Petrophysics 101: An Introduction to Advanced Topics in Petrophysics

Thursday 7th March 2019

The Geological Society, Burlington House, London

Start Time	End Time	Name	Company	Talk Title
08:30	09:00	Registration		
09:00	09:15	Dawn Houliston	LPS	Welcome address
09:15	09:45	Donald Clarke	ExxonMobil	Keynote: What is a Petrophysicist?
09:45	10:20	Paul Hoddinott	Independent consultant	Petrophysics of Thin Beds
10:20	10:55	Andrew Foulds	Petrafiz	Petrophysics of Shale Source Rocks and Coal Bed Methane
10:55	11:25	Refreshment Break		
11:25	12:00	Rubi Rodriguez	Schlumberger	Shaly sand reservoirs - Impact on Porosity and Water Saturation; the Dual Water model
12:00	12:35	Alan Johnson	Integrated Petrophysical Solutions Ltd.	Waxman Smits – The Rolls Royce of Shaly Sand Models
12:35	13:10	Kanad Kulkarni	Portsmouth Uni.	Unconsolidated oil sands property determination using micro-CT
13:10	14:00	Lunch		
14:00	15:00	Brian Moss & Steve Cannon	Independent & Clara	Carbonate reservoir evaluation of mineralogy, pore geometry, saturation and permeability
15:00	15:35	Jose Montero	Halliburton	Petrophysical Techniques for Calculation of Total Organic Carbon (TOC) Content and the use of Machine Learning for Unconventional Reservoirs
15:35	16:00	Refreshment Break		
16:00	16:35	Quentin Fisher	Leeds Uni.	Rapid Estimation of the Flow Properties of Tight Gas Sandstone Reservoirs from Cuttings Analysis
16:35	17:10	Adam Moss	AKM Geoconsulting	Flow Zone Index and Saturation Height Function Modelling in Low Permeability Sandstones
17:10	17:15	Dawn Houliston	LPS	Closing remarks
17:15	19:00	Networking Reception in the Library		

£150 for delegates (Speakers exempt)
(LPS is not VAT registered)
Students can register for free
Includes lunch and post-seminar wine and savouries
Doors open at 9am.
For more info or to register for this event please visit ***www.lps.org.uk/events/***

Donald Clarke - ExxonMobil

Keynote: What is a Petrophysicist?

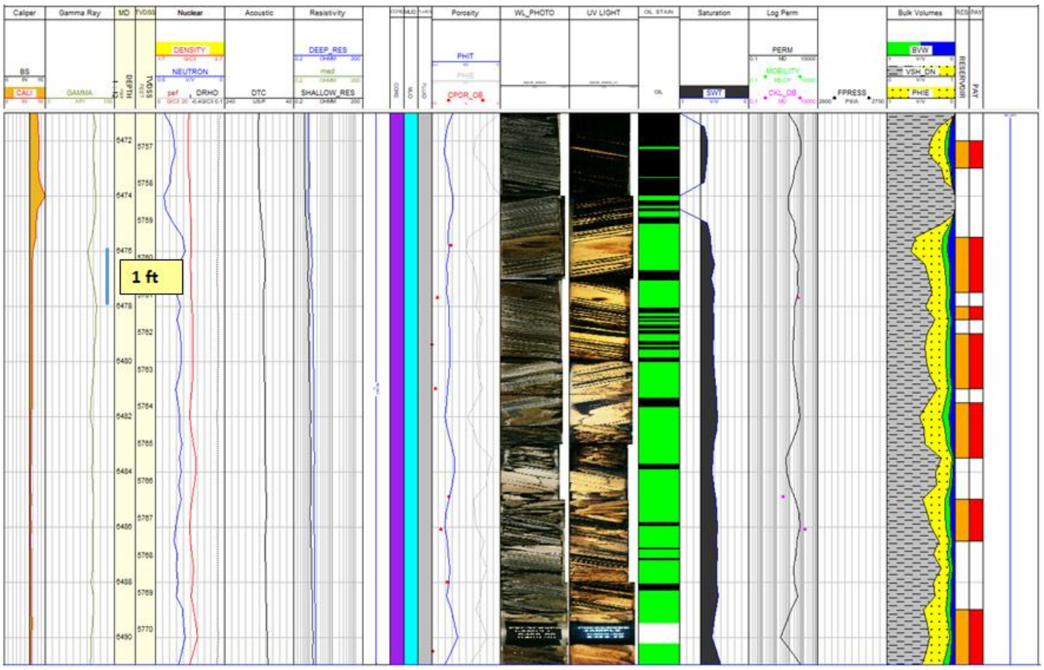
Don will de-mystify the role of the Petrophysicist and give a glimpse of what a career in Petrophysics could look like using his own 20+ years' experience in the field. It is purposefully not a technical talk, but intended to show prospective students and graduates why they should consider Petrophysics.

Paul Hoddinott - Independent Consultant

Petrophysics of Thin Beds

Standard petrophysical evaluations using conventional wireline and LWD logs can generally detect and resolve hydrocarbons in thick porous media which exceed the vertical resolution of the logging tool. For the porosity tools, Bulk Density and Neutron, this vertical resolution could be 20-40 cm. For the deep resistivity logging tools this vertical resolution is even coarser, at some 80 cm or more. The effectiveness of petrophysical evaluations over these thick beds can be demonstrated by comparing to core photographs. The computed Net Pay footage from petrophysics are generally found to be comparable to the footage of oil stain from core photographs over thick beds, resolvable by well logs.

However, for hydrocarbons accumulated in thin beds (cm scale) this presents a major challenge to well logs and standard evaluations. Modern logging tools such as NMR, Triaxial Array Resistivity and Image logs have made a large contribution to resolving and quantifying such thin beds. However, these tools are not always run and there is still the challenge of how to quantify thin beds in older wells.



Using core photographs to quantify footage of oil stain and compare to computed Net Pay. This method can be used to optimise petrophysical cut-offs when computing Net Reservoir & Net Pay

One method is to use core photographs (in a similar way to thick beds) to determine if petrophysical evaluations are under- or over-estimating computed Net Pay over thin beds. This technique can be used to optimise petrophysical cut-offs until computed Net Pay replicates footage of oil stain.

The talk will also highlight the importance of checking Composite logs (cuttings) and Core descriptions for evidence of thin beds and unusual mineralogy that may affect the petrophysical evaluations.

An example is given of an interval with common glauconite sand that gives a ‘shaley’ appearance on the well logs. Without careful attention this interval could have been incorrectly interpreted and Net Pay not properly computed.

Andrew Foulds - Petrafiz Limited

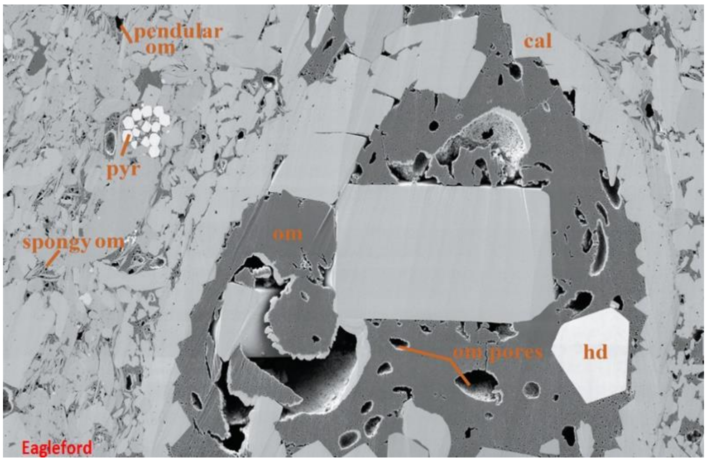
Shale Source Rock and CBM Petrophysics

The phenomena that is Shale gas and its maturity driven associated exploration target, shale oil, (both termed here as shale source rock plays) has taken the world by storm. The fairly recent technology change that has allowed multi-stage hydraulic frac stages to be performed in horizontal wells has initially transformed the gas market, and is now impacting the oil market in North America, but is now beginning to spread around the world. Recent economic conditions have slowed down the exploitation rate, however, it is a phenomenon that has been with us for a number of years both from a resource base and a technology knowledge base, but we are still learning, and petrophysics plays a central role in this respect.

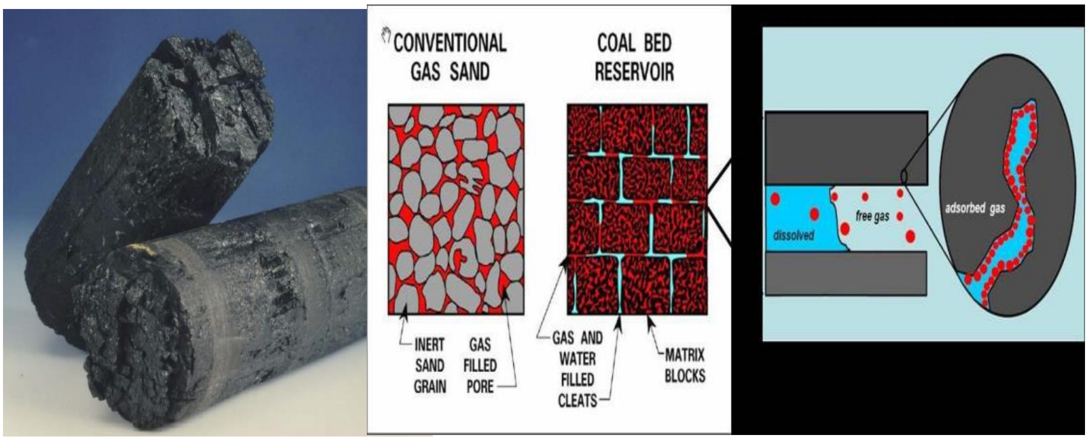
It also a subject that attracts a great deal of debate not only from the environmentalist, but also an economics viewpoint; both of which provide interesting and often vitriolic debate amongst proponents and distractors. It seems that everyone has an opinion on shale source rock plays – it seems to have attracted the attention of many people from all walks of life, both professional experts as well as layman.

CBM, exploration is less well developed both from an analysis perspective and is less well developed as a resource source, primarily due to low production rates and the time it takes to reach economic levels of production. Petrophysical analysis again follows normal petrophysical analysis, skewed to answer specific coal related issues, through an understanding of the resource base and potential to flow.

Exploration and exploitation of these resources are firmly based on formation evaluation characterisation of the resource using conventional and non –conventional petrophysical techniques. Petrophysicists need to learn new techniques as well as adjust existing knowledge and understanding to better evaluate these often-strange rock/fluid systems. The need for shale and coal specific core data to drive the analysis of the wireline data is paramount in understanding the resource base and is often unavailable until targeted wells are planned and drilled. The use of analogues and compiled rock specific databases become critical in initial assessment. Additional knowledge of formally regarded specialised petrophysical techniques like Geomechanics, together with those than are not normally associated with Petrophysicists, like Organic and Inorganic Geochemistry, are required to assist in understanding these plays, both from a resource base and a producibilty perspective.



No new paradigms in the evaluation techniques are suggested. The understanding of the rock/fluid system by conventional core to log integration techniques is paramount. New analyses and methods are required by the Petrophysicists to better understand the rock system but conventional principles are still required. However, shale source rock and CBM petrophysics, are still in their nascent period and there is so much scope to apply better analytical techniques to fully unlock the potential of this important resource base. Each play can have its specific nuances, which need to be understood both from a positive as well as their negative perspectives.



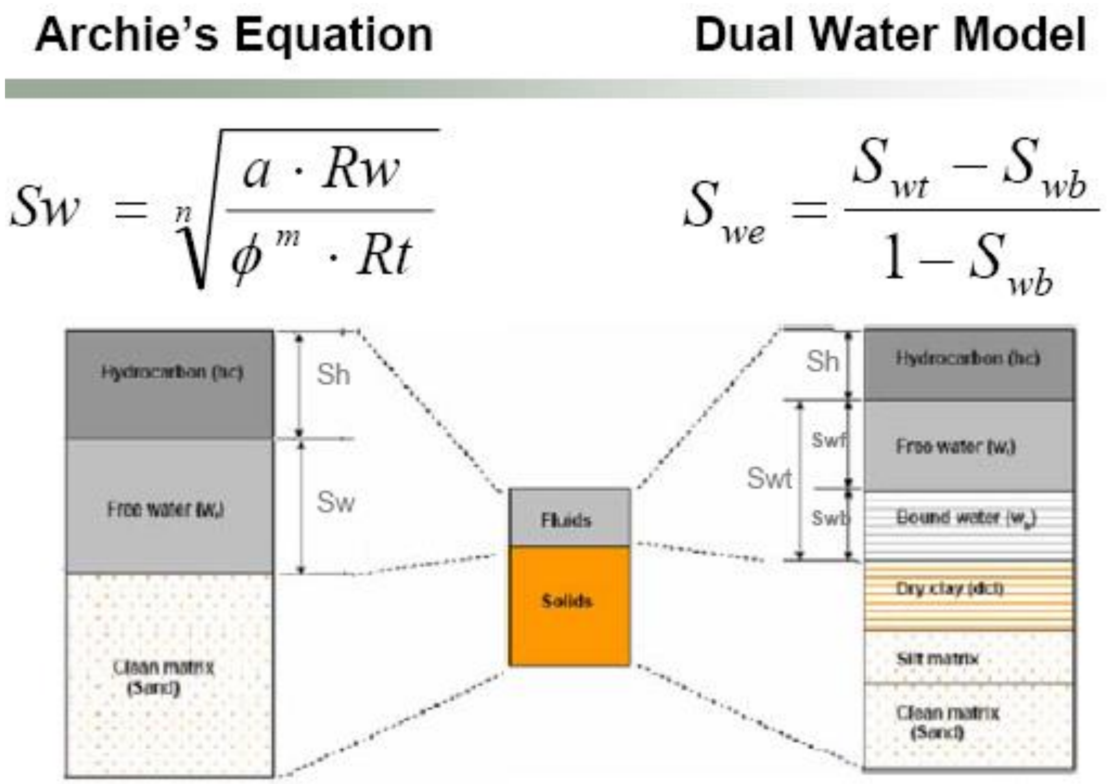
Rubi Rodriguez- Schlumberger

Shaly sand reservoirs- Impact forever on Porosity and Water Saturation

Petrophysical parameters such as porosity and water saturation are integral components to compute Hydrocarbon Initially In Place (HCIIP) in order to evaluate if a field has commercial quantities of hydrocarbons. However, reservoirs are not homogeneous, especially clastic reservoirs, they often contain some amount of clays or shales. Along with their effects on porosity and permeability, the electrical properties of a clay have a great influence on the determination of fluid saturation.

The interpretation of shaly sand formations has always been a challenging problem for log analysts. For this reason, many global and regional shaly-sand models have been empirically developed. A major disadvantage of these models is that they do not consider the shale composition nor the mode of distribution within the zone of interest. For example, it is well known that variations of clay mineralogy can result in different shale effects for the same shale fraction (Vsh).

This presentation introduces the way shaliness affects log readings based on their properties and their distribution and the different saturation models with a focus on Dual Water Model, developed by Schlumberger. Examples will be shown to give a flavour and understanding of shaly sand interpretation.



Alan Johnson – Integrated Petrophysical Solutions Ltd

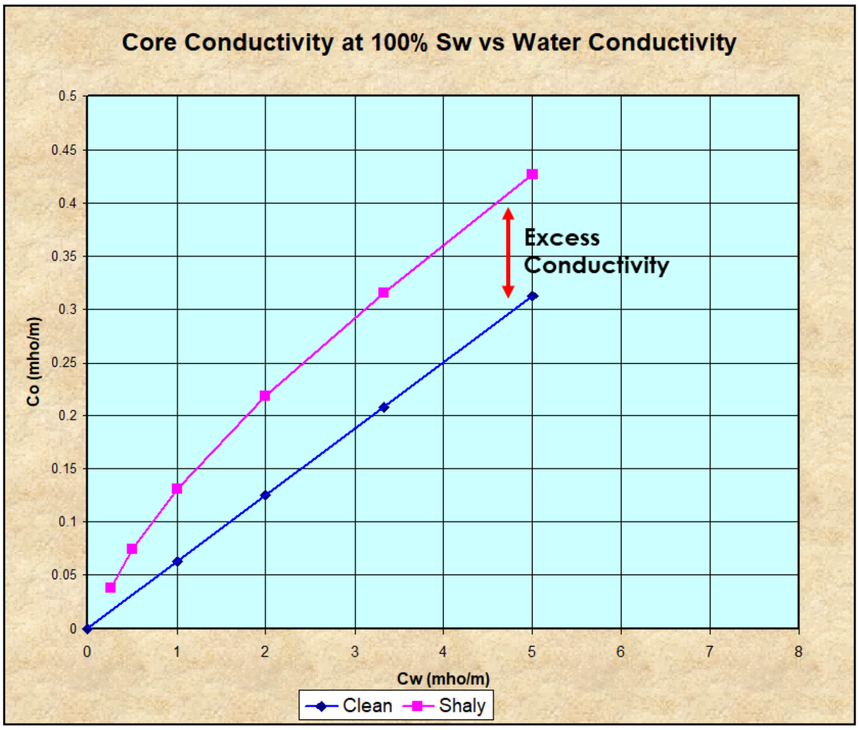
Waxman Smits – The Rolls Royce of Shaly Sand Models

This talk presents an overview of the Waxman-Smits shaly sand model, from its basis in core analysis to the practical application in saturation determination.

The Waxman-Smits relationship, first published in 1968, is an extension of the Archie clean sand model, presented in 1942. Unlike Archie, it takes account of the additional conductivity provided by the presence of dispersed clay in the pore throats. Most crucially, like Archie's relationship, it's robustness it is based on the analysis of actual core data, hence its robustness.

The presentation will examine the data and reasoning behind the Waman-Smits relationship together with practical examples of the derivation of the key parameters, Qv, m* and n*.

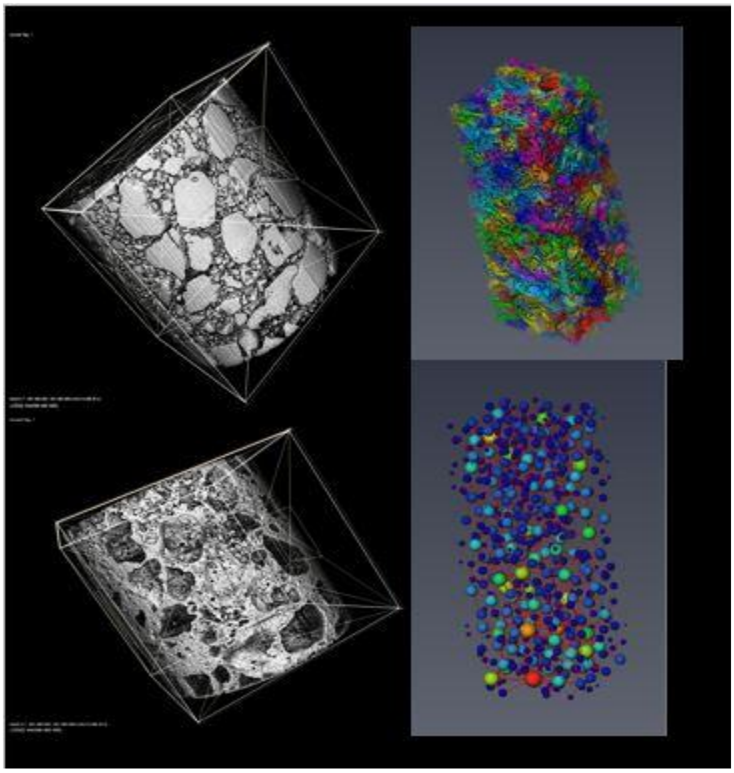
Time permitting, the talk will go on to review the impact of the derived relationship on our understanding of the effects of clay on other petrophysical parameters: porosity, permeability and capillary data.



Dr Kanad Kulkarni – Portsmouth University

Unconsolidated Oil Sands Property determination through the use of micro CT

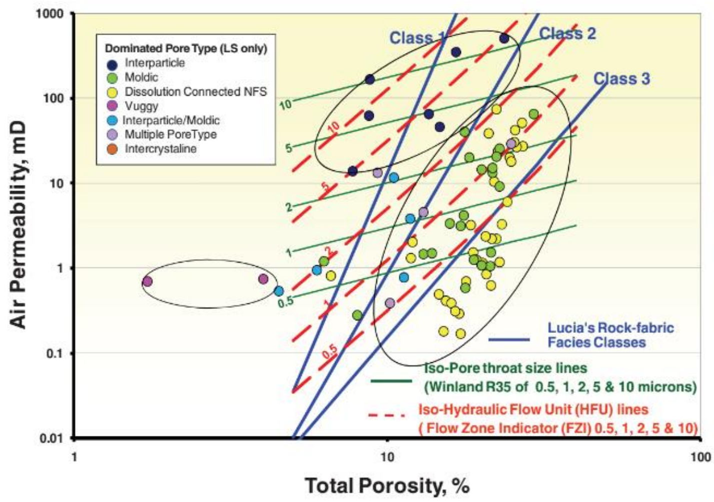
Unconsolidated reservoirs such as Canadian Oil Sands are always difficult to work with owing to the nature of the formation and absence of any cementing matrix. The challenge is further aggravated when bitumen acts as a consolidating/ cementing material. In such cases use of RCAL techniques is of no use as the sample is disintegrated the moment it is subjected to any cleaning. Furthermore, there are chances of losing fines (clays) from the core. To overcome such challenges, use of rapidly advancing micro –tomography techniques have proven to be a good alternative technique. Micro – CT scan are able to provide high resolution 3D image stacks of porous material with unprecedented details. Through this presentation, you will be introduced to this technique and how our research has been able to successfully apply it to determine properties from one such reservoir.



Brian Moss & Steve Cannon – Independent consultant & Clara

Carbonates: How to choose the right petrophysical evaluation method - Evaluation of mineralogy, pore geometry, saturation and permeability

Log analysis alone cannot resolve rock and fluid properties in carbonates; it is essential to understand their chemical and biological make-up and the depositional history of these complex reservoirs. Carbonate minerals are generally less stable than quartz and are altered more readily during diagenesis, resulting in irregular and unpredictable pore geometry. This complex pore geometry requires that a thorough study of pore character is carried out in every case. Whilst it is true that some carbonates have predominantly interparticle porosity, most comprise a mixture of pore types that can include interparticle pores, intraparticle micropores, dissolution voids and fractures within the same formation. There may or may not be a lithological control on pore type. As a consequence, simple zonation schema based on lithology/mineralogy seldom capture completely the controlling heterogeneity, which exists from pore to reservoir scale, and a more thorough differentiation into distinct petrofacies is usually required, albeit within distinct and large-scale depositional sequences. To this end, exploratory data analysis techniques and the use of advanced downhole technologies such as imaging, dielectric and magnetic resonance measurements, grounded in core inspection and analysis results, offer a robust workflow to derive the petrophysical deliverables required for the static reservoir model. The extent to which pore type differs in character from that of interparticle porosity will dictate the need for special measures for the evaluation of saturation for each petrofacies; one or more petrofacies present may be decidedly 'non-Archie' in their responses to log measurements and calibration against core and/or test data of saturation profiles derived from log data is frequently necessary. It is often necessary to apply non-conventional interpretation strategies to unlock the hydrocarbon potential of carbonate reservoirs.



The image is of data from Ragland 2002, but is drawn from Bust et al., SPE 142819, 2011, SPE Reservoir Evaluation and Engineering. (Full citation in presentation.)

The image, drawn from Bust et al 2011, illustrates a wide range in permeability for any given value of porosity, which is a characteristic of complex pore geometry. Several different possible partitioning strategies are shown relative to the pore types; none captures pore type variation in this example completely and therefore the most fit-for-purpose schema in any given reservoir may vary from reservoir to reservoir.

Jose Montero - Halliburton

Petrophysical Techniques for Calculation of Total Organic Carbon (TOC) Content and Identification of Carbonaceous Facies through a Machine Learning Assisted Lithology Interpretation approach - for Unconventional Reservoirs

Jose Montero, Alexander Bromhead, David Weeks (Halliburton)

The accurate identification of rocks of high total organic carbon (TOC) content is vital to exploration. Rocks with high TOC values represent conventional source rocks as well as unconventional targets. TOC values are often calculated from core samples; however, it is possible to calculate TOC using petrophysical analysis performed on an appropriate suite of electrical logs. Equations from Schmoker and Passey along with the variations can be used to derive TOC values from wireline logs and, in some cases, these can deliver comparable results to laboratory tests of core data. Real-world examples of the techniques are discussed along with strengths and weaknesses of the various methods.

Application of the Schmoker equations and variations yielded positive results in three different real-world examples, The Tuwaiq Mountain Formation (Middle East), the Utica Fm and the Permian Basin (United States) (Fig. 1), allowing the completion of an unconventional basin screening project. - Petrophysical analysis closely matched TOC values obtained from core data using density log. However, areas where downhole washouts are common, density logs can provide erroneous readings, meaning other methods have to be used. This is the case for the Niobrara Formation (United States) where the Passey equations were used in conjunction with sonic, resistivity, and neutron logs. Using these formulas allowed the identification of organic-rich facies in the subsurface, whilst simultaneously generating a training dataset to utilize in a supervised machine learning algorithm to better understand common data responses to select facies automatically based on the petrophysicists' primary calculations. The application of the machine learning algorithm to a dataset of several hundred wells resulted in the correct identification of carbonaceous mudstones across the basin with an accuracy greater than 80%- and the development of a static model in a fraction of - time compared to the manual interpretation.

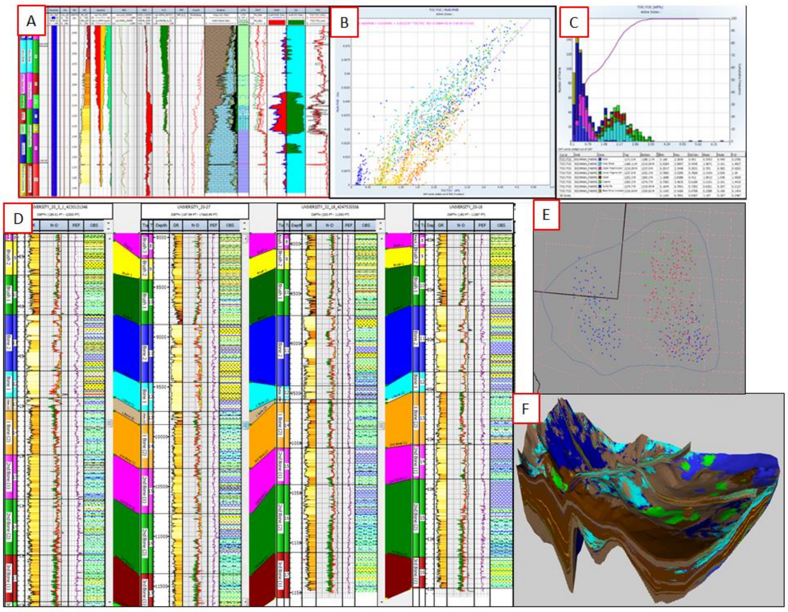


Fig. 1: Illustration showing representative images for the different followed stages A) Petrophysical interpretation performed for the determination of TOC. B) TOC-PHIE relationship. C) Histogram showing TOC distribution for the different considered zonations. D) Correlation showing interpreted facies to include in the training dataset for the machine learning code. E) Location map for the Permian basin showing a high concentration of wells. F) Facies model performed for the Permian Basin.

Prof Quentin Fisher and Dr Carlos Grattoni – University of Leeds

Rapid Estimation of the Flow Properties of Tight Gas Sandstone Reservoirs from Cuttings Analysis

School of Earth and Environment, University of Leeds, Leeds, LS2 9JT, UK

There are many situations in which it is necessary to estimate the flow properties of tight gas sand reservoirs without access to core analysis data. Key examples include: (i) when attempting to interpret well tests or wire-line logs in reservoirs where core was not taken or has not yet been analyser; (ii) when re-evaluating old discoveries that were initially abandoned as tight but could potentially be produced at economic rates using modern drilling and completion technologies. To address these issues we have built a large database of the microstructure and petrophysical properties of tight gas sandstone reservoirs. The data have been incorporated into be-spoke data visualization software to identify the key microstructural controls on porosity-permeability relationships. This knowledge can then be used to assess likely porosity-permeability relationships of other tight gas sandstone reservoirs by examining the microstructure of cuttings brought to the surface with the drilling mud. Apply these porosity-permeability relationships to wire-line log measures of gas filled porosity can be used to broadly estimate permeability height in the reservoir and therefore potential flow rates. If necessary, this analysis can be conducted extremely rapidly (i.e. 6 hours of receiving samples) and can be a valuable aid to the characterization of tight gas reservoirs for which routine core analysis data is not available.

Dr Adam K Moss - AKM Geoconsulting Ltd

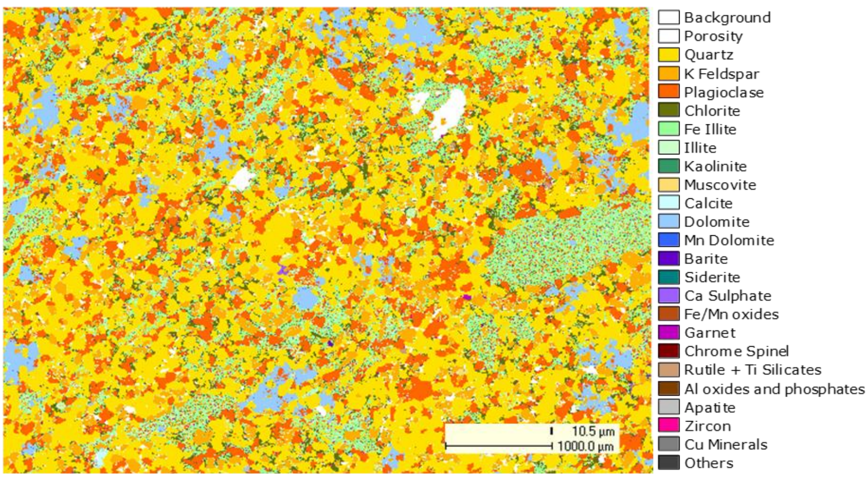
Flow Zone Index and Saturation Height Function Modelling in Low Permeability Sandstones

The key to improved reservoir description and exploitation is to identify and understand the complexities in pore system geometry through a reservoir. This is particularly the case in tight gas sandstones where diagenesis often diminishes pore size and connectivity to a level where a traditional facies approach cannot be used to differentiate intervals with common flow parameters. Permeability prediction is complicated since for any porosity within a given rock type, permeability can vary by several orders of magnitude. In consequence the classic technique of defining empirical relationships between the log of permeability and porosity for a rock type is not applicable. However, in such cases petrophysical analysis can be used to define the existence of distinct zones (hydraulic units) with similar fluid-flow characteristics.

An example data set from a low permeability sandstones gas condensate reservoir is discussed. The fluvial sandstones are very fine to fine grained with variable clay content. Quartz cementation coupled with compaction have degraded the pore system. Consideration of properties by sedimentary facies does not systematically differentiate distinct petrophysical zones but it can be demonstrated that permeability is primarily controlled by clay abundance and distribution. The Flow Zone Index (FZI) methodology has been used to identify and characterise different hydraulic units. This technique is based on the Kozeny-Carmen equation. The relationship between clay and quartz abundance and FZI shows that the method is differentiating mineralogically distinct rock types. Based on core data, using a relationship between bound water volumes from NMR and FZI, the FZI value can be predicted. Applying this core-based relationship to NMR log data allows FZI and permeability to be computed from wireline data.

This approach can be further extended to compute a saturation height function using the Thomeer model. The Thomeer 'pore geometrical (shape) factors (C) and breakthrough pressures (Pb) are calculated from mercury injection data. Relationships between FZI types, the shape factor and breakthrough pressure are derived, thus allowing the Thomeer model saturation to be computed.

In these sandstones where there are complex variations in pore geometry, the flow zone index method has successfully managed to predict permeability and compute a lithology related set of saturation-height relationships which coincide with core results and can be incorporated into reservoir models for the field.



QEMSCAN mineral map from a tight gas reservoir core plug (Kg = 0.13mD, Φ = 9.6%, G.D = 2.66g/cc).