7th International Conference & Exposition
on Petroleum Geophysics

"HYDERABAD 2008"

P - 05

New Generation Permeability Logs

RR Tiwari
B&S Asset, ONGC, Mumbai, India, Email: rrtiwari@rediffmail.com

Summary

Permeability distribution of the rock is of utmost importance while creating a dynamic reservoir model. However, in the absence of any continuous permeability log, the input for this purpose either comes from well test or from core information or from some popular porosity-dependent transform. While the information from well test is on a large scale, the one from core is on a very small scale. Hence neither of these two gives the permeability at an intermediate scale. On the other hand, the porosity-based transforms do not take into consideration the pore size and its distribution, which play an equally important role while deciding the permeability of dynamically connected pores.

Some of the new generation tools introduced during this decade are capable of generating continuous permeability logs. For example, the dry weight percentage of different minerals from ECS, Stoneley wave travel time and attenuation from DSI* and transverse relaxation time (T_2) distribution from CMR* can well be translated into continuous permeability logs. A fairly good estimation of permeability, though not continuous, can also be had during MDT* pressure tests wherein the drawdown created to fill in the pretest chamber and the pressure buildup following the drawdown are directly linked to the mobility of the fluid. These station permeability values from MDT have been used in this work to validate / calibrate the permeability curves generated by ECS, DSI and CMR tools.*

The matrix permeability, also known as K-Lambda permeability, from ECS is based on the computation of surface to volume ratio taking into account the dry weight percentage of different minerals and their specific surface area. Whereas the specific surface areas of the commonly found minerals are known, their dry weight percentage can be computed with the help of SpectoLith program after doing spectral stripping for elemental yield. The dry weights of the minerals present in the formation have been entered into a transform suggested by Herron et al. for clastics. The constant of proportionality has been adjusted in such a way that the resultant permeability log has a good match with the permeability derived from MDT.

The other method for continuous permeability estimation is Stoneley waves from DSI wherein oscillatory pressure pulse guided by well-bore creates fluid movement into zones with effective permeability. The slowness of this type of wave is sensitive to the fluid mobility changes in the formation. Therefore, the permeability can be predicted by comparing observed slowness with a computed theoretical slowness for a formation with no fluid. The technique has been validated with MDT mobility and both of them show excellent parity.

CMR tool also gives a good indication of permeability based on some of the popular transforms and some default coefficients. The T_2 distribution basically tells about the pore body size, which in turn is related to permeability. But as in carbonates the pore to pore connectivity varies a lot and is an important determinant of permeability, the resultant permeability curve should be taken as qualitative unless calibrated. The same has been calibrated with MDT mobility.

None of the tools discussed above is employed for permeability information alone; in fact the permeability information from all the tools comes as a by-product.

Introduction

In the initial stage of the development of any oil and gas field, the petrophysical parameters of importance are porosity, hydrocarbon saturation, reservoir thickness and relative permeability of hydrocarbon with respect to irreducible water. However, as the field approaches its maturity the petrophysical parameters like residual oil saturation (ROS), capillary pressure and relative permeability of hydrocarbon with respect to water (either from the aquifer below or from water breakthrough) start attracting attention. Permeability of the formation, therefore, plays a crucial role right from the development plan to the abandonment plan of the field. However, the permeability input for such purposes either comes from the well test or from core information. Whereas the information from well test is averaged over a large section, the one from the core represents a very small section. Neither of them, therefore, gives the distribution of permeability which is essential if one intends to create a robust and realistic model of the reservoir. The popular permeability transforms, on the other hand, mostly take into account the porosity of the formation and do not consider the pore geometry and pore size distribution of the formation. These transforms may work in a clay-free non-diagenetic environment but the situation may drastically change once we deal with shaley sandstones or carbonates with vuggy porosity.

Some of the new generation tools like ECS, CMR, DSI and MDT are capable of providing reliable permeability information by virtue of high quality of data they acquire and the models we use to translate the tool data into permeability information. The fact that the permeability information from all these tools comes as a by-product and not as a main product does not in any way undermines the importance and quality of this information. In the following paragraphs we will discuss about the theory and method of estimating permeability with the help of these tools and will also demonstrate how these permeability logs match with the MDT permeability (in the absence of any core permeability), once calibrated.

Theory & Method

ECS Permeability

ECS permeability is the mineral form of K-Lambda permeability. It has been shown by different researchers that matrix permeability is inversely proportional to Archie's formation factor, F as well as surface to pore volume ratio, s/v_p, i.e.,

$$k_\lambda = \frac{z}{F^*(s/v_p)^2} = \frac{z\,\Phi^{m^*}}{(s/v_p)^2}$$

where, z is the constant of proportionality and m* is the Archie's tortuousity factor. The denominator is raised to power square for dimensional balance of the equation. The s/v_p ratio can be expressed as,

$$s/v_p = S_o * \rho_m * (1-\Phi) / \Phi$$

where S_o is specific surface area and ρ_m is the matrix density. Assuming that the specific surface area of the sediments can be constructed as a linear function of weight percentage of the minerals present and their respective specific surface areas, the above expression for k_λ can be written as

$$k_\lambda = \frac{z\,\Phi^{m^*} * \Phi^2}{\rho_m^2 * (1-\Phi)^2 * (\sum M_i S_{oi})^2}$$

Taking into account the specific surface area of different minerals, the above expression can be written as,

$$k_\lambda = \frac{z\,\Phi^4}{\rho_m^2(1-\Phi)^2\,(6W_{clay}+0.22W_{QFM}+2W_{carb}+0.1W_{pyr})^2}$$

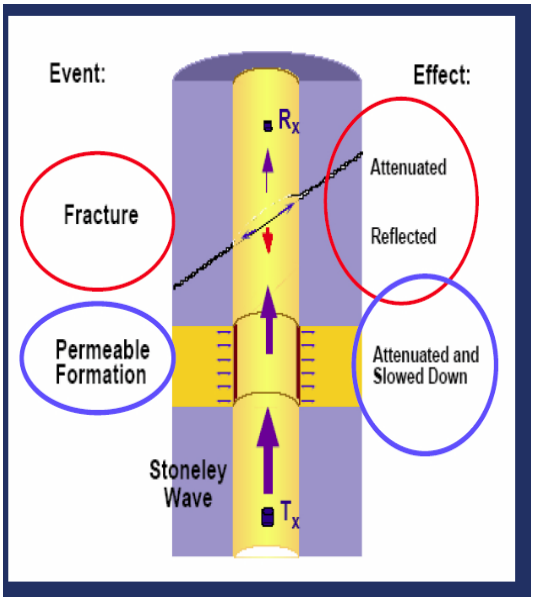
where m* has been taken as 2. The weight percentage values of different minerals are the direct output of ECS SpectroLith processing. The rest of the parameters can be provided from ELAN results. The constant z can be adjusted in such a way that it matches the core permeability. In the absence of any core information, the permeability log has been calibrated with MDT permeability. If the initial estimate is less than 100 md, the final estimate is calculated from the following equation,

$$k_\lambda = 0.037325 * k_\lambda^{1.714}$$

An example is shown in Fig-1.

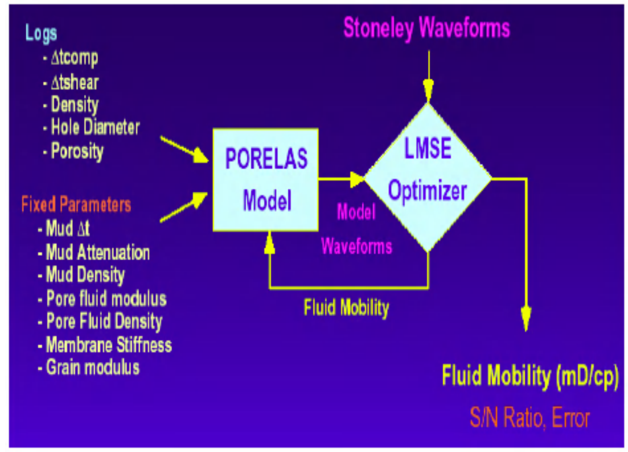
Stoneley Permeability

Stoneley wave is an interface wave between the borehole fluid and the formation which decays rapidly (exponentially) on either side of the interface. It propagates as a guided wave inside the borehole as its wavelength is smaller than or comparable with borehole dimensions. On the solid side of the interface the wave propagates through the motion of particles whereas on the liquid side the propagation is that of a pressure wave which is similar to a piston-like compression of the borehole fluid. When the borehole crosses permeable zones or permeable fractures, some fluid movement occurs between the borehole and the formation. This results in some energy loss (and hence attenuation) and a slowing down of the wave (hence increased Stoneley wave slowness). Fractures and permeable zones have different characteristics and affect the Stoneley wave in different ways. Open fractures cause a strong localized impedance contrast and result in reflection of Stoneley wave which is seen as a chevron pattern on the VDL.



Basically when a low frequency monopole pulse is transmitted it goes through the mud as a compressional wave and then gets converted into different modes. Particular combination of these modes constitutes the Stoneley interface particle motion. As already mentioned the nature of the interface motion is the coupled effect of the solid as well as the borehole fluid characteristics and it is a combination of eight independent modes comprising of incoming and outgoing compressional and shear modes in mud, mud cake and formation. Given the properties of borehole fluid, mud cake and formation it is possible to forward model the above mentioned fundamental modes and generate the Stoneley mode as a linear combination which honours the boundary conditions applicable.

The frequency used during the acquisition of Stoneley is such that the maximum influence on propagation character comes from flushed and partially invaded zones. Under this condition the coupling between the slow compressional mode and the stoneley mode is strong in the sense that the slow compressional expresses itself maximum in defining the characteristics of the Stoneley pressure wave. The slow compressional has pore fluid motion and frame motion weakly coupled and therefore we get direct coupling between the borehole fluid movement and pore fluid movement against permeable zones. Of course, this is based on the assumption that mud cake layer located between the mud and the formation is elastic and flexible and its membrane impedance is known. In that case the Stoneley propagation vector will vary with the formation permeability and the membrane impedance. The real component of this vector gives the Stoneley slowness and the imaginary component the Stoneley attenuation.



Based on the fundamental modes, the Stoneley propagation vector for the case of zero permeability can also be evaluated. After computing this, the imprint or the coupling of the slow compressional into the properties of the solution can be controlled through the formation permeability and the membrane impedance. The program controls this coupling for getting the best fit between the forward modeled Stoneley wave field and the actual Stoneley wave field. The best fit is obtained through the process of least square optimization and the main driver of the optimization is mobility.

To characterize the Stoneley wave properties we search for the axially symmetric normal modes that vary as $e^{i(k_z z-\omega t)}$ in a fluid filled cylindrical borehole surrounded by porous rock. Here, z indicates the position along the borehole axis and k_z is the axial wave vector which is a complex function of frequency. As already discussed, the solution to the problem is written as a linear combination of eight different solutions to the bulk equations of motion, each of which varies axially as $e^{i(k_z z-\omega t)}$. The relative amplitudes of these constituent solutions are determined by the requirement that the complete solution satisfies the requisite boundary conditions, of which there are eight in number. These boundary conditions yield eight linear and homogeneous equations in the eight unknown amplitudes. Therefore, a nontrivial solution can exist if and only if the determinant of the matrix of coefficients is zero. For each frequency ω the axial wave vector $k_z(\omega)$ is determined by numerically searching for the zero of that determinant. This vector can be expressed as,

$$k_z(\omega) = \omega S(\omega) + i\gamma(\omega)$$

where S and γ are the slowness and attenuation for frequency ω.

All the borehole, formation and mud cake parameters are determinable from logging measurements. To reduce the number of parameters to be determined, we fix the mud cake thickness to a small value and rely upon mud slowness to adjust for this effect.

After obtaining the dispersion curves of the Stoneley wave from the above model, the wide band waveforms are back propagated in the frequency domain. A least mean square error estimator is used to find the value of the parameter to be determined, in our case the fluid mobility, which minimizes the total error. This process uses the complex phase (both slowness and attenuation) over a wide frequency band for optimum results.

The process directly outputs the mobility of the formation fluid and does not need any calibration from any external measurement such as core permeability or MDT mobility. The mobility from this process has been compared with the MDT mobility and the result shows an excellent similarity (Fig-2).

CMR Permeability

Reservoir permeability is governed by the pressure drop across pore throats as fluids flow through them. Permeability is therefore controlled by the size of the pore throat – a variable which can be inferred from the CMR measurement of pore body size. Hence a continuous permeability log can be created out of reliable CMR measurements.

CMR derived permeability assumes that there is a well defined relationship between pore body size and pore throat size. Unfortunately this relationship is less predictable in carbonates mainly because of the presence of vugs which are often large and isolated. These vugs increase the ratio of pore body size to pore throat size but are indistinguishable on a CMR log from large intergranular pores. In such cases it may be necessary to use additional logs, such as FMI, to quantify the nonconnected pores.

Two relationships can be used to translate CMR relaxation time into permeability. These are SDR relationship

$$K_{SDR} = A\ (TCMR)^{4}\ (T_{2\log\ mean})^{2}$$

And the Timur-Coats method which is based on irreducible water volume,

$$K_{TC} = A'\ (TCMR)^{4}\ (TCMR\text{-}BFV\ /\ BFV)^{2}$$

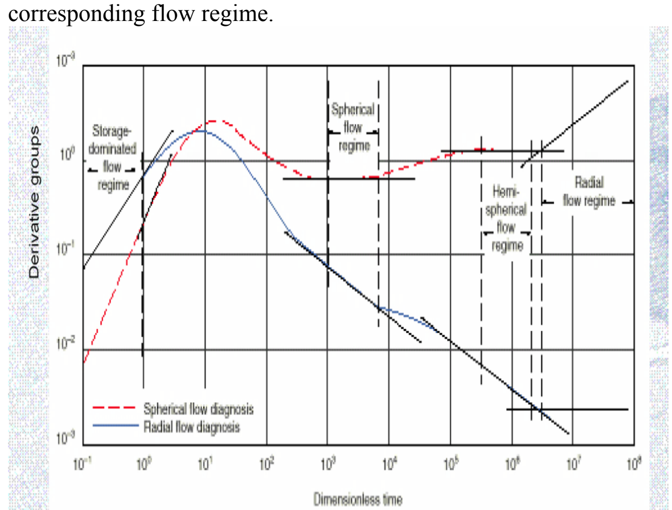
The porosity term $(TCMR)^4$ present in both the relationships is there to make adjustments from pore body size to pore throat size. The second term is related to pore size distribution and therefore permeability.

The constants A and A' can be graphically computed by plotting core derived permeability with formation porosity. In this case, in the absence of core permeability, MDT permeability has been used to adjust these constants so that the resultant permeability log matches with the MDT permeability (Fig-3).

MDT Mobility

During a pretest for measuring the formation pressure, a 20cc pretest chamber is exposed to the formation through a probe. Each pretest acquires both drawdown and buildup pressure data. The drawdown generates a localized flow in the formation with a spherical flow pattern and the drawdown pressure depends on the mobility (permeability normalized for fluid viscosity) of the flowing fluid, usually mud filtrate. The pretest chamber is full at the end of the drawdown and the buildup period starts. The buildup stabilizes when the pressure at the probe reaches the formation pressure. The time required for this buildup is essentially a function of the formation fluid mobility and the pretest volume. Thus, given the time and pressure drop during flow and following buildup period, the mobility can be computed.

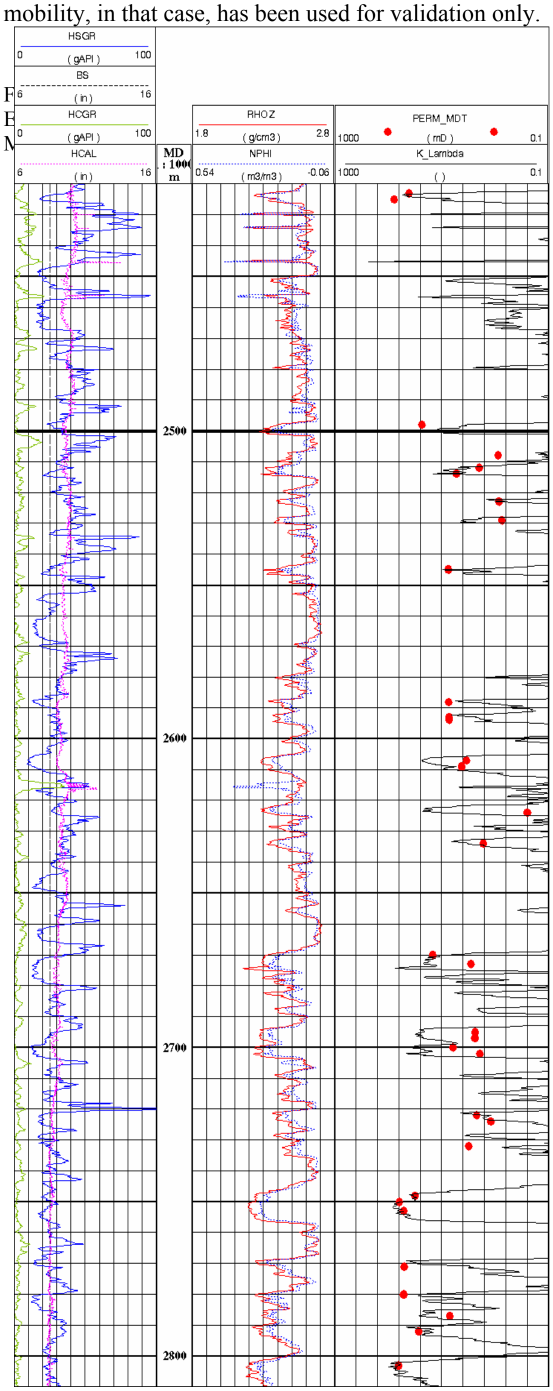
However, the drawdown has a very limited depth of investigation and always gives near well-bore mobility and also includes the skin factor. The buildup, on the other hand, can investigate up to several feet depending upon gauge resolution and length of buildup recording. During the buildup the pressure disturbance diffuses spherically until it gets a bed boundary and eventually changes into a redial flow pattern. These flow regimes can be identified by plotting the pressure derivatives with spherical and redial time functions. Once identified, the mobilities can be estimated using some specialized plots for the corresponding flow regime.



In our work, we have taken drawdown mobilities for all the stations as the flow regime of buildup mobility was not conspicuously distinguishable in majority of cases.

Examples

We present one example each of the methods discussed above. These examples are from carbonate environment of Mumbai offshore area. The resultant logs may not have an excellent match with the actual MDT permeability values because of the heterogeneities often found in carbonates. In case of CMR and ECS, since the resultant permeability curves need calibration, they may be calibrated in terms of any form of permeability – absolute, relative or effective. In this case, as MDT has been used for calibration, they are calibrated for relative permeability of mud filtrate with respect to residual saturation of formation fluid in flushed zone. Same is true for DSI Stoneley which, however, does not need any calibration from any external source. MDT mobility, in that case, has been used for validation only.



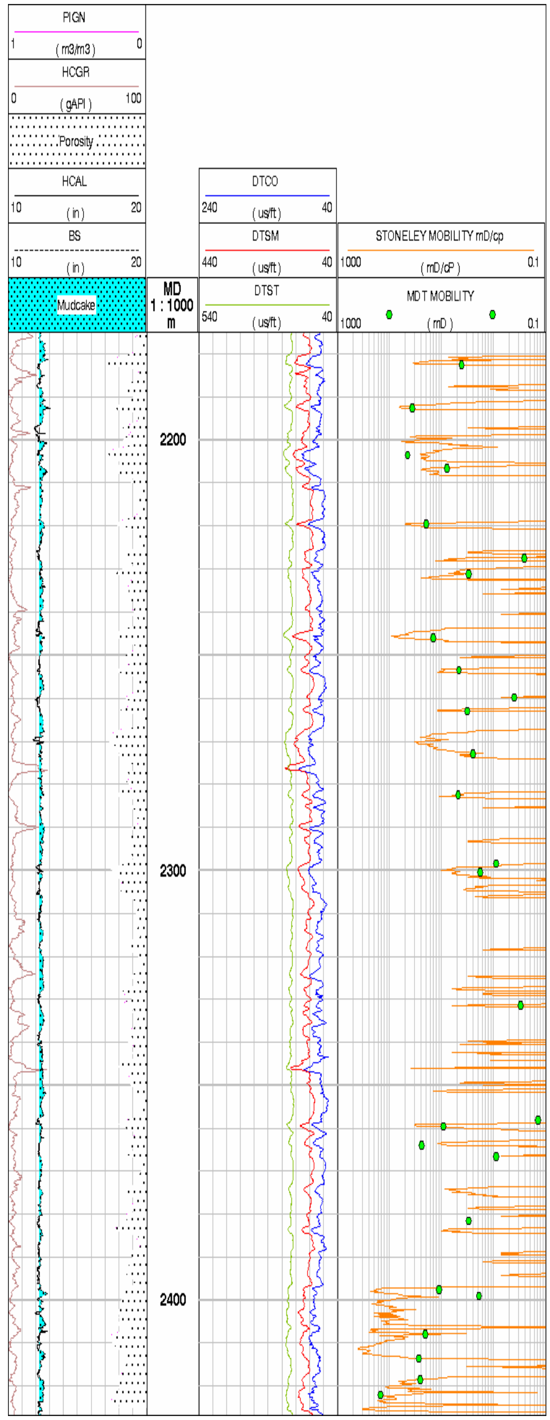


Fig-2: Example of Stoneley mobility from Porlas model. The estimated mobility has a good match with MDT mobility.

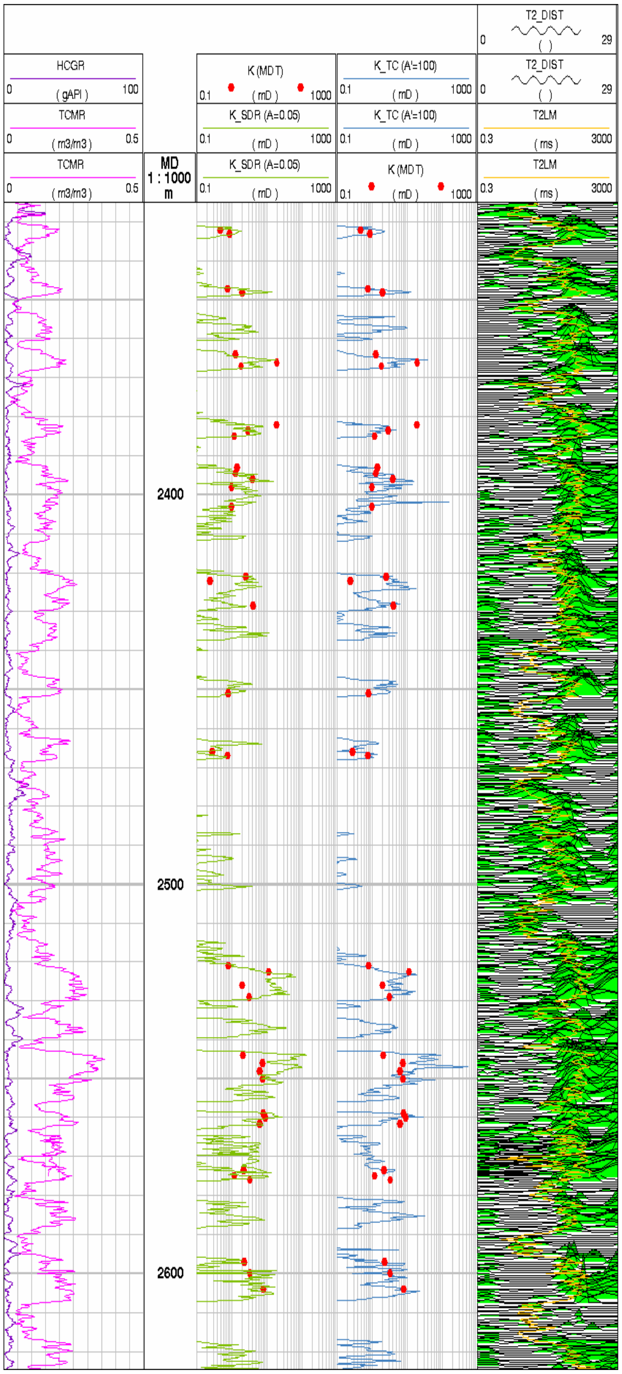


Fig-3: Emample of SDR and Timur-Coats permeability from CMR. The pre-multipliers have been adjusted such that the resultant permeability curve matches MDT permeability.

Conclusions & Limitations

- Continuous permeability curves can be generated from the tool responses of some of the new generation tools like ECS, DSI and CMR. However, these curves need calibration from core data before being used for quantitative purposes.
- In the absence of core information, the calibration of these curves can be performed with MDT mobility.
- The permeability curve from ECS and CMR can be calibrated to any form of permeability – absolute, effective or relative. With MDT mobility, they are calibrated to relative permeability of mud filtrate with respect to residual saturation of formation fluid.
- Stoneley mobility does not need any calibration. However, Stoneley mobility from Biot inversion technique is very sensitive to mud slowness, mud attenuation and pore fluid modulus and can give erroneous results if these parameters are not correctly estimated.
- Calibration with MDT mobility assumes that these mobilities are representative of the formation, which may not be the case due to near-borehole formation property alterations during drilling. Uncertainty in mobility measurements is also introduced due to formation damage during mechanical setting of the probe and also due to non-Darcy flow near the probe.

Acknowledgement

The author is thankful to ONGC Ltd. for its permission to send this paper for presentation in SPG, 2008.

References

- Middle East Well Evaluation Review, 1997
- Quantitative Formation Permeability Evaluation from Stoneley Waves, SPE paper no. 49131
- Oil Field Review, Autumn 2001
- K-Lambda: A permeability estimator for siliciclastics, 17th Annual Schlumberger Oilfield Services Symposiuum, 1997, by Herron et al.
- An Investigation of permeability, Porosity and Residual water saturation Relationships, SPWLA paper, 1968 by A Timur
- An NMR High Resolution Permeability Indicator, by A Sezginer et al.
- Real-time Petrophysical Analysis in Siliciclastics from the Integration of Spectroscopy and Triple-combo Logging, SPE paper, by Herron et al.
