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FLUID FLOW IN MUDSTONES: A FUNCTION OF PORE SIZE DISTRIBUTION OR GRAIN SIZE DISTRIBUTION

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ABSTRACT

Mudstones play vital roles in the entrapment and accumulation of hydrocarbon in reservoirs. They are of major consideration during prospect analysis and evaluating charging risk. Their integrity could be the basis for frontier exploration. Closer examination of mudstones based on Mercury Injection Capillary Pressure Analysis (MICPA) and Sedigraph data for the basis of fluid flow proves that mudstones lithology offers a limited explanation. However, pore size distribution and/or grain size distribution in corroboration with the pore pressure and structural history seem to offer better explanation for fluid flow in mudstones; they also provide better understanding of the leakage mechanisms and pathways of leaked hydrocarbons in mudstone caprocks. In this case study on the caprocks of Valhall oil field in the North Sea, the pore size distribution has been suggested to reflect the grain to grain contact in the matrix of the caprock due to the effective stress by the overburden. Hence, compaction processes better explains the phenomena of similar permeability in different lithologies reflecting distribution profiles for finer and coarser grained sizes of different formations.

Key words: Caprock, Leakage, Fluid Flow, Permeability, Porosity.

INTRODUCTION

Mudstones act as primary control of fluid flow in sedimentary basins and near surfaces. The roles of mudstone transients as aquitards to petroleum systems where they act as source rocks, and influence the choice of migration pathway from source to the trap, principally as seals to petroleum reservoirs are well known (Aplin *et al*, 1999). Environmentally, mudstones have been counted upon as reliable seals for waste disposal sites among other uses (Table 1) (Aplin *et al*, 1999); most recently, the quest to go greener makes it a necessity for holding back CO_2 in depleted underground reservoirs (Aplin *et al*, 1999). However, it has been noted that mudstones with capillary resistance about twice that of petroleum is needed to hold back CO_2 stored in depleted petroleum reservoirs (Li *et al*, 2006).

In the past 30 million years, about 80% of petroleum that has migrated from the source rocks to reservoirs has passed through thick sequences of mudstones (Aplin, 2005). This serves as a pointer to the fact that petroleum seals of which consist mainly mudstones, leak over geological time. The Sleipner CO_2 Project in the North Sea (Ringrose & Eiken, 2011) seems to prove that over a period of ten years the CO_2 injected into the Utsira Formation has gradually migrated into the caprock section in the overburden (Figures 1 and 2). Although there have been claims that the caprock has good integrity (Carlsen *et al*, 2001), studies indicate that the sea water above the field has been observed to show increasing CO_3 (carbonate) content (Bennaceur *et al.*, 2004).The questions this seems to pose are “Does everything leak? What are the controls?” The understanding of their lithologic properties should be fundamental to a lot of processes.

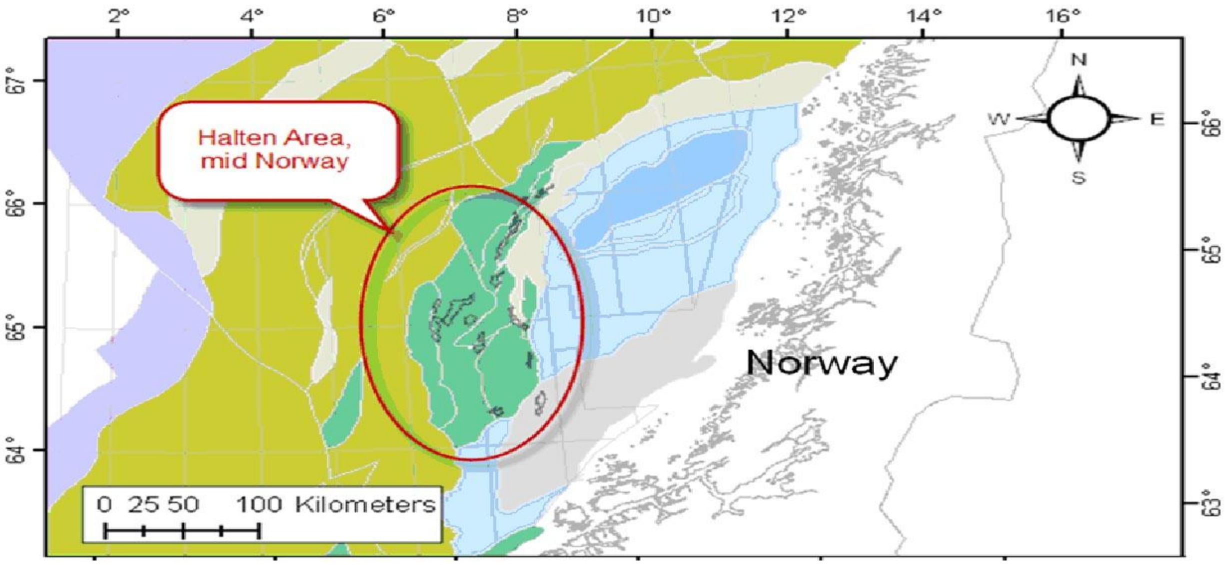

Figure 1a. Geology of the area - Halten Terrace Mid-Jurassic (Source Goggle image 2017)

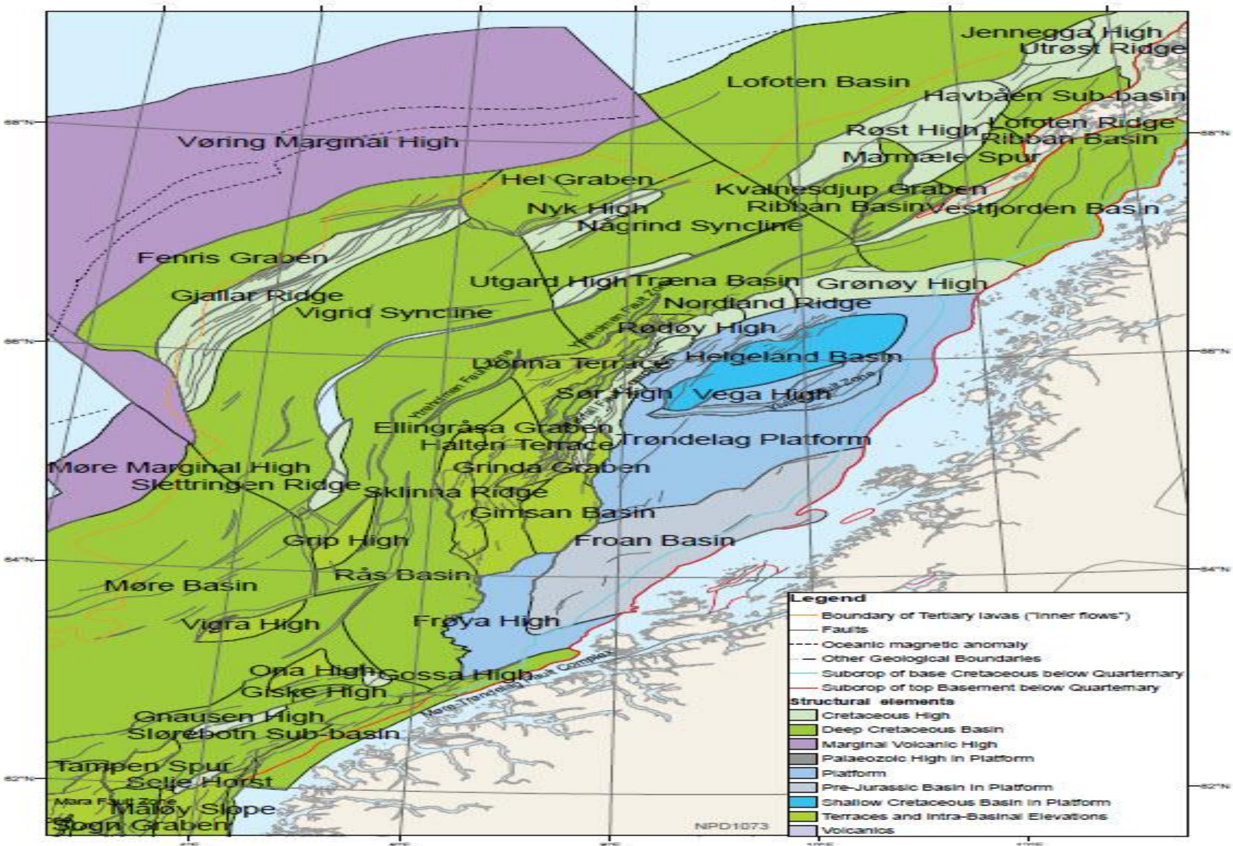

Figure 1b . Geology of the area showing Grinda Graben and More Marginal High area.

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Table 1. The roles of mudstones and their respective fields (Adapted from Aplin *et al.*, 1999).

Discipline	Process
Petroleum exploration and production	Drilling problems/performance
	Pore pressure prediction
	Vertical migration of petroleum
	Seal capacity and caprock integrity
Waste containment	Landfill liners
	Storage of nuclear and hazardous waste
	Contaminant transport
Engineering	Landslide prediction
	Foundation design
	Subsidence
	Swelling and shrinkage
Heavy clay industry	Brick and ceramic raw material

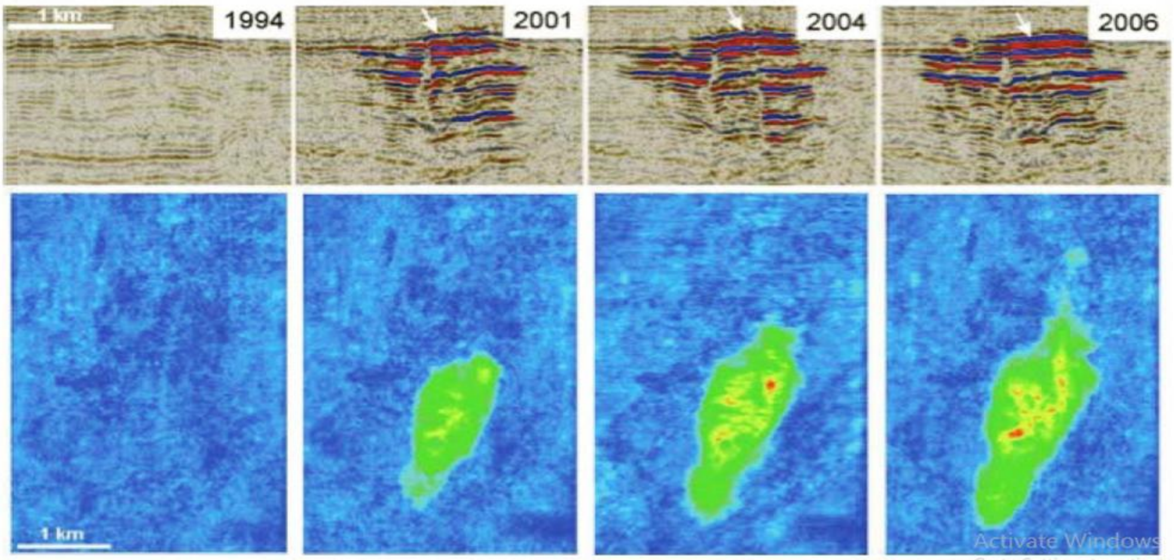

Figure 2. Seismic images of the CO_2 plume at Sleipner from 1994 to 2006. The top most CO_2 layer is arrowed with evidence of increasing CO_2 intensity into the caprock section. (Carlsen *et al*, 2001)

Muds are sediments composed predominately of clay and silt, while mudstone is lithified mud. Shale is a fissile mudstone but in this research mudstones refer to the lithified muds composed of particles smaller than 1/16 or 62.5µm ranging from silt size (<62.5µm) to clay size (<2µm) (Aplin *et al*, 1999). Earlier studies (Dewhurst *et al*, 1999) indicated that a potential permeability range at a given porosity could be due to variations in grain size distribution. Hence at a given porosity, sample with lower clay fraction (percentage of particle lower than 2µm) were about two orders of magnitude more permeable than clayed rich samples (Dewhurst *et al*, 1999).

Studies by Dewhurst *et al*. (1999) showed that clay rich samples were about 50times lower in permeability than silt rich samples for a given effective stress, emphasizing on grain size as control on permeability. This indicates that grain size which is more of a function of lithology, does not seem a plausible explanation for permeability which is the ease of fluid flow or the connectivity of the pores in the matrix of the rock.

In this study, MICPA and Sedigraph data of the Valhall caprocks (mudstones) in the North Sea indicate samples with similar porosities and modes for pore size density distribution profiles but different grain size distribution. Essentially, the grain size distribution largely reflects the lithology of the sample which is a credible representation of the bulk formation. The pore size distribution profiles indicate the distribution of the connecting pore throats. This invariably reflects the permeability of the samples, hence the mudstone formations. The observation portrays similar permeability and porosity regimes but different grain size distributions, hence different lithology. Figure 3 is an example of MICPA results plot (Alpin, 2005).

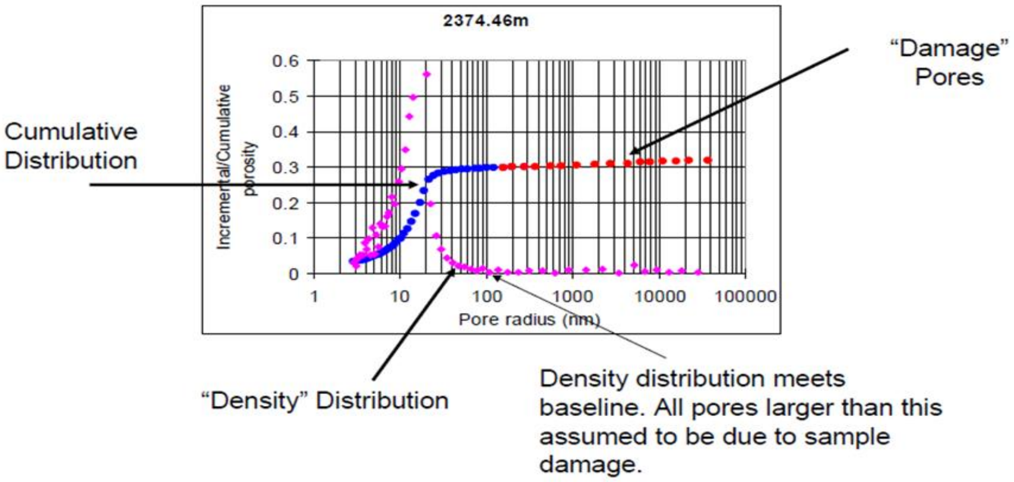

Figure 3. Example of MICPA results (Adapted from Aplin, 2005)

MATERIALS AND METHODS

The samples were drill cuttings and selectively handpicked for Sedigraph, MICP Analysis, thin section and SEM studies. The SEM photomicrographs were of poor quality.

Samples and Sampling.

Samples are drill cuttings that were obtained from the caprock overlaying the reservoir Valhall well 2/8–8. Samples were obtained from water-based mud drilling samples and were also handpicked , viewed with binocular microscope to avoid mud flakes.in mudstones from Valhall caprock sections in the North Sea.

***Mercury Injection Capillary Pressure Analysis*(MICPA)**

The analysis was performed using Micromeritics Autopore II 9220. The process involved first placing the sample in the sample tube, then carrying out a preparatory evacuation within a pressure range of 10.4 psi to 6.0×10^{-4} psi, removing contaminant gases and water vapour. Eventually, enough pressure was created which allows mercury to intrude into the pores of the sample while equilibrating to

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ambient pressure. The sample was moved to the high pressure piston where the high pressure intrusion for much smaller pore space occurred at a range of between 10.4psi to 60,000 psi.

At the end of the analysis, the initial data was obtained and data treatment was carried out to obtain the total porosity, corrected porosity, mean pore radius and the r_{10} which is the pore radius corresponding to 10% saturation of the sample by the non-wetting phase. These data, in corroboration with the data on the total carbon and total organic carbon, were applied for calculating the pore radius, total porosity, permeability, and hydrocarbon column height.

MICPA measures the pore throat diameter rather than the pore body (volume) with the objective of estimating permeability. Pore throats have been suggested as the control for fluid flow while the porosity and grain sizes as suggested to serve as control over pore size distribution. Clay studies by Dewhurst *et al*. (1999) showed that the mean and modal pore throat sizes are much greater for the coarser grained samples than for finer grained samples.

Sedigraph Analysis

Samples for grain size distribution analysis were hand-picked, and subjected to the processes of disaggregation via saturation–freeze –thawing (SFT) for 3 weeks. This method is the saturation – freeze – thawing (SFT) which involves the evacuation of the pores and saturation with distilled and deionised water to intrude the pore spaces. When frozen the water in the pore spaces expands, and eventually gently disaggregates the samples.

Thereafter, the samples were wet sieved to remove the greater than 63µm size using the 63µm sieve. The greater than 63µm was collected dried and weighed. Each of the less than 63µm samples was added with 20mls of distilled and deionized water, then 0.25% of sodium hexa meta phosphate and sodium trioxocarbonate (v). The addition of the compound helps to keep the grains loose in the sample media. The temperature was recorded and appropriate settings of the instrument performed before analysis using Micromeritics Sedigraph 5000ET.

RESULTS

Table 2: A combination of the bulk geochemistry, MICP and grain size distribution data.

Samples	TOC (%)	TC (%)	Cement (%)	Pyrites (%)	$P_{10\%}$ Oil (psi)	Total Ø(%)	Dps (nm)	$r_{10\%}$ (nm)	Oil column	Silt (%)	Clay (%)	Sand (%)
7930	2.6	3.3	5.2	8.9	30	43	80	344	115	56	14.3	29.7
7970	1.1	4.6	29.2	7.3	32	33	15	318	125	50.7	17.4	31.9
7980	1.6	4.3	22.5	9.8	74	37	90	136	291	71.1	20.1	8.8
8080	0.9	2.6	13.8	25.8	97	31	16	104.5	380	79.9	12.5	7.6

Key: TOC=Total organic carbon; TC=Total carbon; $P_{10\%}$=capillary entry pressure at 10% saturation; $r_{10\%}$=mean pore radius at 10% saturation; Total Ø= Total porosity; Oil column=seal capacity expressed as hydrocarbon column height sustainable, Dps= dominant pore sizes.

Table 3: A Brief Description of Lithology

Samples	Brief description
7930	Dark brown, poor laminar, silty
7970	Gray, silty, sand
7980	Gray, laminar, shaly, silty
8080	Light brown, whitish, chalky, bulky, sand

Porosity and Pore Throat Size Profiles

Figure 2 is an example of an MICPA result, it also show the guideline for interpretation of the results. It shows two profiles, the pore throat size distribution profile and the accumulative porosity profile. The pore throat distribution profile effectively highlights the connected pore throats and also the dominant pores throats among the connected pores throats, while the porosity profile infers the effective porosity of the rock sample. The analyzed samples which are coded 7970 and 8080 are mudstones from Valhall caprock sections.

Figure 4 shows that the profiles for both samples have similar porosity and maximum pore throat density which represent the dominant pore throat sizes of the connecting pores. The dominant pore throat sizes for the two samples are 15.0nm and 16.0nm, respectively for samples 7970 and 8080. This invariably infers that the samples have similar permeability. Permeability expresses the ease of fluid flow through the caprock samples.

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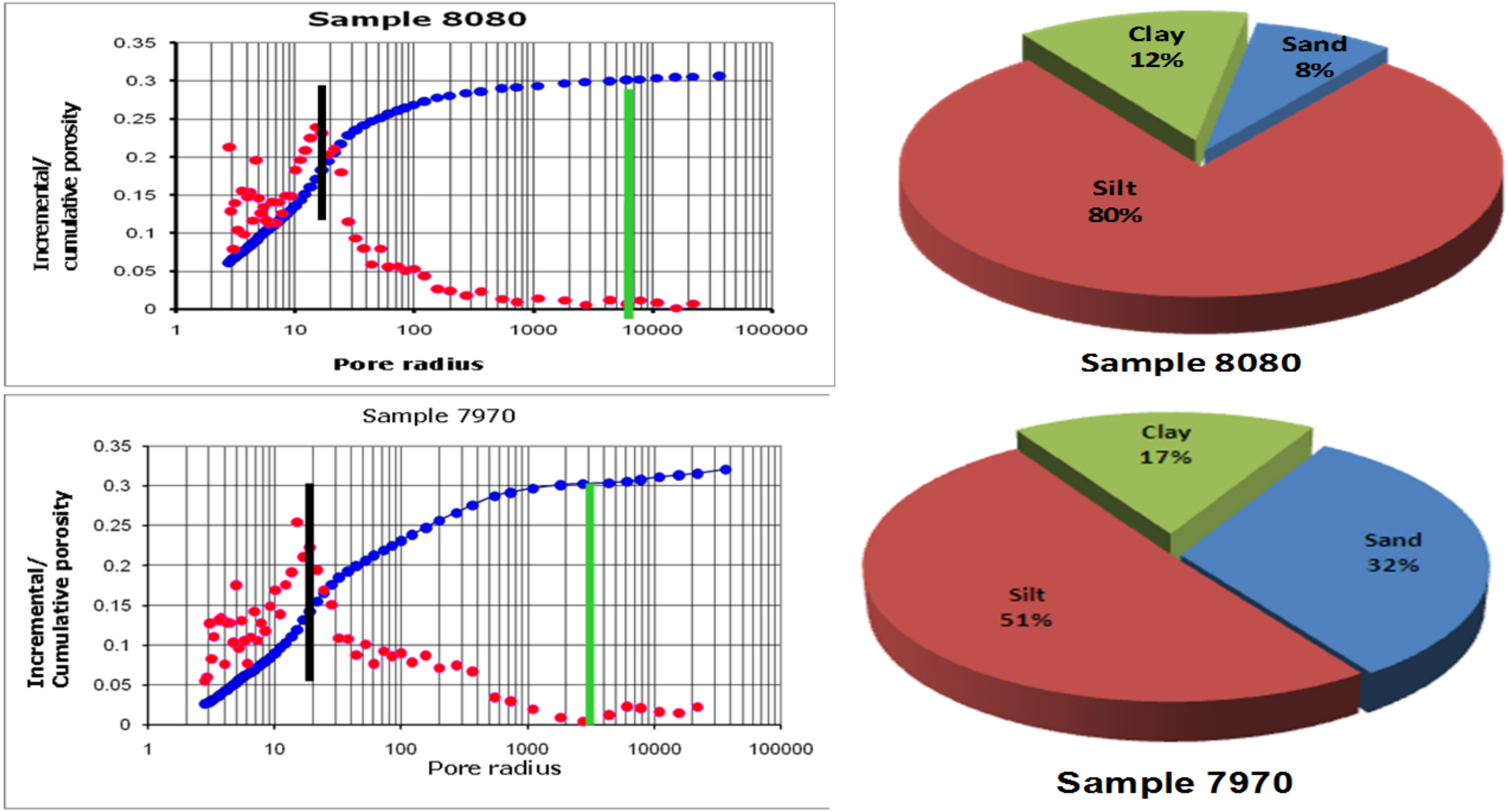

Figure 4. Samples 8080 and 7970 with same porosity and pore size density mode (pore size distribution) but different grain size distribution. Black line is point of maximum density of pore size; green line is cut-off point for damaged pores

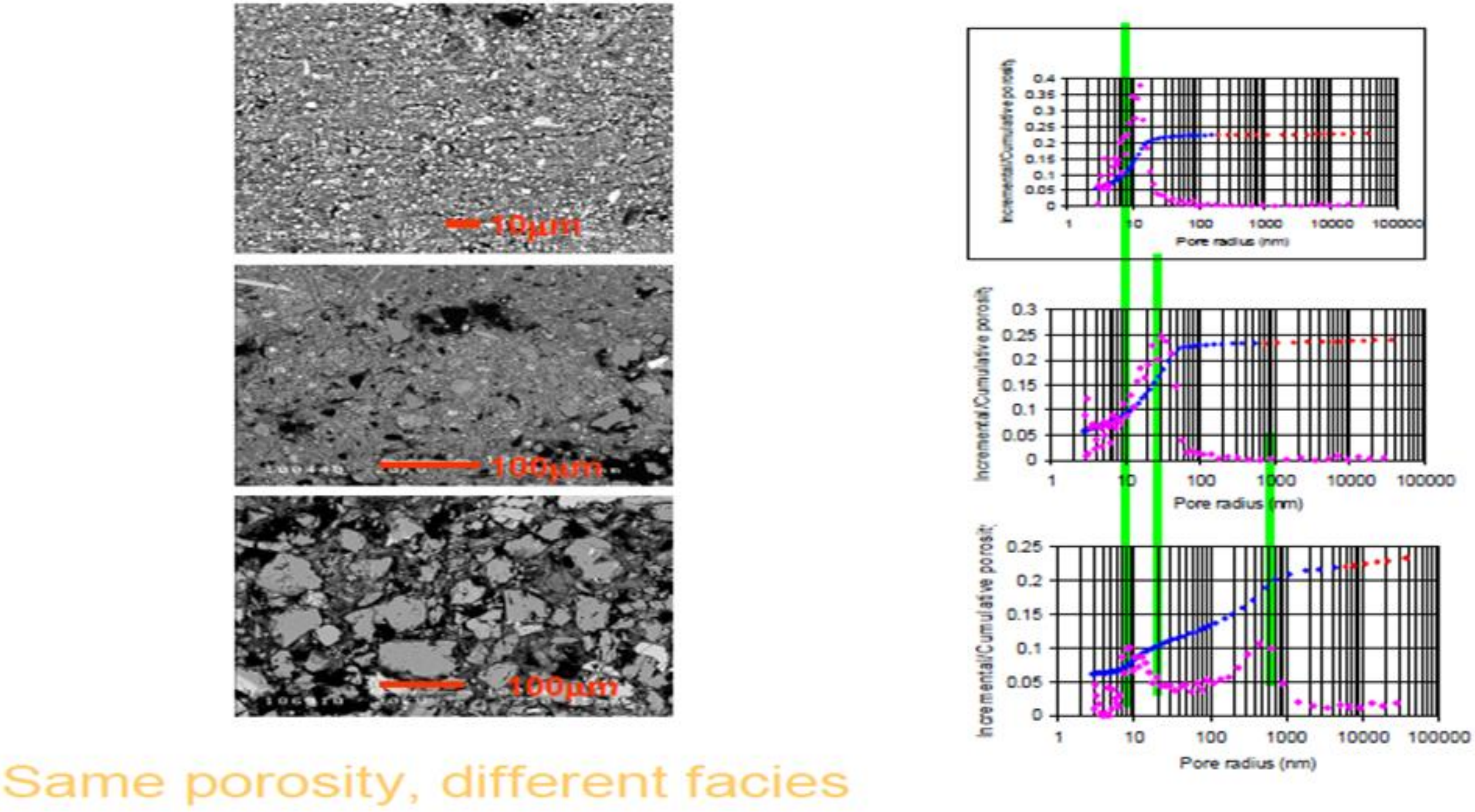

Figure 5. Thin section photomicrograph of samples with similar porosities but different facies (lithology) (Adapted from Aplin, 2005)

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The total porosity could also be expressed as the effective porosity, since it reflects the connecting pore throats which can be inferred from the porosity profile. The effective porosity value is 29% for both sample 7970 and 8080. The porosity reflects the storage volume for migrated or generated hydrocarbon. The fact that the sample7970 which overlays sample 8080 have the same porosity may infer some geomechanical processes or similar facies.

Dominant Pore Throats Sizes

The dominant pore throat sizes can be inferred from the pore throat distribution profiles. The profile indicates the connecting pore throats in the sample, while the point showing the highest occurrence of pore throat sizes portrays the dominant and connecting pores throats. The pore size with the highest frequency is the dominant pore throat size. The dominant pore throat sizes for samples 7970 and 8080 are 15.0nm and 16.0nm, respectively. Larger dominant pore sizes will foster higher permeability, while smaller pore sizes will show lower permeability values.

Corroborating Lithology, Pore Throat Size and Permeability

The pore throat size and the porosity are same for the two caprock samples. However, the grain size distribution shows very clear difference between the two samples. The grain size distributions are 17% clay, 32% sand and 51% silt for sample 7970. For sample 8080,the distributions are 12% clay, 8% sand and 80% silt. Sample 8080 has more silt while sample 7970 has more sand fraction. This implies that two lithologically distinct samples are having the same porosity and dominant pore throat size which fosters permeability. Correspondingly, the critical capillary entry pressure is higher (97psi) for sample 8080 relative to sample 7970 (32psi). The capillary entry pressure is a measure of the resistance posed by the mudstone to be overcome by the buoyant pressure exerted by the migrating fluid.

Different mudstones compact differently in response to burial. Expectedly, high silt fraction should correspond to high porosities, but, it was not observed in this study. Nonetheless, a higher silt fraction may not result to higher porosities at a given effective stress. Higher porosities have been suggested to be a function of over pressured mudstones and shales (Tingay *et al*., 2009). Figure 4 shows the results of a study from Aplin (2005), for which clearly different facies have the same porosity values. In an earlier study, Yang and Alpin (1998) showed that clay content has a simple but robust control over grain size distribution of mudstones. Their studies indicates that differences in lithology (grain size distribution) do not relate to similarity of porosities and pore size distribution (permeability). This observation is attributed to compaction processes where porosity remains constant with increasing depth.

If we consider a hypothetical situation with sand body, effective dewatering will result to lower porosities and lower dominant pore throat sizes. Over-pressure due to disequilibrium compaction can be associated with high porosities and can be transferred within inclined reservoirs or to shallower reservoir by faults or fractures (Yardley and Swarbrick, 2000). Sediments compact in response to the overburden along a loading curve. In the event of disequilibrium compaction, the formation fluid rather than the grain to grain contact bears the stress, thus unloading the stress and thereby resulting in increased porosity.

The porosity could be similar for formations affected and also the pore throat size distribution. Similarity of the pore size distributions fosters similar permeability range in the context of the fact that formation fluid migrates via network of pores in the matrix of the mudstone.

Pressure History

The Valhall pressure history as stated confirms overpressure with the reservoir pressure at 6450psi at 2400m, while the lithostatic pressure is 6800psi with confining pressure of 350psi. Similarly, in another study reservoir pressure of Valhall is stated to be about 6550psi and lithostatic pressure 7200psi at about 2450m (Ali and Alcock, 1992). However, both data are consistent with the fact that the Valhall reservoir was overpressured and the caprock fractured. This could have led to pressure transfer to the immediate caprock regions resulting in unloading, hence higher porosity of the caprock region compared to the more shallow formations.

Pressure history of the Valhall field confirm fracturing and healing of the fractures before charging of the reservoir fluids, which resulted in an overpressure of the reservoir and a refracturing of the caprocks. The transfer of overpressure in the caprocks from the reservoir resulted in the unloading characterized by high but similar porosities and pore size distribution for different lithologies. The implication of the study is that the concept of dominant pore throats sizes could determine the reliable cement mixtures for casing, landfill lining and seals for radioactive dumpsites.

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