Department of Earth, Ocean and Ecological Sciences

UNIVERSITY OF LIVERPOOL

ENVS604
Sandstone Petroleum Reservoirs

A RESERVOIR QUALITY STUDY OF THE BRENT GROUP (THISTLE FIELD, NORTH SEA)

Integrating well log data with detailed core description and clastic petrography

Semester 2 – 2018-19

Name: Yerassyl Bekberov

Student number: 201286517

EVNS604 Workbook content

1. Introduction

The practical workshops in ENVS604 will give you experience in working with, and integrating, real world datasets that have been acquired from a producing field in the North Sea. The dataset includes sedimentary core (& accompanying thin sections), petrographic data including automated mineralogy, porosity-permeability data (CCA), and bulk density and gamma ray data from well 211/18a-33(18) in the Thistle Field.

Combining the results you collect during the workshops with public knowledge from literature, you will – in your group - make a general assessment of the hydrocarbon potential of the Brent Group in this well. This will be assessed through a group poster presentation. Individually you will write a research paper using the data you collected as a starting point.

Where applicable, additional digital templates for data collection (e.g. core description sheets) will be made available on VITAL.

Anticipated outcomes

- Your database will be the cores and the accompanying thin sections, petrological data, and the petrophysical and wireline logs from well 211/18a-33(18).
- By identifying the facies trends by characteristics of individual lithofacies (i.e. assessing their porosity/permeability characteristics) you will be able to calibrate the logs and define a geological reservoir model for Brent Group in the Thistle Field.
- Thin section photomicrographs and detailed petrological data will enable you to compare and contrast petrological, diagenetic and porosity characteristics within the Brent Group.
- Using the dataset above, together with information from literature (well data, potential analogues), your group will make a 'reservoir quality assessment' of the Brent Group in well 211/18a-33(18) – with a focus on (but not exclusively) the formations your group described - and present some discussion of the petroleum play of the Brent Group in the Thistle Field (and beyond) from existing literature. Otherwise, you and your group are free to pursue any angle of the project (e.g. diagenesis, petrophysics) as long as it is relevant to an overall 'story'.

Assessment

The grade for the ENVS604 module is fully based on coursework (20% lab book, 40% poster presentation, 40% research paper) and will be carried out both on a team and an individual basis. In week 7 you had in the lab book, in week 9 (25/03/19) you will be expected to hand in the group poster. The poster presentation will be at a mini-conference on Wednesday in week 9 (27/03/19) and should contain a summary of all the work you carried out as a group (e.g thin section descriptions, core log of group interval, petrophysical data, potential analogues, correlations etc.). Additionally, an 8-10 page research paper is due in week 12 (10/05/19) and should contain your personal summary report that covers one or more aspects in more detail (figures can be taken from group-work). For more details about the assessments see the notes available on VITAL.

Key dates:

Lab book hand-in:	15/03/2019 (online submission)
Group poster hand-in:	25-03-2019 (online submission for printing)
Conference day:	27-03-2019 (groups present their poster)
Individual paper:	10/05/2019 (online submission)

2. The Brent Group and the Thistle Field

The Middle Jurassic Brent Group in the Viking Graben of the northern North Sea is one of the largest producing sectors in the UKCS (Figure 1). In August 1971, hydrocarbons were discovered in the Middle Jurassic (Bajocian-Bathonian) rocks of the Brent Group in well 211/29-1. Since then, the area has been of major interest to numerous oil exploration companies who have investigated the possibilities to explore, develop and produce the 'potential' oil and gas resources in the Thistle Field.

The Thistle field is located in blocks 211/18a and 211/19a of the Brent Province near the northern edge of the Brent deltaic complex, approximately 580 km NE of Aberdeen (Figure 1; Reynolds, 1995; Brown et al. 2003). The Thistle Field is one of the four developments in the Thistle Area: Thistle, Area 6, Deveron and Don (Brown et al. 2003). Oil is present in the field and the first production started in early 1978, with 355 mmbbl produced by the end of 1990 (Reynolds, 1995). Since then it has been part of the most productive reservoir interval, The Brent Group, in the North Sea (Hampson et al., 2004).

The Brent Group overlies the Early Jurassic margin shales of the Dunlin Group and is succeeded by the Humber Group, which consists of Bathonian to late Jurassic marine shales (Figure 2; Brown et al., 1989). The group itself is subdivided into five formations: Broom, Etive, Ness, Rannoch and Tarbert. In the UK, the Brent Group generally occurs below ~3000 m depth in the northern part of the northern Viking Graben (Brown et al. 1989) and is distributed over block-faulted terraces of the East Shetland Basin, between the Viking Graben axial zone and the Graben margin (Figure 3; Brown et al., 1989).

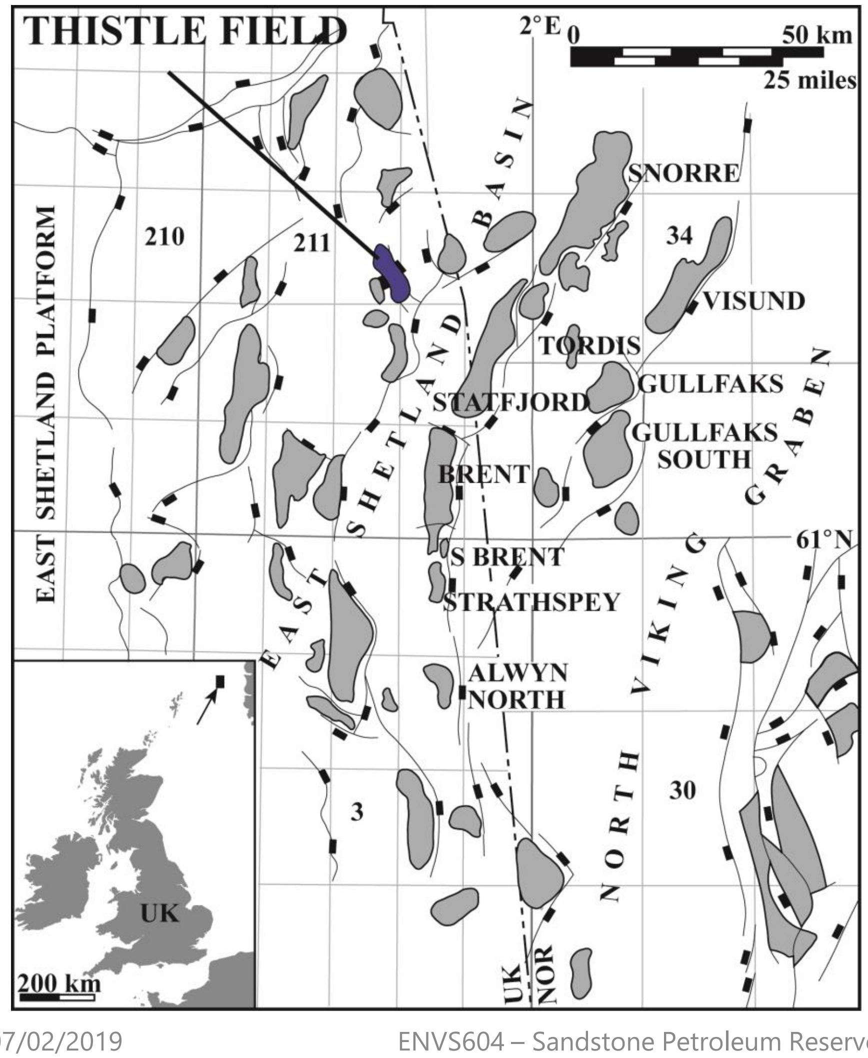


Figure 1: Location of East Shetland Basin and North Viking Graben, North Sea. The Thistle Field, focus of this project, is indicated with a purple fill. The principal hydrocarbon fields are shown in shaded dark grey.

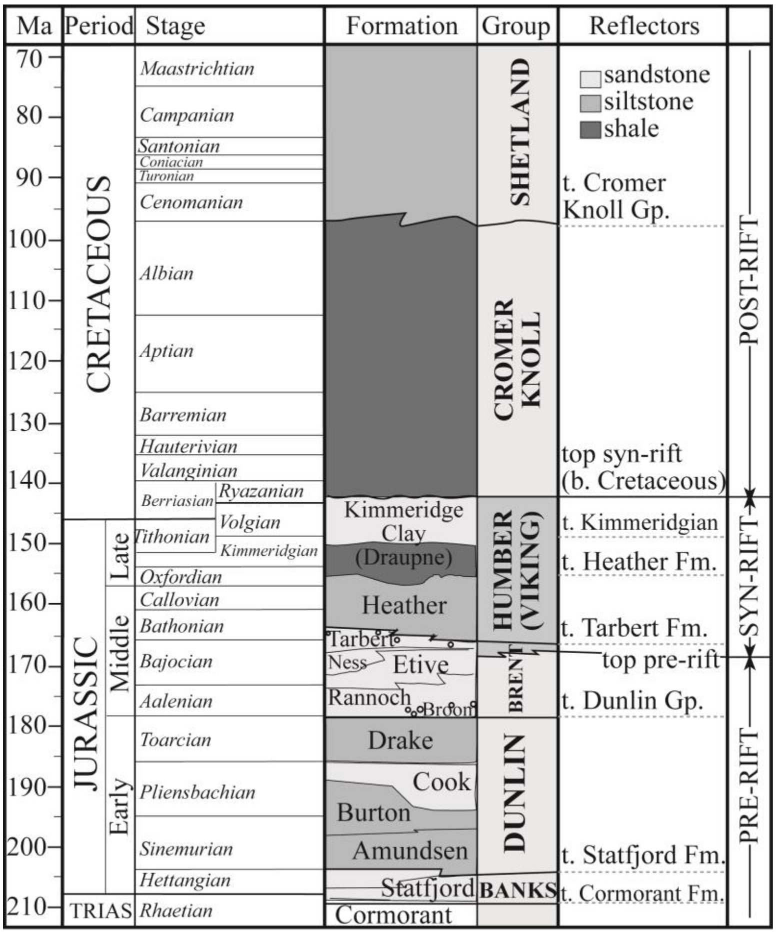


Figure 2: Stratigraphic nomenclature employed in this study. Also shown are the stratigraphic locations of the key seismic reflectors in the northern North Sea (see Figure 3). Pre-, syn- and post-rift refer to the Late Jurassic extensional event.

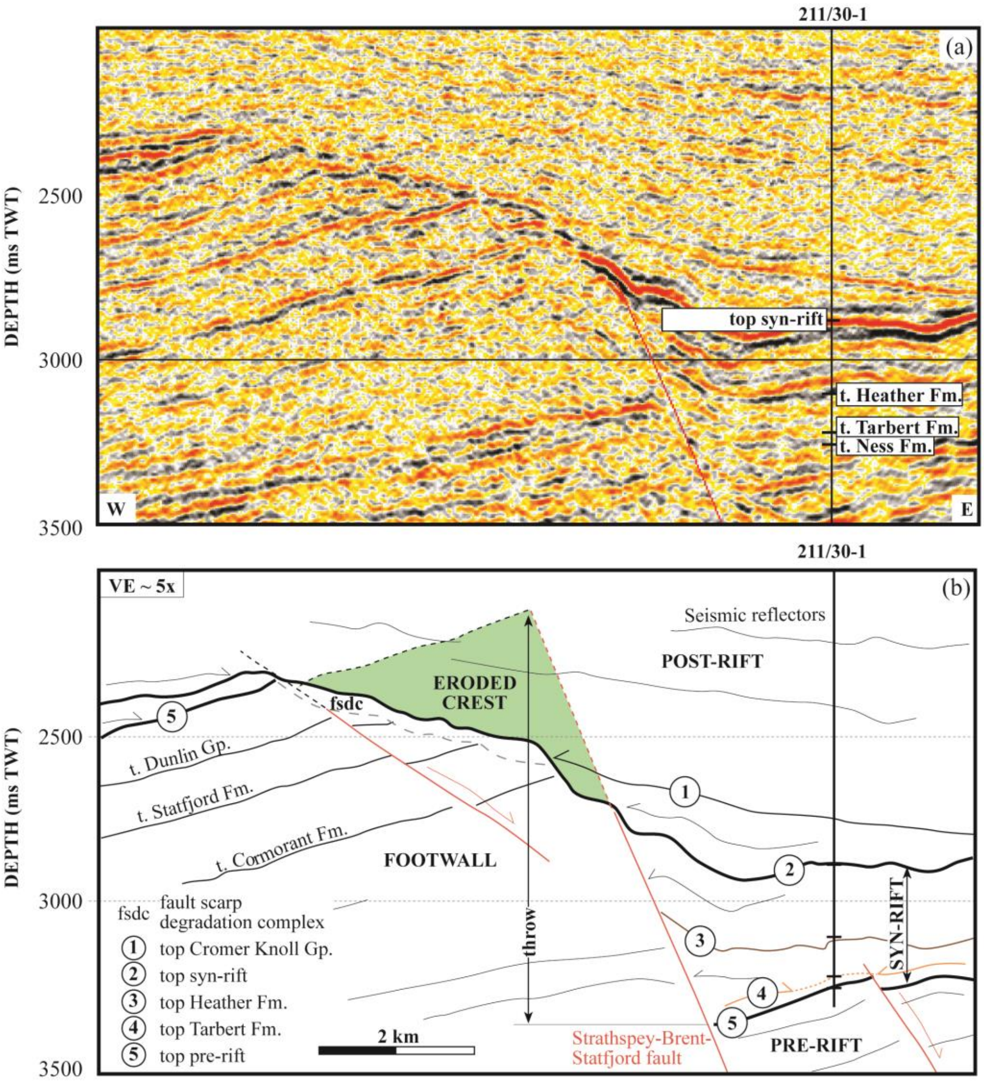


Figure 3: Seismic cross section oriented perpendicular to the strike of the Strathspey-Brent-Statfjord fault array. Key reflectors discussed in this work are shown. The Strathspey-Brent-Statfjord fault is observed to be near planar. (a) Seismic inline 1660 from the Brent (lm96083) survey. (b) Interpretation of seismic inline shown in (a). Reconstruction of the eroded footwall crest is by extrapolation of the top pre-rift and fault reflectors shown (see text for discussion). Vertical exaggeration is approximately five-fold.

3. WEEK 2: Sandstone Petrography

This week your team will look in more detail at the mineralogy of the Thistle Field. The reservoir quality (e.g. porosity and permeability) of a sedimentary rock depends on its initial composition and fabric and the post-depositional, diagenetic history. The lecture this week and this practical session should give you a good basic knowledge of sandstone petrography and will help you to assess the primary composition, diagenesis and reservoir quality of the Brent Group in well 211/18a-A33(18).

You will be provided with ten thin sections of the core from well 211/18a-A33(18) that span each of the major formations within the Brent Group (Table 1). To increase your understanding of the reservoir quality within the well, it is a good idea to look at, if not describe, all ten thin sections. To make sure you have enough data for your final report, you should aim to have described at least 4-5 thin sections of different formations (i.e. different reservoir qualities) by the end of this practical session. You can use the templates on the following pages for this.
Note that this template combines the data of week 2 and 3 (jPOR).

Resources:

- Petrographic microscopes, some with camera/computer connection (CTL)
- 10 thin sections of the Brent core 211/18a-A33(18) (Table 1)
- Three tables that you can use as a guide for sandstone description (Table 2-4)
- Examples of several thin section descriptions (Figure 4)
- Example of a diagenetic history (Figure 5)

Data collection:

- Make comprehensive descriptions of all 10 thin sections (in your group, 4-5 individually) including fully labelled and described photomicrographs, don't forget the scale bar! **IMPORTANT: you need at least one good quality photomicrograph for next week!**
- Create a summary supplementing the thin section descriptions, focussing on any changes or differences in sandstone composition, texture and reservoir quality characteristics and diagenetic history throughout the core.

Suggestions for discussion topics in your group:

- Describe the petrography of the ten thin sections obtained from each formation (e.g. primary porosity, secondary porosity, fabric, composition, sorting, grain size).
- Which diagenetic features can you identify (point them out in the photomicrographs!) and what is the overall sequence of the diagenetic events (diagenetic history)?
- What are the main (if any) differences in sandstone petrography between each of the formations?
- What features might inhibit horizontal and vertical permeability?
- What are the main (primary) controls on porosity and permeability? Does this change with depth/for different intervals?
- Does your petrographic interpretations match from what you learn from the plug/CCA data? Why (not)?

Table 1. Conventional core analsysis (CCA) data for the thin sections of well 211/18a-33(18)

Thin section	Formation	Depth				CCA porosity			CCA permeability (horizontal)		
		top (ft)	bottom (ft)	top (m)	bottom (m)	average (%)	min (%)	max (%)	average (mD)	min (mD)	max (mD)
TS-01	Rannoch II	10706.0	10711.2	3263.2	3264.8	19.9	10.8	24.3	50.9	0.9	82.6
TS-02	Rannoch II	10700.0	10706.0	3261.4	3263.2	21.3	19.8	23.9	47.4	25.2	116.0
TS-03	Rannoch I	10660.5	10665.6	3249.3	3250.9	5.1	3.4	5.8	0.1	0.1	0.2
TS-04	Rannoch I	10641.9	10647.6	3243.7	3245.4	25.2	22.1	27.4	164.2	32.1	275.0
TS-05	Etive	10538.0	10543.3	3212.0	3213.6	28.3	25.2	30.0	3740.0	1640.0	5260.0
TS-06	Ness	10460.7	10466.6	3188.4	3190.2	10.2	7.1	13.3	0.7	0.7	0.7
TS-07	Ness	10389.8	10394.8	3166.8	3168.3	27.3	26.2	28.4	2962.5	1680.0	4890.0
TS-08	Ness	10327.4	10330.8	3147.8	3148.8	28.4	27.9	28.7	783.7	612.0	1060.0
TS-09	Tarbert	10278.3	10283.5	3132.8	3134.4	27.0	25.4	28.4	2898.0	1110.0	5220.0
TS-10	Tarbert	10261.4	10266.8	3127.7	3129.3	23.9	22.5	25.3	395.2	185.0	531.0

Table 2: General scheme for describing sandstones, taken from Tucker (2001)

Hand specimen

Note the colour; grain size; grain shape; bedding, lamination and any other sedimentary structures. Any fossils present? Determine composition/mineralogy of grains and cements if possible

Thin-section

Check the macroscopic features of the thin-section by holding up to light and noting any lamination, large fossils or grains

Texture: determine the grain size, sorting, roundness of grains, grain shape, fabric (any preferred orientation of grains?) and nature of grain–grain contacts

Grains: identify grain types; determine relative proportions of quartz, feldspar, lithic grains and matrix

Matrix: check whether it is detrital; it may have formed from alteration and compaction of labile grains

Compaction: look for concavo-convex and sutured grain contacts, broken/bent mica flakes or bioclasts

Cementation: identify cements, e.g. quartz, calcite, dolomite, clays, and habits—overgrowths, pore-filling, pore-lining, etc.

Replacement/dissolution of grains: e.g. feldspar by calcite or clay; partial to complete dissolution of grains; look for oversized pores, where whole grains dissolved out

Porosity: if present determine origin and type—intergranular, dissolutional, fracture, etc.

Classification: from assessment of matrix content, is sandstone an arenite or wacke? If arenite, assess type (quartz arenite, arkose or litharenite) from grain composition. From texture, assess the maturity

Interpretation

Depositional environment: suggest from texture and composition, and any other information available, such as sedimentary structures and fossils from hand specimen and field data

Diagenesis: determine nature and order of diagenetic events and whether near-surface (pre-compaction) or burial (post-compaction) on basis of textural evidence; suggest evolution of pore fluids and destruction or creation of porosity in context of burial history

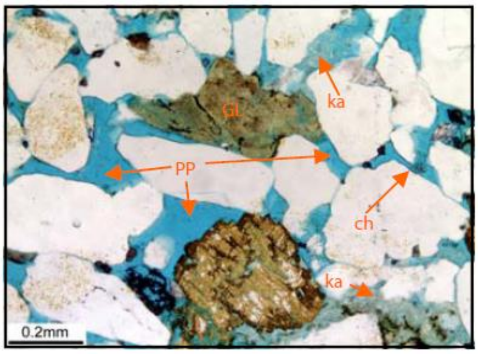
Table 3: Checklist for describing sandstones in thin section, taken from Tucker (2001)

Features	Thin-section 1	Thin-section 2
Grains present and percentage		
Quartz (types)		
Feldspar (types)		
Lithic grains (types)		
Mica (types)		
Bioclasts (types)		
Others		
Texture		
Roundness, sorting, fabric, packing, preferred orientation of grains		
Cements		
Quartz, calcite, dolomite, hematite, clays, anhydrite; cement geometry and timing		
Replacements		
Alteration, dissolution, feldspar preservation, calcite and clays replacing grains		
Evidence of compaction		
Broken and squashed grains, concavo-convex and sutured contacts, stylolites		
Porosity		
Intergranular—reduced/enhanced, mouldic, fracture, stylolitic, etc.		
Sandstone type		
Arenite/wacke, quartz arenite, arkose, litharenite, greywacke—lithic/feldspathic/quartzitic		
Depositional environment		
Marine/non-marine, fluvial/aeolian, shallow/deep, low/high energy		
Order of diagenetic events	1:	
	2:	
	3:	

Table 4: Optical properties of common minerals in sedimentary rocks as observed with the petrological microscope, modified from Tucker (2001).

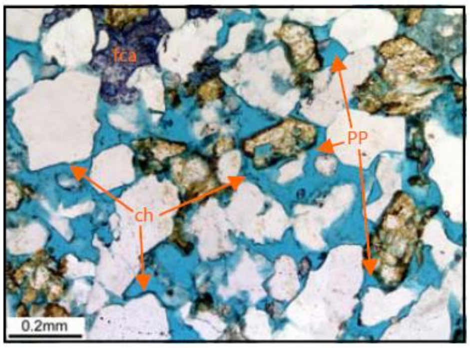
Mineral	Chemical formula	Crystal system	Colour	Cleavage	Relief
Quartz	SiO_2	trigonal	colourless	absent	very low (+)
Microcline	$KAlSi_3O_8$	triclinic	colourless	present	low (–)
Orthoclase	$K(Na)AlSi_3O_8$	monoclinic	colourless	present	low (–)
Albite	$Na(Ca)AlSi_3O_8$	triclinic	colourless	present	low (–)
Muscovite	$KAl_2(OH)_2AlSi_3O_{10}$	monoclinic	colourless	planar	moderate
Biotite	$K_2(Mg,Fe)_2(OH)_2AlSi_3O_{10}$	monoclinic	brown to green	planar	moderate
Chlorite	$Mg_5(Al,Fe)(OH)_8(AlSi)_4O_{10}$	monoclinic	green	planar	fair
Kaolinite	$Al_2O_3 2SiO_2 . 2H_2O$	triclinic	colourless–yellow	planar	low (+)
Illite	$KAl_2(OH)_2[AlSi_3(O,OH)_{10}]$	monoclinic	colourless–yellow	—	low (+)
Montmorillonite	$(MgCa)O . Al_2O_3 . 5SiO_2 . nH_2O$	monoclinic	colourless–pink	—	low (–)
Berthierine–chamosite	$Fe_3^{2+}Al_2Si_2O_{10} . 3H_2O$	monoclinic	green	—	moderate
Glauconite	$KMg(Fe,Al)(SiO_3)_6 . 3H_2O$	monoclinic	green	planar	moderate
Aragonite	$CaCO_3$	orthorhombic	colourless	rectilinear	moderate
Calcite	$CaCO_3$	trigonal	colourless	rhombic	low to high
Dolomite	$CaMg(CO_3)_2$	trigonal	colourless	rhombic	low to high
Siderite	$FeCO_3$	trigonal	colourless	rhombic	low to high
Gypsum	$CaSO_4 . 2H_2O$	monoclinic	colourless	planar	low
Anhydrite	$CaSO_4$	orthorhombic	colourless	rectilinear	moderate
Halite	$NaCl$	cubic	colourless	rectilinear	low
Collophane	$Ca_{10}(PO_4,CO_3)_6F_{2-3}$	a mineraloid	shades of brown	—	moderate
Pyrite	FeS_2	cubic	opaque	—	—
Hematite	Fe_2O_3	hexagonal	opaque	—	—
Magnetite	Fe_3O_4	cubic	opaque	—	—

Mineral	Birefringence	Other features	Form and occurrence	See Section
Quartz	weak		as detrital grains (monocrystalline and polycrystalline types), cements and replacements: fibrous quartz (chalcedony), microquartz, megaquartz	2.5.2, 2.9.2, 9.2
Microcline	weak	grid-iron twinning	as detrital crystals, also authigenic commonly altered to clays, so appearing dusty	2.5.3, 2.9.4
Orthoclase	weak	simple twinning (Carlsbad)		
Albite	weak	multiple twinning		
Muscovite	strong	parallel extinction	common detrital minerals occurring as flakes	2.5.4, 3.4.3
Biotite	strong	parallel extinction		
Chlorite	weak	best identified through X-ray diffraction because usually so fine-grained	as detrital minerals, particularly in mudrocks, also as cement (as in sandstones) and replacements, such as of feldspars and volcanic grains	2.9.5, 3.4.1, 10.7
Kaolinite	weak			
Illite	strong			
Montmorillonite	moderate			
Berthierine–chamosite	weak		ooids and mud in ironstones	6.4.3
Glauconite	moderate		forms synsedimentary grains	6.4.3
Aragonite	moderate	can be distinguished by staining (Section 4.1)	form grains, matrix, cement and replacements in limestones, dolomites, sandstones, etc.	4.2, 4.3, 4.7, 4.8, 2.9.3
Calcite	extreme			
Dolomite	extreme			
Siderite	extreme	alters to brown colour	fine and coarse crystals in ironstones	6.4.2
Gypsum	weak		anhedral to euhedral crystals	5.2
Anhydrite	strong	parallel extinction	equant to lath-shaped crystals	
Halite	—	may have fluid inclusions	often coarsely crystalline	5.3
Collophane	isotropic or weak	if bone—organic structure	forms ooids, pellets, bones, some shells	7.2
Pyrite	—	yellow in reflected light	aggregates and cubic crystals, authigenic	6.4.4
Hematite	—	red–grey in reflected light	cryptocrystalline, a pigment and replacement	6.4.1, 2.9.6
Magnetite	—	grey–black in reflected light	cryptocrystalline, detrital	6.4.1



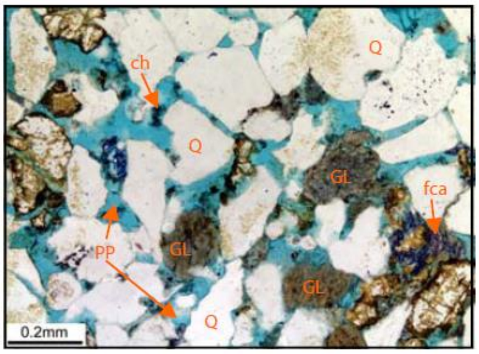
Well: XXXXX
Depth (DD): XXXXX m
Lithofacies: Sm (Sx)
Facies association: A4
Sorting: moderately well sorted
Modal grain size: lower medium sand
Helium porosity: 21.8%
Kh: 318mD

Moderately well sorted, lower medium grained, subfeldspathic arenite, with 2.0% ductile clay content. Ductile grains are minor (1.5%) comprising mica and glauconitic pellets (GL). Weak to moderate compaction has produced a mixture of point and long grain contacts. The primary intergranular porosity network (PP) is largely clean and well interconnected although local grain-coating radial chlorite (ch) is present along with patchy kaolinite (ka). Reservoir quality is assessed as high. PPL.



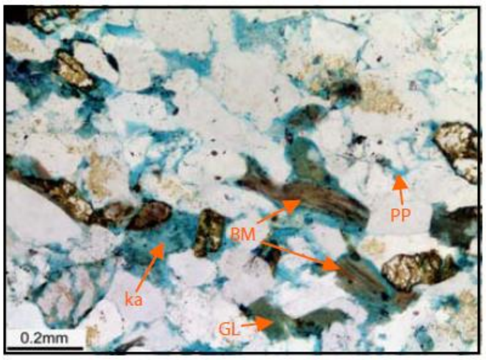
Well: XXXXX
Depth (DD): XXXX m
Lithofacies: Sm (Sp)
Facies association: A4
Sorting: moderately well sorted
Modal grain size: lower medium sand
Helium porosity: 23.5%
Kh: 152mD

Moderately well sorted, lower medium grained, subfeldspathic arenite with only 1.0% ductile clay content. Ductile grains (8.0%) are significant, largely comprising mica and glauconitic pellets. Grain contacts are a mixture of point and long, indicating weak to moderate compaction. The primary intergranular porosity network (PP) is well interconnected despite widespread (but volumetrically minor) grain-coating radial chlorite (ch). Patchy late ferroan calcite cements (fca) occlude macroporosity. Reservoir quality is assessed as high. PPL.



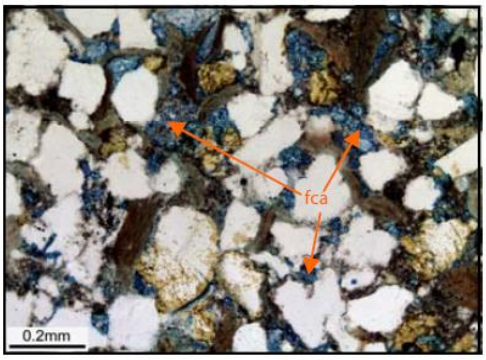
Well: XXXX
Depth (DD): XXXX m
Lithofacies: Sm
Facies association: A3
Sorting: moderately well sorted
Modal grain size: upper fine sand
Helium porosity: 21.1%
Kh: 58.2mD

Moderately well sorted, upper fine grained framework which is dominated by monocrystalline quartz grains (Q). Ductile clay content (0.5%) is very minor and restricted to patchy detrital clay. Ductile grains (5.5%) largely comprise glauconitic pellets (GL) which are variably compacted into intergranular areas. Patchy authigenic chlorite (ch) is located within primary intergranular pores (PP) which are moderately interconnected. Ferroan calcite locally reduces macropore connectivity. Reservoir quality is assessed as moderate. PPL.



Well: XXXXX
Depth (DD): XXXX m
Lithofacies: SMd1
Facies association: A4
Sorting: well sorted
Modal grain size: lower fine sand
Helium porosity: 16.0%
Kh: 2.96mD

Well sorted, lower fine grained, feldspathic arenite with only minor ductile clays (0.5%). Ductile grains (9.0%) largely comprise variably expanded biotite mica (BM) and glauconitic pellets (GL). Primary intergranular pores (PP) are small and poorly interconnected, mainly as a result of moderate compaction (largely long grain contacts). Expansion of mica grains has also reduced the connectivity of primary intergranular pores. Local secondary intragranular porosity has been generated, but largely negated by kaolinite (ka). Reservoir quality is assessed as low. PPL.



Well: XXXX
Depth (DD): XXXX m
Lithofacies: SMh2
Facies association: B1g
Sorting: well sorted
Modal grain size: lower fine sand
Helium porosity: 8.8%
Kh: 0.09mD

Well sorted, lower fine grained, calcitic subfeldspathic arenite containing 13.0% ferroan calcite cement (fca) which occludes all macroporosity. Reservoir quality is assessed as extremely low. PPL.

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Figure 4: Examples of thin section description. Note scale bar on the images!

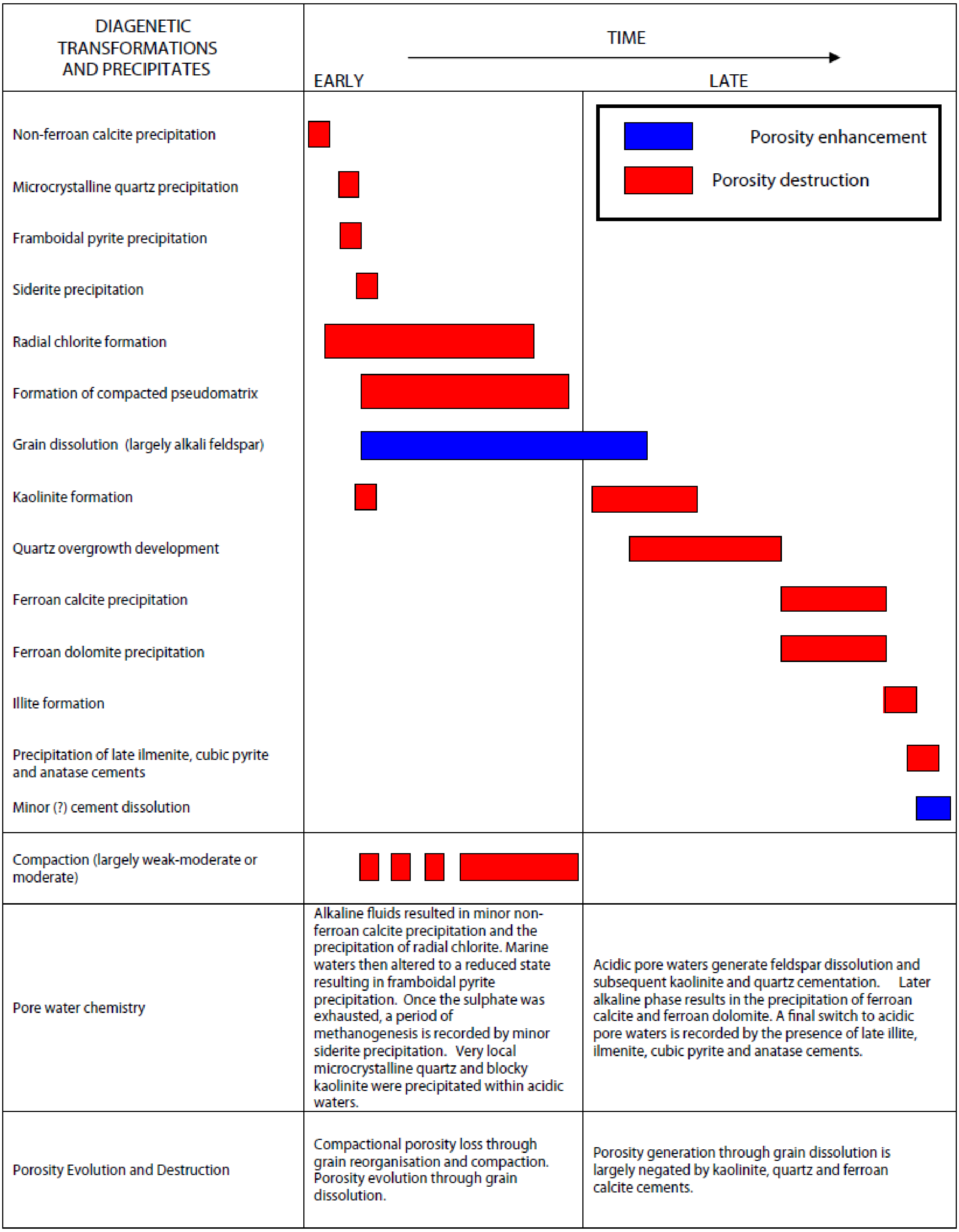
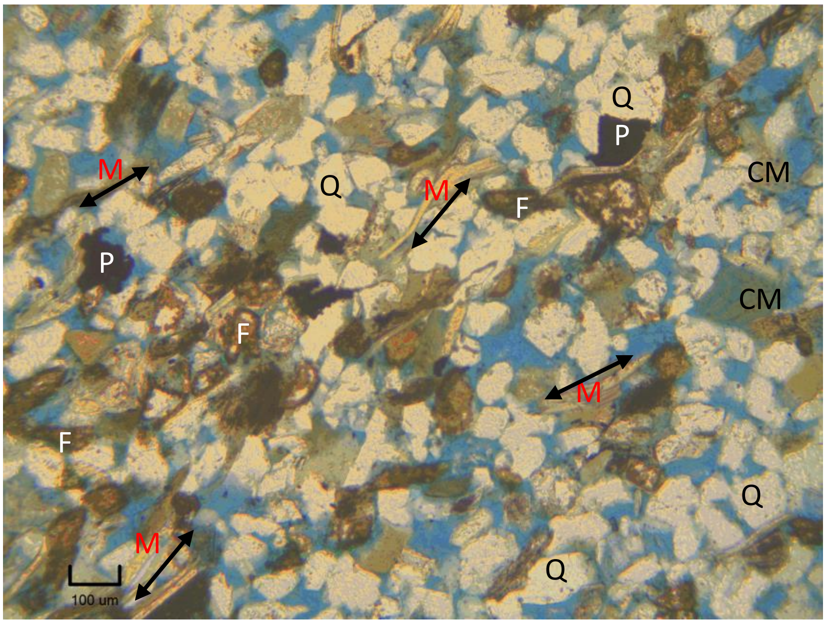


Figure 3.5: Diagenetic history RECORDED BY xx NUMBER OF SAMPLES FROM THE xxxx FORMATION IN THE bRENT gROUP WELL xxxx

Figure 5: Example of a diagenetic history with potential diagenetic effects. Note timings are relevant to each other, not exact ages.

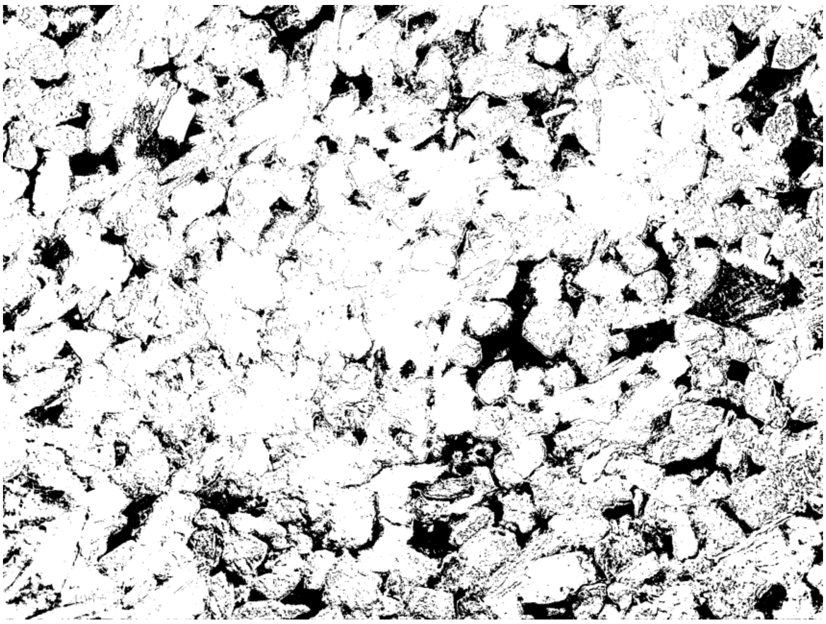
Photomicrograph descriptions

Well: 211/18a-A33 **Depth (DD)**: TS-2 (10700-10706ft)



Sorting: Moderately well sorted
Modal grain size: Very fine
Facies: Lower Shoreface
COPL: 15%
CEPL: 24%

Description of thin section photomicrograph:
Sub-rounded. Heterogeneous grain framework. Mainly quartz Q. Mica M, Feldspar F, Pyrite P as clay mineral, Clay minerals CM. Preffered orientation of muscovite. Minor cementation. Compaction? Minor feldspar dissolution.

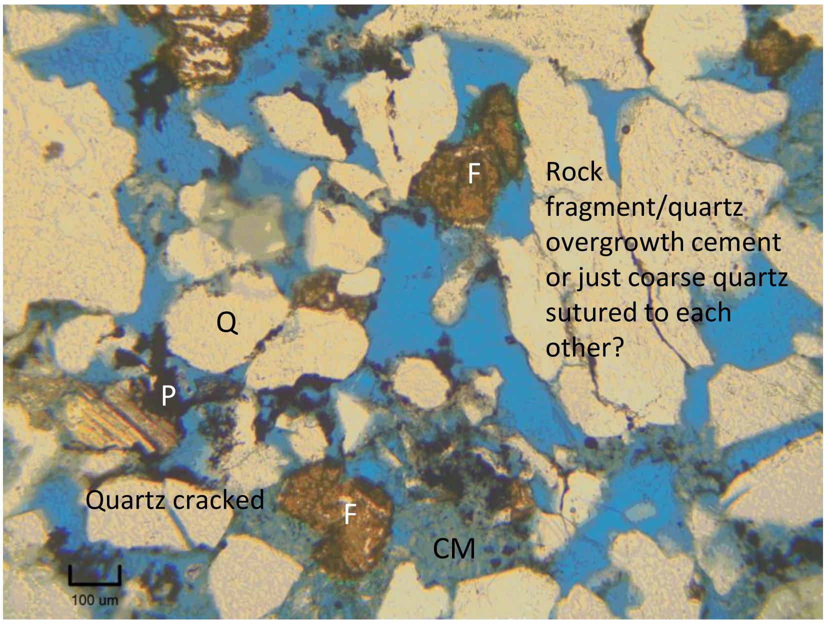


He porosity: AVG 21%
JPOR porosity: This 21%
KL permeability: AVG 47mD

Description of ImageJ-JPOR pore-network image:
Pore spaces are affected by the size of very fine grains. Porosity is also affected by distributional areas of grains

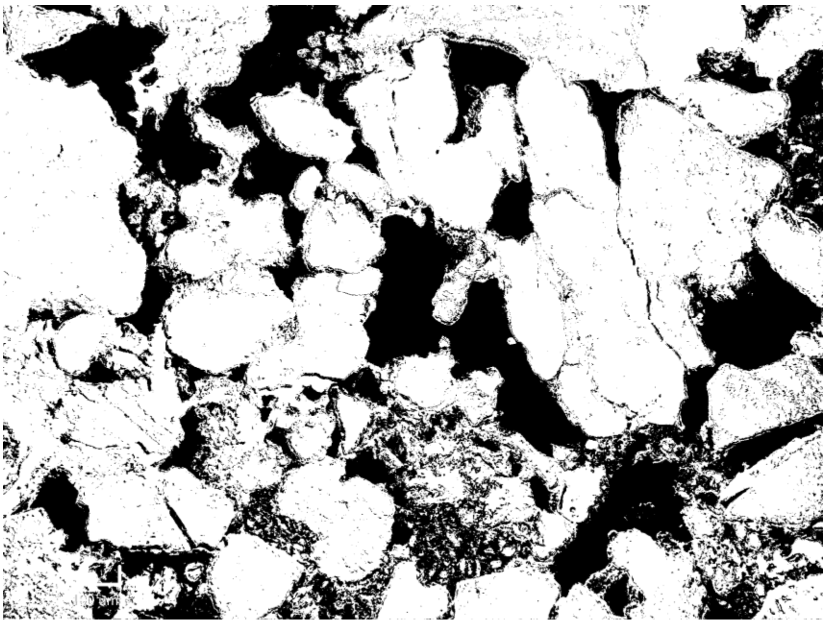
Photomicrograph descriptions

Well: 211/18a-A33 **Depth (DD)**: TS-5 (10538-10543ft)



Sorting: Moderately sort.
Modal grain size: Fine-medium
Facies: Upper shoreface
COPL: 4%
CEPL: 32%

Description of thin section photomicrograph:
Sub-angular. Mainly quartz grain framework. Feldspar, Pyrite, Clays are present. Point/free contacts. Clay in pore spaces? Some quartz fractures

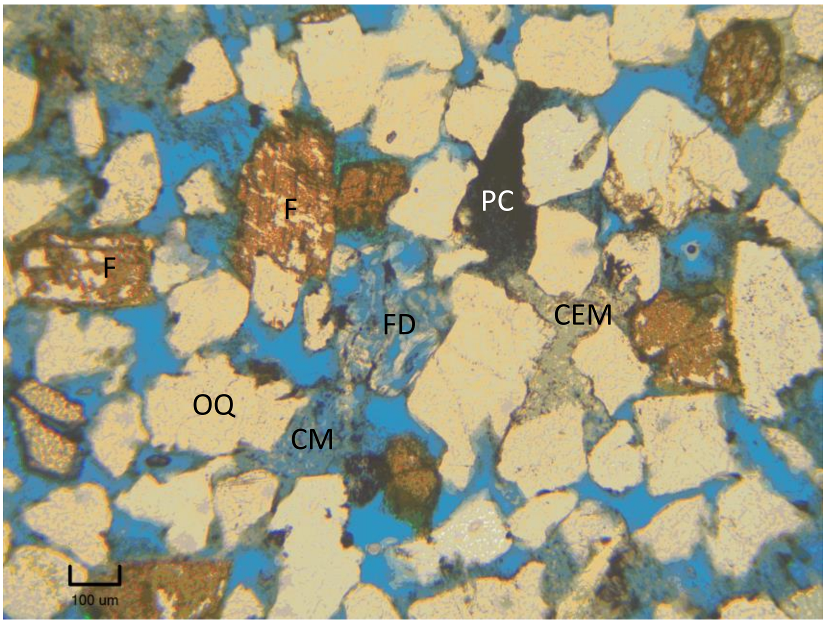


He porosity: AVG 25%
JPOR porosity: This 31%
KL permeability: AVG 3740mD

Description of ImageJ-JPOR pore-network image:
Big porous areas due to medium grain size. Small particles of disrupted (dissolved) material can reduce the quality of the pores but also can generate more pore spaces. High porosity

Photomicrograph descriptions

Well: 211/18a-A33 **Depth (DD)**: TS-6 (10460-10467)



Sorting: Well sorted

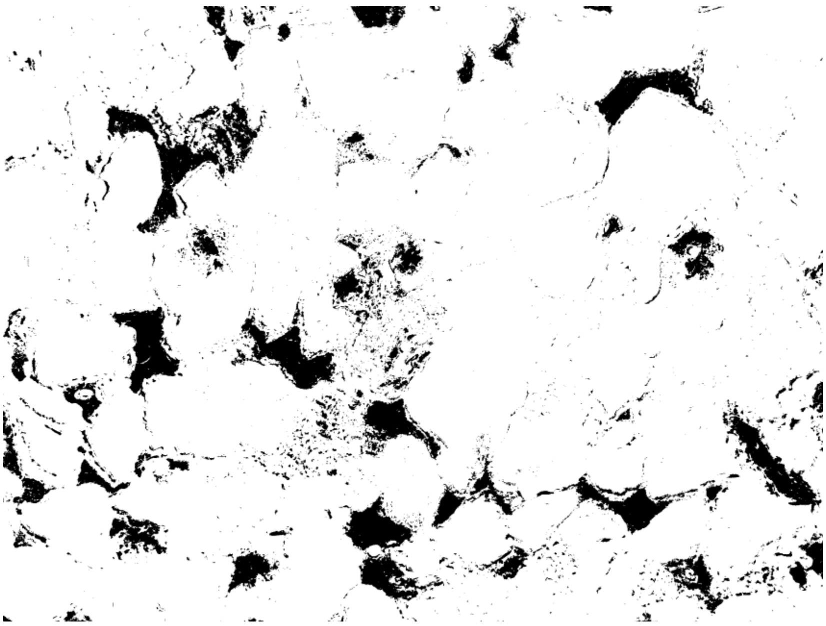
Modal grain size: Fine

Facies: Lagoon (barrier)

COPL: 4%

CEPL: 36%

Description of thin section photomicrograph:
Sub-angular. Mainly quartz grain framework, some of them overgrowth OQ. Feldspar, Pyrite clay PC and other clay minerals CM are present. Sutured/point contacts. Major cementation CEM. Feldspar dissolution,



He porosity: AVG 10%

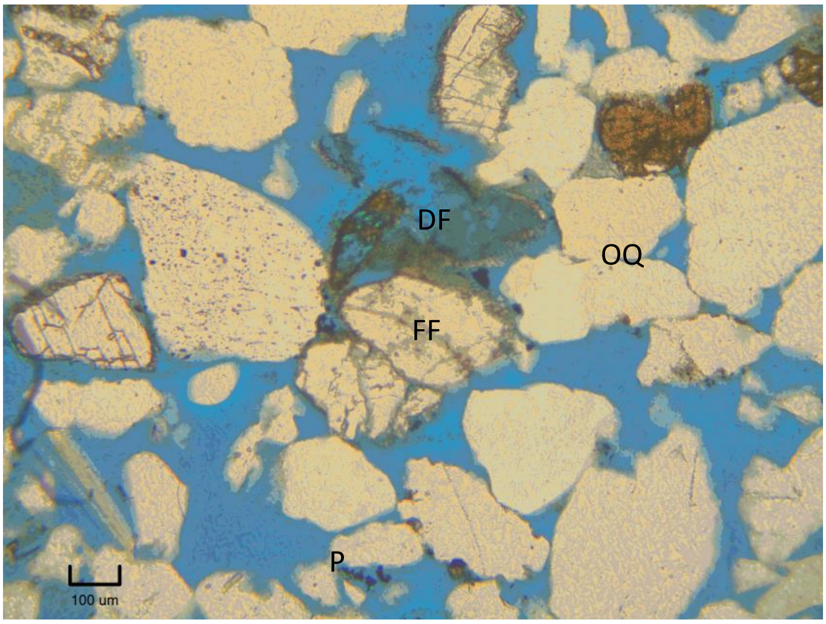
JPOR porosity: This 10%

KL permeability: 0.7 mD

Description of ImageJ-JPOR pore-network image:
Less porous due to cementation of pore spaces. Dissolved material reduces porosity. Grains are close contacted.

Photomicrograph descriptions

Well: 211/18a-A33 **Depth (DD)**: TS-7 (10389-10395ft)



Sorting: Moderately sort.

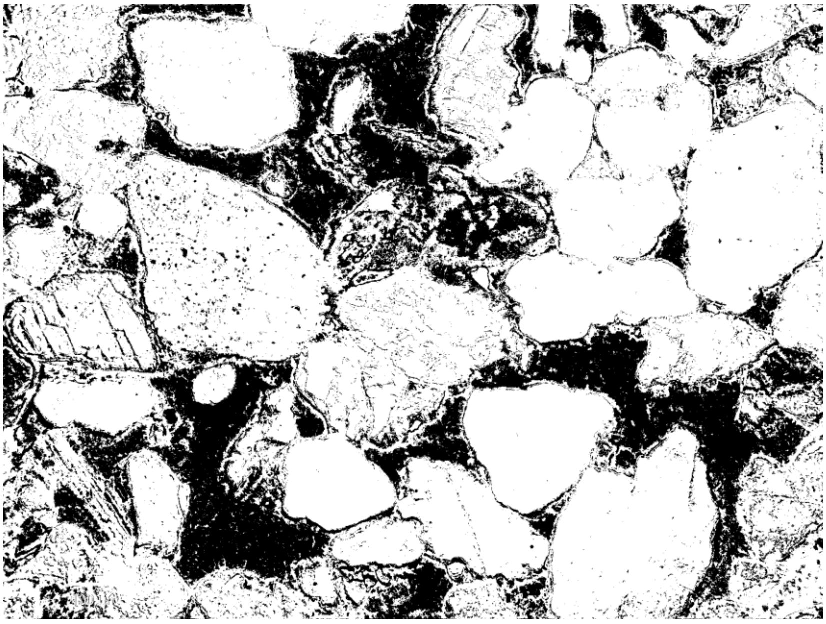
Modal grain size: Fine-medium

Facies: Fluvial channel (delta)

COPL: 2%

CEPL: 34%

Description of thin section photomicrograph:
Sub-rounded. Homogeneous quartz grain framework, some overgrowth quartz OQ. Feldspar F and Pyrite P are present. Free contact close packing. Some feldspar dissolution DF and fracturing FF.



He porosity: AVG 27%

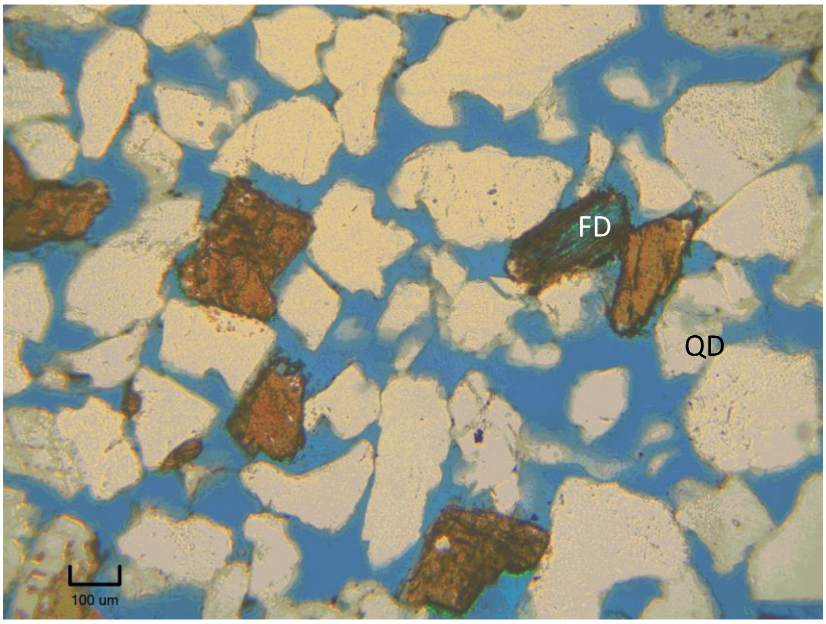
JPOR porosity: This 27%

KL permeability: AVG 2963mD

Description of ImageJ-JPOR pore-network image:
Dissolution generates more pore spaces. Overgrowth quartz reduces it.

Photomicrograph descriptions

Well: 211/18a-A33 **Depth (DD)**: TS-9 (10278-10283ft)



Sorting: Moderately well sorted

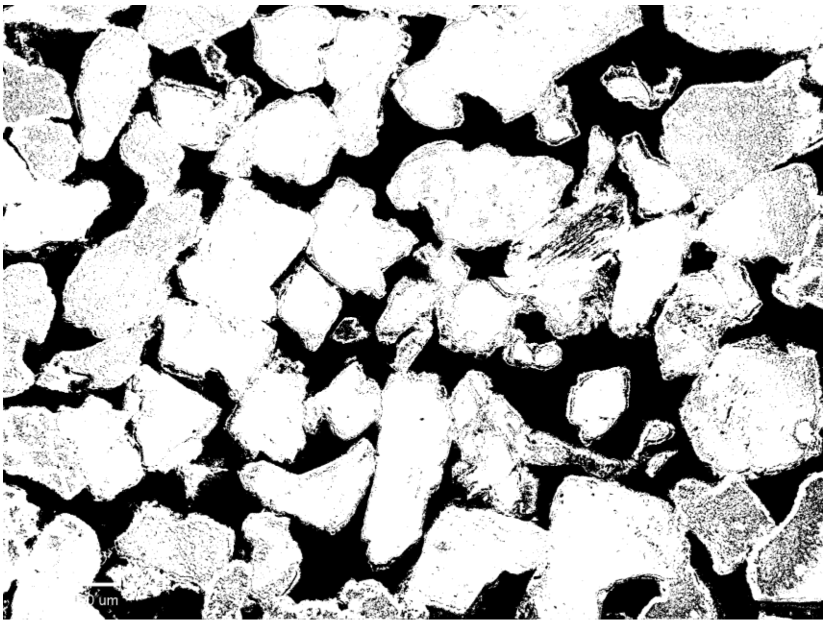
Modal grain size: Fine

Facies: Marine shelf

COPL: 3%

CEPL: 35%

Description of thin section photomicrograph:
Sub-rounded. Homogeneous quartz grain framework. Feldspar and Pyrite are present. Free contact close packing. Some feldspar dissolution FD. Minor quartz dissolution QD.



He porosity: AVG 27%

JPOR porosity: 30%

KL permeability: AVG 2898mD

Description of ImageJ-JPOR pore-network image:
Well distributed intergranular porosity. Well sorting of fine grains can generate this. Absence of small fragments between grains.

Week 2: Sandstone Petrography Discussion

Option to include your notes and discussion of your observations made during the petrographic work on the thin sections.

-Photographed 6 images for each thin section horizon.
-This analysis of thin sections is very limited because it have not obtained enough images and thin sections itselves to assess the wide distribution of grains, features, etc.
-Table is created to better formulate raw interpretation (discussion) of thin sections
-More details in the next discussion slide

TS	Formation	Interpretation	Average porosity of 6 TS
2	Rannoch	Very fine grained. Preferred orientation of muscovite. Compaction affected	21%
5	Etive	Good porosity and permeability. More medium grains. Big pore spaces and some cementations	25%
6	Ness	Strong cementation and compaction affected Fine grains. Particles of dissolved material can reduce primary intergranular porosity by precipitation.	15%
7	Ness	Good porosity and permeability. More medium grains. Feldspar dissolution creates secondary porosity	28%
9	Tarbert	Good porosity and permeability. Fine grains. Well sorting and absence of fragments in intergranular space.	20%

4. WEEK 3: jPOR and COPL/CEPL

During this week's workshop your group will use image analysis techniques to investigate the porosity and permeability relationships and use automated mineralogy data to estimate compactional and cementational porosity loss (COPL/CEPL).

Using your photomicrographs from last week, you can use ImageJ to calculate the porosity for each image (see guidelines on how to use ImageJ and jPOR below).

Permeability (k) can be approximated empirically in a number of ways but it is best expressed by Darcy's law:

$$k = \frac{Q\mu L}{A\Delta P} \qquad (1)$$

where ΔP represents the pore pressure differential (i.e. inflow fluid pressure – outflow fluid pressure) across the sample, Q is the flow rate, μ is the fluid viscosity, L is the sample thickness and A is the sample cross-sectional area. Recent experiments carried out by the University of Liverpool demonstrate that permeability will vary as a function of porosity, increasing by approximately four orders of magnitude (at ambient pressure) for intact samples (i.e. no fractures) across a range of porosities (1.2-41.7%; see lower dashed line on Fig. 6). The equation of this line represents the non-linear relationship between permeability (κ) and porosity (ø), which is given as:

$$k = 3 \times 10^{-17} Q^{3.11} \qquad (2)$$

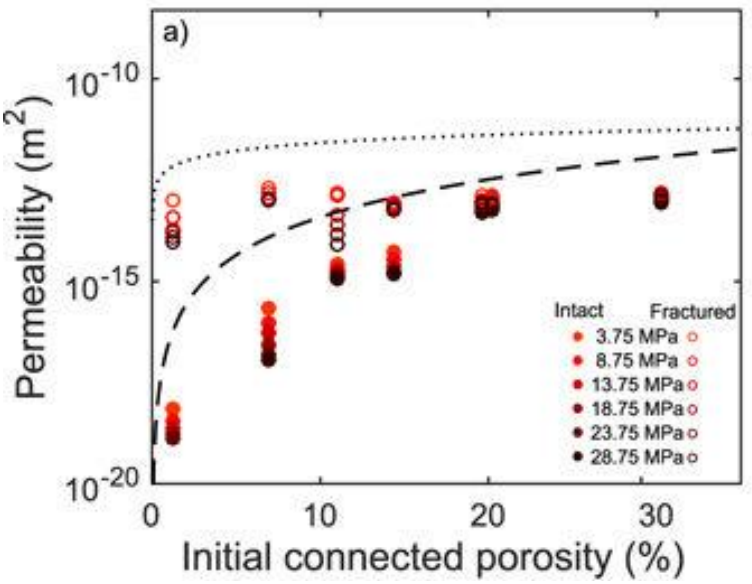


Figure 6: Permeability – porosity – effective pressure relationship for intact (filled circles) and fractured (open circles) rocks. Distribution of permeability and connected porosity data compiled as a function of effective pressure (darker colours represent higher pressures). The dashed and dotted curves display the best fits obtained for the intact and fractured samples, respectively, at ambient pressure.

Figure 7 shows the schematic distribution of porosity and grains in a rock at deposition and at present day. To calculate the compactional porosity loss (COPL) and cementational porosity loss (CEPL) you have to take into account the volume change:

$$COPL = P_i - \frac{(100-P_i)IGV}{(100-IGV)} \qquad (3)$$

$$CEPL = (P_i - COPL) - \frac{IGV-P_o}{IGV} \qquad (4)$$

where Pi is depositional porosity; Po is primary, intergranular macroporosity (point-counted); IGV is intergranular volume (defined as the sum of all intergranular clays, cements and primary porosity; not including detrital mud*). More background information on COPL/CEPL can be found in Ehrenberg (1989), Pate (1989) and Lundegard (1992).

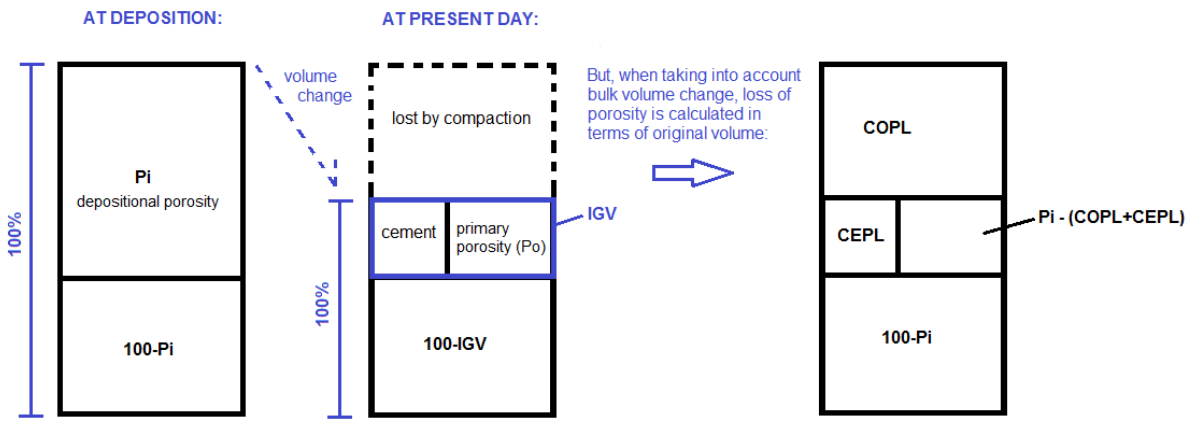


Figure 7: Overview figure showing the schematic distribution of porosity and grains in a rock at deposition and at present day (based on Lundegard (1992)).

Resources:

- Petrographic microscopes, some with camera/computer connection (CTL)
- 10 thin sections of the Brent core 211/18a-A33(18) (Table 1)
- ImageJ software and the jPOR plug-in (VITAL)
- Petrography data: point-counting and automated mineralogy (VITAL)
- Class database of porosity and permeability (created during this workshop)

Data collection:

- In your group calculate the porosity for all 10 thin sections using ImageJ and collect and describe the pore network images and add them to the thin section descriptions.
- Calculate the permeability (at ambient pressure) of the thin sections using equation 2. Ensure that you use % porosity for calculation (e.g. 26%) and convert your answer from m2 to millidarcy, mD [1 m2 = 1.01 x 1015 mD]. Add the values to your descriptions.
- Save the porosity and permeability data and add them to the class database (excel file open during the practical workshop)
- Using the petrography and automated mineralogy data (VITAL) calculate the COPL/CEPL values for each of the thin sections. Add the values to your thin section descriptions.

Suggestions for discussion topics in your group:

- Does the ImageJ calculated porosity match your expectations from the mineralogical description in week 2?
- How well does the calculated porosity match the CCA porosity? (Table 1)
- What can you infer about the permeability from this image (for example the pore throat sizes or the connectivity) and how does this compare with the CCA permeability?
- How does your calculated permeability compare to permeability derived from CCA?
- The production permeability is not the same as ambient permeability calculated above. The core was originally located at more than 3000 m depth with a pressure in excess of 30 MPa. Reading off the value for intact rock at 28.75 MPa on Fig. 6, you can estimate the production permeability. How does this value compare to permeability derived from conventional core analysis (CCA)?
- Describe the reservoir quality trends within well 211/18a-A33 by ordering all 10 thin sections in terms of their reservoir quality (1 = the worst reservoir, 10 = the best reservoir). Discuss why they were given a score by discussing the mineralogy, diagenesis, porosity and permeability, bringing together the information you gathered in weeks 2 and 3.
- Using the class database you can plot and examine the porosity and permeability for the thin sections you described in week 2. Discuss the variability you see in the data.
- Do your calculated COPL/CEPL values match your observations from the thin sections?

a. JPOR: ImageJ based porosity calculation

This text is based on user guide Version 1.1 by Clayton Grove and Dougal, A. Jerram.

Introduction

ImageJ is a public domain (i.e. freely available) image processing program. JPOR is a macro toolset designed to work with ImageJ and allows the rapid measurement of porosity on prepared images of blue stained thin sections. JPOR is easy to use and requires no specialist computer training. Images can be sourced from either a digital film scanner or microscope making the use of high specification scientific equipment optional.

Installing ImageJ and jPOR

• **Step 1: install ImageJ**

If ImageJ is not already installed on your machine, the software is available to download from University Applications. It can be found under "Life Sciences" and should only take a couple of minutes to install.

• **Step 2: download JPOR**

Other than ImageJ, you also need to download the jPOR files from VITAL (jPORv1.1a.zip) and save them on your M-drive. In case you cannot find the files on VITAL or they do not work, the original link to the plugin is http://www.geoanalysis.org/jPOR.html

• **Step 3: load JPOR toolset**

Load the jPOR macro toolset by replacing (i.e. copy/paste) the file 'Startup_Macros.txt' in "C:\IMAGEJ 1.48\macros" with the .txt file with the same name from the jPORv1.1a folder. It is a good idea to back-up the original 'Startup_Macros.txt' file on your M-drive, just in case.

• **Step 4: check**

After this, jPOR will automatically load each time ImageJ starts and a clickable icon  will appear within ImageJ to start jPOR. If the macro copy/paste does not work, the file jPOR.txt can also be copied to the ImageJ plugins folder within a new folder (you have to create a new folder) and will then appear in the dropdown plugins menu within ImageJ.

Image Acquisition

Use the microscope cameras and Infinity Analyze software available in the CTL to take photomicrographs directly from the thin section and save to your M-drive. I recommend to save the images as .tiff files, which preserves the image resolution.

Pre-processing images for JPOR

The .tiff files are likely to be 24-bit which is not suitable for jPOR. The aim of pre-processing is to produce a paletted ('indexed' in Adobe Photoshop) 8-bit file of a small enough size to run on ImageJ. Critical to the success of porosity calculation is having a 256 colour palette with the 'blues' associated with porosity together so they can be thresholded together. There are two ways to do this: (1) making an optimised palette or (2) applying the jPOR custom 8-bit palette. You can apply the custom 8-bit palette (jPOR60) as follows:

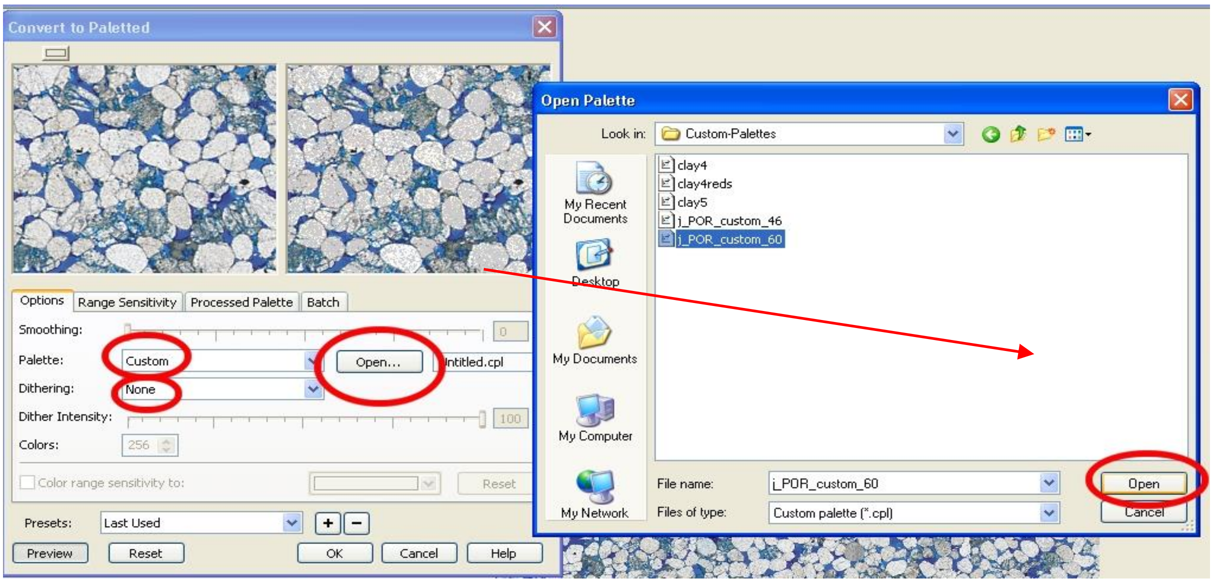
Step by step guide to pre-processing

1. Open image in your chosen image processing software (e.g. Corel Photo-Paint, Adobe Photoshop or IrfanView (free)). Corel Photo-Paint is available on UoL computers.
2. If necessary crop the image to make a rectangle only comprising of sample i.e. no slide mounting or edges.
3. <u>Either</u>:

Convert to an 8-bit paletted file using the provided custom palette. Make sure that no dithering is set. The image may look slightly unnatural, but the area of porosity will be preserved, albeit with fewer colour values.

In Corel Photo-Paint (available on CTL computers; see screenshot below):

- Open Corel Photo-Paint
- Window > colour palettes > open palette
- Open jPOR60 palette (from jPORv1.1a folder, you might need to select "Legacy palettes" behind "File name")
- Now open the thin section photo
- Image > convert to paletted 8-bit > (merge image) > select jPOR60 palette with dithering option none > click OK
- Save the processed image as a .bmp file (windows bitmap)



Screenshot CorelDraw showing palette selection.

Using JPOR

Open ImageJ and click the icon JPor to begin, then follow the instructions on the screen:

1. To threshold porosity press F1
2. To calculate porosity press F2 (requires threshold stage to be completed)
3. Save pore-network image if needed (File > Save as)
4. To continue batch press F3
5. To end batch press F5

jPOR is best used on batches of images that are saved in the same folder, once a batch has been completed press F5. This will end jPOR and copy results to the clipboard for export into spreadsheet software. The log file can be saved manually if required.

During the operation of jPOR the ImageJ zoom tool can be used to zoom in on areas of interest during thresholding if needed. To use the zoom tool left mouse click to zoom in, right mouse click to zoom out

jPOR functionality and limitations

jPOR will deliver accurate porosity determination comparable to point counting. However jPOR relies on the acquisition of sharp, focussed images. An out of focus image will introduce additional error in determining the pixel threshold value.

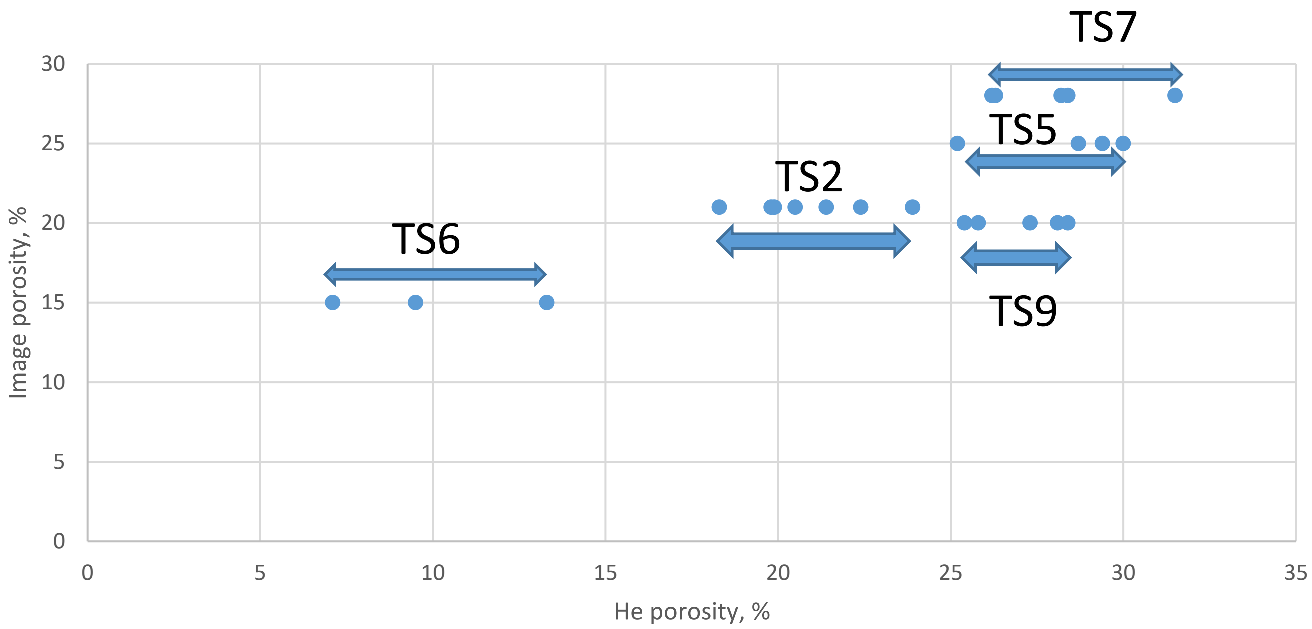
Other than during image acquisition, error is introduced by threshold determination. Use of the custom palette reduces this by automatically making blues associated with porosity lie within the sub 60 pixel value on the threshold histogram. However in rare cases where significant microporosity or resin colour variance exists it may be necessary to extend the threshold beyond 60 pixels. This choice introduces a human error or user-bias component.

Where a custom palette has not been used (optimised palette generation) the automatic threshold value (F1) will need to be manually adjusted for each image. A typical optimised palette for an aeolian sandstone will consist of ~40 blue values, ~160 greys/whites, and various browns. The transition from blue to grey will make thresholding very reliant on judgement. The custom palette removes this judgement because the blue colour values have deliberately been separated from common rock forming colours.

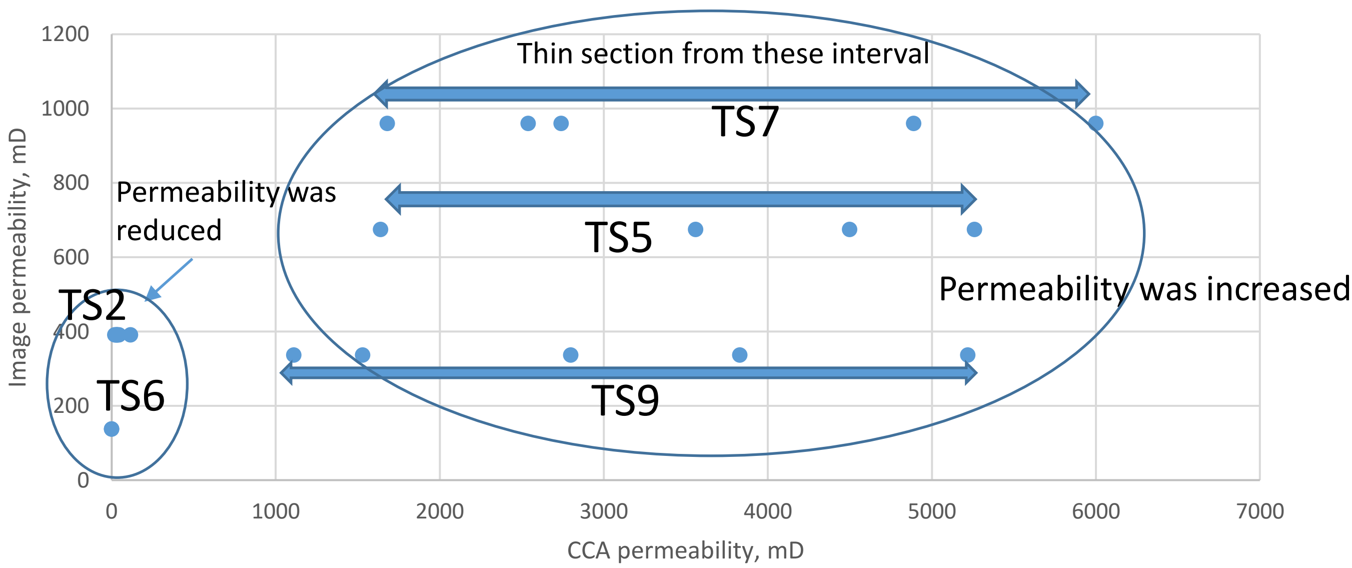
For the most part (except for testing on other image editing platforms) jPOR has been developed using Corel Photo-Paint X3. Photo-Paint X3 is therefore the preferred pre-processing software, it also has the added flexibility of a palette editing function. Applying the jPOR60 palette works equally well in any photo editing software.

Porosity and Permeability Data

Well: 211/18a-A33 **Depth (DD)**:

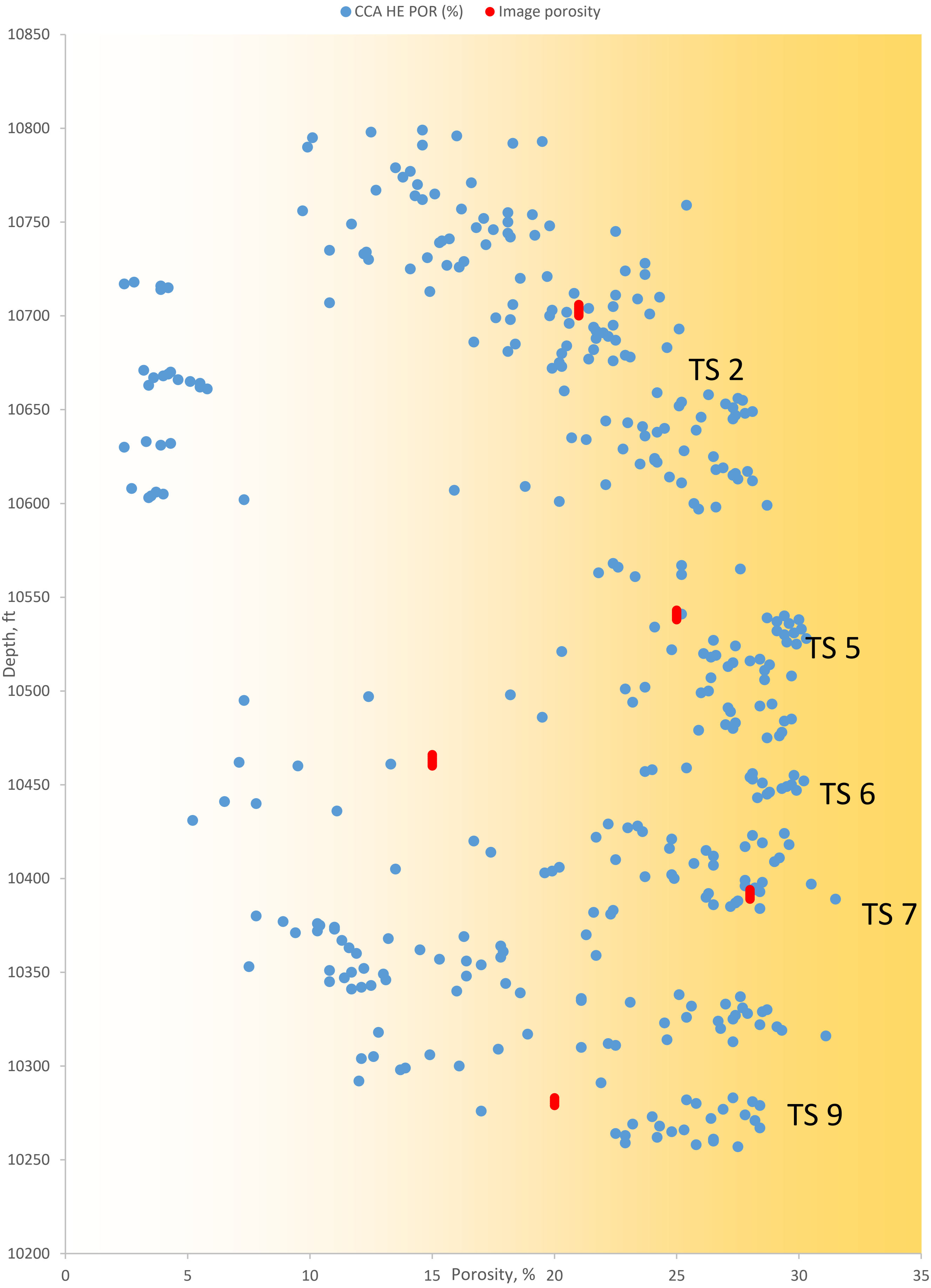


Description of porosity plot:
Porosity values that was derived as average porosity from 6 photomicrographs were named as "Image porosity". It was plotted to He porosity from the CCA data. You can notice the range of He porosity for each Image porosity, it explains that thin section depths were collected in a range of 5-10meters. Good correlation.



Description of permeability plot:
Image permeability was derived from calculation of Image porosity by oversimplified equation without any controlling factors to permeability affection. However, Image permeability represents only dependence to image porosity and burial and therefore this plot can tell how permeability was affected.

CCA (He) porosity vs depth
Image porosity and thin section representation



Week 3: jPOR and COPL/CEPL Discussion

Option to include your notes and discussion of your observations made during the image analysis of thin sections and calculations using petrographic data.

-ImageJ calculated porosity gives quantitative value to better interpret the photomicrograph and was helpful to estimate pore spaces that was detected in mineralogical description.
-As it can be seen in page 22, correlation of Image porosity to CCA porosity was good. It can be so because we chose 6 microphotographs to derive average porosity among them.
-Permeability is not only depends on pore spaces it is also depends on some controlling factors such as grain sizes, cementation, preferred orientation of grains, compaction etc. For instance, explanation of low permeability of thin section 2 can relate to very fine grain size, preffered orientation of muscovite because of compaction, cementation , low permeability of ts 6 can be explained by sutured contacts of grains and cementation.
-Difference of Image permeability to CCA permeability was explained in page 22.
-High values of TS 5,7,9 can relate to pore pressure (effective pressure) of fluids within intact rock.
-Table below was created to describe quality trend and ordering thin section in terms of their reservoir quality, 1-5 from the best reservoir to worst:

Thin section	Image porosity, %	Image Permeability, mD	CCA porosity, %	CCA permeability, mD	Description (Mineralogy and diagenisis)
1. TS 7	28 COPL: 2% CEPL: 34%	960	27	2963	Fine/Medium sub-rounded grains with good porosity and permeability, some feldspar dissolution affected and microfracking. Free grain contact
2. TS 5	25 COPL: 4% CEPL: 32%	675	25	3740	Fine/Medium sub-angular grains with good porosity and excellent permeability. Dissolution of feldspar.
3. TS 9	20 COPL: 3% CEPL: 35%	337	27	2898	Fine sub-rounded grains. Good permeability. Free grain contact
4. TS 2	21 COPL: 14% CEPL: 24%	392	21	47	Very fine sub-angular grains. Moderate porosity and low permeability. Preferred orientation of muscovite. Compaction affected.
5. TS 6	15 COPL: 4% CEPL: 36%	128	10	0.7	Fine sub-angular grains. Relatively low porosity and very low permeability. Sutured grain contact. Cementation and compaction affected.

Compaction porosity loss for almost all thin sections from the table was only 2-4% except thin section 2 where COPL is 14%. Cementation porosity loss for thin section 5,6,7,9 is 32-36% except TS 2 that is 24%. TS2 compaction affection is matched.

5. WEEK 4: Understanding Facies

This workshop is designed to get you used to working with facies, facies successions and facies models, using fluvial environment as an example. When complete you will understand the value of facies analysis and how it can be used to decipher palaeoenvironment.

Resources:
All data needed for this workshop are included in this workbook. Consider printing out Figures 8, 9, 11 and 13 of the workbook to make the sketches on paper.

Data collection:

- Identify the different lithofacies on the graphic log in Fig. 8 and assign each lithofacies a facies code (in the facies column). Clearly label any repeating cycles and make brief notes in the descriptions and interpretation columns.
- Complete the facies table in Fig. 9 covering the range of facies present in Fig. 8.
- Figure 10 can be used as a suitable analogue. Annotate Fig. 10 highlighting the main architectural elements in the system (e.g. active and abandoned channels, point bars, floodplain lakes), indicate the migration direction of various reaches of the channel, indicate regions of sand-grade sediment accumulation and regions of fine-grained sediment accumulation.
- Using your facies interpretation to generate a qualitative (sketch) 3D fluvial facies model in Fig. 11. It should have realistic vertical and lateral dimensions and annotations. A detailed example of a fluvial facies model is given in Fig. 12.
- Build a simple 2D stochastic model of the fluvial reservoir (Fig. 13), see guidelines below.

Reservoir model:
The model template depicted in Fig. 13 is a cross-sectional view of a fluvial system that flows through a two kilometre wide fault-bounded graben system which is thought to be present in the centre of the reservoir interval. Subsidence on the basin bounding faults is considered to have been responsible for enabling the vertical accumulation of the fluvial deposits that make up the reservoir interval. The well log (Fig. 8) suggests that the fluvial channels were 10 m deep, and modern analogue studies show that channels of this size avulse (jump position) on average once every 100 years in response to major flooding events. The model in Fig. 13 depicts 4 such events (TA-TD). Your task is to simulate further avulsion events by applying some simple rules to this model. Some aspects of sedimentary system behaviour are intrinsically random (e.g. channel avulsion), and hence the modelling process utilises an element of randomness such that the results of every model simulation will be slightly different. This stochastic modelling approach is a standard way of modelling natural systems and is routinely used in reservoir modelling.

I. Assume that subsidence creates accommodation space (space for deposition) at a rate of 0.05 m/yr and that the channels avulse every 100 years. The model will step through a series of 15 time steps each representing 100 years of evolution.
II. Following each avulsion event, determine the number and position of new channels using the random number generator (RAN# button) on your calculator. 0-0.333 signifies the creation of 1 large channel (150 m wide), 0.334-0.666 signifies the creation of 2 medium sized channels (each 75 m wide), and 0.667-0.999 signifies the creation of 3 smaller channels (each 50 m wide). All channels are 10 m deep.

III. Next, determine the position of your new channel(s). Again, use your random number generator. 0.1 = a position 10% of the way across the 2 km-wide basin floor (i.e. 0.2 km from the western bounding fault), whereas 0.2 = a position 20% of the way across the 2 km-wide basin floor (i.e. 0.4 km from the western bounding fault). Perform a new random number selection to locate each channel if you have more than one.
IV. Next, determine the direction in which each channel migrates laterally. Again, use your random number generator. 0-0.499 signifies channel migration to the west; 0.5- 0.999 signifies channel migration to the east.
V. Next, determine the rate of lateral migration. Again, use your random number generator. 0-0.333 signifies slow lateral migration rate of 0.5 m/yr such that a channel migrates 50 m over a 100 year time step. 0.334-0.666 signifies moderate lateral migration rate of 1 m/yr such that a channel migrates 100 m over a 100 year time step. 0.667-0.999 signifies fast lateral migration rate of 3 m/yr such that a channel migrates 300 m over a 100 year time step.
VI. Draw on your new channel configurations for 5 avulsion events (i.e. simulate 500 years of evolution with one avulsion every 100 years & subsidence of 5 m after each avulsion event; these intervals represent time steps 1-5 in your model run).
VII. For the following 500 years (time steps 6-10), the faults are inactive and the subsidence rate is zero. However, the channels still avulse and take up new 'random' positions on the floodplain and they still migrate laterally. How does this affect the degree to which channel sandstone bodies are laterally connected?
VIII. For the following 500 years (time steps 11-15), the faults generate subsidence at a rate of 0.1 m/yr. How does this affect the degree to which channel sandstone bodies are inter-connected?

Suggestions for discussion topics in your group:

- Are all cycles in the graphic log the same?
- What defines the base of each cycle?
- What is the ratio of coarser versus finer grained facies in each cycle?
- What is a facies association? Label them on the log in Fig. 8.
- Structurally restored azimuth reading of cross bedding foreset dip directions are also provided on Fig. 8. What does the distribution of data suggest about the variability of the palaeoflow direction? What type of fluvial system might this indicate?
- Based on your annotations, where on Figure 10 do you think the different facies will accumulate?
- What is a lateral accretion surface and how do they form?
- What variables act to control the sedimentary architecture of fluvial depositional systems?
- Explain how subsidence controls the stacking of good quality (channel sandstone) reservoir, i.e. reservoir connectivity.
- Using the architecture generated by your model estimate the net-to-gross ratio for different intervals, for example i) time steps 1-5; ii) time steps 6-10; iii) time steps 11-15.

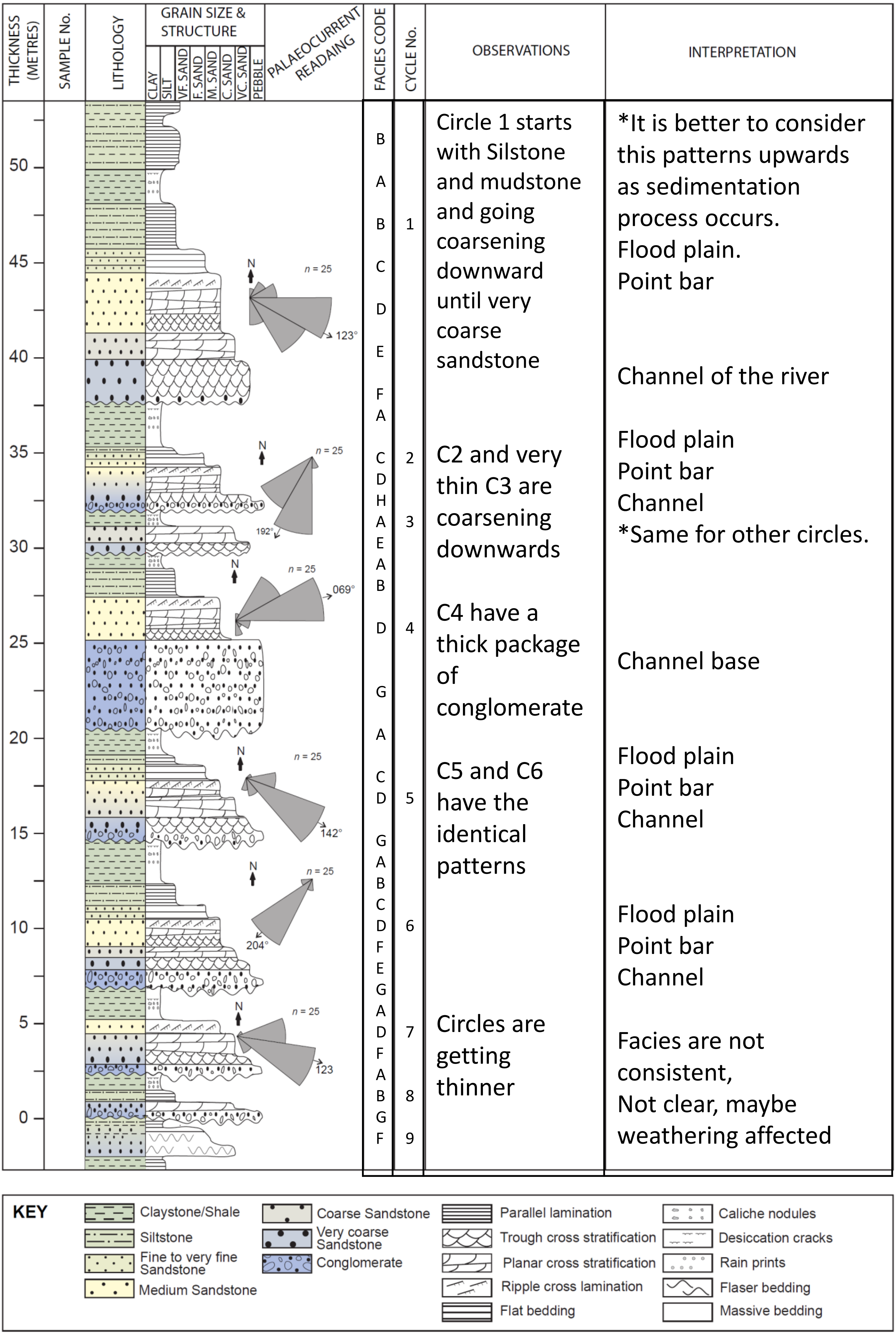
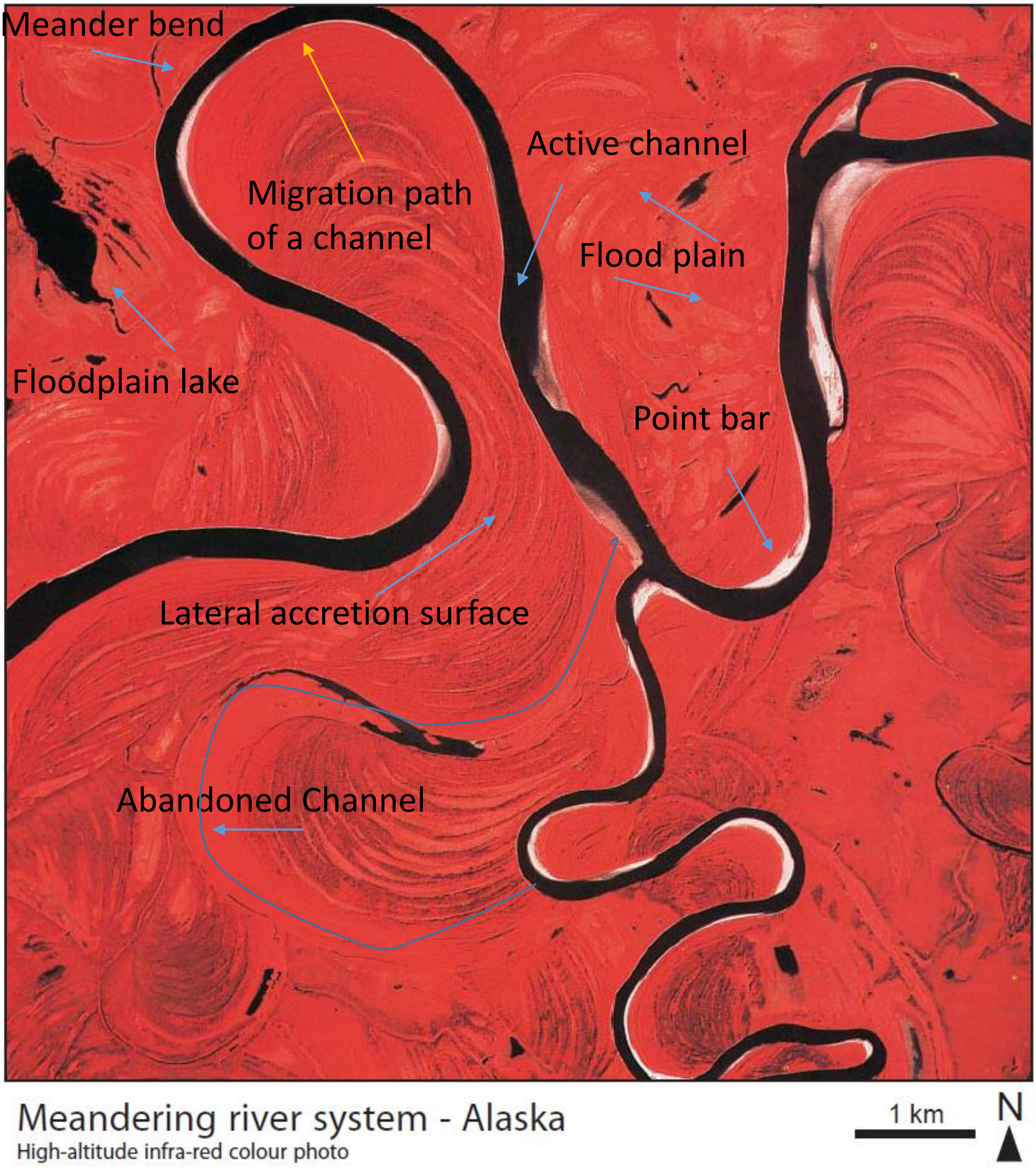


Figure 8. Stratigraphic succession

F. code	F. Ass	Facies description	Facies interpretation (process interpretation)
A	FP	Claystone and mudstone. It is common to see associated bioturbation and root traces.	Flood plain – area of land adjacent to a river. No energy. Levee – ridge that is parallel to river. Abandoned channel. Upon avulsion, channels become abandoned and can be filled with fine grained sediments
B	FP	Siltstone. Climbing ripples is common. Root traces.	Flood plain. Thin beds of sandstone can be associated with crevasse splays.
C	PB	Fine sandstone. Small trough cross beds, rippled surface.	Point bar. It is found mostly on the inside of meander bends
D	PB	Medium Sandstone. Some trough cross beds.	Point bar
E	CH	Coarse sandstone. Planar cross beds and horizontal beds.	Channel. Sand forms by deposition off a bar front. Horizontal bedding is associated with bar top.
F	CH	Very coarse sandstone	Channel floor. High energy
G	CH	Conglomerate	Channel floor. Base of channel. Very high energy.

Figure 9. Facies table



Notes

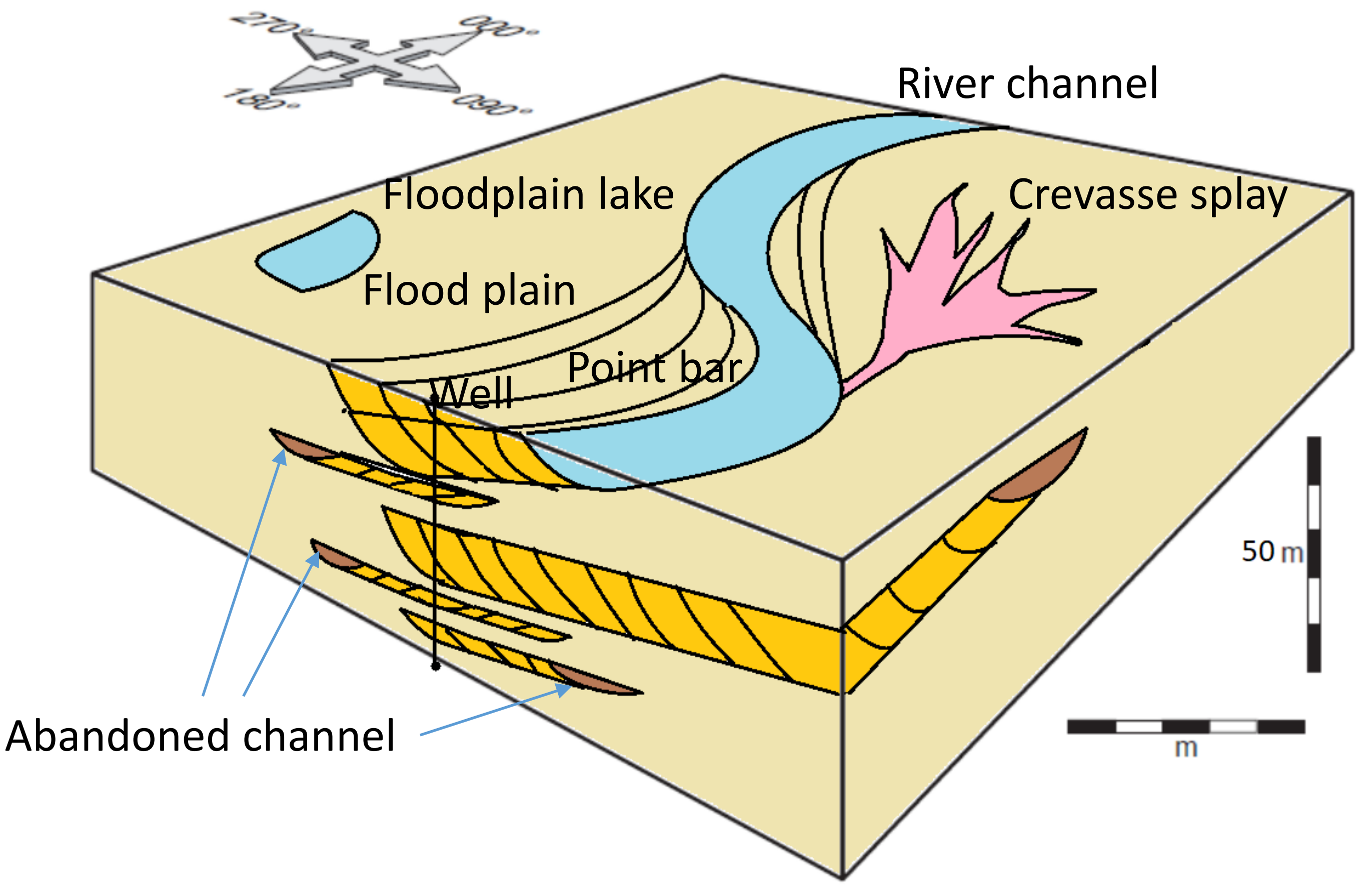
This image represents various components of the meandering river system. Important elements of this system is main river and small one that flows into. It can be noticed that there is an abandoned channel that was a previous path of the river. Additionally, there are many other elements of fluvial sediments such as floodplain, point bar etc.

Sand grade sediment accumulation can be found in the channel itself and in the point bar if we look only on surface at the present time. In the subsurface, they presented where channel base was before (in the abandoned channel and in the direction of lateral accretion surface).

Fine-grained sediments are common in the abandoned channel, elsewhere where flood plains are presented.

Photo from Hamblin and Howard (1989), Exercises in Physical Geology

Figure 10. Infra-red aerial photograph of a meandering fluvial system from Alaska



Additional notes & sketches/logs:
An effort to illustrate a 3d sketch of fluvial facies model. It has a serious limitation because it is only one well data. As a result it is hard to represent the distribution of the channels and the horizontal scale of the sketch. It is decided to not attempt intently for this task because we have the same illustration on the next slide.

Figure 11. Qualitative 3D fluvial facies model template.

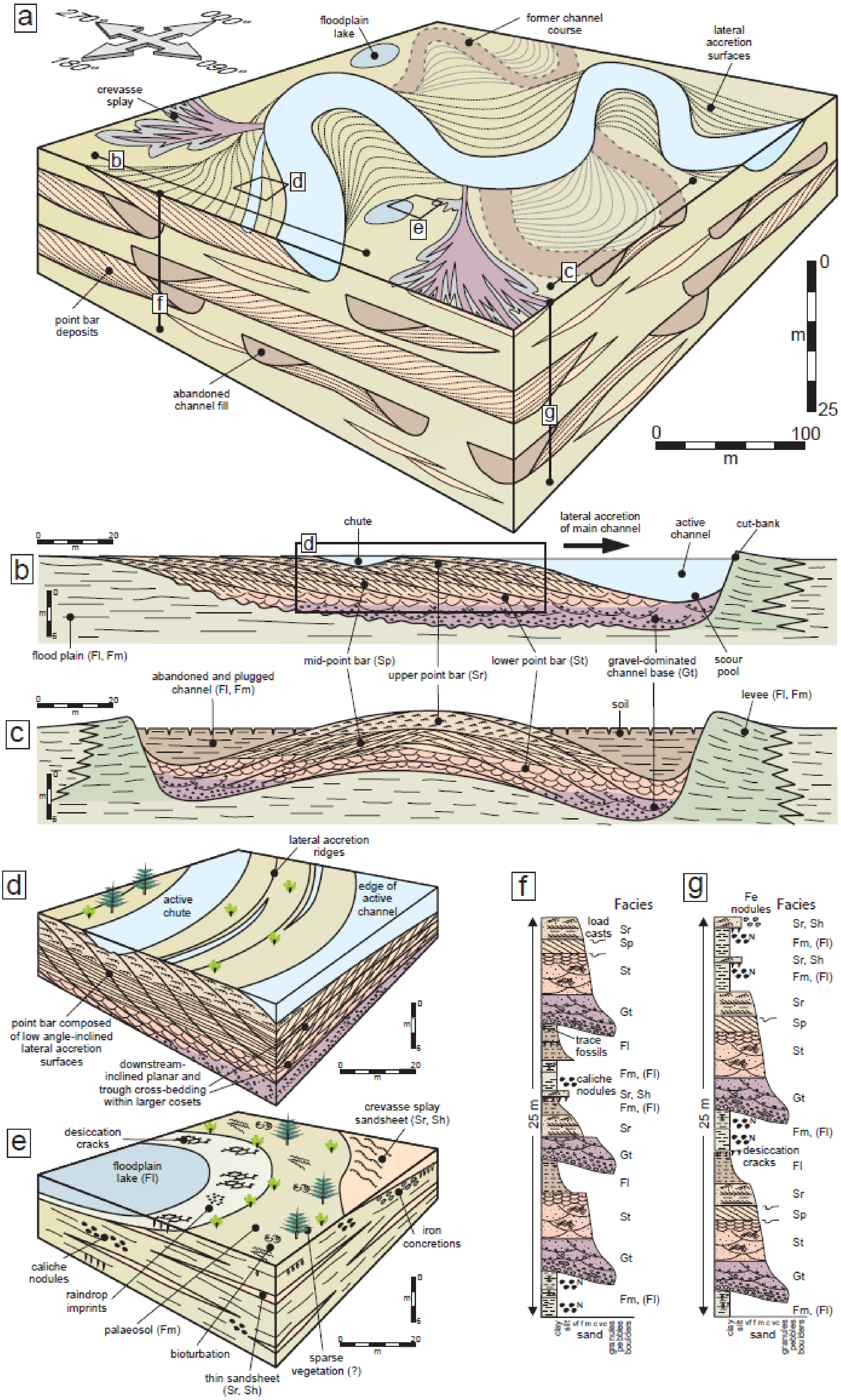


Figure 12. Example of a fluvial facies model for a meandering river system.

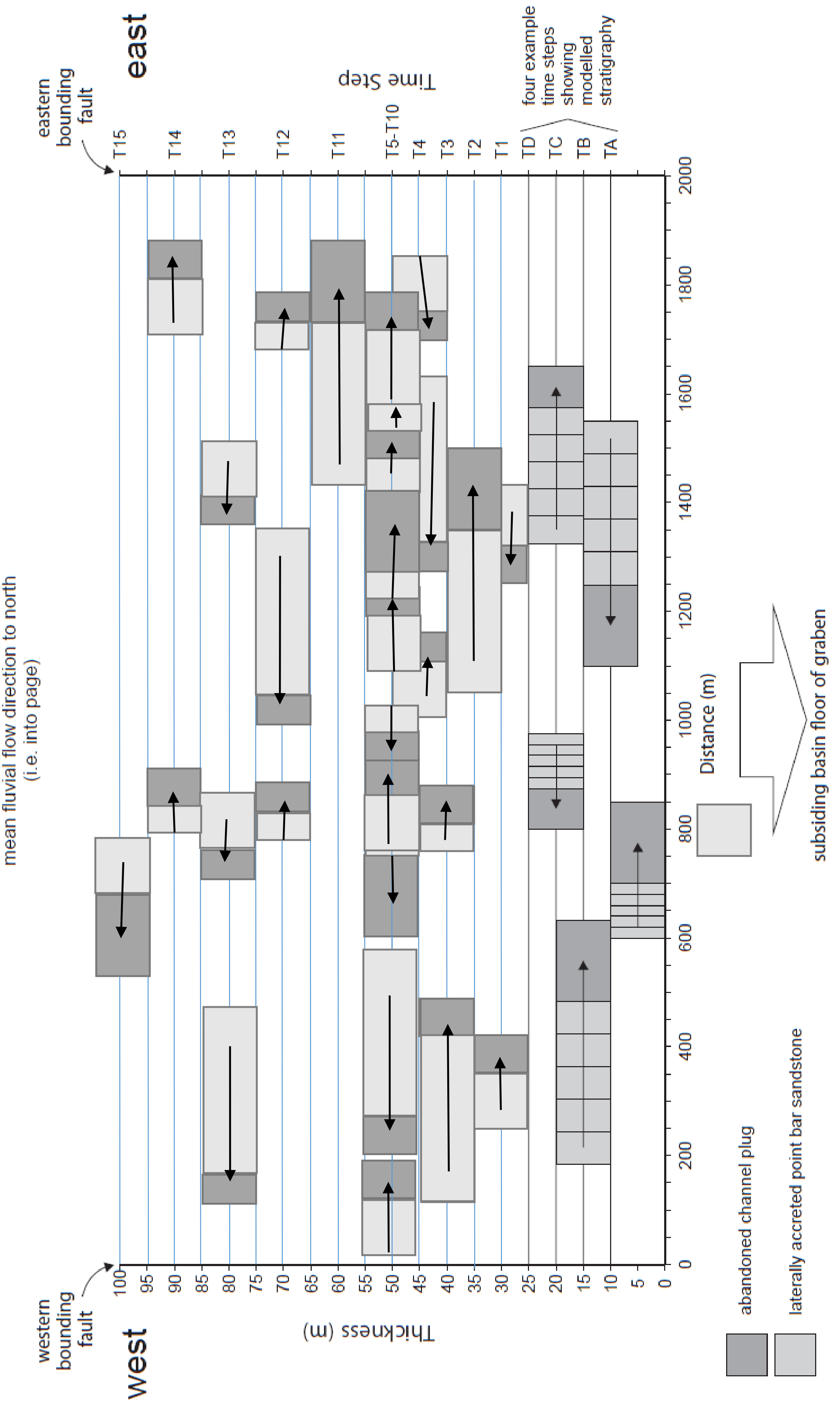


Figure 13. Template for the construction of a 2D fluvial reservoir model.

Week 4: Understanding Facies Discussion

Option to include your notes and discussion of your observations made during the your facies descriptions and modelling.

-Figure 8 represents a graphic log where several circles were recognised. Presence of this circles is repetitive and has a pattern of coarsening downwards that can connected with sedimentation of fluvial system motion. The main feature is that every circle is corresponded to the set of sediments that has a different thicknesses.
-The base of each cycle defines by coarse sandstones.
-As we go to the top of each cycle it turns to finer grained sediments.
-Facies association is related to fluvial system that composed by: channel – point bar – flood plain.
-The pattern of paleocurrent flow that is presented in graphic log indicates that this system can be related to meandering fluvial system.
-Figure 10 exhibits the geographical map of the meandering river and its facies distribution on the surface
-One of the important feature is lateral accretion. It presents on the one side of the river and formed by the previous path of the channel that migrates.
-Variables, such as a rate of subsidence, a rate of lateral migration, channel avulsion, topography of fluvial area as well as flooding event, control the sedimentary architecture.
-Channel and point bar create good medium-coarse sandstones that can have a good reservoir quality (porosity/permeability). However, connectivity of these facies depends on controlling factors because the width of the channel is relatively short to accumulate economically profitable reservoirs for the one fluvial system. Therefore, controlling factors (avulsion, migration and subsidence rate so on) can create the good connectivity for sandstones by combining several channels or juxtaposition in case it is the mud of abandoned channel.
-Net to gross ratio results for the fluvial model:
1)T1-T5 – 0.26
2)T6-T10 – 0.53
3)T11-15 – 0.15

6. WEEK 5: Core Workshop

This week you and your group will start investigating the core that is available for well 211/18a-33(18) in the Thistle Field. Rather than going straight into detailed description (planned for week 6), the workshop is aimed at describing and understanding the different formations, recognising major subdivisions and thinking about the consequences for reservoir quality and field development/production.

Resources:
- Full length of the Brent 211/18a-A33(18) core
- Hand lens
- Grain size card
- Ichnofacies atlas
- Guide to sedimentary structures
- 10 thin sections from different intervals of the Brent core 211/18a-A33(18)
- Thin section photomicrographs with porosity and permeability cross plots
- Core summary log with GR, NPHI, RHOB and porosity and permeability logs
- Petrographic microscopes, some with camera/computer connection (CTL)

Data collection:
- Collect notes during the workshop, covering the description of the main packages, focussing on the depositional environment or facies, the key controls on reservoir quality and reservoir potential.
- Describe the main bounding surfaces (e.g. are there any sequence boundaries, flooding surfaces and if so where are they?).
- Optional: photos of sections of the core might be useful for your poster/paper.

Suggestions for discussion topics in your group: (continue this in week 6)

- Delineate sandstone and mudstone intervals: identify intervals of net vs. non-net (you can do this on your core log)

- Rank the mudstones in terms of their likely influence on Kv (vertical permeability). For example, for a set of mudstones labelled a-e, we might consider that a>e>d>c>b, with a having the biggest impact and b the least impact.
    - What key features have you used to develop your ranking?
    - Which mudstones may form seals between reservoirs, or become important during pressure depletion and injection?

- Are there any flow units within the sandstones?

Note: A flow unit is "A mappable portion of the reservoir within which geological and petrophysical properties that affect flow are internally consistent and predictably different from the properties of other rock volumes i.e. flow units. Ebanks (1987)"
    - What features have you used to recognize them?
    - Are there any vertical trends?
    - Do they all have clear sedimentological explanations?
    - Which are likely to be mappable?
    - What depositional elements might erode the mappable features that you have identified to provide vertical communication? Possibilities may include: valleys, tidal distributaries, fluvial channels, bioturbation, sandstone injection.

- What facies associations do you recognise?
    - On the basis of these, what depositional elements would it be appropriate to model? Possible elements include valleys, tidal distributaries, fluvial channels, crevasse splays, mouth bars, mudstones, etc.
    - Are there alternative possibilities?
    - What dimensions and shapes, orientations and proportions do you suggest for the depositional elements?
    - How do the scales compare to the scale of the model, or a typical paralic reservoir? (see Figure 14, 15)

- For the most important depositional elements, sketch 1 or 2 facies that are likely to have a distinct impact on fluid flow (blank diagrams available on the next pages):
    - Can you draw a permeability log through each of your sketches?
    - How representative is the plug data/CCA data?
    - What aspects of the sedimentology are important in upscaling plug and wireline log data to derive appropriate properties at a reservoir modelling scale?

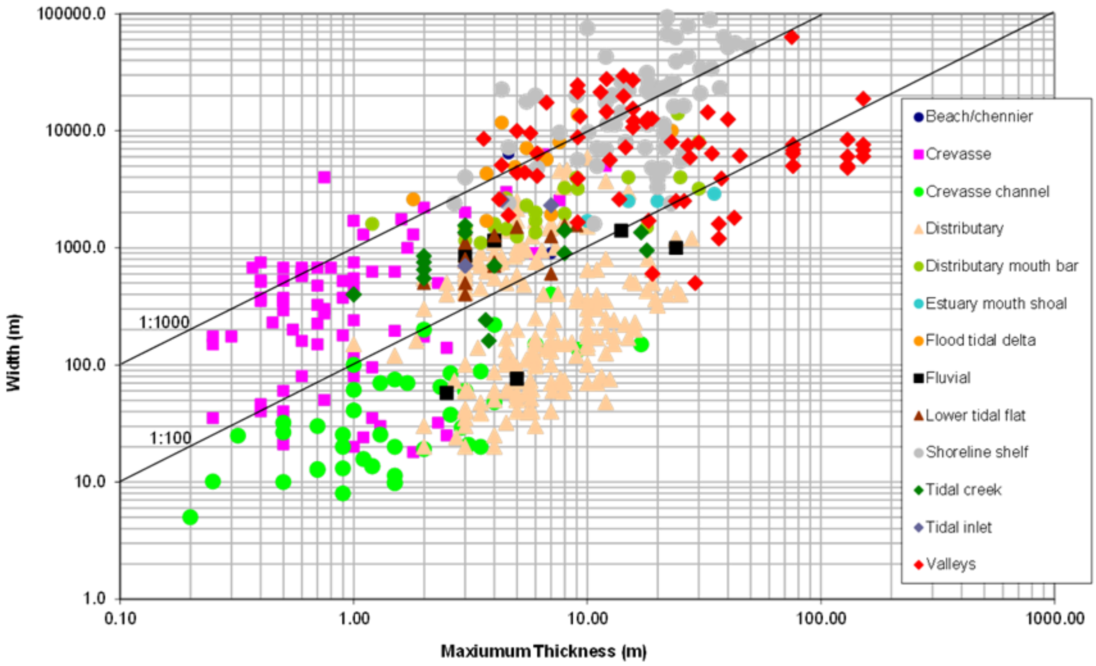


Figure 14 Dimensions of paralic sandstone bodies (from Reynolds, 1999)

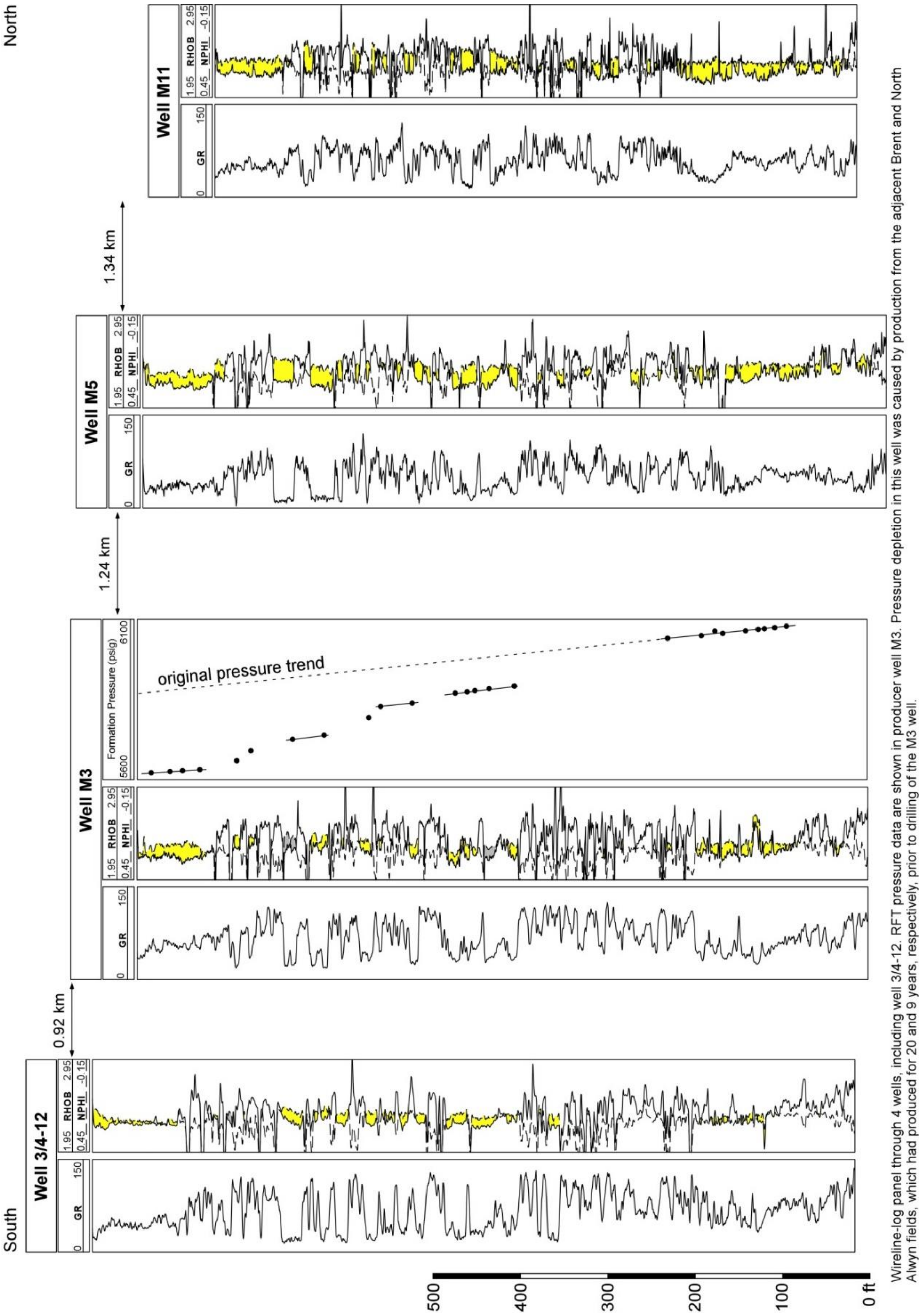


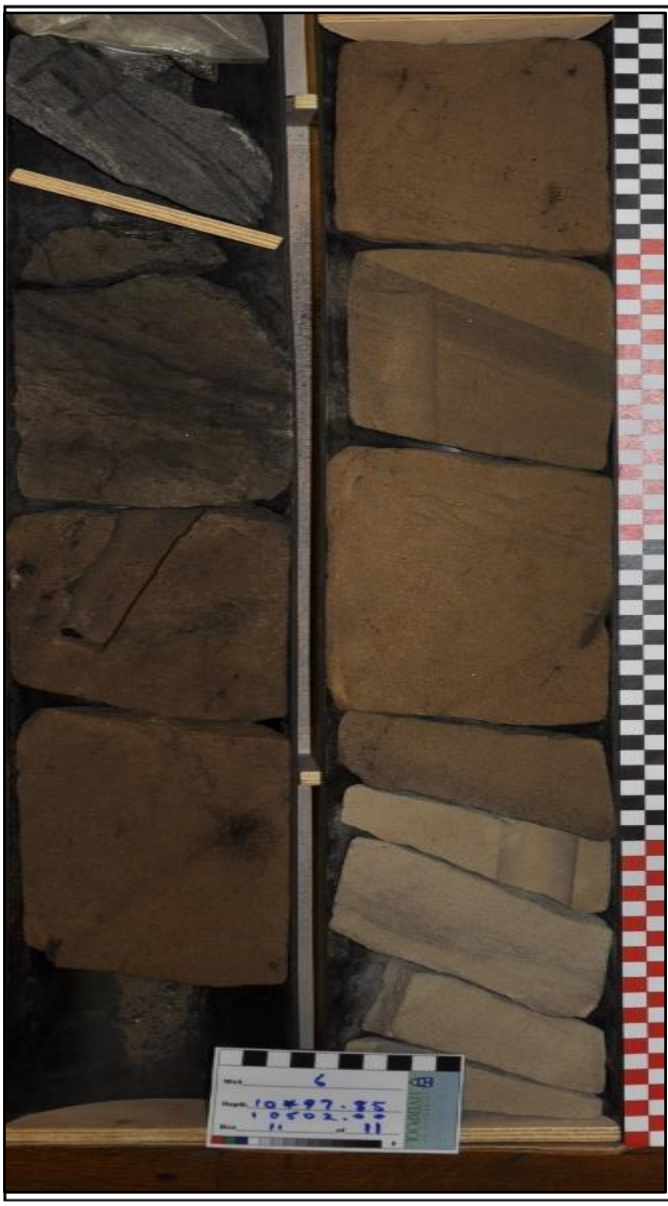
Figure 15 Cross section in the Strathspey Field, another Brent field like the Thistle Field (section courtesy of Gary Hampson).

Facies Trends

Well: 211/18a-A33 **Depth (DD)**: 10500-10466ft

Depositional element: Lagoon, Barrier

Facies 1:



Facies 2:

Description of facies 1:

Barrier.

Bioturbation low. Argillaceous sandstone. Localised rootlets. Coal in the middle.

Transition from marine(shoreface) to non-marine lagoon environment(upwards).

Etive to Ness transition zone.

(Below this core wave-dominated sandstones are present – Upper shoreface)

Description of facies 2:

Lagoonal mudstone on the left.

Dark grey mudstone.

Barrier or Lagoonal sheet sandstone on the right.

Lower delta plain or delta front

Lower Ness unit.

(some fluvial/deltaic systems can be found upwards)

Week 5: Core Workshop Discussion

Option to include your notes and a discussion of your observations made during the core workshop.

1) Some net intervals are found in our section(Core 6,5,4) of Ness/Etive formations. Can be seen in core by massive sandstones and by Density/Neutron variables in log

2) Mudstones that were found in our section of Ness formation can be differentiated as following:
A-Floodplain mudstone (of deltaic system) – massive mudstone that is good barrier to unitflow
B- Lagoonal mudstone – intermediate influence on permeability
C-Thin mudstone interbedded with lagoonal sheet sandstones – possibly minor impact
D-Coal beds can be as a barriers and related to mudstones – minor impact

3) Lagoonal sandstones are interbedded with mudstone and mud drapes and not consistent in lower-middle Ness, in lower Ness / upper Etive some homogenous sandstone unit was found with potentially good reservoir quality – medium/fine well sorted grains, “oily” colour, relatively thick 20-30m – probably related to Barrier/Upper shoreface

4) Next facies were found in our section of the core workshop:
Upper shoreface sandstones (wave dominated with ripples and lamination)
Barrier sandstones (homogenous, “clean” sandstone with root traces)
Lagoonal mudstone (dark grey mudstone can be rippled and bioturbated)
Coal thin beds
Lagoonal sheet sandstones (bioturbated, root traced)
Fluvial and tidal channel can be present as well

7. WEEK 6: Core Description

This week your group will log a selection of the cores from well 211/18a-33(18) at a 1:20 (or 1:50) scale using standard sedimentological logging techniques (Fig. 16; lecture notes VITAL).

Your group will be logging the same section of the core as you examined last week during the core workshop. Subdivide the work between the members of your group and split the core into appropriate and fair divisions based on thickness and complexity.

When all team members have completed their individual logs, you can transfer your data to the 'core description' column on the team summary log sheet provided on VITAL. During this process take some time to discuss your descriptions and interpretations amongst the team, and then draw on your team knowledge to start to build up a picture of the core as a whole.

Resources:
- Access to the core (Friday week 6)
- Standard logging sheets (provided during practical)
- A team summary log sheet, including WLL data (provided during practical)
- Standard legend with symbols for lithologies, structures etc. and a guide with some more information on the legend (VITAL and provided during practical).
- Atlas of ichnofacies (VITAL)
- Atlas of sedimentological structures (VITAL)
- Core photos (VITAL)

Data collection:
- Each team member creates a core description at 1:20 or 1:50 scale: a single A3 logging sheet provided allows you to record approximately 60 ft (18 m) of core at 1:50 scale.
- Your logs should be combined into a 'group summary log'
- **<u>Result</u>**: a single, 'neat' team summary log including your interpretation on depositional environment and facies distribution. This log will be of the appropriate sections and will feature in your final presentation.
- Think about integrating with the wireline and core analysis data (Fig. 17ab; VITAL).

Suggestions for discussion topics in your group:

- Divide the reservoir into distinctive elements. On what basis have you done this?
- What is your interpretation of the detailed depositional environment(s) of the reservoir?
- Given your interpretation of depositional environment(s), what are the likely geometries and/or lateral continuity of these elements?
- Hydrocarbon staining: why is hydrocarbon staining present in some sandstone intervals and not in others?
- Can you identify key surfaces, sequences and/or stacking patterns?
- Integrate with wireline and CCA (Fig. 17):
  - What is the relationship between porosity-permeability and sedimentary facies, and what is controlling the difference (if any)?
  - What is the relationship between horizontal permeability (Kh) and vertical permeability (Kv) of the entire dataset? What is the relationship between porosity and permeability of individual facies?
  - Are there internal heterogeneities that might affect permeability (think barriers/ baffles in the horizontal (Kh) and vertical (Kv) dimensions?

- How does the observed vertical variability in permeability and porosity of the core as a whole tie in with your sedimentological and petrography observations? How does the data tie in with your stratigraphic framework?
- Does facies control reservoir quality within the Brent Group?
- What is the log response of (increasing in scale): individual facies, facies associations and sequences?
- Use the core to define an optimal gamma ray cut off (sand line). Consider calculating the net/gross (% sand) over certain intervals.

TIPS

Log detail: Sedimentary logging is usually considered a data collection method, however it is very important to continually think about the sedimentary processes and depositional environments you see and need to capture in your description. Because during description you are not only creating a schematic overview of the core but also give an interpretation:
you decide which features are most important, because you cannot draw all of them. Therefore, if you understand what the main controls are, the better your description will be.

Defining a lithotype scheme: this should make logging and interpretation more efficient. Make sure that you record all the sedimentary structures, grain size profiles, bioturbation index (and type of bioturbation if you can), oil-staining, mud content etc. To do this, you can use the key for symbols and abbreviation sheet provided on VITAL. An example of a core description is given in Figure 16.

Logging scale: The choice of scale will constrain the nature of the log, since it is largely determines the level of detail of information that can be recorded. There is no theoretical maximum scale, and if considerable detail is needed from a short length of core, there is no reason why it should be logged in as much detail deemed necessary. One of the prime functions of logging, however, is usually to produce a condensed summary, and for most purposes, a scale no greater that 1:20 is sufficient to record all pertinent information clearly, and 1:50 is still considered a large scale. At 1:100 it becomes necessary to stylize and merge thin beds and small-scale structures, and some detail is inevitably lost, although the greater conciseness achieved may outweigh the loss. 1:200 is a good scale for summarising logs of longer cores (>15 m), and is the standard scale for displaying wireline logs in hydrocarbon wells, allowing direct comparison of cores with well data. At 1:500 only the gross lithological properties can be recorded, and a log at this scale will indicate only the general nature of the core.

Core logging checklist: It is a useful policy to write or record descriptions systematically in a set order to ensure that important information is not omitted. The range of rock properties recorded and the order in which they are recorded will depend on the logger and of course of the lithology of the core. The titles and boxes on the log sheet will give suggestions what to record.

Descriptions: Some logging forms allow the descriptions and comments to be made wherever the geologist thinks fit, whereas others require descriptions at set intervals. In the former case, the geologist would generally divide the core on the log into sections displaying similar characteristics. Each section would then be separately described. In the latter case, the core would be divided at set intervals (every 0.25 m for instance) and each section described.

Logging at pre-determined intervals is methodological, and ensures that each part of the core receives the same level of scrutiny, but this method does tend to obscure the natural division of the core into lengths of different lithology or structure.

Core photographs: Although a core log endeavours to communicate and record all of the important information regarding a core, its purpose is not to convey exactly what a particular core looks like. Even the best logs, with full descriptions and sketches, will be unable to communicate the true impression of the nature of the core, which would only be gained by studying the core itself. Fortunately, the gap between the information from the core log and looking at the original core can partly be filled by good quality colour core photographs. Almost any photograph is better than none at all. Any photograph taken will usually be either for illustrative purposes in a report (for instance of a specific feature or structure), or for the long-term data storage in case of core loss or damage (generally overview photos). When taking a core photograph make sure it includes a scale(!!). NOTE: overview core photos are available on VITAL.

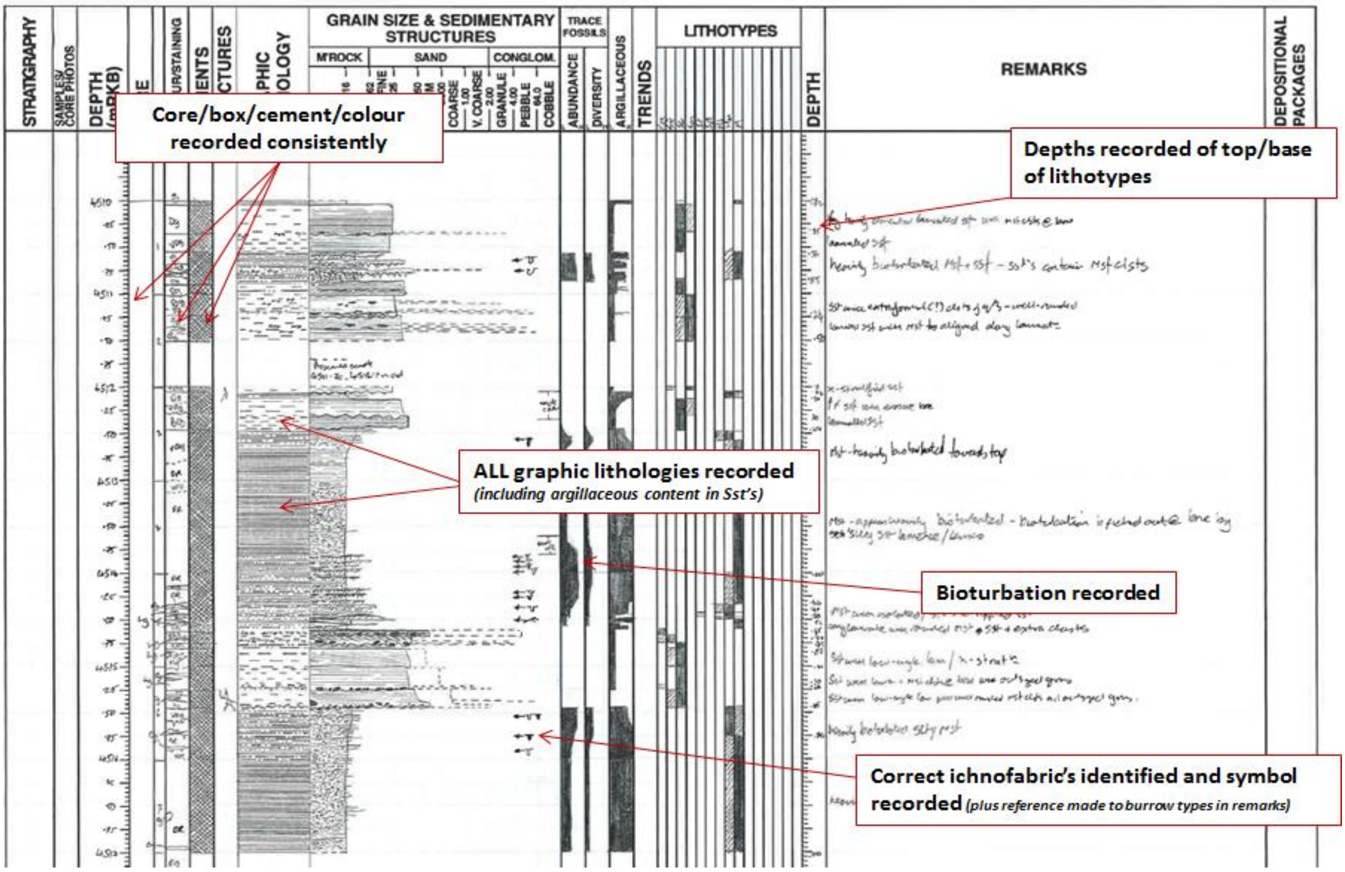


Figure 16. Example core description, lecture notes on VITAL for more examples.

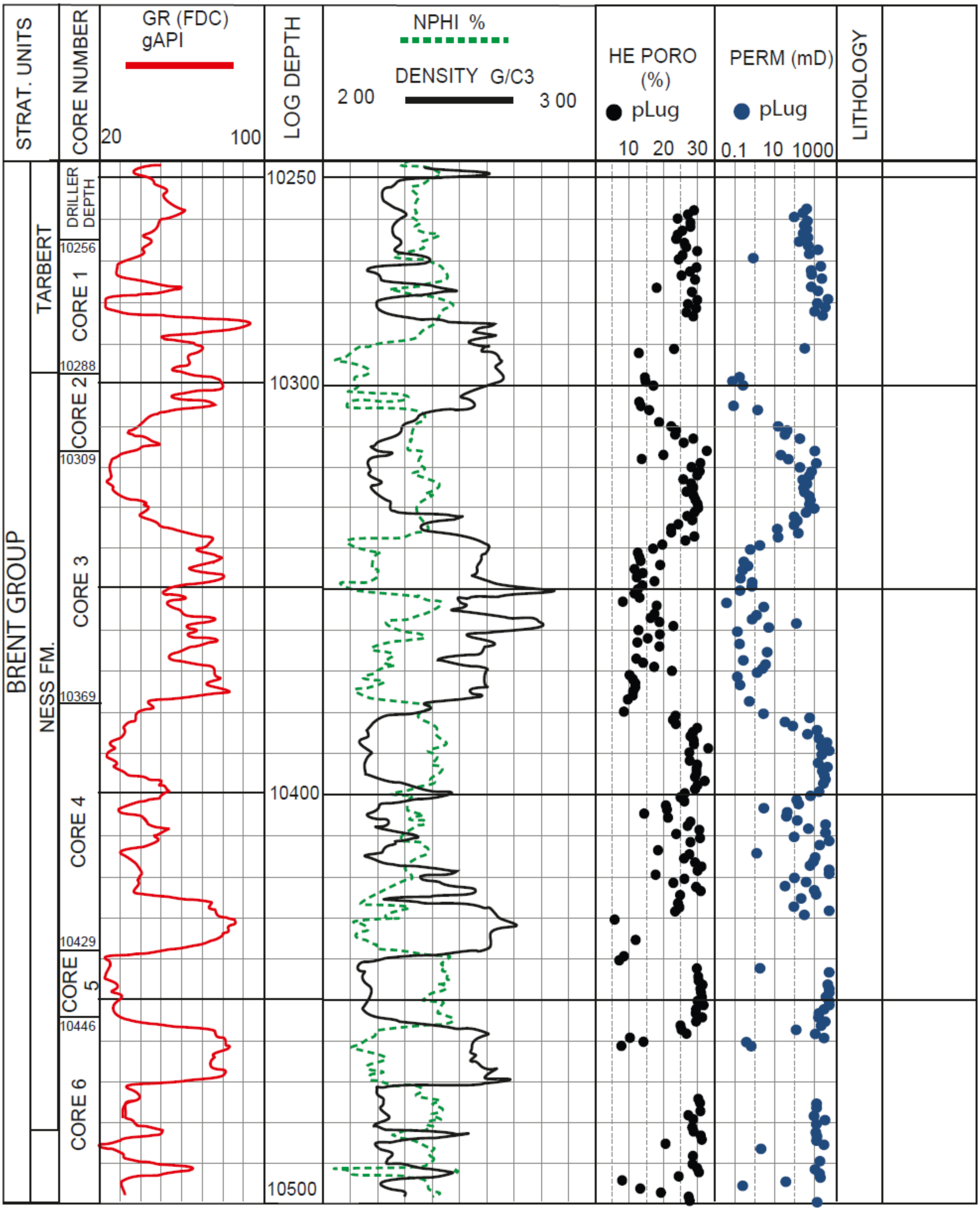


Figure 17a. Wireline and core analysis (poro/perm) data for upper part of well 211/18a33(18)

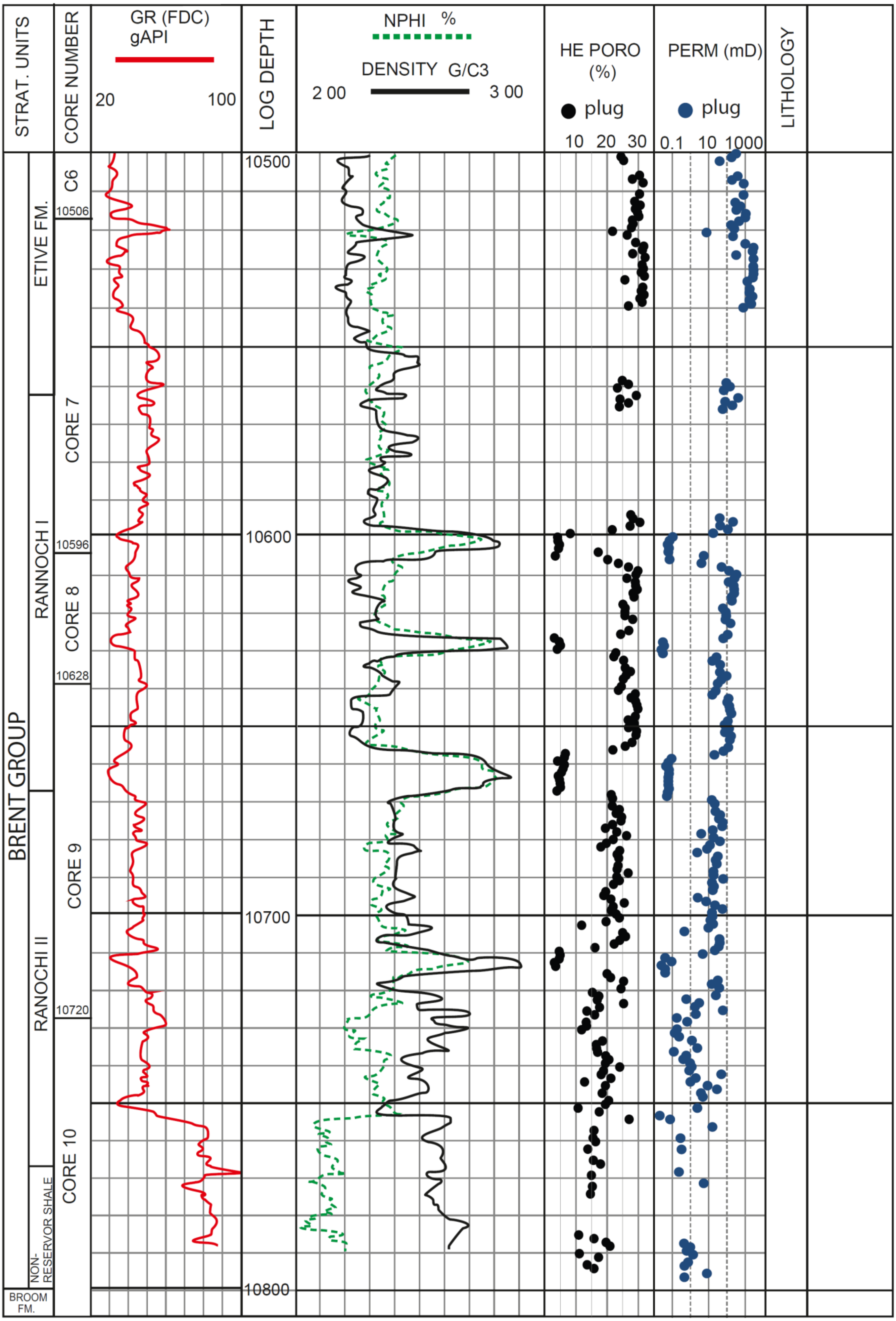


Figure 17b. Wireline and core analysis (poro/perm) data for lower part of well 211/18a33(18)

Week 6: Core Description – sedimentological log

Option to include your scanned or digitised sedimentological core description.

Week 6: Core Description Discussion

Option to include your notes and discussion of your observations made during your detailed sedimentological core description.

1) The best separation of whole core can be by formations:
Rannoch, Etive, Ness, Tarbert
also it can be separated locally by units:
Caprock (mudstone) – reservoir (sandstone)

2) In general this core is related to shallow marine depositional system.

3) Progradational system from surface by fluvial deposition – deltaic environment – lagoons – barrier – tidal inlets – to shoreface wave dominated environment.

4) The presence on hydrocarbons in one units not another depends on some factors such as quality of reservoir units and overlying flow barriers such as low permeable mudstone or local faults (not determined in core workshop)

5) For example as we go up from Etive to Ness, we see first coal bed and suspension of wave rippled sandstone to root traced sandstone with interbedded mudstone, that is can be indication of changing the environment from shoreface to lagoonal/deltaic.

6) If we compare wireline log/CCA data and find the trend of increasing porosity and permeability from bottom (Rannoch) to Ness formation, we can distinguish that reservoir characteristics of some Ness and Etive horizons have the best quality. These reservoir units related to sandstones of fluvial and/or upper shoreface facies and have a barrier of lagoonal and deltaic mudstones. It can be noticed that some reservoir units have different formation pressure that can be evidence of compartmentalisation. Additionally, a reservoir unit in lagoonal(lower deltaic) sandstone have horizontal mud drapes than can reduce vertical permeability.

Week 7: Summary of reservoir quality trends – overall notes/discussion

Option to include your notes and discussion to create a synthesis of the reservoir quality trends you observed during the practical work.

This workbook includes a bunch of information related to shallow marine silicaclastic reservoir system of well-known Brent formations. Practical exercise was step-by-step straightforward and completed the whole picture of reservoir quality at the finish.

Petrography/Porosity analysis.

Interpretation of 5 thin section for person generates that some of them within Ness, Etive formation have a good reservoir quality.

Understanding facies.

Exercises of determination fluvial facies give basic knowledge in facies interpretation and have prepared to the core interpretation.

Core workshop and wireline analysis.

Section of core was described to understand shallow marine environment and quality of reservoir units within the core successions of Brent formations

To connect information from thin section and core description table below is created (green – good reservoir, red – bad)

Thin section / depth	Image porosity, %	Image Permeability, mD	CCA porosity, %	CCA permeability, mD	Description From core
TS 2 (10700-10706ft)	21 COPL: 14% CEPL: 24%	392	21	47	Rannoch II. Lower Shoreface. Wave-dominated marginal marine. Planar lamination. Micaceous, very fine grained SS
TS 5 (10538-10543ft)	25 COPL: 4% CEPL: 32%	675	25	3740	Etive. Upper Shoreface. Wave-dominated marginal marine. Weakly cross-stratified. Fine-medium grained SS
TS 6 (10460-10466ft)	15 COPL: 4% CEPL: 36%	128	10	0.7	Etive/Ness. Lagoon. (Barrier) Transition between dark grey rippled mudstone and mud draped sandstone
TS 7 (10389-10395ft)	28 COPL: 2% CEPL: 34%	960	27	2963	Ness. Fluvial Channel (Deltaic). Lagoon/Lake margin. Bioturbated medium SS
TS 9 (10278-10283ft)	20 COPL: 3% CEPL: 35%	337	27	2898	Tarbert. Marine shelf. Bioturbated shale SS

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