LPS One-Day Seminar

Permeability - from Reservoir Quality to the Simulator

Thursday 25th June 2015, 9am - 5pm

The Geological Society, Burlington House, London W1J 0PG

Time	Presentation	Presenter	Affiliation
09:00	**Registration**		
09:20	Welcome & Introduction	**Michael O'Keefe**	LPS
09:30	Permeability – from Laboratory to the Core Flood Simulator	**Andrew Cable**	Weatherford Labs
10:05	An Investigation of Permeability Anomalies	**Michael Burke**	Gaia
10:40	**Morning Tea Break**		
11:00	Practical Permeability Estimates for Petrophysicists	**Colin Carter**	Perenco
11:35	Use of permeability in rock typing and saturation height modeling workflows	**Olivier Marche**	SLB Software Integrated Solutions
12:10	Well Testing to Calibrate Static Models to Dynamic Data.	**Tim Whittle**	BG Group
12:45	**Lunch**		
13:30	Permeability from Wireline Formation Testers : When and How to use it?	**Shyam Ramaswami**	Shell
14:05	Advances in Transient Formation Testing and Multiphase Transport Properties	**Cosan Ayan**	SLB Wireline
14:40	**Afternoon Tea Break**		
15:00	Permeability and Upscaling: from core and logs to the static model and the simulator	**Roddy Irwin**	Gaffney Cline and Associates
15:35	The Importance of Understanding Permeability Uncertainty for Field Development Decisions	**Andrej Bulat**	SLB Software Integrated Solutions
16:10	The problems of averaging permeability - do the reservoirs and fluids appreciate the problems they create for simulation?	**Richard Dawe**	University of West Indies, Trinidad
16:45	**Concluding Comments**	**Michael O'Keefe**	LPS

Presentation #01: **Permeability – from Laboratory to the Core Flood Simulator**

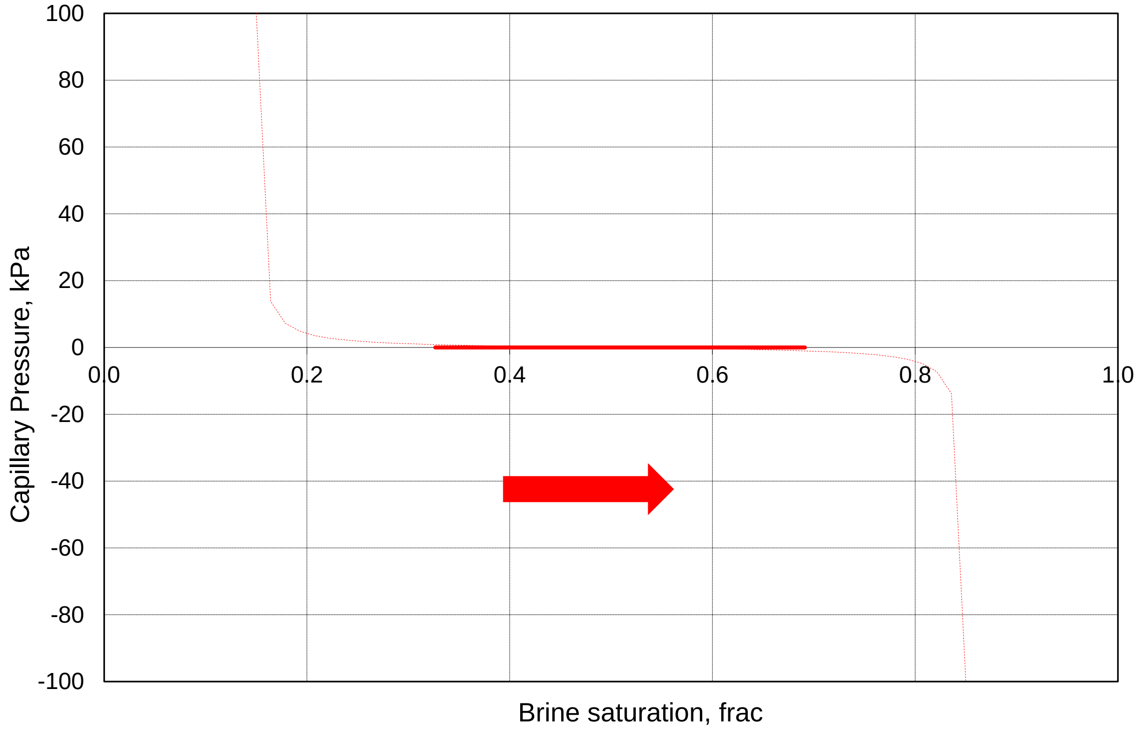
Presenter: **Andrew Cable, Laboratory Manager, Weatherford Laboratories**

Abstract:

Core flood simulation is routinely undertaken by Weatherford Laboratories using *Sendra*™, a proprietary simulator based on a two phase 1-D black oil simulation model together with an automated history matching routine. *Sendra*™ is used to reconcile time and spatially dependent experimental data and provides relative permeability output data that is corrected for the effects of laboratory scale capillary pressure. In the laboratory, at the core plug scale, capillary pressure may have a dominant effect on the displacement processes. If left uncorrected, this may give misleading relative permeability information. Capillary pressure effects can be observed from in-situ saturation monitoring data. Ideally, capillary pressure effects are minimised by core flooding at high rate (so that viscous forces are dominating) or by increasing the length scale (so that capillary pressure is small relative to pressure drop). Plug characteristics (length, diameter, porosity and base permeability), injected fluid properties (μ_w and μ_o), core flooding rates, brine fractions and flooding durations are used as input parameters for core flood simulation. For history matching, measured transient data is also added to the model (ΔP f{time}, S_w f{time} and S_w f{length fraction}.

In this presentation, Andrew will show how modelling experimental in-situ saturation monitoring data can be used to derive capillary pressure. By showing (anonymous) case histories the presentation will show examples of water-wet, neutral and oil-wetting fluid saturation distributions and the resulting modelled capillary pressure (and relative permeability) curves. Core flood simulation is the ultimate tool in understanding reservoir wettability and its influences on imbibition capillary pressure and relative permeability.

Case History: Imbibition Capillary Pressure ('P_c= 0')



Presentation #02: **An Investigation of Permeability Anomalies**

Presenter: **Michael Burke, Gaia**

Abstract:

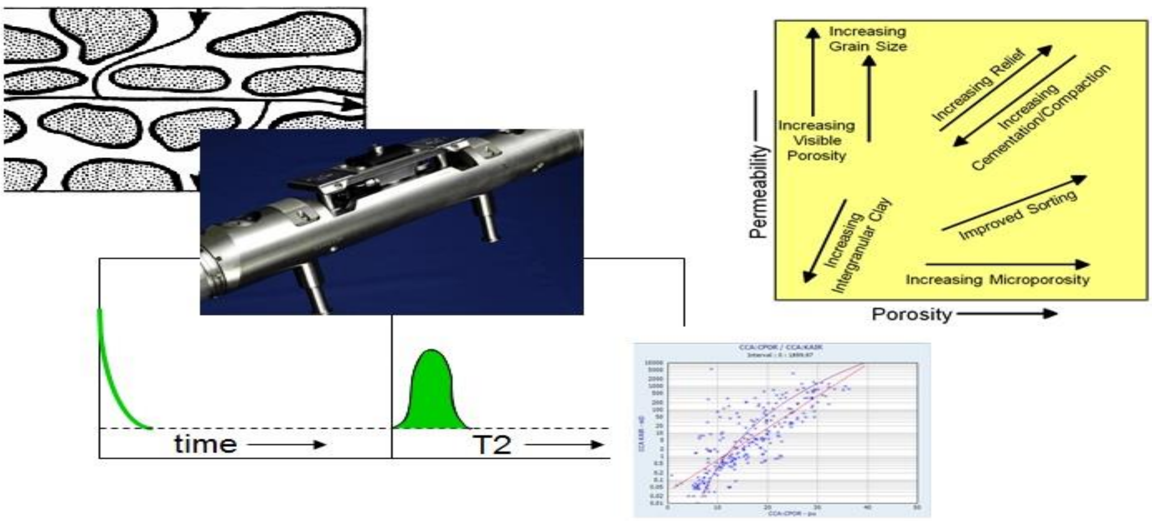
Imbibition relative permeability is derived from special core analysis (SCAL) and is defined as the effective permeability normalised to a suitable reference permeability – which is often taken as the effective oil or gas permeability at irreducible water saturation. This presentation relates RCAL measured permeability (K) and porosity (Φ) to a simple pore scale model to help judge the validity of one type of relative permeability anomaly. Specifically: can the relative water permeability (krw), when defined as effective water permeability (kew) at residual oil saturation (Sor) divided by the effective oil permeability (keo) at residual water saturation (Swi), be greater than 1 for the condition Sor > Swi ? In other words: can permeability through a porous medium increase when the pore volume is reduced and is it therefore valid to use such "anomalous" measurements for field simulation purposes?

Presentation #03: **Practical Permeability Estimates for Petrophysicists**

Presenter: **Colin Carter, Petrophysicist, Perenco**

Abstract:

Permeability is integral to petrophysics, providing us with an indication, if not proof, that the fluid we calculate in our CPI will flow. However, there is no direct continuous log measurement of permeability and it remains a conundrum to estimate for petrophysicists. We will look at the practical aspects of permeability estimation for operational and field petrophysicists, exploring options available for quicklook analysis through to inputs to reservoir modelling. Methods discussed will include; Poro-perm plot, NMR, K-lambda, Sonic, Formation Testers, Core and DST. A brief description of each method and its advantages will be discussed in each case.

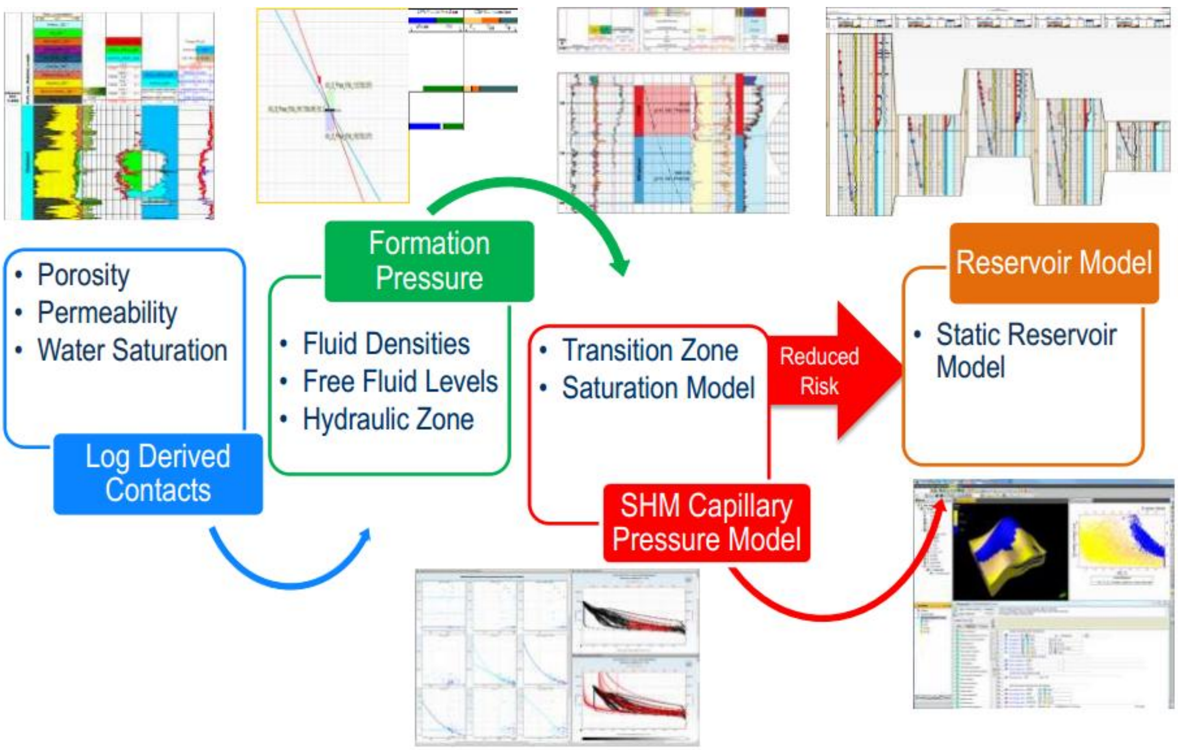


Presentation #04: **Use of permeability in rock typing and saturation height modeling workflows**

Presenter: **Olivier Marche, Schlumberger Software Integrated Solutions (SIS)**

Abstract:

Permeability is a key dynamic measurement which differs from all the traditional log measurements. It is central to the rock typing process used to prepare saturation functions that can accurately compute saturation for the static model. We will show an example of this workflow starting from core measurement to preparation of the static model in 3D reservoir model platform and the different techniques available to combine information coming from multiple measurements (core, log and insitu dynamic measurements).



Presentation #05: **Well Testing to Calibrate Static Models to Dynamic Data**

Presenter: **Tim Whittle, BG Group**

Abstract:

Exploration and appraisal well testing provides early information about well and reservoir performance. The pressure transient data acquired during a well test contains the dynamic signature that depends on the reservoir properties and their variation within the volume of investigation. Depending on the magnitude of permeability and the duration of the test, this volume can be a significant proportion of the reservoir.

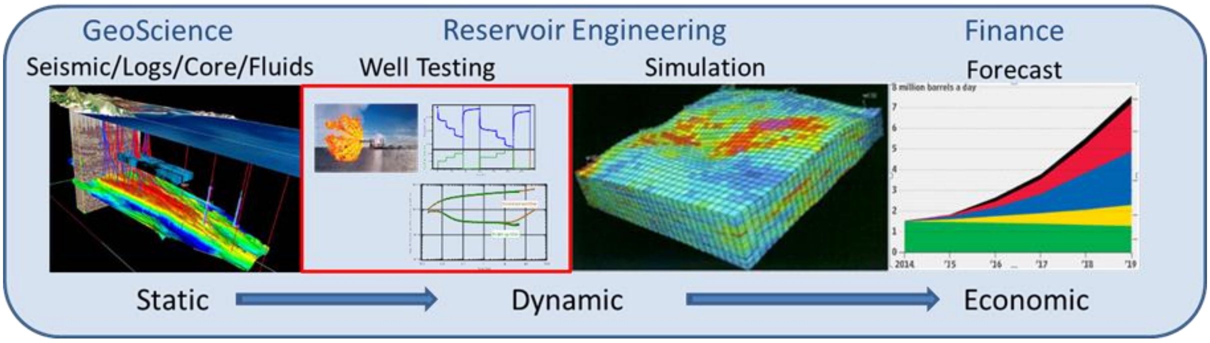
Typically, deconvolution is used to extract the dynamic signature from the measured pressures and flowrates. A log-log plot of the deconvolved pressure response and its derivative is the best way to visualise this signature. The shape of the derivative is used to identify different flow regimes (e.g. radial, linear and pseudo-steady state) which correspond to various well and reservoir characteristics (e.g. fractures, permeability, heterogeneity and boundaries).

Traditionally, simple analytical models are used to match the observed response and quantify the well and reservoir parameters that control the behaviour. These parameters are then used to update the inputs to much more complex and detailed numerical models based on all the data acquired during field exploration and appraisal (seismic, logs, cores etc).

A complimentary approach is to compare the dynamic signature of the numerical models directly with the acquired data. The reservoir properties are then adjusted to achieve a history match to the well tests whilst continuing to honour the static input data.

Such calibration of reservoir models requires good collaboration between subsurface disciplines to ensure that each of their particular data sets continue to be honoured. The result should be a model or series of calibrated models that are better able to provide meaningful ranges of expected outcomes during future field production.

The talk will discuss some of the theory involved and present examples of its application.

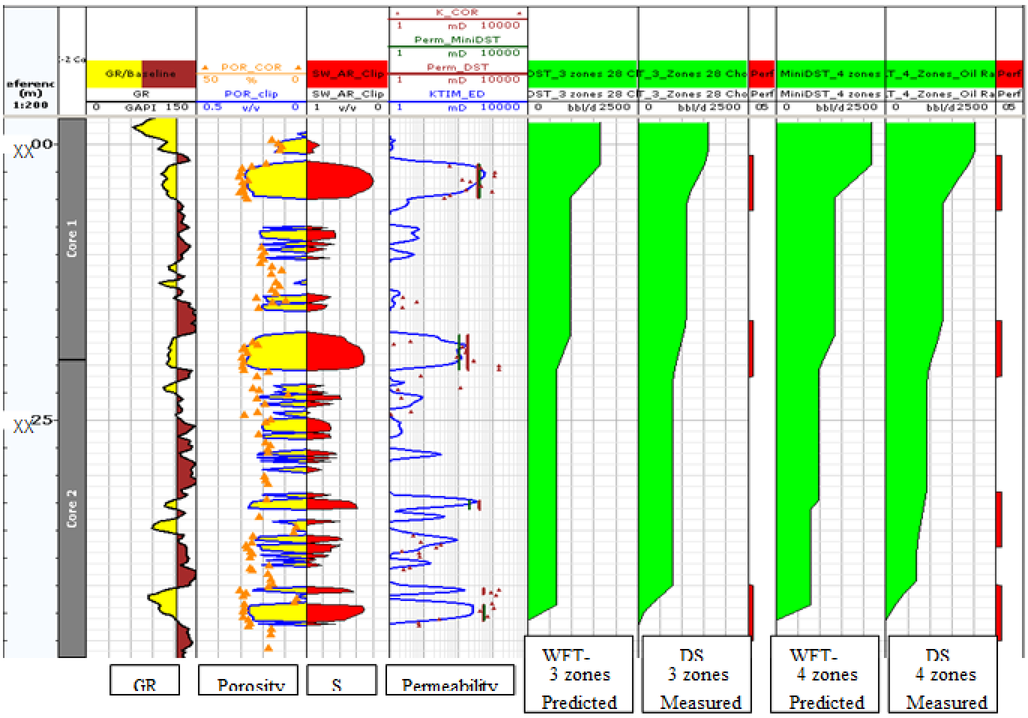


Presentation #06: **Permeability from Wireline Formation Testers : When and How to use it?**

Presenter: **Shyam Ramaswami, Petrophysicist, Shell FEAST**

Abstract:

The use of pressure transient data in the field of Formation Testing in efforts to describe productivity and permeability of reservoirs is considered mature technology, particularly when applied to data collected through production testing. The extension of this technique to data obtained using Wireline Formation Testers, where either a single probe or a straddle packer is used to propagate a pressure pulse into a reservoir, has been gaining momentum in the industry over the past decade, however the integration of these outputs with other measurements of rock and fluid data is not always straight forward. This talk presents different methods of using pressure transient data from Wireline Formation Testers such as quantitative permeability determination, identification of permeability discrepancies in homogenous clastic formations, upscaling of permeability in a complex stacked reservoir and comparison of Wireline Formation Tester and conventional well test derived permeabilities. Additionally, this talk highlights the challenges one faces while planning, acquiring and interpreting pressure transient data from Wireline Formation Testers, as well as the importance of real-time monitoring and control of data.



Presentation #07: **Advances in Transient Formation Testing and Multiphase Transport Properties**

Presenter: **Dr. Cosan Ayan, Reservoir Engineering Advisor, Schlumberger Wireline**

Abstract:

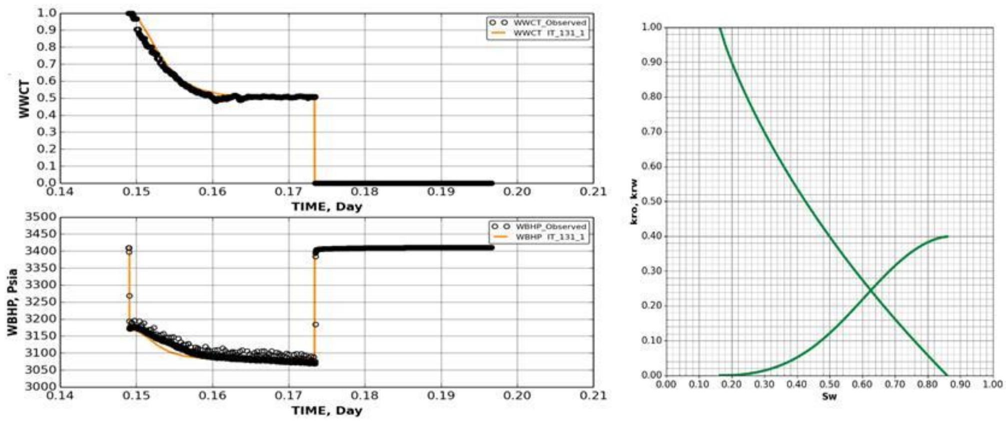
While pressure testing (pretesting) with wireline formation testers (WFT)has been around for about half a century, multi-probe transient formation testing is relatively new. While we say relatively new, this technique has been around since 1992, which is more than 20 years. This technique has been referred under multiple names, such as "mini-DST", WFT vertical interference test (VIT), Interval Pressure Transient Test (IPTT). It started with multiple single probes, then dual packer type tools became common. Today this technique has now expanded with new devices, such as Saturn 3D Radial probe™ (3DRP). A recent addition to the arsenal is the "Formation Testing While Tripping" the FTWT technique.

In addition to expanding to new hardware, existing hardware become more reliable; today days of pumpout operation is common, followed by buildups. In conjunction, interpretation methods and software also expanded, adding new models and real time capabilities. A natural extension was the application of deconvolution to formation testing transients as well.

Coupled with optical spectroscopy data, WFT transients and sampling data can also be used to estimate multiphase transport properties. This has been demonstrated a few times in the last 20 years but now, the technique is reviving with more complete representation of tool behavior. A field example of the final result is given below:

Parameter results in the optimization cycle for the 3DRP field example.

	swi	sor	korw	TIME1	SKIN	LW	EW	TW	LO	EO	TO
Optimizer Input Range	0.01 , 0.3	0.01 , 0.3	0.1 , 0.9	6 , 20	0 , 5	0.5 , 5	0.5 , 5	0.5,2.0	0.5 , 5	0.5 , 5	0.5, 2.0
Optimizer Final	0.164	0.140	0.399	7.4	1.668	2.000	1.434	1.500	1.000	1.500	0.900



The best match is highlighted for the 3DRP field example.

In this paper, we will shortly review the WFT transient testing technique; touch base on deconvolution and real-time interpretation software. We will see the FTWT and what it can bring to reservoir characterization. We will also present recent cases in which we attempt to obtain multiphase transport properties.

Presentation #08: **Permeability and Upscaling: from core and logs to the static model and dynamic simulator**

Presenter: **Roddy Irwin, Gaffney, Cline & Associates.**

Abstract:

Petrophysical relationships are commonly created at a finer scale than that which is appropriate for geocellular models and reservoir simulators. Often the algorithms that relate permeability to porosity are established at the core scale. If these algorithms are applied directly to coarser scale well log data, errors can be introduced. Moreover, their accuracy of prediction further declines if they are then applied to the geocellular and simulator grid cell scales without due consideration of the effects of scale.

The challenge is to ensure that during upscaling of permeability properties and predictive algorithms, reservoir heterogeneities and flow characteristics are preserved. This talk will identify the potential pitfalls and will highlight some best practices to ensure that appropriate upscaling techniques are applied which honour fluid flow dynamics from the core scale through to the reservoir simulator.

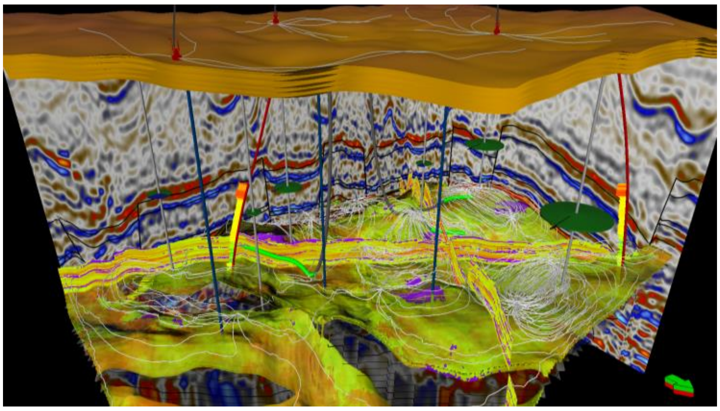
Presentation #09: **The Importance of Understanding Permeability Uncertainty for Field Development Decisions**

Presenter: **Andrej Bulat, Schlumberger Software Integrated Solutions**

Abstract:

These are interesting times for the oil & gas industry. The increasing cost and technical complexity of producing hydrocarbons drives the ongoing change in work processes for efficiency gains. Today field development decisions require more upfront studies regarding the underlying uncertainties and risks. Permeability is a key property often dictating the placement and design of field infrastructure.

This presentation will explain the importance of permeability in reservoir engineering workflows. You will see how permeability is used in modeling and upscaling, its effect on reservoir connectivity and selection of representative geological models for simulation. Further the role of permeability for optimal well placement and production management will be shown, and the significance of its regular update in history matching.



Presentation #10: **The problems of averaging permeability - do the reservoirs and fluids appreciate the problems they create for the simulator boys & girls?**

Presenter: **Professor Emeritus Richard Dawe, University of West Indies, Trinidad**

Abstract:

The modelling of reservoirs has always been a challenge. In particular the uncertainties of the geology create a myriad of geological descriptions but, even with a perfect description, the current limitations of CPU capacity cannot cope. Grid blocks are still too large and do not represent what is within the block. Fluids inside a block do not respect any averaging and will flow as they believe the local physics dictates. Upscaling always causes headaches and the physics and reality can become the casualty.

In this talk we examine the averaging problem via the well known quadrant model. We then demonstrate some complex flow patterns within 'simple' heterogeneous bead packs of lens, stripe, and quadrant. This experimental evidence may suggest the difficulties of how the essential reservoir physics may/may not be represented in reality by the simulator. Simulation of these flow patterns can be attempted but geological description also needs to be accurate for field production estimations. As the scale-up of parameters derived at the core scale to real reservoir dimensions is based on a number of assumptions, some of which may be false, this scale-up may make the derived interpretations dubious. Finally, Local Grid Refinement which is used in some simulators, has to be used with insight, otherwise increased error seen as extra dispersion can occur. The physics used to represent the transmission of fluids from block to block during displacements must be correct in order that the reservoir simulation results do not lead to gross miscalculations and wrong recovery forecasts.

The main thrust of this presentation is showing some of our visual beadpack results, with thoughts on implications for simulator gridding. The practitioner /listener is left to ponder on their significance.

Contents of talk

The complex geometry of the reservoir

Grid blocks - problems of Scale-up - averaging

Model flow - do the fluids respect the grids?

Lens, Stripes, Quadrant

Local Grid Refinement

Summary & Consequences