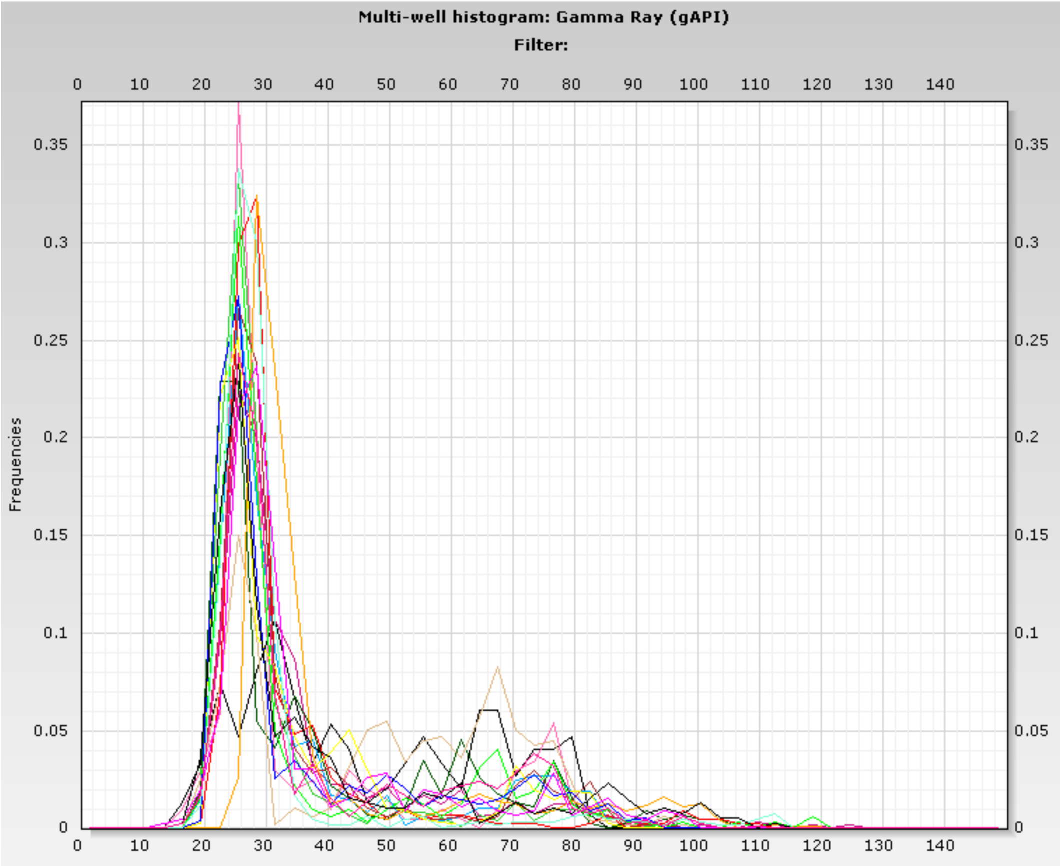

Figure 1. GR distribution profile in Captain Sandstone of Goldeneye & surrounding wells

2.2. Formation Tops

Formation tops are exported from Static Models where they were selected according to sedimentary and structural characters from core, cuttings and logs. Full zonation list is given in Table 2. Shallower zones are defined as Groups down to secondary seals, the Dornoch mudstone and Lista Shale. Thereafter the zones are based on formations. Rodby Fm is the primary seal for Captain Sandstone, which has its zoning defined into subunits.

Table 2. Goldeneye stratigraphy sequence within Overburden to Captain Sst

Groups	Member/Units
Nordland	
Westray	
Stronsay	
Moray	Beauly Mb
	Upper Dornoch Sst
	Dornoch Mudstone Unit
	Lower Dornoch Sst

Montrose	Lista Fm
	Mey Sst
	Upper Balmoral Sst
	Upper Balmoral and Tuffite Sst
	Maureen Fm
Chalk	Ekofisk Fm
	Tor Fm
	Hod Fm
	Herring Fm
	Plenus Marl Fm
	Hidra Fm
Cromer Knoll	Rodby Fm
	Valhall / Upper Valhall Mb
	Kopervik Sst
	Captain Sst Subunit E
	Captain Sst Subunit D
	Captain Sst Subunit C
	Captain Sst Subunit A

2.3. Petrophysical Facies

Sand quality and clean sand thickness control petrophysical facies and produce three classes based on core description and logging response. Classification also considers variation in grain size and depositional environment, which can be described as follows:

- Class 1

  Massive or substantially thick and clean sandstone as seen in Captain D subunit. It exists occasionally within subunit C (e.g in 14/29a-3). Sand thickness in this class is 25 ft or more and has uniform medium grain size.

- Class 2

  Heterogeneous clastic sequences with varying sand quality and mudstone content. It typically exists in subunit C which has large number of thin sandstone layers.

- Class 3

  Uppermost interval of Captain sand, contains 2-3% clay fraction in some location, possibly injection from massive sandstone subunit. It is makes up the bulk of subunit E.

The facies distribution is shown in Figure 2 and listed in Table 3. Development wells are not included in the property model evaluation due to limited data acquisition.

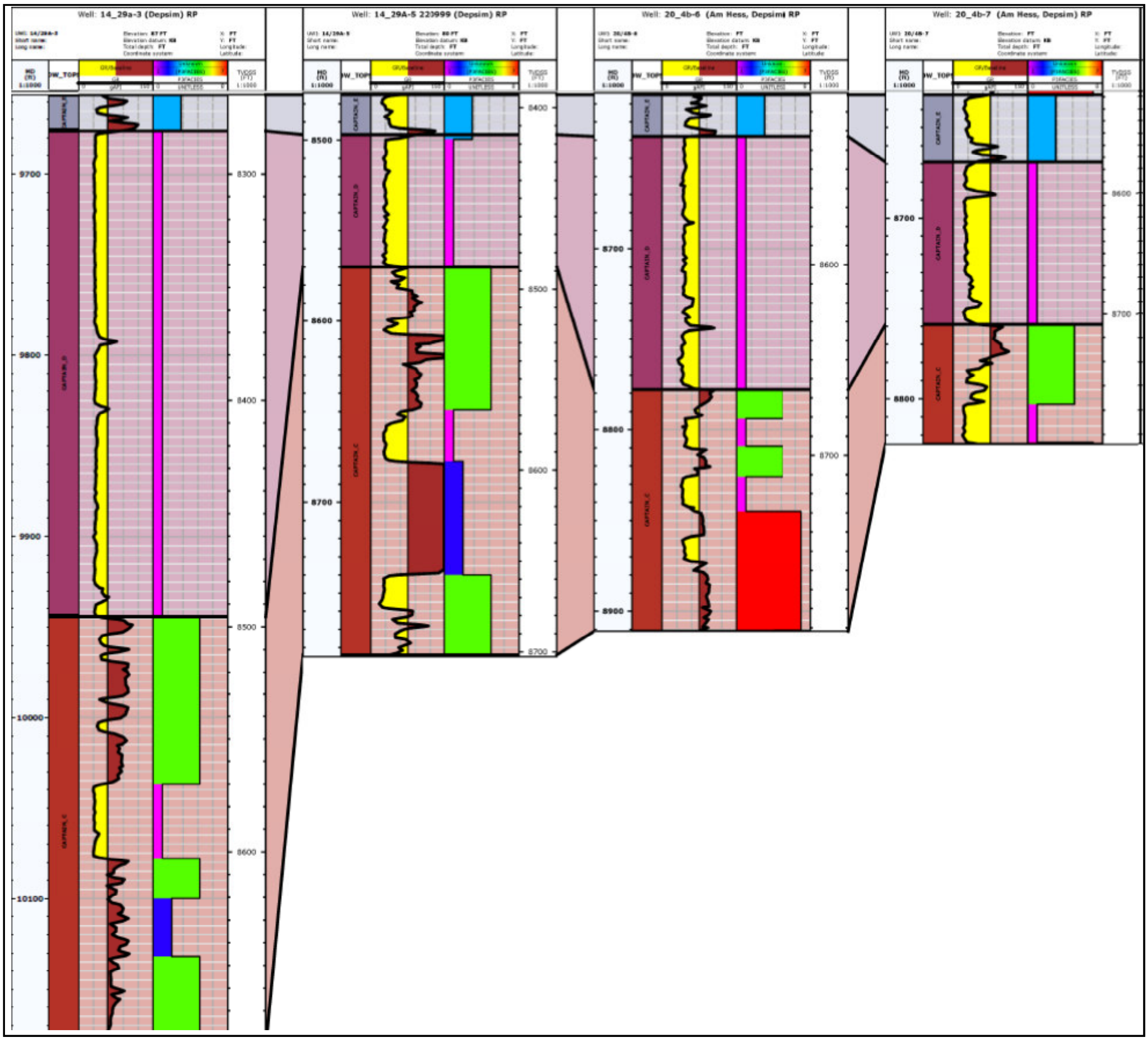

Figure 2. Petrophysical facies distribution in Goldeneye exploration wells

3. Interpretation Methods

Porosity is calculated from log data and calibrated using stress corrected core porosity. Permeability is derived from porosity and calibrated further using in-situ core permeability. Net to gross is defined from GR based shale volume and porosity at the optimum cut-offs whilst saturation model is based on log derived saturation within Captain D interval.

For overburden and aquifer models, only porosity and net sand can be obtained from the selected well log data. Permeability and capillary pressure entry data were provided by fairway analogue or regional trends. Pressure gradient and other log data has been used to estimate fluid contacts for the fields within the aquifer model.

3.1. Porosity

Porosity is computed from bulk density and then matched with in-situ (stress) corrected core porosity by applying a suitable fluid density. The Captain Sandstone interval in Goldeneye field is well calibrated because the core was obtained from all four-exploration wells across subunits A to E.

Porosity is derived from following formula:

$$\varphi = \frac{(\rho_{ma} - \rho_b)}{(\rho_{ma} - \rho_{fluid})} \quad \text{......(1)}$$

Where : ϕ = total porosity (v/v)

ρ_{ma} = matrix density (g/cc)

ρ_b = bulk density (g/cc)

ρ_{fluid} = fluid density (g/cc)

The matrix density is obtained using core grain density derived from routine core analysis reports whilst fluid density is estimated from porosity to core porosity comparison (i.e. at 14/29a-3, Figure 3). Resultant porosity is stress corrected to pre-production state.

For overburden and aquifer models, the porosity in overburden formations and the Captain Fairway is determined using the generic matrix density of 2.65 g/cc for sandstone and 2.71 for limestone (chalk). Fluid density depends on mud type. Assuming moderate mud filtrate invasion during drilling, the respective values for water-based-mud (WBM) and oil-based-mud (OBM) are 1.1 g/cc and 0.9 g/cc.

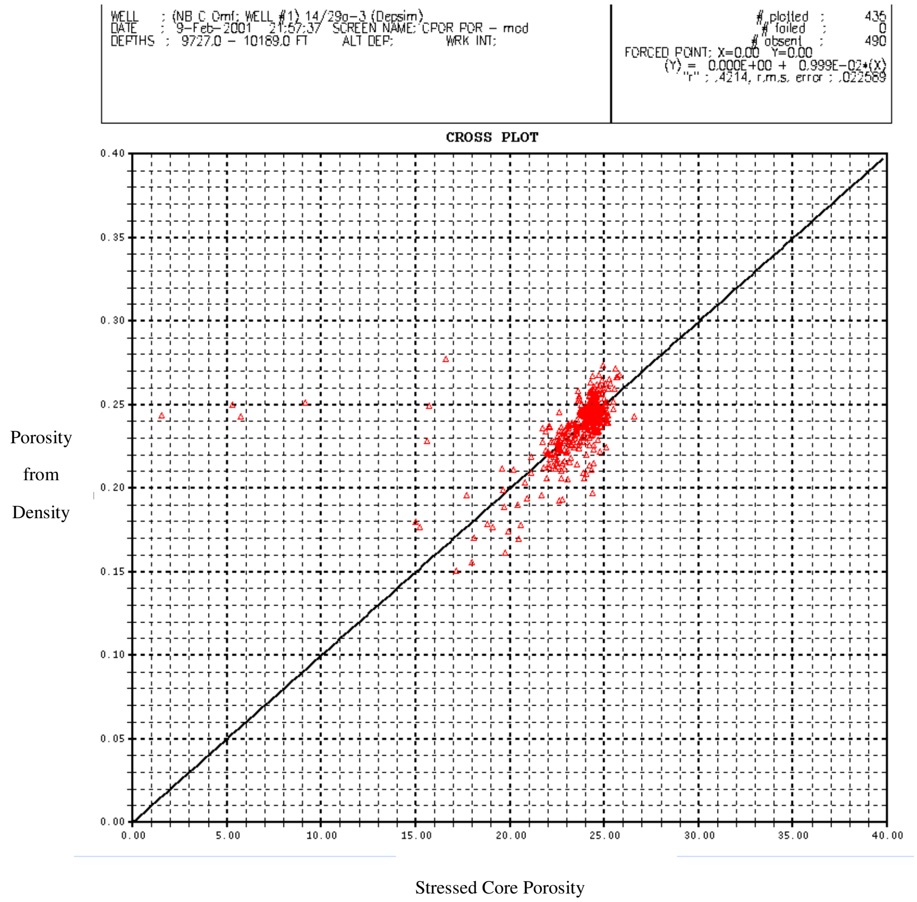

Figure 3. Core Porosity (X-axis) relationship to Porosity (Y-axis) performance compared to y = x line in well 14/29a-3

3.2. Permeability

Permeability is facies dependent, since Core permeability data shows a strong relationship to facies classes which were built based on geological understanding. It is corrected to in-situ properties using permeability under overburden stress measurements from well 14/29a-3 and 20/4b-6 to pre production state.

The porosity to permeability relationship for each class is:

Class 1 PERM =MIN(2500,10^(0.2472*(ϕ*100)+ -2.92932))

Class 2 PERM =MIN(1000,10^(0.1873*(ϕ*100)+ -2.28723))

Class 3 PERM =MIN(2500,10^(0.2029*(ϕ*100)+ -2.5382))

……………………………………………………………………………………………(2,3,4)

Table 3. Petrophysical facies distribution in exploration wells

Well	Top (ft md)	Base (ft md)	Facies Classes
14/29a-3	9656	9676	2
14/29a-3	9676	9944.5	1
14/29a-3	9944.5	10037	3
14/29a-3	10037	10078	1
14/29a-3	10078	10100.5	3
14/29a-3	10100.5	10132	Non-Net
14/29a-3	10132	10183	3
14/29a-3	10183	10684	1
14/29a-5	8475	8499.5	2
14/29a-5	8499.5	8569.5	1
14/29a-5	8569.5	8649	3
14/29a-5	8649	8677.5	1
14/29a-5	8677.5	8740	Non-Net
14/29a-5	8740	8784	3
14/29a-5	8784	8895.5	1
14/29a-5	8895.5	8956	3
14/29a-5	8956	9043.5	1
14/29a-5	9043.5	9100.5	3
20/4b-6	8615	8637.5	2
20/4b-6	8637.5	8777.5	1
20/4b-6	8777.5	8794	3
20/4b-6	8794	8809	1
20/4b-6	8809	8826	3
20/4b-6	8826	8845	1
20/4b-6	8845	8910.5	Non-Net
20/4b-6	8910.5	9371.5	Non-Net
20/4b-7	8632.5	8668.5	2
20/4b-7	8668.5	8759	1
20/4b-7	8759	8803	3

Well	Top (ft md)	Base (ft md)	Facies Classes
20/4b-7	8803	8824	1
20/4b-7	8824	8880	Non-Net
20/4b-7	8880	9372	Non-Net

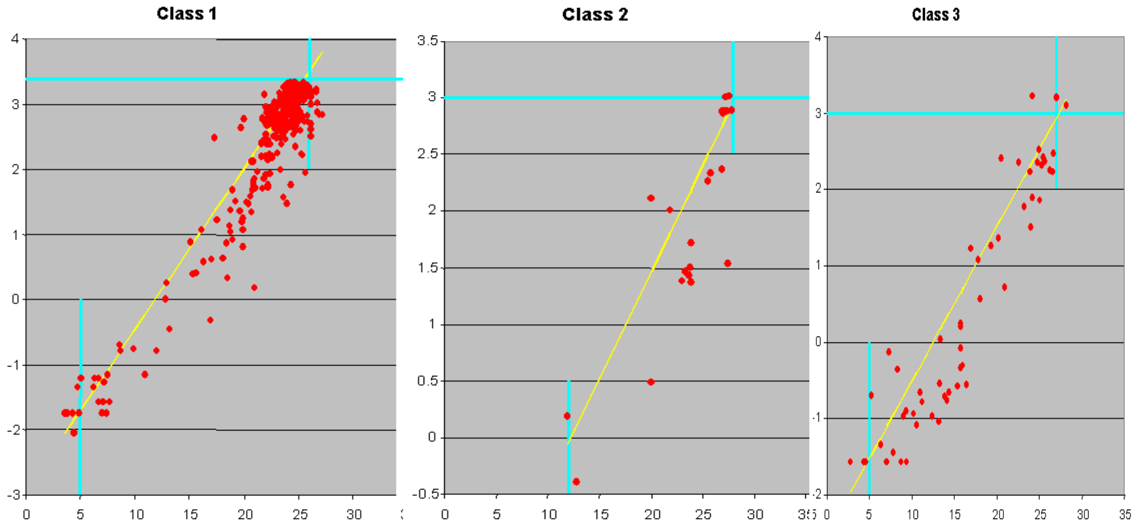

Figure 4. Core Porosity (% unit – x axis) relationship to Core Permeability (order of magnitude in mD – y axis) in each facies class

3.3. Net-to-gross (NTG)

Net-to-gross is obtained from the GR derived shale volume and porosity that satisfies the Captain Sandstone NTG criterion. The porosity cut-off removes tight sandstone streaks which exist mainly in facies class 2.

GR derived shale volumes are calculated using the following methods:

$$V_{shale} = \frac{GR - GR_{sand}}{GR_{shale} - GR_{sand}} \quad \text{...(5)}$$

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)

Based on observations from four Goldeneye exploration wells, the relevant cut-off for shale volume and porosity is 0.5 and 0.14 respectively. Therefore net-to-gross in Captain Sand is defined by conditions as follows:

- Shale volume < 0.5

- $\phi > 0.14$

Captain Sandstones in the Captain Fairway and overburden formations follow the above net-to-gross criteria with the exception of the chalk group. The chalk group, based on the log reading, has clean properties throughout its formations, including the Plenus Marl, yielding a net-to-gross ratio of 1.

3.4. Fluid contacts and Fluid-Level

Fluid levels are obtained from open hole pressure data, whilst fluid contacts are obtained using core and logs to cross check the fluid level reading. Goldeneye field pressure data is derived from wells 14/29a-3, 14/29a-5, 20/4b-6 and 20/4b-7, plotted in Figure 5. The 14/29a-3 is slightly offset from the common hydrocarbon gradient due to different tool calibration and the greater depth uncertainty for the measurement.

Three fluid phases, gas, oil and water are present in the Goldeneye Captain Sand. The FOL and FWL are consistent with GOC and OWC from core and log data. The Free water level can be confidently picked at 8592 ft/2619 m TVDSS for Goldeneye field wide and Free oil level at 8577 ft/2614 m TVDSS.

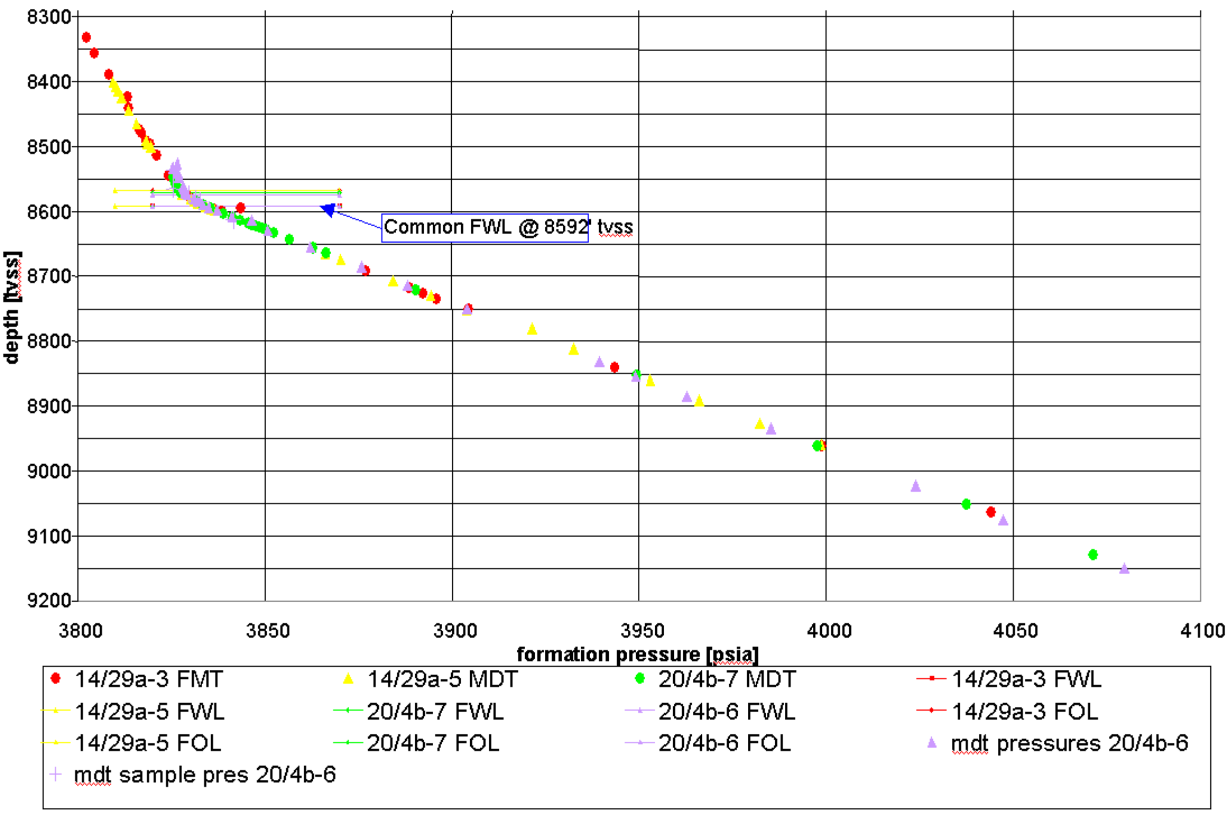

Figure 5. Goldeneye Pressure data in Captain Sst. The intersection of hydrocarbon and water gradients indicates the FWL

The Goldeneye overburden formations are water bearing. So far, there is no indication of hydrocarbon based on log data, cuttings and gas chromatograph readings. The only possibility of hydrocarbon content comes from shallow gas in the Lark formation (approximately 1500 ft/457 m

TVDSS), which shows 1-3% total gas based on gas chromatograph interpretation in several development wells.

To be able to differentiate between properties in hydrocarbon and water legs separately, the FWL in fields within the Captain Fairway is examined locally. These are stated as follows:

- Hoylake

  Interpreted wells are 14/29a-4 and 20/4b-3, where only 14/29a-4 contains a gas column. These exploration wells were plugged and abandoned.

- Hannay

  The hydrocarbon well is 20/5c-6 containing an oil column. Other wells surrounding the field, 14/30B-3 and 14/28B-2, are included to provide analysis for the regional water gradient.

- Atlantic

  Interpreted wells are 14/26a-6, 14/26a-8, 14/26-1 and 14/26a-7a, all of which have gas columns on the top of the water leg.

- Cromarty

  One well contains a gas column, 13/30-3. Several wells are also included, 13/30-1, 13/30-2 and 13/30A-4, to observe the regional water gradient.

- Blake

  The furthest field to the west of the evaluation scope, one water wet well is included, 13/24-1.

Water gradients across the fields from pre production pressure data suggest common aquifer flow across the Fairway trough as seen in Figure 6. FWL for individual well is listed in Table 4.

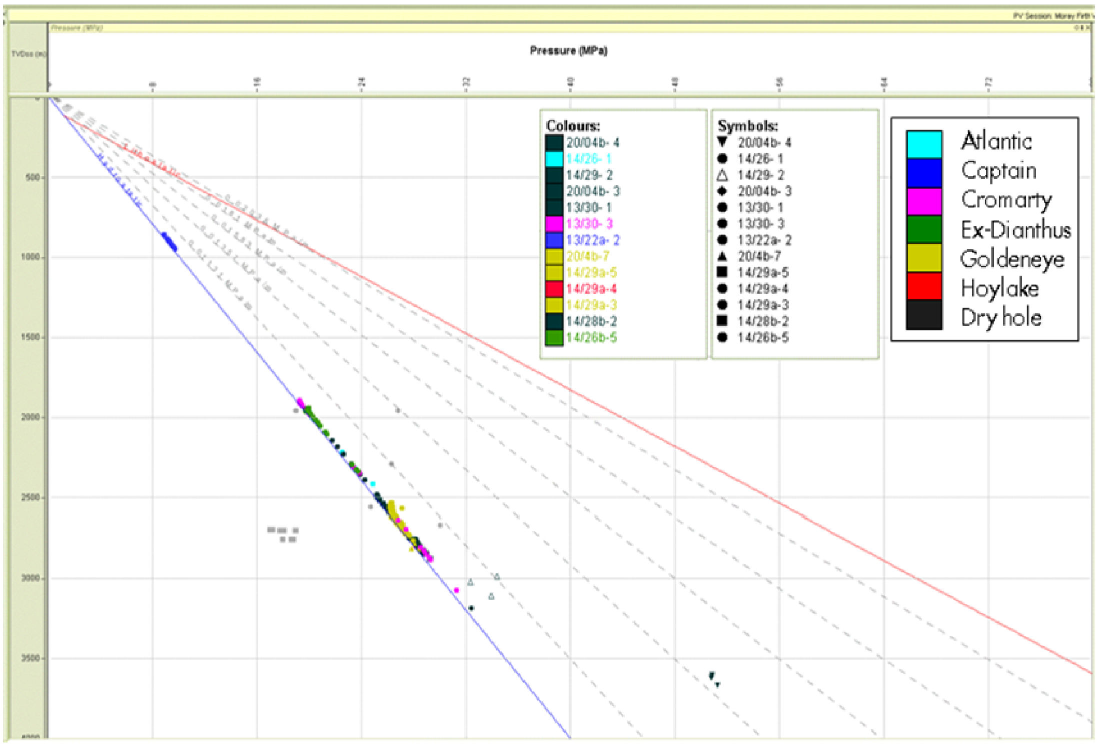

Figure 6. Uniform water pressure gradient in the fields within Fairway trough

Table 4. Fluid contact in selected wells surrounding Goldeneye

	14/29a-4	20/5c-6	14/26a-6	14/26a-8	14/26-1	13/26a-7a	13/30-3
Location	Hoylake	Hannay	Atlantic	Atlantic	Atlantic	Atlantic	Cromarty
Gas or Oil Water Contact (ft TVDSS)	8795	9505	6447	6471	6443	6463	6245

3.5. Saturation height Model

The Goldeneye Captain D saturation height model is derived using the Leverett-J [1] method on logging data. The log input only includes clean sand which satisfies the following criteria:

- Porosity above 20 %
- Low clay content, CEC less than 0.1 meq/ml

The initial saturation model is calculated from clean sand logging data. It is then compared with log derived saturation and mercury injection capillary pressure data. Water saturations produced from both inputs show good agreement, with uncertainty less than 0.05 s.u. within net intervals.

Archie log saturation is calculated to verify the Leverett-J model performance using water resistivity from a Pickett Plot and Archie parameters (saturation and cementation exponent) from wells 14/29a-3 and 20/4a-6. The comparison is shown in Figure 7.

[1] M.C. Leverett (1941). "Capillary behaviour in porous solids". *Transactions of the AIME* (142): 159–172

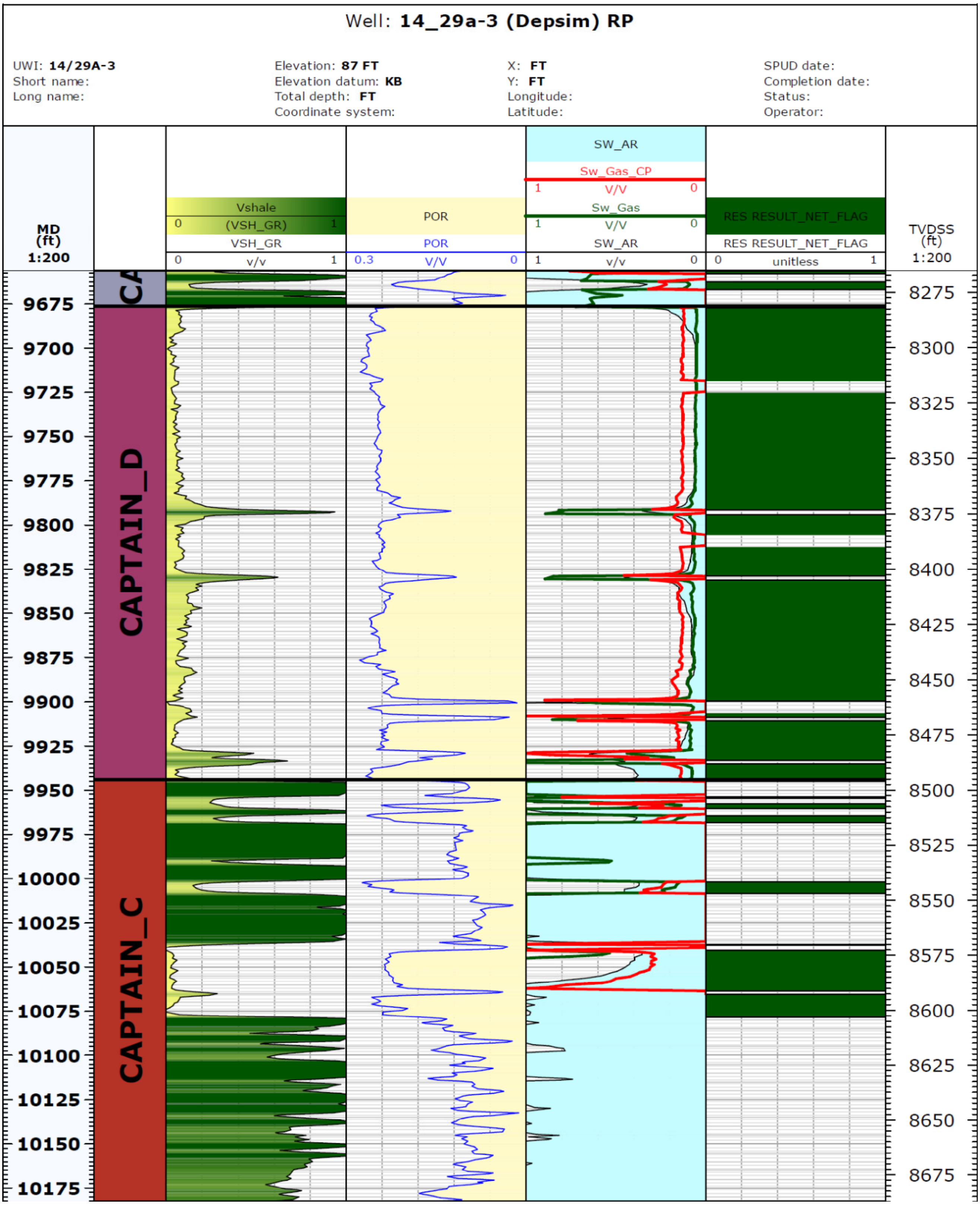

Figure 7. Saturation height derived Sw comparison to Archie log saturation in well 14/29a-3. Black curve is Archie Log saturation, Green curve is Log SHF derived Sw and Red is Capillary Pressure SHF derived Sw.

Log data are used as input to the Leverett-J method producing two saturation models for gas and oil. The additional inputs are fluid gradients from the pressure plot, minimum saturation from log at infinite HAFWL, and default IFT reservoir based on hydrocarbon content.

The input detail is listed in Table 5 for gas saturation and Table 6 for oil saturations. The equation is as follows:

$$J = \frac{HAFWL}{\sigma \cdot \cos\theta} \cdot \sqrt{\frac{K}{\phi}} \cdot (\rho_{water} - \rho_{hc}) \quad \text{(6)}$$

Where : J = Leverett-J function (unitless)

HAFWL= height above free water level (ft)

σ = interfacial tension (mN/m)

θ = contact angle (deg)

K = permeability (mD)

ϕ = total porosity (v/v)

ρ_{water} = water density gradient (psi/ft)

ρ_{hc} = hydrocarbon density gradient (psi/ft)

Table 5. Gas reservoir parameter input

σ	[mN/m]	31
ρ_{water}	[psi/ft]	0.44
ρ_{gas}	[psi/ft]	0.103
θ_{gw}	[deg]	0

Table 6. Oil reservoir parameter input

σ	[mN/m]	25
ρ_{water}	[psi/ft]	0.44
ρ_{oil}	[psi/ft]	0.32
θ_{ow}	[deg]	50

4. Analogues

Limited permeability and capillary pressure entry in overburden and some wells in the Fairway trough drives the need to use representative analogue data for the overburden and aquifer static models. The bullets below describe each requirement for analogue data and the suitable analogue used in the models:

- **Permeability analogue for Goldeneye Chalk Group:**

  The Chalk group is water bearing and based on current investigation, does not contain any geological feature which may suggest property enhancement. However, it does not guarantee that fine fracture networks do not exist. The analogue data is provided by a Shell internal Chalk study in the North Sea UK sector under the current working assumption that the chalk is in matrix condition. The study covers the Ekofisk, Tor and Hod formations and the result is applied to the rest of the Chalk Groups due to the uniformity observed from the logs. Permeability for the chalk groups is set at 0.001 mD. This data is then used in the overburden model.

- **Capillary entry pressure analogue for Goldeneye overburden chalk groups:**

  Capillary entry pressure is derived from Poisson ratio and porosity using the method described in Danish Chalk paper, Fabricius et.al[2]. The paper states that Poisson ratio is related to carbonate content and pore stiffness; therefore it sufficiently reflects surface area which correlates to capillary entry pressure. With the absence of core measurement, Poisson ratio can be determined from the sonic and shear log using following method:

  $$\upsilon = (\upsilon_P^2 - 2\upsilon_S^2)/(2(\upsilon_P^2 - \upsilon_S^2))$$

  Where: υ = Poisson ratio

  υ_p = Sonic slowness (ft/s)

  υ_s = Shear slowness (ft/s)

  The relationship between capillary entry pressure, porosity and poisson ratio based on observation from several chalk reservoirs in Denmark and Pierce chalk in the UK sector is displayed in Figure 8. Goldeneye Overburden formations have poisson ratio between 0.3 – 0.35 of which is similar to Pierce Chalk data. This data is then used in the overburden model

- **Permeability Analogue for Goldeneye Montrose Groups:**

  Average permeability is initially taken from literatures/studies of various fields across the Captain Fairway. It is then compared on a well-by-well basis by correlating the average permeability to the sand quality that is represented by GR, on each formation within Montrose Group. This data is then used in the overburden model.

- **Permeability Analogue for Fairway trough Captain sandstone (excluding Goldeneye):**

  Several wells in the Captain Fairway have core acquired from within the Captain sandstone, where the permeability could be defined using porosity transform for each field. An example is the Atlantic field shown in Figure 9. For small fields or exploration wells drilled between

[2] Fabricius et.al, (2007) How depositional texture and diagenesis control petrophysical and elastic properties of samples from five North Sea chalk fields.

fields, permeability is calculated using the regional permeability relationship. This permeability data is used in the aquifer model.

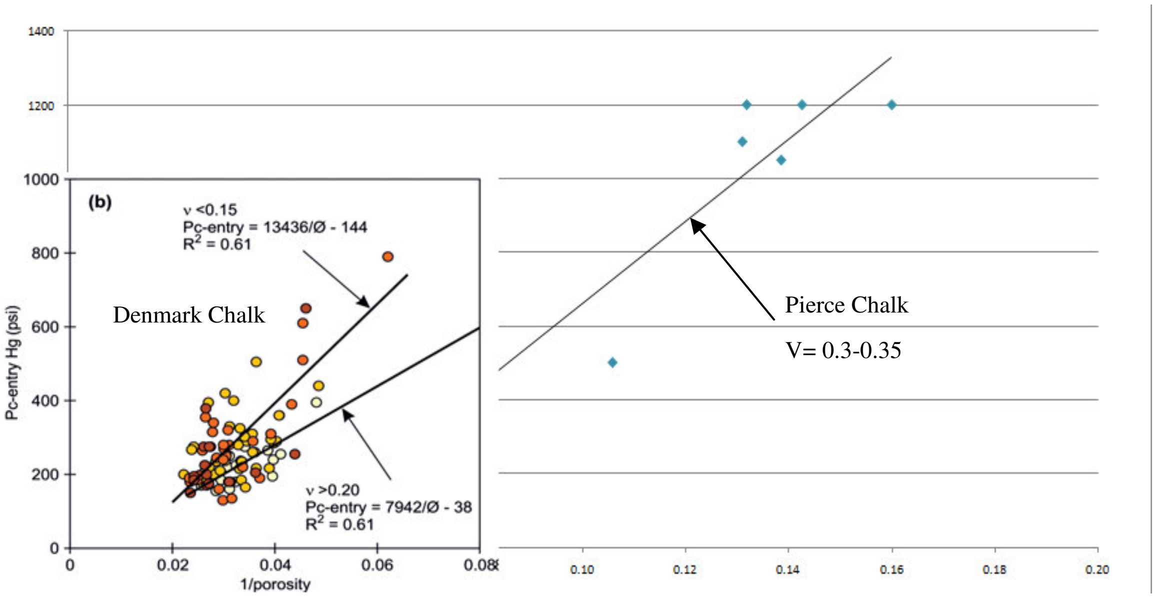

Figure 8.Capillary entry pressure prediction using porosity and poisson ratio described in Fabricius et.al. 2007.

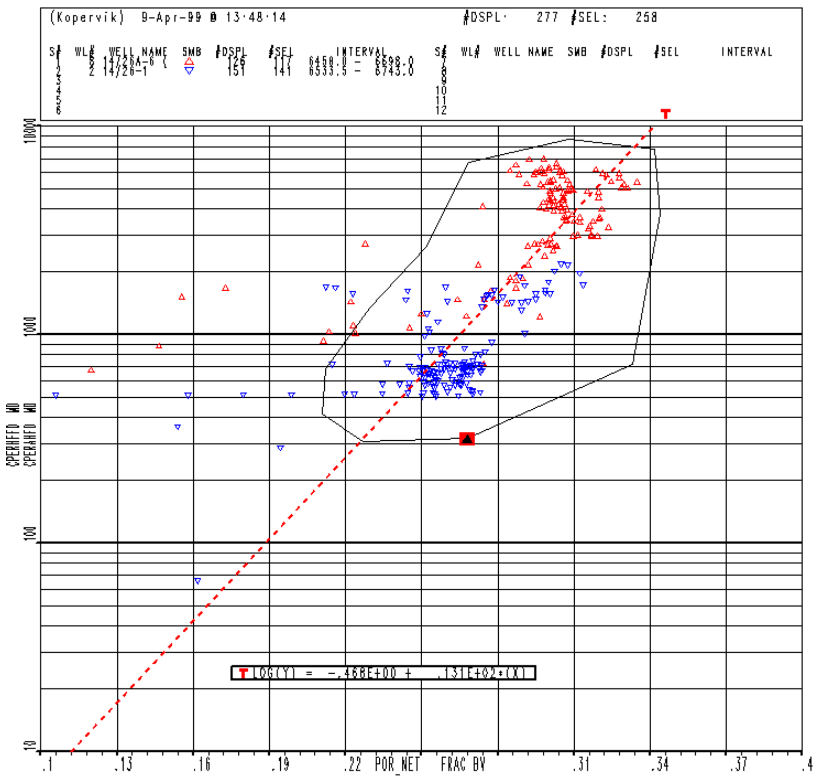

Figure 9.Porosity to permeability relationship used to determine permeability in Captain Sst within Atlantic field

5. Input to Static and Dynamic Model

Three reservoir models have been built to simulate Goldeneye Captain reservoir (FFM) performance and model CO_2 behaviour. Porosity, Permeability, NTG and fluid contacts are the inputs to all static models with the addition of saturation height functions for the FFM. The detail of the property input to the FFM static model is included in the Static Model report (RT 060). Input properties for the overburden and aquifer static models are stated in Table 7 and 8 respectively.

Table 7. Property input to Overburden static model based on formation

Formation	Ave Por (v/v)	Ave N/G	Ave Perm(mD)
T Moray Gp	0.326	0.468	470
T U Dornoch Sst Unit	0.34	0.47	370
T Dornoch Mudst Unit	0.34	0.27	80
T L Dornoch Sst Unit	0.31	0.39	290
Top Montrose Gp (Lista Shale)	0.242	0.06	0
T Mey Sst Mb	0.34	0.46	210
T U Balmoral Sst Unit	0.30	0.61	350
T L Balmoral Sst and Tuffite Unit	0.27	0.81	350
T Maureen Fm	0.24	0.83	370
T Ekofisk Fm.	0.11	1.00	0.001
T Tor Fm	0.04	1.00	0.001
T Hod Fm	0.06	1.00	0.001
T Herring Fm	0.05	0.99	0.001
Plenus Marl Fm	0.07	0.40	0
T Hidra Fm	0.05	0.99	0

Table 8. Property input to Aquifer model based on wells

Field	Well	Ave Por (v/v)	Ave N/G	Ave Perm(mD)
Blake	13_24-1	0.319	0.197	110
Water wells	13_30-1	0.231	0.740	852
Water wells	13_30-2	0.277	0.759	1285
Cromarty	13_30-3	0.313	0.890	1865
Water wells	13_30A-4	0.274	0.715	934
Atlantic	14_26-1	0.277	0.730	694

Field	Well	Ave Por (v/v)	Ave N/G	Ave Perm(mD)
Atlantic	14_26A-6	0.317	0.821	1468
Atlantic	14_26A-7A	0.306	0.529	1795
Atlantic	14_26A-8	0.340	0.840	1583
West GE	14_28B-2	0.234	0.768	1022
GE	14_29A-3	0.288	0.757	700
Hoylake	14_29A-4	0.239	0.672	510
GE	14_29A-5	0.201	0.482	700
East GE	14_30B-3	0.232	0.700	279
Hoylake	20_4B-3	0.228	0.880	406
GE	20_4B-6	0.240	0.783	700
GE	20_4B-7	0.276	0.705	700
Hannay	20_5C-6	0.232	0.663	331

These overburden and aquifer properties may be varied in next phase to reflect sensitivities in dynamic modelling during fluid migration scenario simulation. The extent of variation will be included in overburden and aquifer static model reports.

In the FFM model porosity and permeability are fixed based on statistical value to create three saturation model representing sand flow facies. These facies and associated properties are described as following:

- High porosity-permeability sand, porosity = 0.25 v/v and permeability = 1000 mD
- Interbedded unit , porosity = 0.15 v/v and permeability = 30 mD
- Debris flow, porosity = 0.07 v/v and permeability = 5 mD

6. Abbreviations

Table 9 List of Abbreviations

CCS	Carbon, Capture and Storage
CO_2	Carbon Dioxide
FFM	Full Field Model
LWD	Logging While Drilling
SCAL	Special Core Analysis
RFT	Reservoir Formation Tester*
MDT	Modular Dynamic Tester*
OBM	Oil Based Mud
WBM	Water Based Mud
GR	Gamma Ray

GR NORM	Normalized Gamma Ray
FWL	Free Water Level
Sst	Sandstone
Mb	Members
Fm	Formation
HAFWL	Height Above Free Water Level
N-D	Neutron-Density
FOL	Free Oil Level
GOC	Gas Oil Contact
OWC	Oil Water Contact
Sw	Water Saturation
IFT	Interfacial Tension
NTG	Net to Gross

In the text well names have been abbreviated to their operational form. The full well names are given in Table 10 below.

Table 10. 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