INTEGRATION OF CORE, LOG AND TEST DATA TO IMPROVE THE CHARACTERISATION OF A THINLY BEDDED RESERVOIR

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ABSTRACT

Low resistivity, thinly bedded formations are typically less than a foot thick and are usually below the resolution of traditional logging tools. This paper discusses the improved characterisation of such formations by using routine and special core analysis data, wireline logs, well test data, core NMR measurements and FMI images.

A variety of water saturation models (Archie, Indonesia, Waxman-Smits, Simandoux) were used and comparison of the results demonstrated that water saturation in low resistivity sands was high (approximately 60-85%). The issue of resistivity log resolution was not investigated. The results from well testing showed that dry gas was produced from a ‘wet’ interval. Subsequent NMR analyses showed that the water saturation was high due to a large volume of clay and capillary bound fluid that was immobile during production. Capillary pressure measurements also suggested high irreducible water saturation.

INTRODUCTION

Over the last decade it has become apparent that the reservoir potential of thinly bedded sand/shale, turbiditic formations is significant. Although difficult to identify, the reservoir quality of these laminated units is often very good. However, these formations are frequently poorly characterized by traditional logs due to lack of tool resolution. They typically display low resistivity with little lithological character and can easily be interpreted as shales or water bearing sands. Traditional interpretation methods, therefore, lead to an underestimation of hydrocarbon reserves or, in extreme cases, even missing the reservoir altogether. Core data can play an important role in the characterisation of low resistivity sands.

The objective of this study was to improve the characterization of low resistivity sands. Emphasis was placed on the integration of traditional interpretation methods with new technologies.

This paper describes how special core analysis data has been integrated with traditional wireline, NMR and image data to provide an improved understanding of a finely laminated and lithologically complex reservoir. Four saturation models; Archie, Indonesia, Simandoux, and Waxman-Smits, were used to estimate Sw and the results from these have been compared and contrasted. In this case, the reservoir rock was poorly consolidated and contained a substantial amount of reactive clay material, notably smectite. Core handling

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techniques and interpretation methods were, therefore, modified accordingly. Dynamic data from well testing was also included to further refine the analysis.

This work forms the basis of an improved methodology for the evaluation of turbidite reservoirs that is being employed for other fields.

GEOLOGICAL SETTING

The field discussed in this paper is located in the Eastern Mediterranean. The reservoir sequence consists of fine to medium grained, moderate to well-sorted subfeldspathic arenites that were deposited by channelised turbidity currents in a submarine delta slope by the rapidly northward prograding delta. The overall depositional environment is interpreted as an amalgamated submarine channel/levee complex. Individual reservoir sands represent the meandering axes of single channels, or a series of coalesces or stacked channels forming a more laterally extensive "channel belt". These are elongate and usually oriented in a north south or northwest – southeast direction, down the paleo-slope.

It was established, from regional data, that well A was drilled on the edge of a channel in laminated sandstones. Based on Formation Micro Imaging (FMI) the laminated sandstones were interpreted mainly as overbank facies. To the west from the well the facies characteristics are interpreted as remaining constant. However, to the east the character of the deposits changes. The overbank deposits turn into channel complex facies. Seismic data has demonstrated that the thinly bedded sandstones become thicker towards the east. Core analysis data confirmed that they also become cleaner and their poro-perm characteristics improve with transition from laminated overbank facies to the channel core sands i.e. towards the axis of the channel.

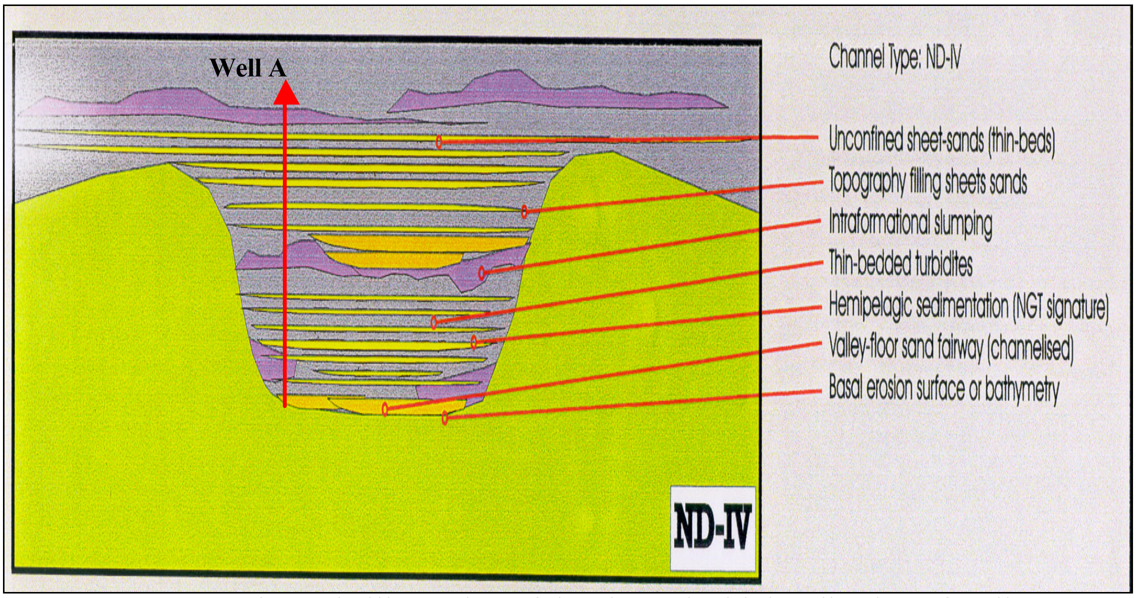

Figure 1. Schematic illustration of the channel with localization of well A

Core analysis in low resistivity formations

The first step in the core and log integration was to quality check and review the routine and special core analysis from 3 wells. This preliminary work established a number of discrepancies within the dataset. Before log interpretation could commence the inconsistencies had to be reconciled or at least understood in order to correctly assess the uncertainty.

X-ray Diffraction Analysis (XRD) revealed that all core samples contained a significant amount of clay with size fraction < 2 microns. The average clay fraction ranged from 16.3 wt.% to 38 wt.%. The main clay minerals present were mixed illite/smectite, free smectite and illite and some subsidiary kaolinite. Smectite is known to be a highly reactive clay mineral and to swell when in contact with water. This phenomenon put certain constrains on core analysis procedures and might be responsible for discrepancies that were found in some special and routine core analysis results. However no information on core preparation was available hence the data interpretation was based on assumptions about lab procedures employed.

The first of these discrepancies was in the measurement of total and effective porosity. The data indicated that effective porosity was higher than total porosity.
In order to explain this behaviour the following was assumed:

- total porosity was measured after drying in a hot oven and at which stage the bulk volume was also determined.
- The sample was also saturated with weak brine, which was displaced with gas. The expelled volume was used to calculate the effective porosity
- Re-hydration of the dried clays caused swelling and an increase in bulk volume of the plug.

It is not clear whether the bulk volume of the re-saturated sample was measured and it is assumed that the volume of the dried sample was used in all calculations thus resulting in an overestimation of effective porosity.
It is difficult to reconcile these discrepancies without detailed explanation of the laboratory procedures, which casts some doubt on the results from the core analysis.

In future work in samples with reactive clay minerals it was proposed to use high salinity brine to minimise sample swelling but also to measure sample volume prior and after brine saturation.

Comparison of Archie, Indonesia, Waxman-Smits and Simandoux saturation models

It was apparent from the logs and core material that the formation contained shaly sand. The reservoir interval studied was subdivided into: laminated sand interval, clean channel sands and base shale interval. The log interpretation compared predictions from the clean sand (Archie) and shaly sand (Indonesia, Waxman-Smits and Simandoux) saturation models.

The first uncertainty in log interpretation is always associated with evaluation of the shale volume, Vsh. In general, Vsh is usually estimated from several shale indicators and the lowest value is used (Dewan J.T, 1983). The neutron-density was chosen as the best method in this formation.

The log derived, total porosity was calculated from the density–neutron cross-plot and agreed well with core total. The effective porosity was calculated from pre-computed total porosity.

The Qv curve was calculated from the correlation derived between core-measured Qv and CMR log data.

The comparison of saturations from shaly sand and clean sand models (Indonesia, Waxman-Smits, Simandoux and Archie - Figure 2) proved that all these models behave consistently in clean sands and shales (see middle and lower part of the interval displayed in Figure 2. In low resistivity sands, the upper part of the interval (Figure 2), the Archie equation predicts total water saturation while the shaly sand models resolve the hydrocarbon saturation to various degrees. The Waxman-Smits model predicted the highest gas saturation when compared to other models.

In this case, the high irreducible water saturations appear to be attributable to low resistivity formations. The vertical resolution of the standard logging tools is approximately 2 ft. The tool response from low resistivity, laminated reservoir is averaged over this interval making it difficult to identify hydrocarbon bearing zones. The averaged response suggests a high proportion of clay when in fact the reservoir itself may consist of relatively clean, thin sands interspersed with thin shale laminae. The evaluated shaly sand models do not resolve thin beds.

Nuclear magnetic resonance

NMR is a rapid and non-destructive tool that can provide a great deal of information about the fluids saturating a rock and about a rock itself. The dataset provided for NMR scans was not extensive and had an unknown history. The core proved to be of poor quality due to its unconsolidated character, small sample dimensions and mineralogy. Previous experiments carried out in the core laboratory made the core even more difficult to handle. Nonetheless it was possible to choose 3 samples and carry out NMR scans on them. All samples contained ~20 wt% of the clay, mainly smectite.
All NMR scans were made using the Maran Low Field (2MHz) instrument, manufactured by Resonance Instruments Ltd. The measurements were taken at a temperature of 20^{o}C and at ambient pressure. All samples had been stored, wrapped up in silver foil, cling film and PTFE tape. When unwrapped they were friable and poorly consolidated. The NMR scans made on the samples "as received" showed that they were dry. Samples were subsequently sleeved using heat shrink material with the ends secured with a few layers of nylon mesh. Once sleeved, samples were saturated with ˙ ˙_h salinity brine (magnesium and potassium) using a vacuum saturator. A T2 measurement was made (Figure 3), followed by single

phase brine permeability measurement. Afterwards, the samples were cleaned with methanol (approx. 50 pore volumes) to remove brine and salts, which might have precipitated in the pore space. The samples were then dried in an oven at 70°C. The single phase gas permeability was determined.

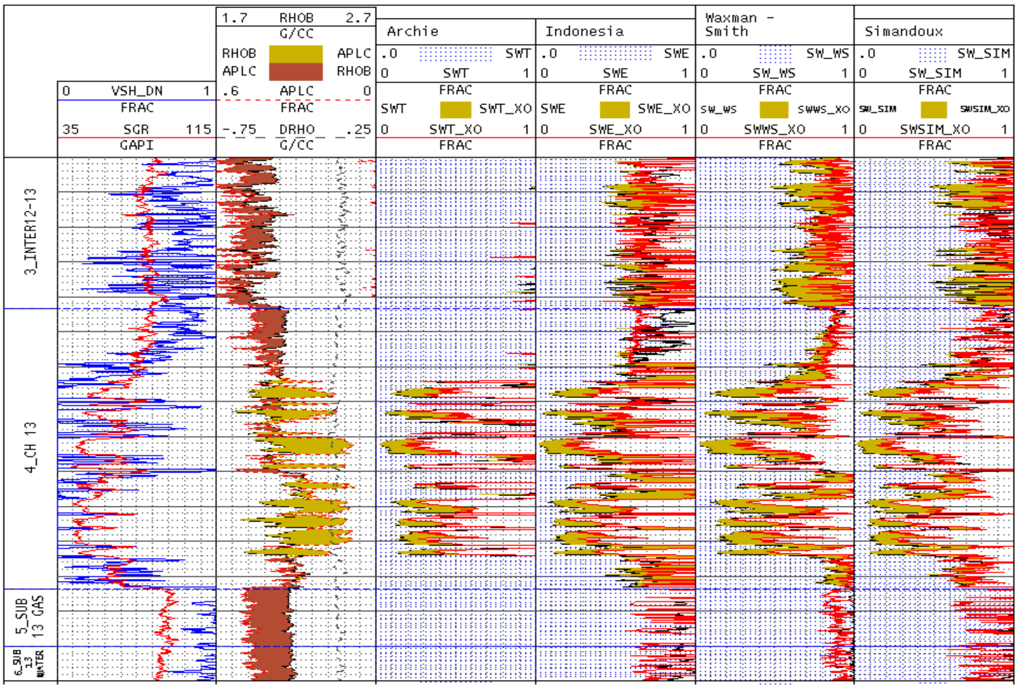

Figure 2. Comparison of saturation models

Based on T2 measurement the sample porosities were determined. The results are shown in Table 1. For comparison, the buoyancy porosity was determined and proved to be 3-4 p.u. lower than the NMR derived value. This was not entirely unexpected since the samples may not have been totally dry and could have contained some water together with some salts. The amount of water that actually entered the pore space may not be representative of the total pore volume. As discussed above, there are experimentally induced uncertainties associated with sample volume and hence porosity.

The NMR T2 distribution is a representation of the pore size distribution within the rock This pore size distribution can be interpreted to provide other petrophysical properties. For the rock studied the T2 distribution is shown in Figure 3. The large amplitude below 10 ms suggests that NMR is detecting clay-bound water. This also suggests that the samples are dominantly clay-rich. The XRD analysis suggested approximately 20 wt.% of clay but this measurement is routinely made on dry samples. The clay volume under reservoir conditions (i.e. wet) can be at least twice as much. The peak amplitude at ~1ms, which is present in all analyzed T2 distributions suggests, that the clay type does not change from sample to sample. The region between ~2-3 and ~8 ms is probably associated with clay-bound water but may also contain some capillary-bound water. The second smaller peak occurring at ~15 ms is an indicator of capillary bound water. No signal between 40 – 200 ms suggests that the late time peak, at ~500-600ms, is associated with the larger pores within sand-rich laminae. These larger pores probably control the flow. They probably contain a small amount of capillary bound water – possibly represented by a small amplitude peak at ~200ms on the T2 distribution made on partially saturated sample. This late-time peak is probably representative of free fluid in pores between 10 and 100 μm. Unfortunately, the pore distribution data from mercury injection was not available to validate the above interpretation.

To check the consistency of the results the samples were re-saturated and T2 measurements were repeated. The second round of measurements showed a slightly altered T2 distribution (Fig. 4). The most prominent peak still occurred at ~1ms. The second peak, corresponding to capillary-bound water, was smaller (samples 30 & 127) or was partially obliterated (sample 7). The late time peak was also smaller and occurred earlier than in previous T2 distributions. This may have been due to the mobilisation of fines by the methanol flushing and subsequent blocking of the pores, starting with the smallest first. It was assumed that the pore geometry was altered during the cleaning and re-saturation procedures. It may be concluded the NMR scans on the re-saturated samples are not the most reliable indicator of the pore structure. Although the T2 distributions made on re-saturated samples look slightly different they show very similar porosity values to the ones obtained from the previous NMR scans (Table 1).

The NMR scans were also used to establish an irreducible water saturation for the sample The irreducible water saturation was determined from the ratio between bound fluid volume (BFV) and pore volume. The BFV was derived from the T2 distribution by applying a T2 cut-off between clay and capillary bound and free fluid. A routinely used cut off varies between 30 to 40 ms however it is known to vary over a much wider range. In order to investigate the effect of applying different cut-offs, Sample A was desaturated on a porous plate to an irreducible water saturation. Subsequently, the T2 distribution on a partially saturated sample was measured. The cut-off was derived from the comparison of NMR scans made of the sample at 100% and at reduced water saturation. It was assessed to be 7ms (Figure 5).

The influence of the T2 cut-off on BFV and permeability was investigated by comparing results obtained using values of 30 ms and 7ms. Permeability (after J.White, 2000) showed strong dependence on T2 cut-off. The difference may reach an order of magnitude –Table 2. Based on the cut-off the ratio of BFV/PV characterizing the amount of irreducible water saturation in the sample was established (Table 2). For the samples tested, it varied between 89 and 92 % of the pore volume for cut-off equal to 30 ms and from 73 to 83% for the cut-off of 7ms.

The reduced water saturation for Sample A was also assessed by brine displacement and was calculated to be 75 % compared with the NMR value of 73%. The difference between both methods is within the reproducibility of the results. This high irreducible water saturation confirms that conventional log interpretation gives consistently high water saturation in low resistivity, thinly laminated sandstones. In terms of gas production from these thinly bedded intervals the well test result suggests that it contains water close to irreducible saturation

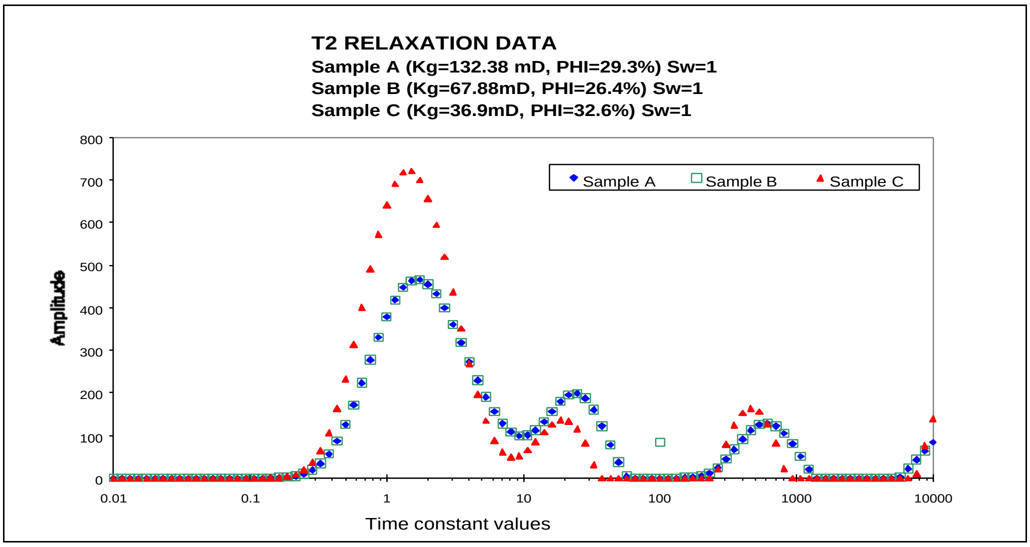

Figure 3. T2 relaxation data – first saturation

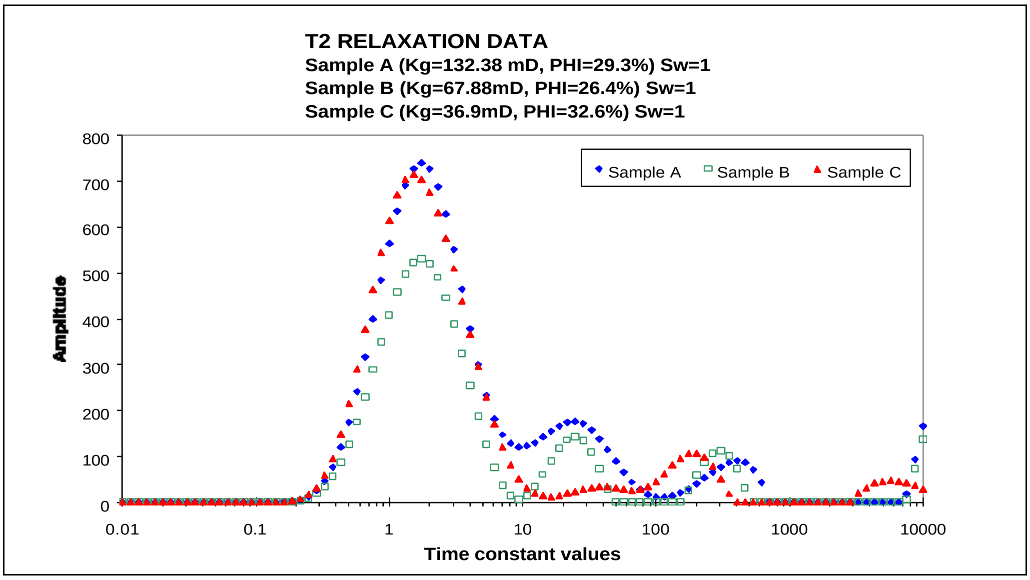

Figure 4. T2 distribution – second saturation

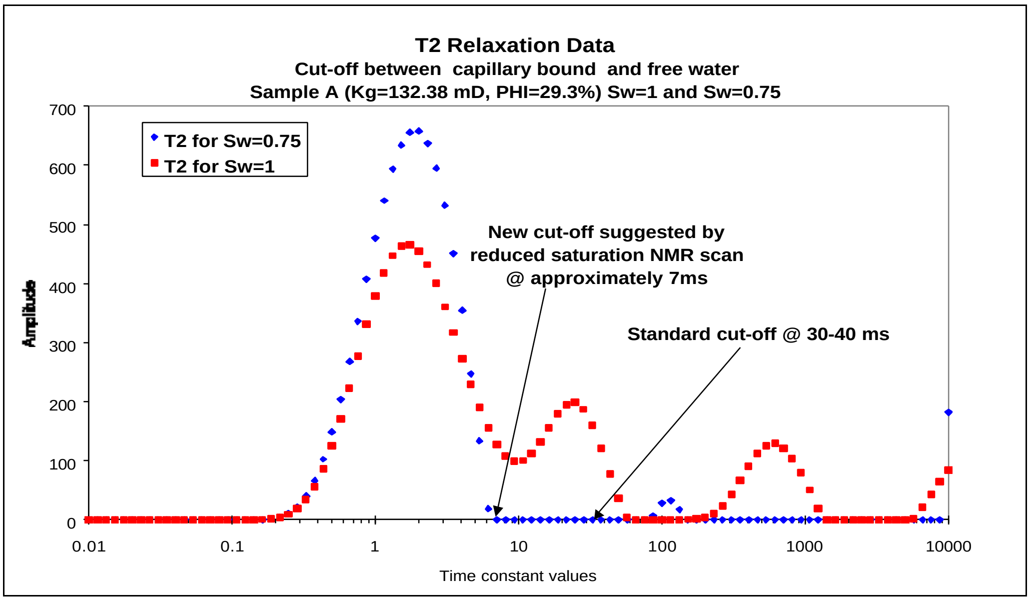

Figure 5. BFV cut off determination

Sample	NMR porosity p.u. First saturation	NMR porosity p.u. Second saturation	Dry porosity p.u.
Sample A	0.33	0.33	29.5
Sample B	0.30	0.28	26.4
Sample C	0.32	0.33	32.6

Table 1. Comparison of NMR and routine porosity data

Sample	NMR permeability (mD) Cut-off 30ms	NMR permeability (mD) Cut-off 7ms	Sw irr (%) Cut-off 30ms	Sw irr (%) Cut-off 7ms
Sample A	1.34	18.32	90	73
Sample B	1.17	10.95	89	78
Sample C	0.92	1.58	92	83

Table 2. Comparison of NMR permeability and Swirr based on various cut-offs

INTEGRATION OF WELL TEST INTERPRETATION WITH STATIC DATA

The first uncertainty in the well test interpretation was a clear determination of net pay thickness. In Well A , the 26 m thick interval of thinly laminated sands was tested. The well flowed a high quality gas at a medium rate with minor amounts of liquid.

Given the limited resolution of the conventional logging tools and their inability to resolve thin beds, a facies model was constructed from the FMI data (Fig. 6). Poro-perm characteristics for the different facies were assigned using core data. Since not all facies were cored in well A, regional data were used where necessary.

The tested interval encountered three facie-types: overbank deposits, gullies and shales. Properties for these facies were:

Overbank Facies
- Porosity range 14-38% Permeability range 0-850 mD

Gully Facies
- Porosity range 12-20% Permeability range ~0 mD

Shale Facies
- Porosity range 10-24% Permeability range 0-200 mD

The core sands present in the axial part of the channel, to the east of the tested well, had very good porosities ranging from 30% to 40% with permeabilities between 200 mD and 3 Darcies.

In terms of net pay the gullies and shale facies were classified as non-pay. It was assessed that a net to gross ratio of the overbank facies in Well A was approximately 20%. Hence the producing thickness was interpreted to be approximately 3.25–4m. Pressure build-up test interpretation was based on this net thickness value (Figure 7). The model adopted for the well test interpretation was linear composite. It was assumed that the producing well is in a homogenous reservoir, infinite in all directions but one where the reservoir changes across the linear front. It was confirmed by seismic that to the west from the well the facies did not change dramatically. However to the east there was an increase in sands thickness and permeability.
Two build-up periods were interpreted indicating that in the near well bore area the permeability was approximately 200 mD

This value was consistent with a core-derived permeability for a thinly bedded formation. The pressure data from the build-up analyses indicated that at about 220-270 feet to the east of the wellbore the permeability could increase to more than a Darcy. An increase in the sand thickness in the same direction is also probable. The results of the well test interpretation correlate well with the reservoir properties inferred from static data.

CONCLUSIONS

The low resistivity, thinly laminated formation is difficult to evaluate using standard log interpretation techniques. The limited resolution of existing logging tools coupled with the presence of the reactive clay minerals-smectite and illite made the task of formation evaluation complex. Laminated and dispersed clays are likely to be present.

Facies Associations	Thickness
OVERBANK	4 m
GULLEY	0.5 m
OVERBANK	2 m
SHALE	5 m
OVERBANK	8.5 m
GULLEY	1 m
OVERBANK	2.5 m

Figure 6. Facies model

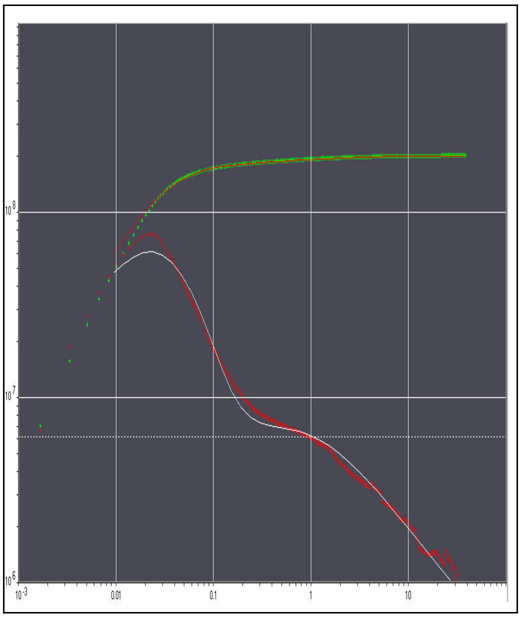

Figure 7. Well test interpretation

The fact that the clays present in the rock will swell dictates that core analysis techniques must be carefully designed. The alternative to fresh formation brine is to use high salinity brine containing additionally magnesium and potassium. The ratio between calcium, magnesium and potassium salts should be the same as in formation water, which will control the swelling most efficiently. However the electrical properties measured under these conditions may not be entirely representative of the reservoir. It is recommended to correct measurements for excess conductivity based on multiple salinity Co/Cw measurement. and use a shaly sand conductivity model rather than Archie.

The comparative study of four saturation models showed that Waxman Smits method produced highest moveable gas saturation when compared to other models. But further verification against direct core Sw measurements or capillary pressure based saturation-height analysis is needed.

It must be stressed that the average water saturation resulting from the Waxman Smits method is still substantial (approximately 60-70%). It may be concluded that this occurs due to dispersed clay minerals present in laminated formation. However the conventional resistivity logs do not resolve thin beds. More advanced logging techniques (FMI) that can resolve thin beds or resistivity modelling is recommended.

Although performed on a limited dataset, the NMR core analysis provided a valuable insight into rock internal pore structure. It was concluded, based on measured T2 distribution, that the samples were clay rich and had high irreducible water saturation that correlated well with the general trend of high water saturation obtained from log interpretation. In practical terms it means that the gas production is likely to be water free. Additionally, NMR measurements performed on desaturated samples demonstrated the requirement for a variable cut-off between clay and capillary bound and free water rather than the use of an arbitrary standard value. The data indicated that the cut off might be moved, in this particular case from a standard value of 30-40 ms to 7 ms. An extensive dataset, ideally covering all facies is required to assess the cut off change more precisely.

Core to log integration proved to be very helpful in well test interpretation. The FMI images calibrated to core data reduced the uncertainty connected with net pay evaluation.

The core data and new technologies such as NMR and FMI considerably reduced the uncertainty connected with rock characterisation and increased the accuracy of reservoir performance prediction.

Nomenclature

NMR – Nuclear Magnetic Resonance
XRD – X-ray Diffraction Analysis
F – Formation Factor
RI – Resistivity Index
Swi – Irreducible Water Saturation
Vsh – Volume of Shale
CMR – Combinable Magnetic Resonance
Qv – Quantity of Cation Exchangeable Clay present; meq/ml of pore space
T2 – Transverse Relaxation Time; ms
BFV – Bound Fluid Volume
PV – Pore Volume
FMI – Formation Micro Imaging

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