Aberdeen Formation Evaluation Society

AFES

SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS

AFES 2021 Seminar

Porosity & Permeability

Wednesday 21st April 2021 – 13:00 to 15:00

Online Event

We invite you to attend the 2021 AFES Half Day Seminar on the subject of porosity and permeability. If you would like to attend this online event, please register at the following link:

https://www.eventbrite.co.uk/e/afes-2021-seminar-porosity-and-permeability-tickets-149722238245

If you have any questions, please send by email to seminars@afes.org.uk

13 April 2021

AFES SEMINAR 2021			
TIME (UK - BST)		PRESENTER	TITLE
13:00	13:30	Alan Johnson	Effective porosity from capillary data
13:30	14:00	Keith Milne	Incorporating directional permeability into geological modelling
14:00	14:30	Steve Cuddy	Should petrophysics calculate total or effective porosity?
14:30	15:00	Craig Lindsay	Relative porosity – does it exist and if so how can we measure it? Does it matter?
15:00	15:30	Ibrahim B. Milad	Permeability prediction in a complex carbonate reservoir in south Iraq, by combining FZI with NMR

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ABSTRACTS FOR PRESENTATIONS

13:00 – 13:30 Effective Porosity from Capillary Data

Alan Johnson – Integrated Petrophysical Solutions (IPS) Ltd.

In 1979 Waxman and Thomas of Shell published the results of laboratory studies carried out by Hill, Shirley and Klein, internally in Shell, in the early 1960's (1). One of the key findings of that work was a relationship between the volume of clay bound water in a shaly rock sample and the measured cation exchange capacity of that sample. This provided an empirical laboratory-based relationship between total and effective porosity:

$$\frac{\emptyset_E}{\emptyset_T} = 1 - (0.084 \times Co^{-\frac{1}{2}} + 0.22) \times Qv$$

Where:

ϕ_E = Effective Porosity

ϕ_E = Total Porosity

Co = Salinity in meq/ml

Qv = Cation Exchange Capacity in meq/ml

Provided reliable measurements or estimates of cation exchange capacity are available, this relationship provides an objective, laboratory based, link between estimates of total and effective porosity and provides a reliable quality control check on, in particular, effective porosities derived by purely log based techniques.

In their paper, the authors also proposed using this relationship to correct mercury air capillary data, which uses air as the wetting fluid and so ignores clay bound water, to the oil brine or oil brine system. The resulting corrections were simply defined by Juhasz of Shell, also in 1979(2):

$$Pc_{Hg}(corr) = Pc_{Hg}\left(\frac{\emptyset_E}{\emptyset_T}\right)^{-1/2}$$

$$S_{Hg}(corr) = S_{Hg}\left(\frac{\emptyset_E}{\emptyset_T}\right)$$

The presentation will demonstrate the validity of these relationships through a number of real examples and also show that, in the absence of core measurements of Qv, these relationships can be used to derive estimated values of effective porosity (and Qv) by comparing mercury/air and air/brine capillary data from the same reservoir.

1. Hill, H. **J.,** Shirley, 0. **J.** & Klein, G. E. (1979), Bound water in shaly sands-its relation to **Qv** and other formation properties (Ed.: by M. H. Waxman & E. C. Thomas). Log Analyst, May-June 1979.
2. Juhasz, I (1979), The central role of Qv and formation-water salinity in the evaluation of shaly formations. Log Analyst, July-August 1979.

13:30 – 14:00 Incorporating directional permeability into geological modelling

Keith Milne - Reservoir geologist (associate at Tracs International)

In dynamic reservoir modelling, we typically need to understand fluid flow on a kilometre scale to plan wells and estimate recovery. Petrophysicists often spend a lot of time analysing cross plots and well logs to derive a poro-perm relationship and this is usually related to the measurements of the core plugs and gives an estimate of horizontal permeability.

However, reservoir engineers often have to play with permeability modifiers (especially vertical permeability) in the simulator to match dynamic behaviour such as production and pressures. In some cases this is because the baffles and facies architecture has not been captured in the static model. In a reservoir, some features are not often sampled by core plugs or are below log resolution, for example extensive shale drapes or laminated facies. However measurements of shale are published and can be used to estimate vertical permeability.

One method to estimate the permeability reduction due to shale drapes is to geologically model a single simulation cell on a very fine scale. This gives a directional permeability estimate for a shale-drape cell (cell with a particular facies combination of reservoir and minor shale).

Importantly, in the full-field model, the shale-drape cells need to be placed consistently at the base of geological objects and a method is shown to achieve this (and avoid a scatter).

The use of baffles and facies is illustrated using a simple reservoir model at simulation scale. This can result strongly anisotropic directional permeability (even with only slight changes in porosity).

We learn from this the importance of estimating the vertical permeability and distributing shale geologically.

Some further ideas about natural patterns and grouping petrophysical poro-perm measurements are suggested.

ABSTRACTS FOR PRESENTATIONS

14:00 – 14:30 Should petrophysics calculate total or effective porosity?

Steve Cuddy – Petro-Innovations

The petrophysicists define two porosities, the total porosity (PHIT) that includes isolated pores and the space occupied by clay-bound water and the effective porosity (PHIE) which excludes isolated pores and pore volume occupied by water adsorbed on clay minerals. Reservoirs with a high formation water salinity and a low clay mineral content are called Archie reservoirs, where the effective and total porosities are essentially the same, because there are negligible clay bound water effects. Otherwise, they are called non-Archie reservoirs, because there can be a significant clay bound water saturation. Non-Archie reservoirs can be evaluated in terms of either effective or total porosity.

Different water saturation (Sw) equations use different porosities. In clean formations the Archie equation can be used, as it is assumed PHIT is equal to PHIE. In shaly formations the water saturation equation must correct for the shales' excess conductivity. Waxman-Smits, Juhasz and Dual Water use PHIT, whereas Simandoux and Indonesia use PHIE. Using PHIT or PHIE should give the same hydrocarbon in place (HCIP). The question is which is most useful and gives the most accurate determination of HCIP.

Density Porosity (PHID) is not PHIT and represents a porosity somewhere between PHIT and PHIE. This is because the matrix (Rhoma) and fluid (Rhofl) densities used for PHID are picked for clean formations and may be different in the shales. Consequently, it is necessary to calibrate PHID to the core porosity using log to core regression. Without core, it is necessary to first calculate PHIE using an appropriate density response equation. To calculate PHIT from PHIE requires knowledge of the shale porosity (PHISH) due to clay bound water. This can be determined from Qv (cation exchange capacity per unit total pore volume) using a unique algorithm or from a specially designed bulk density vs. neutron porosity crossplot.

Using these techniques, it is recommended that the petrophysicist calculate both PHIT and PHIE. Finally, it is essential that a shaly sand water saturation equation be selected to correct for the shale's excess conductivity. This equation can be confirmed using a bespoke technique where 'unlimited' Sw is plotted against the volume of shale (Vsh) in the water leg.

14:30 – 15:00 Relative porosity – does it exist and if so how can we measure it? Does it matter?

Craig Lindsay – Core Specialist Services Limited

Porosity means many things to many people both in the oil and gas industry and beyond. Porous media plays a role in every aspect of lives from drinking water to brewing a jug of coffee.

This presentation will look at porosity from a core analysts' perspective.

In the realm of core analysis various methods exist for measuring porosity.

Porosity can be measured or calculated in various conditions – dry, saturated, part saturated and so on. Each of these variants has a role to play in understanding the properties of porous media.

Pore space can be compartmentalised by saturating fluid, micro, meso and macro porosity.

Some types of porosity can't easily measured from core – fractures.

Rock such as conglomerates have large porosity contrasts between matrix and clasts – how can we deal with this when attempting to measure porosity?

Can the ways we prepare samples and measure porosity adversely change porosity?

Are shales porous and can we measure their porosity?

How important is all of this?

We will not settle the argument "what is the correct value of porosity" any time soon, but we will examine these aspects and more to see that not only is porosity not a fixed value for any given rock but that it can vary during the timescale of our interaction with the rock.

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ABSTRACTS FOR PRESENTATIONS

15:30 – 16:00 Permeability prediction in a complex carbonate reservoir in south Iraq, by combining FZI with NMR

Ibrahim B. Milad, Russell Farmer & Milad Saidian **– BP**

The Rumaila field is in South East Iraq contains multiple reservoir intervals, including the Upper Cretaceous Mishrif carbonate reservoir, one of the major reservoirs in the world, that has been producing at considerable oil rates for more than 50 years. With billions of barrels yet to be recovered it is expected to play a significant role in sustaining Rumaila production for decades. Reservoir pressure has dropped due to historical production and, therefore, large scale water injection is planned to support and enhance future production rates and oil recovery.

One of the key subsurface challenges in carbonate reservoirs is to understand and characterise reservoir complexity and heterogeneity, with permeability being one of the key factors in understanding sweep behaviour and predicting production and injection rates. Rumaila has extensive surveillance programs and production and saturation logs in particular are used to refine static and dynamic models and to better characterise individual well performance. With more than 1,000 well penetrations to date, efficient management of wells is key to optimising production.

It was recognized several years ago that the available log and core datasets at that time did not enable a fully characterised model of the pore system, resulting in a large uncertainty in the permeability model. As a result, four new wells were cored, and advanced modern logs acquired to expand the datasets to support a rebuilding of rock typing and permeability models to better understand pore system distributions and the extent and impact of heterogeneity in the Mishrif reservoir.

This paper presents a workflow that utilises NMR logs, NMR core analysis and FZI techniques to predict permeability. The approach is focussed on distinguishing between different pore types by estimating the relative proportion of large pores (Large Pores Index - LPI) from NMR data and using this as an input to enhance the prediction of FZI rock types and subsequently the prediction of permeability. The results show a significant improvement in permeability estimates compared to more traditional approaches.

The improvement in permeability prediction has been reflected in better predictions of production and injection indexes, improved understanding of sweep behaviour and the prediction of timing for water breakthrough, leading to more optimal management of reservoir performance. Moreover, at the well level, the new model has resulted in enhanced completion decisions for newly drilled wells, as well as ongoing well-work operations (additional perforation and re-perforation campaigns) on existing producers and injectors.