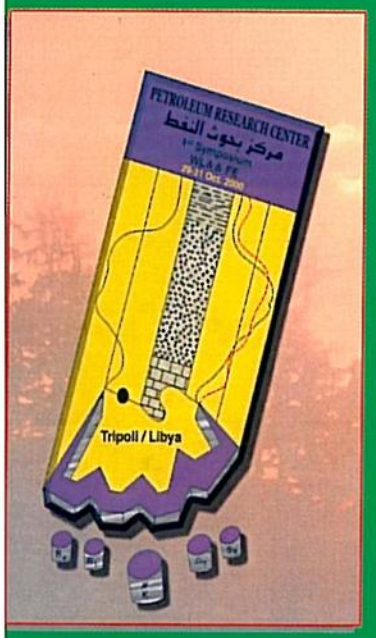


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Great Socialist People's Libyan Arab Jamahiriya

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Libya 2000 - A Review of Logging and Interpretation Problems

- a keynote lecture -

Claude Boyeldieu*

مراجعة لمشاكل تسجيل وتفسير السرود: ليبيا 2000

كلود بويلدو

من مهام موظف الشركة الخدمية الجديد عند وصوله إلى أحد الدول المنتجة للنفط هو أن يُكيّف نفسه مع الظروف الجديدة المحيطة به، وكمحلل لسرود الآبار فإن شغله الشاغل سواء كان البئر مفتوحاً أو مغلقاً: هو جيولوجية المنطقة وتقييم المكامن وتحليل السرود.

عندما وصلت أول مرة إلى ليبيا في سنة 1961 كنا في منتصف مراحل الاستكشاف. وفي الفترة ما بين عامي 1968–1970 حصلت بعض الاكتشافات النفطية الكبيرة. وتمت مراجعة المشاكل المتعلقة بطرق تفسير سرود الآبار في ليبيا بمؤتمر تقييم الآبار الذي تم عقده عام 1970، وقد أثار دهشتنا وجود اكتشافات كثيرة في ليبيا لمكامن نفطية ذات خواص فيزيائية مختلفة من نفاذية منخفضة لصخور الكوارتزايت المتحولة والمتشققة وصخور رملية وأخرى جيرية ذات نفاذية عالية، ولا ننسى كذلك الزيت المستُخرج من صخور الجرانيت.

وعلى مدى ثلاثين عاماً فإن الشكل الهندسي وجيولوجية المكمن لم يتغيرا مع أن معظم المشاكل التي مررنا بها في الستينات والسبعينات مازالت موجودة مثل المكامن المتشققة ذات الطبقات الرقيقة، أما الظروف الأخرى فقد تطورت وذلك لثلاثة أسباب رئيسة:

- تعد ليبيا في عام 2000 دولة نفطية متقدمة.
- طرق الحفر والانتاج قد تغيرت.
- طرق تسجيل وتحليل السرود وكذلك تقييم المكامن قد تحسنت كثيراً.

Abstract: *The duty of a newly arrived service company person in an oil producing country is to familiarize himself with the conditions. As a log analyst his preoccupations will concern the borehole logging, both open and cased, geology, log and reservoir evaluation. When I was first arrived in Libya, in 1961, we were in the middle of the exploration phase. Later in 1968-70 I witnessed some of the large oil discoveries. During this period a review of logging and interpretation problems in Libya was presented in Well Evaluation Conference (W.E.C) held in 1970. It was interesting to note that in Libya we faced a large inventory of reservoirs with very different petrophysical properties, from low porous fractured quartzites to traditional shaly sands or highly porous carbonates, not forgetting some oil production from granite.*

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Over the past 30 years the geology and the reservoir geometry have not changed. Most of the problems experienced in the 60's and 70's are still persisting, such as OBM log evaluation, fractured reservoirs or thin layers. However other conditions have drastically evolved for 3 main reasons:

- *In 2000 Libya is a mature oil producing country*
- *Drilling and oil production concepts have changed*
- *Logging and log/reservoir evaluation have improved dramatically.*

Libya 2000

In the 60's and early 70's we were evaluating virgin reservoirs. Now, the more acute problems are associated with saturation monitoring in cased and in open holes owing to the presence of fresh water as a result of the water injection programs. Production logging should be associated with cased hole evaluation programs. To improve oil recovery we often face the problem of re-evaluating old logs. It is usually a matter of data gathering, log analyst education and evaluation software.

Drilling and Production Concepts

Nowadays many wells are drilled using OBM mud. More and more are drilled horizontally in order to improve production efficiency. A precise evaluation of the reservoir requires the use of adapted logging tools during drilling and also the need to adapt the log interpretation to such well geometry.

New Logging Technology

More tools, less trips in the well, computerized units, onsite evaluation... The evolution of the logging technology is astonishing. Borehole imaging tends to replace the traditional dipmeter measurements, but more is still to be obtained in this domain. The most impressive progress concerns the applicatiom of Nuclear Magnetic Resonance, Reservoir saturation through casing and Formation Testing.

INTRODUCTION

Libya subsurface is known to me, as I have worked there for two periods, in the 60's from Benghazi and in the late 60's and 1970 from Tripoli. Conditions have definitely changed. Names of fields like Amal, Ad Deffa, Gialo, An Nafoorah, As Sarir and others make me remember the hours spent on the logs for quality control, interpretation and discussions with the geologists and reservoir engineers. Logs were not as numerous as they are now and with the exception of the HDT (High Resolution Dipmeter) they were only recorded on film hence the necessity to digitize them, when studies, were performed on computer. Yes, indeed, in 1968 we had a computing centre in Clamart, France, the centre which was involved in the preparation for the Well Evaluation Conference held in Libya in 1970 (Fig. 1). In those years, logging problems were mainly concerned with bad hole conditions and a few OBM drilled holes. In interpretation we had the classical shaly sands, quartzitic formations, fractures, complex

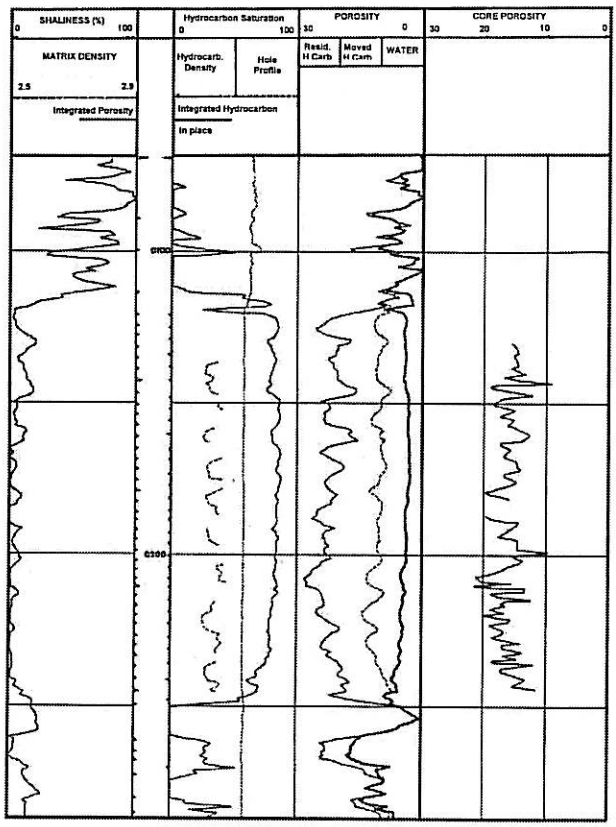


Fig. 1. 1970 Shaly sand evaluation.

lithology which included granite where hydrocarbons were present. In 1969 and 1970 the first borehole televiewer was introduced with the help of Joe Zemanek of Mobil Oil. It proved to be rather helpful to detect fractures (Fig. 2) and also, casing defects. Oil water contacts were observed behind casing with the help of the first TDT (Thermal Decay Time Log), with excellent results in Sarir. In Zelten the water movements were

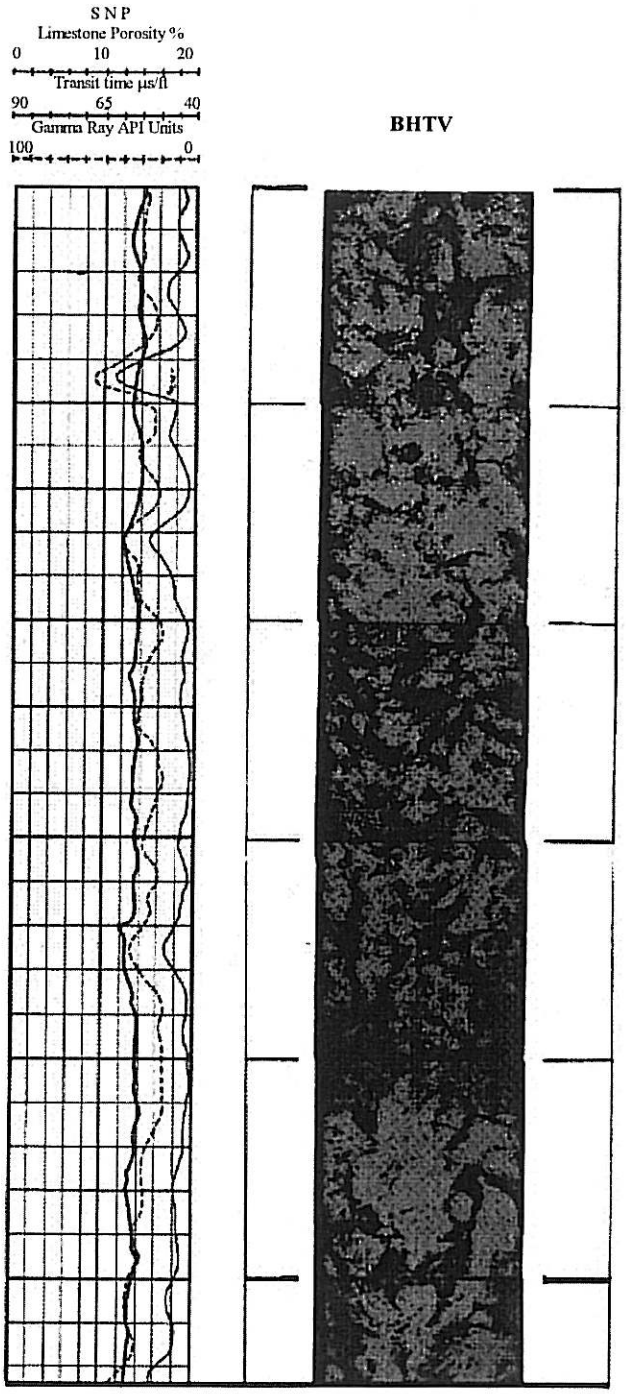


Fig. 2. Fractured hard rock.

detected using an induction tool run in observation wells cased with plastic casings.

LIBYA 2000

30 years have passed since my last assignment in Tripoli, and although I have had the opportunity to visit Libya a couple of times, I needed to refresh my memory. However, most of the fields I have known, if not all, are still producing, but conditions have drastically changed as the result of 3 main factors:

1. Libya – a Mature Oil Producing Country

Many of the producing fields are now over 30 years old. Depletion has mainly been compensated by water flooding and water injection programs, in the very early times of the production, like in Intisar Reef. The waters used can have a salinity equivalent to the one of the original interstitial water but more frequently the injected water is rather fresh. Producing zones and others will be invaded with such water and behind casing, in the pores, 3 fluids are present: the remaining hydrocarbons, the formation water and the flushing fluid. The traditional Thermal Decay Time tools have difficulty to evaluate the precise percentages of oil and water, the answer being the domain of spectral analysis using a Reservoir Saturation Tool.

When wells are drilled through zones affected by injected waters, the evaluation becomes complicated considering that in the so-called invaded zone 4 fluids are present: the remaining hydrocarbons, the "irreducible" formation water, some injected water and the mud filtrate. A solution was proposed in the late 70's[2] which asked to drill these new wells with a mud having the same resistivity as the original interstitial water (Rw) and being, when convenient, even doped with boron (Borax).

Secondary/tertiary recovery programs require often a re-evaluation of old data. Old logs will be interpreted, a task taken with some anxiety by the computing centers: difficult to collect the information, logs to be controlled for log quality before digitization, borehole corrections to be applied... Log analysts have to be re-educated to perform these tasks but also the modern software programs have to be adapted.

Formations of the Hamada field have fresh formation water, a situation often encountered in the Far East. Great care is then required in the choice of the drilling fluid and consequently in the choice of the resistivity logging tools. Depending of the ratio Rmf/Rw a laterolog or an induction device will be used but, in any case, a SP curve of good quality will have to be recorded, generally the only way to get a fair estimate of Rw.

Some of the problems met in the 60's are still present despite the great improvements in the

measurements. Thin, multilayered reservoirs are difficult to interpret owing to the diversity of logging tool characteristics mainly in their difference in vertical resolution. More difficulties are even to be expected when such reservoirs are drilled with OBM muds, missing the opportunity to run laterolog type devices or high-resolution resistivity imaging.

Low porous fractured quartzitic formations in the At Tahady field present serious difficulties in the interpretation of the logs owing to the low intergranular porosity. If the fractures are fairly well detected using borehole imaging only a range of the fracture porosity can be obtained.

To my surprise, I have heard mention of a recent rare case of very deep invasion observed in the Elephant field and also of oil production from relatively low resistivity zones, which when evaluated, show high computed water saturation incompatible with the water-free oil production.

2. Drilling and Production Concepts

Seldom used in the 60's and 70's except in special cases, OBM muds are now widely used for more drilling efficiency and borehole stability. In Libya, in 1999, 70 wells were drilled with such muds. Three domains of logging and log interpretation still suffer from the presence of a non-conductive fluid in the well bore:

- the resistivity logging of high resistive zones
- the evaluation of zones of variable and unknown Rw
- the dipmeter and resistivity imaging

However, modern induction tools will provide a satisfactory measurement of the conductivity down to 1 mmho, a value that satisfies most of the formations. Unfortunately, the SP curve cannot be recorded, a severe handicap in the case of unknown formation water. Note that, in this domain of OBM interpretation, the Electromagnetic Propagation Tool can provide an evaluation of the flushed zone and be of some help for further fluid saturation estimation. Borehole imaging is obtained from an ultrasonic device when borehole conditions allow but it has not yet the resolution obtained from resistivity imaging. Also the present OBM dipmeters have not the accuracy of the previous High Resolution Dipmeter using button electrodes.

Over the past 15 years, the number of horizontal wells (mainly offshore) has dramatically increased and the trend is irreversible. In the past we had what were called the highly deviated holes which, to be logged with traditional logging tools, required to be attached and pushed down the logging tools with the drill pipes. This was called TLC jobs (Tough Logging Conditions) and it was really tough. Nowadays, horizontal wells are logged with tools integrated into the drill collars, as close as possible to the drilling bit, tools built to give a response practically identical to the response of the conventional tools. However, some differences exist owing to a few factors: the invasion is not as deep as at the time of the open-hole logging and the borehole affects the measurements in a different way.

The logging, while drilling, has 2 main objectives: to provide the driller with a direct, nearly real time, information concerning the trajectory of his well and to give the geologists and reservoir engineers the necessary information concerning the formation parameters and the geometry of the reservoir. If these 2 objectives are well achieved with the modern fleet of LWD tools the interpretation of the data remains a difficult task, considering the fact that the tools are positioned horizontally within the layers.

Unfortunately owing to the lack of such equipment, horizontal wells drilled in several fields in Libya (An Nafoorah, Al Bouri...) are not logged today.

3. New Logging Technology

Over the past 3 decades only a few new logging concepts have been introduced in the list of measurements. The logging tools have dramatically improved in terms of reliability, accuracy, length, combinability and application. None of the tools used in the 70's had such performance. Only 2 measurements have survived: the SP curve and the natural gamma ray curve-often replaced by the natural gamma ray spectrometry. The logging logistic evolved from a logging cab full of panels, power supply, a huge

9 "galva" camera to the Platform Express truck fully computerized allowing the recording of most of the tools in one trip in the well and on-site interpretation when not in real time. The logging industry has taken advantage of all the progress made in the miniaturization of the electronic and sensors, microprocessors and data transmission over a piece of equipment which has not changed since its introduction in the early 50's (the 7 conductors steel cable). All the tools have taken advantage of these developments, in particular those recording huge quantities of data mainly due to the high sampling rate, such as the borehole imagers both resistive and acoustic, the array devices of the induction or sonic.

Some of the modern logging tools have not been introduced yet in Libya. Water saturation through casing in presence of fresh water can only be made with tools which do not rely only upon chlorine estimation like the Thermal Decay Time Log. Porosity, saturation and permeability estimations are now benefiting from the use of Nuclear Magnetism tools. And as I said before logging while drilling equipments are badly needed.

CONCLUSION

I hope and expect that the latest modern logging tools will be introduced in Libya in the near future. They will help to solve the various problems mentioned before. In the mean time engineering centers are developing and testing new logging equipment. For example, a High Resolution Laterolog Array will provide more measurements and information in highly resistive fractured formations. For OBM muds better dipmeter tools are being developed to offer an efficient dip computation and, in the future, a borehole image. Cased hole evaluation will take advantage of a cased hole formation resistivity measurement. It will show water intrusion and also detect previously missed oil-bearing zones. The observation of fluids movements between wells will be achieved with an array of electrodes placed along the casing of observation wells, and electrodes able to detect a waterfront from distances of 30 to 100 meters. Further developments are expected in logging while drilling tools such as a nuclear magnetism device.

ACKNOWLEDGEMENTS

The author wishes to thank the management of the Petroleum Research Centre in Tripoli for its kind invitation to participate to this symposium.

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Petroleum Res. J. Vol. 13 (2001); P. 7–14, 3 Figs.

Formation Evaluation Seen by a Geologist

- a keynote lecture -

Oberto Serra*

رؤية الجيولوجي لتقييم المكمن

أوبيرتو سيرا

حيث أن قياسات سرود الآبار تعتمد اعتماداً قويا على العوامل الجيولوجية، فإن أي تفسير لهذه السرود سيكون بالطبع تفسيراً جيولوجياً. فهي تمثل المصدر الأساسي للمعلومات تحت السطحية. والسؤال هو: من يستطيع أن يفسر هذه السرود أفضل من الجيولوجي؟

بالطبع فإن الجيولوجي يجب أن يعرف الأسس الفيزيائية للمعدات المستخدمة وكذلك العلاقة بين المتغيرات الفيزيائية والتفسيرات الجيولوجية. ولسوء الحظ فإن تفسير سرود الآبار قد تم إحتكاره من قبل البيتروفيزيائيين. ويؤكد هذا الرأي التسمية التي أطلقتها جمعية محللي سرود الآبار المهنيين على مجلتهم Petrophysics وتناسي مجلس إدارة هذه الجمعية أن هناك آخرون من بين المختصين بعلوم الأرض يقومون بتحليل وتفسير السرود لأغراض أخرى.

إن البيتروفيزيائيين يتعاملون مع صيغ إختبارية رياضية، وعند تركيزهم على تحليل المكامن، فإنهم غالباً ما يتناسون الأخذ في الاعتبار التكاوين الجيولوجية التي حدث فيها ذلك.

ولا يمكن حصر تقييم المكامن في إيجاد الخواص الفيزيائية للمكمن، ولكن الأهم من ذلك هو وضع المكمن في إطاره الجيولوجي وذلك لربط امتداده الجانبي وحجم المواد الهيدروكربونية والسماكة الفعلية وبيئة الترسيب والتشوهات المحلية. هذا بالتأكيد هو مهمة الجيولوجي، ويجب أن يدرك البيتروفيزيائيون أن تقييم المكامن لا يمكن تحقيقه من خلال حل المعادلات الرياضية نظراً لوجود عوامل جيولوجية متعددة تؤثر على قياسات سرود الآبار.

ولذلك فإن تفسير السرود يجب أن يكون شاملاً وكاملاً، ويجب أن يتم دمج جميع المعلومات وأصولها وطبيعتها ومقاييسها المختلفة. إضافة إلى ذلك، فإن قياسات الرسوبيات المجمعة لأجل تفسيرها لا تمثل حجم الصخور الفعلي، وإن بعضها يتأثر بظروف قاع البئر، علاوة على ذلك، فإن بعض المعلومات لا تمثل الواقع الجيولوجي خاصة عندما تكون الوحدات الترسيبية رقيقة ومتعددة.

لهذا كله فإنني أقترح إتباع الطرق الجيولوجية لتقييم المكامن ويجب علينا أن نحدد بقدر المستطاع من جميع المعلومات الواقع الجيولوجي. والذي يتلخص في الآتي:

- التعرف على كل وحدة ترسيبية.
- إيجاد الخواص الجيولوجية لتلك الوحدات وذلك لحساب الحجم والامتداد الجانبي.
- تقييم الخواص الفيزيائية لتلك المكامن.

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Abstract: *Since well log measurements depend strongly on the geological parameters, any log interpretation is by nature a geological interpretation. Logs represent a fundamental source of information in subsurface. Who can interpret them better than a geologist? Of course the geologist must know the tools physical principles and the links between physical parameters and geological attributes.*

Unfortunately, log interpretation has been "monopolized" by petrophysicists. SPWLA review's brand new title: Petrophysics, proves it and the board of directors of this society has forgotten that other geoscientists also analyse and interpret logs for other purposes!

Petrophysicists deal with empirical mathematical formulae. While focusing on reservoir analysis, they often forget to consider in which geological formation they occur.

Formation evaluation cannot be restricted to reservoir petrophysical properties determination. It is of the utmost importance to put back the reservoir in its geological context in order to link lateral extents and hydrocarbon volume to real thickness, environment and local deformations.

This is definitely a geologist's work. Petrophysicists must realize that reservoir evaluation cannot be achieved by solving equations. Too many geological parameters affect log measurements. Log interpretation must be global and total. It must integrate the whole set of data and their different origins, natures and scales. Moreover, log measurements, combined for interpretation, do not correspond to the same volume of rock and some of them are affected by borehole environment. In addition, some of the data do not represent the geological reality, especially if the units of depositions are thin and numerous.

Therefore, I propose to follow a geological approach to reservoir evaluation. We must determine, as much as possible from the whole set of data, the geological reality. This consists in:

- *recognizing each depositional unit,*
- *determining their geological setting in order to estimate their volume and lateral extent,*
- *evaluating their own physical properties.*

INTRODUCTION

Being conscious or not – it should be better to be conscious! – any log interpretation is by nature a geological interpretation as well log measurements depend fundamentally and strongly on the geological parameters (Table 1). Logging tools are the instruments of the geoscientist who studies subsurface formations. They provide one of the fundamental source of information in subsurface. As logging measurements depend on geological parameters, who can better interpret them than a geologist? You wouldn't think of a radiologist analysing medical images without knowing the anatomy! Why would you entrust your log-interpretation to a petrophysicists who wouldn't know about geology? Of course the geologist must know the physical principles of the tools and the link existing between the physical parameters and the geological attributes, as the radiologist must know the principles of the instruments that provide the images, in order to detect any bad functioning.

As previously suggested, any formation evaluation is in fact a geological interpretation. To be complete and valuable, this evaluation must not be limited to the determination of the reservoir petrophysical properties (porosity, permeability, water saturation). It must, as much as possible, allow the evaluation of its lateral extent and the hydrocarbon volumes in place. To achieve these goals it is of the utmost importance to put back the reservoir in its geological context, in other words in its depositional environment and its tectonic setting, in order to link its lateral extent to its real thickness and environment, and to the observed local deformations. This determination is based not only on well logs but also on surface and well seismic, on testing results and on core analysis. It must also include interpretation of the borehole images in order to recognize firstly each depositional unit composing the reservoir and their internal organization (texture and structure) from which the determination of the facies and the depositional environment will be possible, secondly the tectonic features that will allow the reconstruction of the structural shape through the determination of the folding, the presence of faults and fractures. This implies the study of reservoir and non-reservoir sections, the latter being often ignored by petrophysicists. The interpretation of

all these data requires as well a good geological knowledge, which petrophysicists do not necessarily have. Consequently, the interpretation will be more complete and reliable if conducted by an experienced geologist knowing well log and seismic interpretation.

GEOLOGICAL REALITY

For many petrophysicists, a reservoir is, according to the definition, "a subsurface volume of rock that has sufficient porosity and permeability to permit the accumulation of crude oil or natural gas under adequate trap conditions"[1] and, I would add, their extraction. Referring to the logs, petrophysicists consider a reservoir each depth interval that presents typical responses. In addition, they often assume that the reservoir depositional environment does not vary from one well to the other. During their study, they do not take into account the information provided by borehole images or dipmeter data. They have to realize that a reservoir is generally composed of several beds or, more precisely, units of deposition. Each unit shows variable thickness and extent as a function of its depositional environment. In other terms, a unit is composed of a vertical and lateral succession of two types of geological objects: volumes (beds, strata, layers) delimited by surfaces. What is generally called a bed may often be subdivided into several depositional units as illustrated by figure 1. In fact, the petrophysical properties of a reservoir essentially depend on the petrophysical properties of each unit that composes it. Too often, standard logs, owing to their lack of resolution, reflect imperfectly the average petrophysical properties of a bed, not the real ones of each depositional unit that composes it.

Table. 1. Relative influence of geological attributes on well logging measurements (adapated from [4]).

	Type of measurement		Parameters directly accessible	Relative importance of geological attributes on the measurement: Composition	Texture	Structure	Fluid
Electromagnetism	Resistivity		R				
	Conductivity (< or = 2 MHz)		C				
	Propagation time of an electromagnetic wave		tpl				
	Attenuation of an electromagnetic wave		eatt				
	Nuclear Magnetic Resonance		Time T2				
	Spontaneous potential		SP				
Natural radioactivity	Total natural radioactivity		GR				
	Natural gamma ray spectrometry		K, Th, U				
Interaction γ rays - rock	Bulk density		ρ_b				
	Photoelectric Index		Pe				
Interactions neutrons - rock (nucleus)	Elastic collisions	epithermal neutrons thermal neutrons neutron gamma	IH - ϕ				
	Die away of thermal neutrons		Σ				
	Spectrometry of induced γ rays - by capture of thermal neutrons - by activation		Si,Fe,Ca,H S,Gd,Ti,Cl Al				
	Spectrometry of induced γ rays by inelastic collisions of neutrons		C/O				
Acoustic	P waves (compressional)	Slowness Attenuation	t_C A_C				
	S waves (shear)	Slowness Attenuation	t_S A_S				
High resolution	Dipmeter	Curve shape Surfaces	Intern. org. + Dip				
	Borehole images	electrical acoustic	Intern. org. + Dip				
	Caliper		$d_h \cdot t_{mc}$				
	Thermometry		T°				

Petrophysicists deal with a reduced set of empirical equations to evaluate reservoir properties. You cannot expect to solve the complex geological puzzle by solving empirical equations involving only a few parameters. In fact the mathematical approach is restrictive and reducible in itself. For instance, take an arkosic sandstone. It results from granite or gneiss weak weathering. Therefore, its mineralogical composition includes quartz, microcline, plagioclases, micas, amphiboles, heavy minerals and some clay minerals, like kaolinite, plus a cement. That means that a minimum of ten minerals must be included in the lithological model. We all know that current most advanced software models cannot resolve this mineral complexity. Yet, log measurements are affected by those minerals and some other parameters as well. They contain this information.

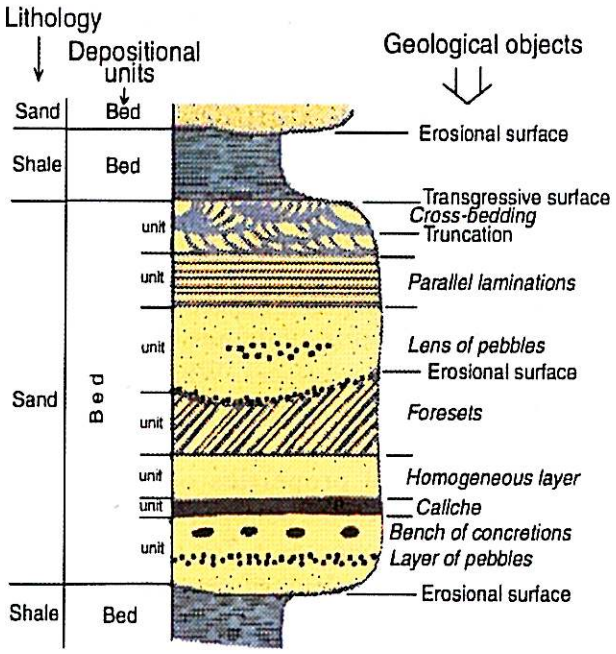


Fig. 1. Subdivision of a bed in geological objects (adapted from [2]).

Furthermore, subsurface data are of different origins (seismic, cores, logs, tests), scales (millimetres to kilometres) and natures (qualitative and quantitative). Many of them cannot be easily quantified. But the information they provide must be used to achieve a reliable interpretation.

The accuracy of interpretation will be improved by integrating the information provided by all available data (logs, images, cores, tests, pressure measurements, well seismics, surface seismic surveys, *etc.*). Accumulation of observations and real facts of different natures allows the interpreter to avoid erroneous conclusions. Any interpretation that would be based on a reduced set of information would suffer of a lack of reliability.

In the early stage of a field or basin study, integration of log and image data calibrated on core analysis, results of well and surface seismic surveys processing, guided by information provided by logs and dips, and test measurements, are a must. This will ensure firstly an accurate and reliable evaluation of the economic potential of formations, secondly a more precise description of the geometrical distribution of the depositional units absolutely necessary for the development of a field and its secondary recovery phase.

It is the reason why formation evaluation must be global and total and cannot be restricted to reservoir petrophysical properties determination. This evaluation is definitely a geologist's work.

Each depositional unit has its own petrophysical characteristics. The latter are function of its composition, its porosity and permeability which depend essentially on its texture, its internal structure, the diagenetic effects that it has undergone, and its fluid content. These characteristics result, on one hand, from the physical-chemical and environmental conditions of the setting of deposition (latitude, longitude, altitude, geologic period, energy in the medium of deposition), in other terms of its facies and depositional environment, and, on the other hand, from the evolution of these original characteristics during their geological history under diagenetic effects and tectonic stresses.

Each surface has its own transmissibility properties that both depend on its nature and origin and on the properties of the units that surround it.

INTERPRETATION MODEL

Any formation evaluation requires an interpretation model that depends on five interdependent sub-models (Fig. 2) :

- the borehole model
- the tool model
- the geological model
- the reservoir model
- the mathematical model.

GEOLOGICAL APPROACH

The geological model is the angular stone of the interpretation model as the measurements to be recorded (tool model) must be selected as a function of the problems linked to the type of formations that will be crossed. The tool model depends itself on the borehole model, and, finally, the reservoir and mathematical models that are selected for quantitative evaluation are also depending on the geological attributes of the reservoir to evaluate. The geological and reservoir models can be determined from the logs and images following a certain methodology as explained in Table 2.

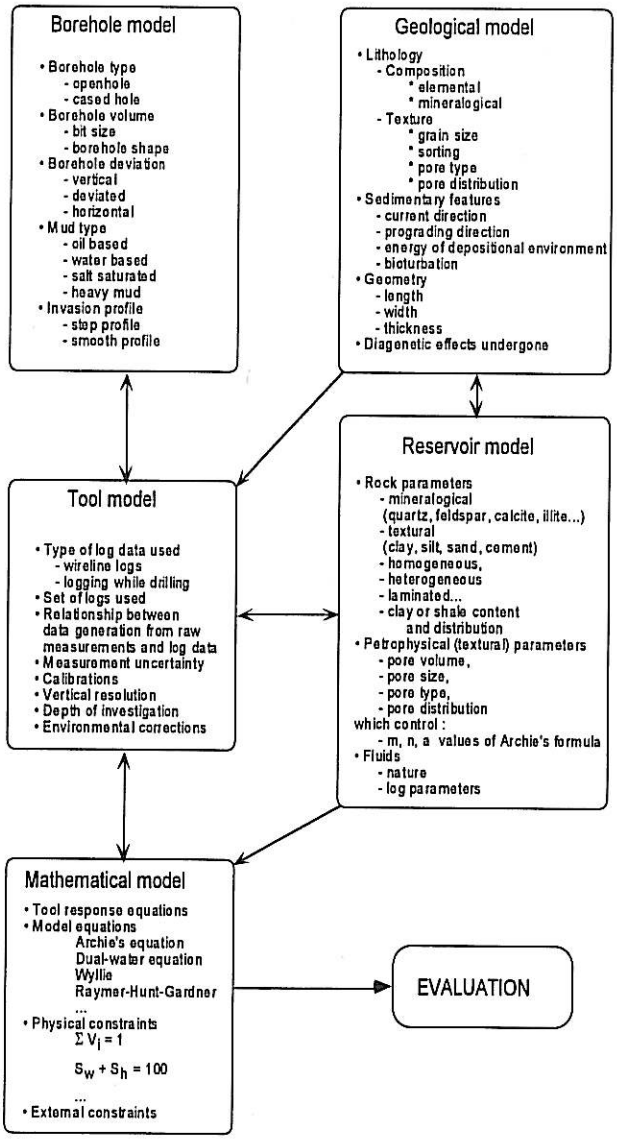
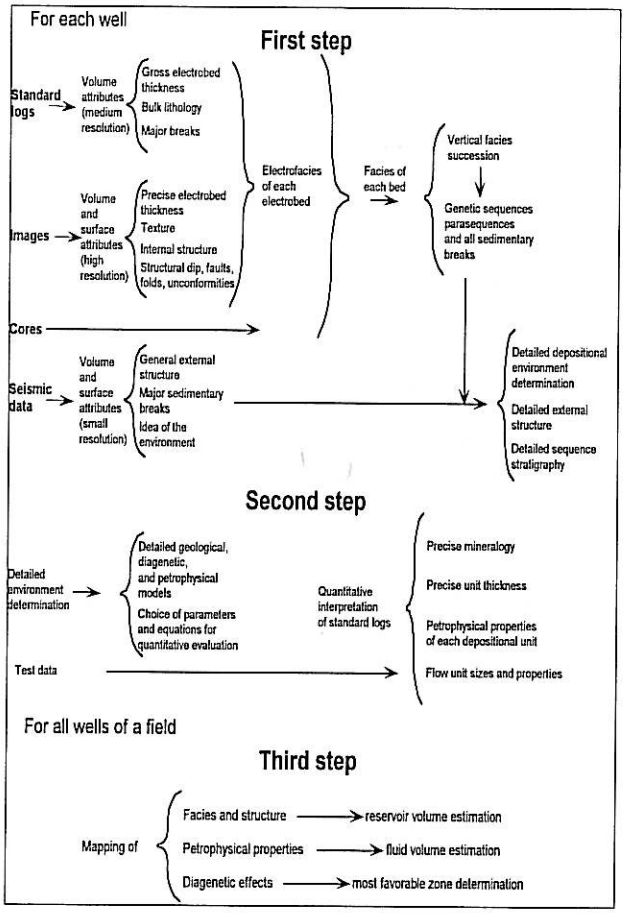


Fig. 2. The interpretation model and its five sub-models.

The "bed" notion, used in surface geology, must be adapted to subsurface and the type of logging data. It must be replace by the "electrobed" concept. An electrobed is the smallest unit that can be differentiated on logs from the surrounding units due to significant changes in logging parameters. The minimal thickness of an electrobed varies as a function of the logging type of measurement. It depends on the intrinsic and qualitative vertical resolution. In order to detect the thinnest units of deposition, imaging tools are required since they have the highest vertical resolution : approximately 1 cm. An electrobed identified on a log with lower vertical resolution may in fact be composed of several smaller units, each of them having their own petrophysical properties.

Table. 2. Interpretation methodology (modified from [31]).



Any modern reservoir interpretation must be able to recognize each depositional unit and evaluate its own properties. However, up to now, one was essentially interested in standard logs only able to detect volumes of a certain thickness. In addition, log measurements, combined for quantitative interpretation, do not represent the same volume of rock and some of them are affected by borehole environment. Lastly, due to the lack of resolution of several tools, some of the data do not represent the geological reality, especially if the units of depositions are thin and numerous. In relation to these drawbacks evaluation errors may occur.

Thanks to borehole images it is now possible to recognize each depositional unit at a very detailed scale and evaluate their own properties (Fig. 3). It is the reason why images are so interesting and fundamental in any modern reliable reservoir interpretation and formation evaluation. The additional cost, required for their acquisition, will be compensated for by saving one or more

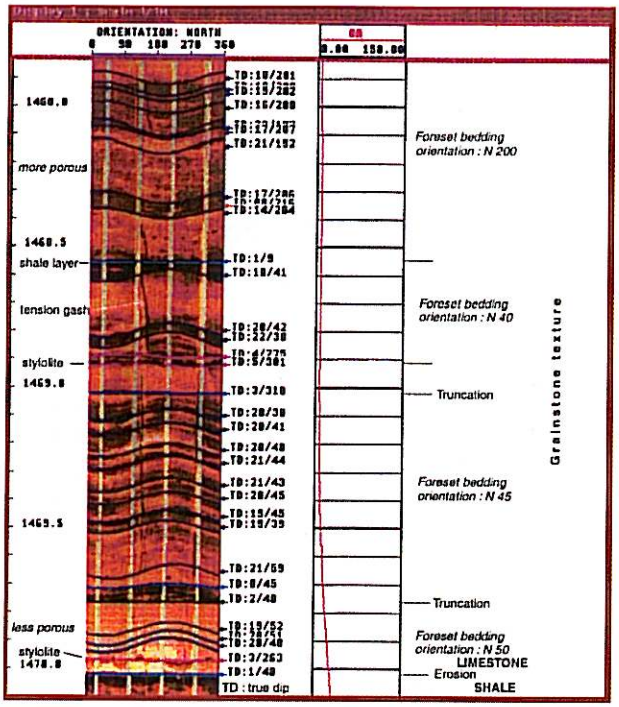


Fig. 3. Example of depositional units perfectly detected on a borehole image.

dry wells and, therefore, the information they provide will increase oil companies return.

The images allow us to:
- recognize each depositional unit,
- determine their internal organization : texture and internal structure,
- measure their real thickness,
- detect and classify each surface,
- evaluate their transmissibility properties,
- clarify the tectonic features: folds, faults, fractures,
- better understand the reservoir complexity and its dynamic behaviour.

It is also fundamental to quantify the information the borehole images provide (Table 3).

Geological interpretation of well logs requires the same type of work as studies of outcrops or cores (Table 4). As logs strongly depend on geological parameters, detailed and precise observation and description of events seen on logs and images, comparison with previous studies, interpretation based on experience, and prediction must be also the successive steps of geoscientists working on subsurface data.

As previously mentioned, any log interpretation is by nature a geological interpretation. The goal of the geological approach of well log interpretation is to convert the logging data into geological attributes. This requires an interpreter who knows both "languages".

Thus, recognizing each depositional unit crossed by a well and extracting information related to its lithology, composition, texture, structure (sedimentary and tectonic), thickness, geometry, diagenetic effects and reservoir characteristics, is the main goal of geological interpretation of well logs, images and dip data (Table 2).

Characterizing these geological attributes assists geologists in the description of the facies, genetic sequence, depositional environment, types of traps and stratigraphy. Based on these data and the other information provided by well and surface seismic, and tests, they will make a more reliable

Table 3: Quantitative borehole image analysis (adapted from [5]).

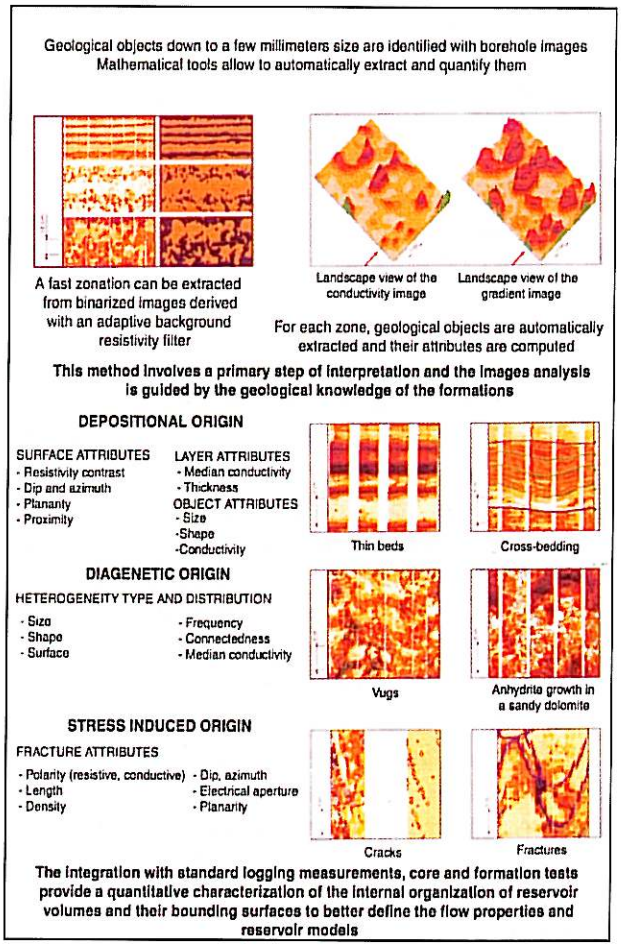
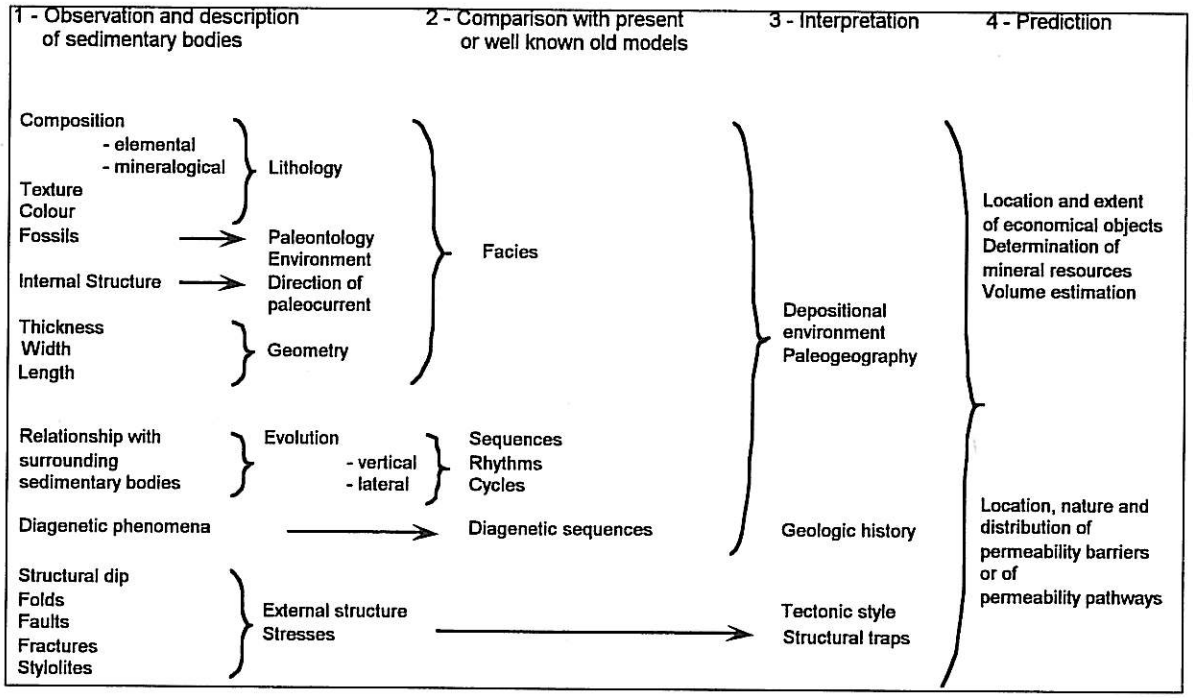


Table 4. Geologist's work to apply to well log data.



volume evaluation. In addition, from this information, reservoir engineers can determine the presence of permeability pathways or barriers and reservoir flow properties, allowing them to better determine the scheme of the field development and the calculation of the net pay.

As one can understand, the study of any formation starts with the determination of the lithology of each unit composing it, that is, its mineral composition and its texture as a whole. This first step requires a multiple crossplot and histogram analysis of standard log data for an accurate composition determination. Analysis of borehole images and nuclear magnetic resonance data will provide textural information. This study carries on with determination of the sedimentary features, from borehole images, which will inform us about the energy and biological activity in the medium of deposition, therefore about facies and the depositional environment through the analysis of the facies succession or sequence. This study will be completed by the determination of the transformations (diagenesis) and deformations (tectonics) undergone by the formations since their deposition.

Applying this approach to each well of a field will considerably improve the perception of your field. Data, provided by the analysis of each well, are the basic elements for a good and accurate mapping.

CONCLUSION

Formation evaluation requires more than well log and petrophysical knowledge. Being accurate, reliable and economic requires a geological approach. The latter should identify each depositional unit composing a reservoir and evaluate its actual properties. These units must be integrated in the geological setting (depositional environment and tectonic feature) in order to estimate their volume and extent. Due to their very high vertical resolution, images are fundamental to reach those goals. It is the reason why formation evaluation should be the responsibility of geologists knowing about the tool physics and the links existing between log parameters and geological attributes. Petrophysicists should exploit image information. Geologists should keep an eye on standard logs while interpreting images.

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Petroleum Res. J. Vol. 13 (2001): P. 15–22, 6 Figs.

The Future of Petrophysics in Reservoir Description
– *a keynote lecture* –

E. R. (Ross) Crain*

مستقبل البيتروفيزياء في دراسة وصف المكمن

روس كرين

الطفرة التي حدثت في طرق تحليل تسجيلات الآبار على مدى سبعين سنة خلت مبهرة وساحرة، حيث نستطيع أن نتعلم الكثير من متابعة هذه التغييرات سواء التدريجي منها أو التي حدثت بقفزات نوعية مفاجئة إلى الأمام.

إنه من السهل نسبياً التنبؤ بأي تغيير يحدث تدريجياً، ولكن الشخص المحظوظ فقط هو الذي يستطيع أن يتنبأ بالتقدم الكبير الذي سوف يحدث في مجال التحليل البيتروفيزيائي.

من الكلمات الرنانة التي سوف يكون لها صدى في المستقبل القريب في مجال علم البيتروفيزياء هي التصوير والتباين والتكامل. وهناك كلمة رنانة مازالت تتردد على مسامعنا بالرغم من قلة نجاحها وهي كلمة الذكاء الاصطناعي.

Exploration, development, and exploitation of oil, gas, and minerals requires "Petrophysics First" — it's an essential ingredient in any recipe for success. Petrophysics is the central core upon which all other geosciences depend.

Abstract: *The evolution of log analysis methods over the past seventy years is a fascinating and illuminating subject. We can learn a great deal by observing the gradual changes, as well as the sudden leaps forward that have occurred. It is, of course, fairly easy to predict gradual changes, but only the lucky person could predict the next great advance in petrophysical analysis. The major buzzwords of the near future are imaging, resolution, and integration. A buzzword from the past, artificial intelligence, still haunts us with its lack of success.*

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INTRODUCTION

The perpetual evolution of logging tools to improve data quality, signal to noise ratio, bed resolution, and depth of investigation demonstrate the gradual, almost un-noticed, changes in our industry (Fig. 1). This will no doubt continue – but how far can we go, or want to go, is an open question. We may already record more data than we can conveniently use. The question really is "Is it the right data to give the answers we need?"

The introduction of digital image logs and signal processing theory to log data are dramatic improvements that have fundamentally altered how we use logs, for example in quantifying fracture porosity and intensity or in evaluating depositional environment. What could be the next great leap is not at all clear. We have exhausted most of the available frequencies of the electromagnetic spectrum (except maybe the infrared) and have tested most physical principles.

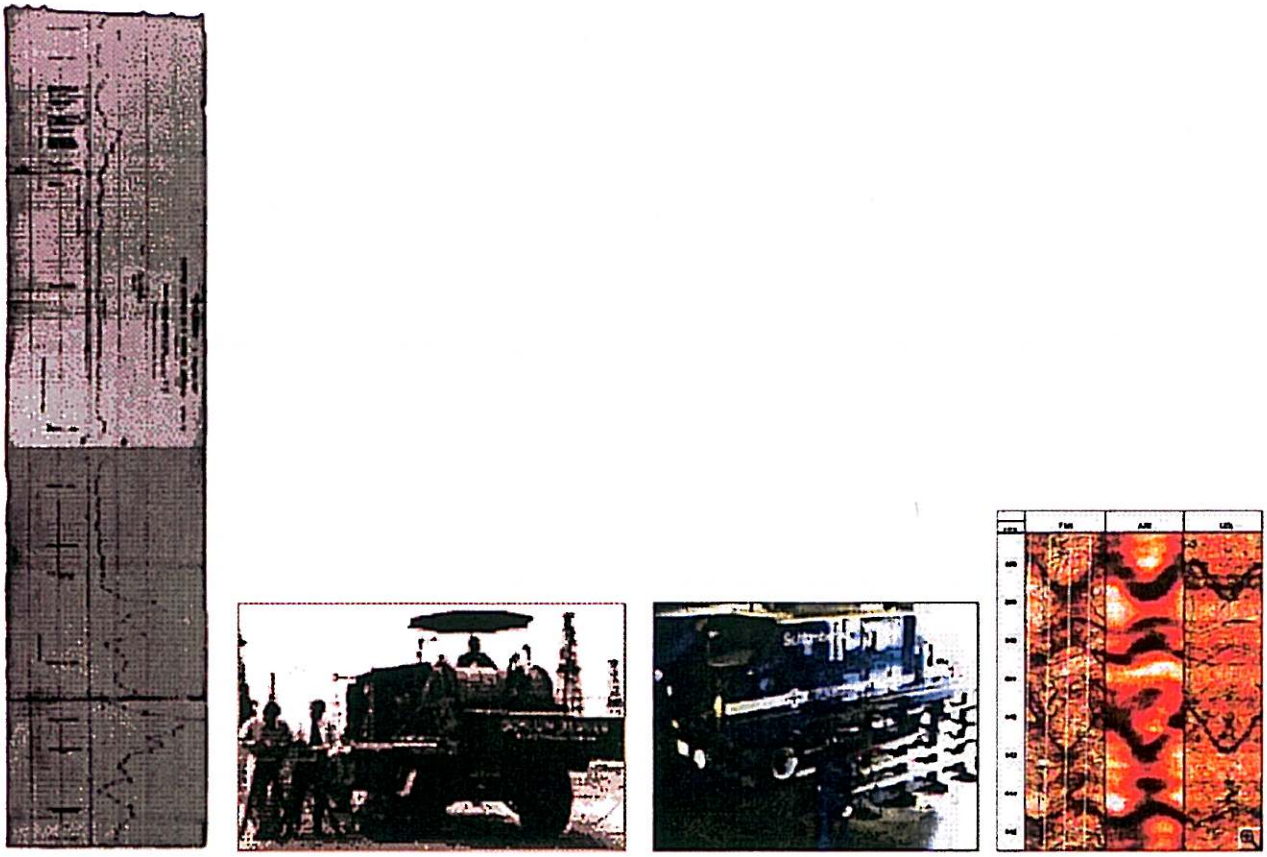


Fig. 1. Evolution – First ES log, first logging truck, modern truck, modern image log.

We have come a long way since the Schlumberger brothers put the first electrical log onto paper in 1927.

The incredible and unpredictable growth of other technologies outside our industry also has had dramatic effects. Low-cost high-speed computers, powerful spreadsheet and graphics software, satellite data transmission, and group work via local area networks or the Internet have changed the way we do our work. The massive increase in data quantity brought about by these technologies threatens to overwhelm us, since training, corporate infrastructure, and management style can barely keep up. How much faster can computers run ever more complicated software with ever larger data sets?

To give you a sense of the progress in computer-aided log analysis, I wrote my first program in 1963 on an IBM 1401 computer to solve mineralogy and ore grade in the potash fields in Saskatchewan. The computer filled a room the size of an assembly hall and the program was about 100 lines long. Later, I programmed a desk-sized computer (an IBM 1130) then more room sized beasts (EMR 6050 and CDC 3300). In early 1976, I recognized the need to pursue a small portable solution, and after evaluating several rack mounted industrial machines, I settled on a desktop calculator/computer – the HP 9825. This became the first commercial log analysis system on a desktop - LOG/MATE – five years before IBM "invented" the PC. By the way, the original; HP 9825 had only 4 Kilobytes of memory and the floppy disc held only 256 K. It cost 10 times more than today's 500 MHz machine with 32MB memory and 10GB hard drive! We have clearly made progress here, too.

IMAGES

So lets take a look at what is new and developing in our field that will benefit the oil and gas industry. Three buzzwords summarize the current state of the art in well log analysis - imaging, resolution, and integration. Lets look at these in turn.

Two logs provide a more or less complete image of the rock on the wall of the wellbore. One is the formation micro-scanner or micro-imaging

log, a super-micro, multi-electrode, multi-pad resistivity log, an offshoot of the dipmeter tool. The log appears similar to a photograph; low resistivity is shaded a dark colour, high resistivity is white. The shading between colours is cunningly chosen so that stratigraphic features can be seen, usually with better resolution than can be seen with the naked eye on real cores. Fractures and bedding planes, along with their dip angle and orientation, are readily identified. Image enhancement software similar to that used for air photos can be applied to help bring out subtle detail.

This log also leads in the resolution category – it can visualize fractures of only a few microns in width. Further numerical processing leads to quantitative assessment of fracture intensity, fracture aperture, and fracture porosity. These results emphatically debunk much "conventional wisdom" regarding fracture aperture and porosity.

The second tool that gives a real image log is the acoustic imager, often called a televiewer log. It uses a rotating head that emits and receives an acoustic signal. Both sound amplitude and sound traveltime are recorded, giving images proportional to acoustic impedance and borehole diameter respectively. Resolution is lower than the micro-scanner, although most significant bedding events and fractures can be seen in well consolidated formations. The log can be enhanced in image processing software.

To capitalize on the imaging concept, newer versions of the induction log, laterolog, and sonic log are presented in an image format as well as the usual wiggly curve format. The resistivity log image from the azimuthal resistivity log (a form of laterolog) is a coarser resistivity image similar in appearance to the micro-scanner. The azimuthal resistivities are very helpful in horizontal wells as curves looking upward into shale or tight cap rock or downward into a water zone can be isolated from the horizontally aimed curves.

The array induction log presents 5 resistivity curves of 5 different depths of investigation, as well as a coloured map of these values. This aids interpretation of invasion profiles. The array sonic log offers the usual three acoustic log curves, recorded at a multiplicity of spacings if desired, as well as a colour image of acoustic wavetrains. This allows visualization of the changes in amplitude and arrival time of the three acoustic waves and emphasizes interference patterns that indicate fractures.

Where can image logs go in the future? I hope "everywhere"! To do this, logging speed will have to increase and costs will have to drop. An article in Hart's E&P magazine states that one-third of the world's oil is locked up in low-resistivity laminated shaly sands. The high resolution of the micro-scanner and televiewer are the only logging tools available to determine net sand in this environment (Fig. 2).

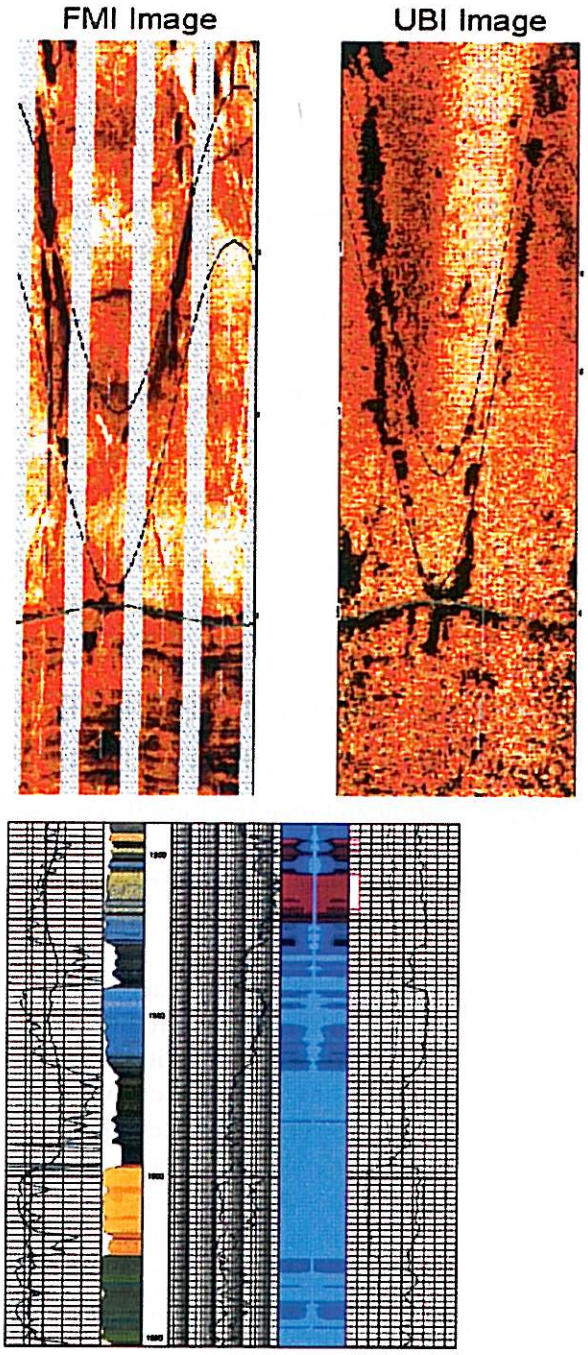


Fig. 2. Image logs – microscanner, televiewer, resistivity (saturation profile).

Look forward to this revolution and be prepared to pay the price for logging, processing, and interpretation that comes with the huge data volumes.

RESOLUTION

The last three tools described above also qualify in the thin-bed resolution sweepstakes, as they attempt to resolve beds to about 1/3 the thickness of previous tools. Combined with thin bed processing of the newer density, neutron, and gamma ray logs, we are now able to obtain more accurate porosity and water saturation in beds as thin as one or two feet instead of the more usual three to six feet. Unfortunately, little can be done for older logs that already exist in our file cabinets. The thin bed processing available today requires high density digital recording and this cannot be extracted from earlier data files or paper logs.

Unfortunately, high resolution logs look noisy (Fig. 3). Many are filtered "to look nice" – this is a tremendous waste of data. In 1967, I delivered some of the first deconvolved seismic sections in Canada to a client. He was horrified because the data looked so noisy. Where would seismic processing be today without deconvolution? I have always been amazed at how slow the well logging companies have been in applying decon to log curves. Now, if we could just get them to square up the bed boundaries!

High resolution and imaging logs also require excellent borehole conditions. Management must ensure that drilling and mud engineers are part of the team.

These logs provide more megabytes of data than ever before. Fortunately computer speed, memory size, and data storage capacity of modern desktop computers have kept pace with this development. Hardware costs are much lower than fifteen years ago. However, log analysis software costs are higher than ever, partly because the software does more than it ever did and partly because we demand such attractive screen and printer images. The larger integrated software packages are ill-suited for casual users, so there is still a strong need for small easy-to-use packages.

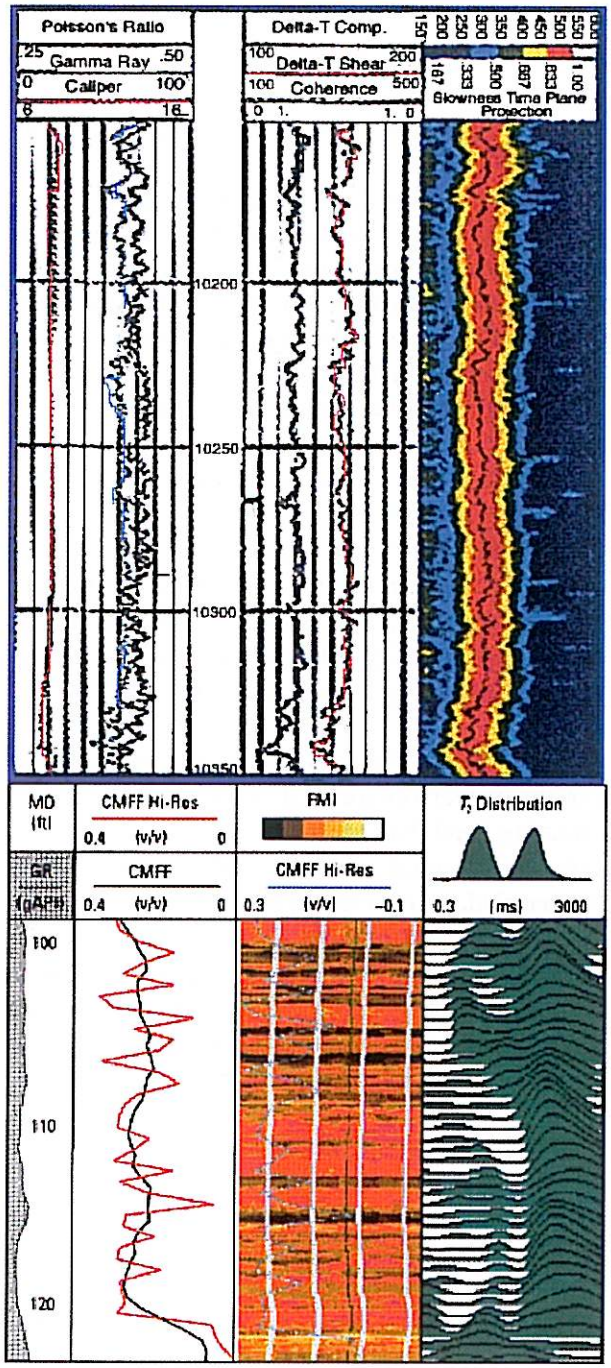


Fig. 3. High resolution – sonic wavetrain, microscanner, nuclear magnetic resomance.

Lower borehole signals, stronger signal sources, more sensitive receivers, and signal summation techniques will continue to improve resolution at a steady pace.

INTEGRATION

Integration means the cooperation and interchange of ideas, data, and results between the

various geoscience disciplines involved in a pool study or reservoir simulation. Integration means that all team members have a common understanding of what the logs and log analysis indicate. Feedback between each group forces iteration and refinement of all results.

I am still asked to review projects where the log analysis has not been compared to core analysis, well performance, or sample description! I call this type of review a "Forensic Log Analysis" – it usually involves an autopsy, or at least major surgury, to find out what went wrong. Recomputation is inevitable when log analysis is done in isolation from the other disciplines. There is no point in performing a "Blind" log analysis; this is merely data processing, without ground truth control. As some of you may know, I am legally blind, so maybe that is why I am so sensitive about this issue.

Integrated projects (Fig. 4) require an extraordinary effort in communication between team participants. Many professionals are not good communicators – we talk a good line but we don't listen well. Turf wars, ego, and seniority must be put aside. Team leaders must be adept at locating barriers to good communication. Team members must be willing to give up some independence in order to give and receive the knowledge needed for a successful project. This is never easy and I predict that there will still be many reservoir description failures caused by poor communication, not by lack of data or lack of effort.

Integrated exploration, development, and simulation software is readily available. This helps to share data and results, but does little to help share understanding unless those good communication skills are present.

Another form of integration is also taking place – corporate merger and acquisition by both

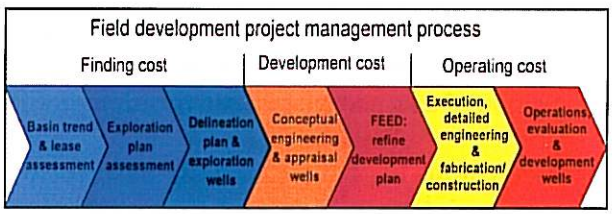


Fig. 4. Integration – project planning and implementation.

logging service companies and oil exploration companies. The three major well logging service companies now have most field services (logging, testing, cementing, etc) tied up under one roof, and have added geophysics, geology, engineering, simulation, production, and management services and software to offer one-stop shopping for the resource owner. They are now offering to run complete oil field operations from discovery, through production, to field abandonment.

It will take a major change on the part of the resource owner to monitor the performance of such a service. Instead of doing the work in-house, they will have to check and monitor others and request changes or improvements in performance. These are roles that many professionals are not ready for, so training and corporate infrastructure will have to change dramatically. The changes will have to be made well before such contracts are given out. Unless a resource owner is ready for contract development, I predict some very unhappy scenarios.

Finally, we should mention the Internet as an integrating as well as a liberating force. Databases are more easily accessible, results and reports can be transferred by email, and much work can be done away from the corporate office environment. Soon, major application software and technical learning centers will be widely available on the Net. I currently receive and deliver the vast majority of my work over the Internet. Although it is always nice to have face-to-face meetings with clients and co-workers, it is not necessary to over do it. Many professionals complain that they spend too much time in meetings. Group work or consulting via the Internet reduces the need for many meetings.

Electronic mail beats "telephone tag" and gives a permanent record of what was really said. I see a great future for remote group work. The only perceived snags are data security and loss of control over employees, but these are capable of solution with a little effort.

ODDS AND ENDS

There are other areas of petrophysics where change will certainly occur. Controversy still rages over the best water saturation method. The

ultimate water saturation equation has yet to be presented. Maybe some one in this audience will develop the perfect equation.

The nuclear magnetic resonance log (Fig. 5) dominates the technical papers submitted at conferences. After 30 years of development, the tool is just reaching adulthood. Customer resistance to previous hyperbole will gradually disappear. However, the small rock volume seen by the tool will continue to make it difficult to integrate this data with conventional logs. Some people see this tool as a panacea for all that ails conventional log analysis. This just isn't true. For example, a claim is made that the NMR porosities are independent of lithology, yet the T2 cutoffs that determine porosity vary with lithology.

Geostatistics to predict petrophysical rock properties away from the well bore is growing in popularity. Good software exists and some successes have been published. Further integration

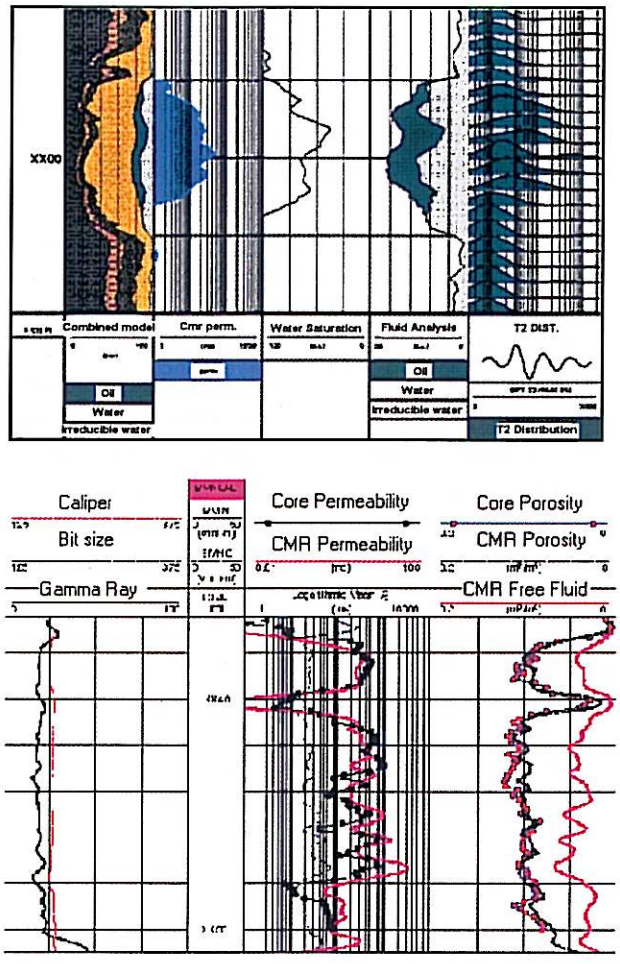


Fig. 5. NMR – pay in high SW environment, porosity and permeability vs core.

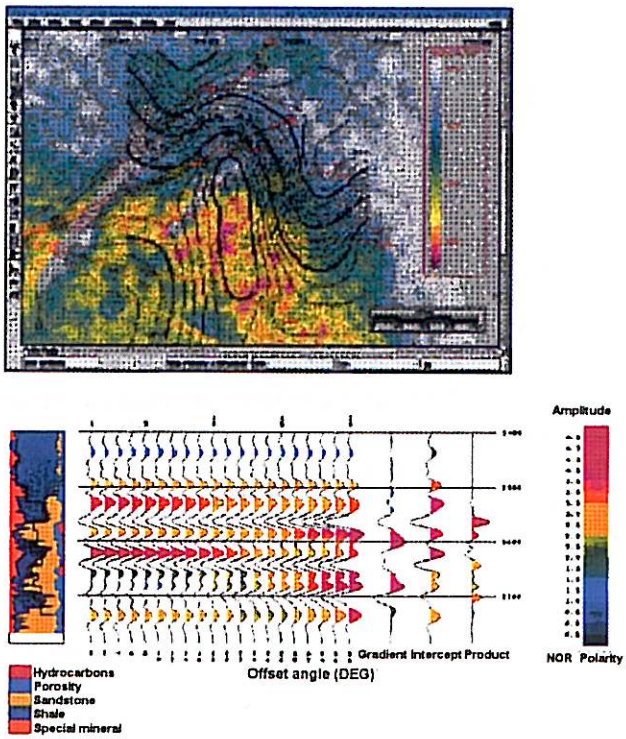


Fig. 6. Geostatistical porosity distribution map, AVO seismic model from log analysis.

of geostatistics with seismic attributes and seismic petrophysics is in its infancy (Fig. 6). Lack of training and expense are the current holdups to more widespread use.

Seismic petrophysics, especially with long offset spreads, is on the rise. Again, 30 years have passed since seismic inversion was first practical and we are just now getting close to real petrophysical properties. Again much training is needed, since many practitioners seem to forget that sonic and density logs see an invaded zone and the seismic signal does not. How much longer will it take to learn this simple truth?

We cannot ignore the tremendous strides in Logging While Drilling. Most conventional open hole measurements can be made near the bit, before invasion becomes too serious. Even the NMR is in an LWD test program. More deviated, deeper, hotter holes will require this technology. Reservoir description is enhanced because of the immediate acquisition of data and the reduced invasion profile.

Cased hole logs for reservoir description, completion integrity, and fluid flow evaluations are much enhanced over previous efforts. Casing,

tubing, and cement image logs are readily available but seldom used to their full extent in solving well performance problems. Production logging is underutilized in remedial work. When they are run, interpretation skills are weak, especially in deviated, multi-phase flow. There seems to be no concerted effort to correct this lack of training.

With favourable cement bond, most open hole measurements including sonic, density, and resistivity, can be measured through casing. The resistivity log is being field tested by the major logging contractors. It's about time – an independent Canadian company offered such a tool over 25 years ago. Not all that is new or useful comes from the major research centers – the "little guy" has an important role to play. NMR and highly focussed induction logs both came from outside our industry and were pioneered by small independent research labs. Although I have no idea what the next important advance will be, it is likely that it will come from an unrelated field.

ARTIFICIAL INTELLIGENCE

Artificial intelligence is another buzzword that seems to have disappeared. In 1984 and 1985, I was head of a research team that was investigating the use of artificial intelligence to help reduce complexity in log analysis. The team had high hopes for this project. I would like to read a short passage from my textbook, "The Log Analysis Handbook" (Pennwell 1986), written as this project was about halfway completed:

"The future? It will probably involve artificial intelligence - the darling of the academic world in the 1980's. Computer based expert systems will learn from experts in the field of log analysis, and will subsequently advise and consult with less expert users. As the expert system is increasingly used, its cleverness will heighten, until it is more intelligent than any single expert. Such hardware and software already exists, albeit for much simpler situations than log analysis. However, it is known that major service companies, oil companies, and consulting firms have embarked on research in this field, emphasizing log interpretation.

The success of a log analysis is judged by how well the analysis predicts the future performance of the completed zone. Many analysts and their managers are unaware whether their results were good or bad. Artificial intelligence with a learning data base, should provide the kind of "perfect memory" and the unbiased question/answer sequence needed to keep track of success and failure.

Hopefully we will learn how to do better work as time goes on, by studying the background to each success or failure, monitored automatically by the expert system.

The future holds the promise of a long sought goal in well logging - an automatic, universal interpretation program that never fails and adapts to change. Of course, this is just a dream, right?"

Fifteen years have passed since the above was written and the prediction seems no closer to fruition. This just goes to show how poor a forecaster I am! What happened to all that research effort and all those prototype systems?

CONCLUDING REMARKS

There is much happening in our field. Petrophysics is changing. The uses of petrophysics are changing. We will never be out of work!

In the face of continuous change, humans yearn for consistency. We normally resist change and strive instead for the traditional approach. Unfortunately, we will never optimize oil production this way. We must learn to accept the challenge of change, adapt to it, and in fact, lead the charge by innovation and invention of new solutions to the problem of data overload, complex reservoirs, and working with multi-discipline team members.

Petroleum Res. J. Vol. 13 (2001); P. 23–32, 7 Figs.

FlexInLog: Flexible, Integrated Well Log Analysis Software, Developed by PRC

- a keynote lecture -

Bourima Ali Belgasem* and Zoltan Barlai*

تطوير منهاج تكاملي مرن لتحليل سرود الآبار بمركز بحوث النفط

أبو ريمة علي أبو القاسم وزلطان بارلاي

قام فريق تقييم المكامن بمركز بحوث النفط خلال الفترة 1992–2000ف، بتطوير منهاج علمي لتفسير تسجيلات الآبار بهدف الرفع من مستوى التحليل الكمي لتسجيلات الآبار بقطاع النفط في ليبيا منذ بداية البحث عن النفط عام 1959م.

ففي الآبار القديمة، لا تتوفر إلا تسجيلات جاما، والنيوترون وقياس الجهد الذاتي وهو ما يحد من فاعلية المنهاج ليعطي فقط المسامية ϕ، والحجم الجزئي لحجر الطين وكذلك درجة تشبع صخور المكمن بالماء والزيت.

أما في الآبار المحفورة حديثاً، فتتوفر مجموعة كبيرة من سرود الآبار وتشمل أشعة جاما وتسجيل النيوترون، وتسجيل كثافة الطبقات والتسجيلات الصوتية وقياس قطر ثقب الحفر الأمر الذي يمكّن من استنباط التركيبة الصخرية ويعطي القدرة على تحديد عدد من الخواص البيتروفيزيائية لصخور المكمن بدقة جيدة بعض الشيء حتى في محاكاة المكمن.

ويتميز المنهاج بالمرونة لملاءمته البيتروفزيائية لتسجيلات الآبار القديمة والحديثة على حد السواء وله صفة التكامل وقدرة ربط المعلومات ذات المصادر المختلفة ويمكن معايرته باستخدام العينات اللبية وبيانات إختبار الآبار والسجل التاريخي للإنتاج حيث أن المنهاج يتمتع بصفات بيانية وإحصائية لكونه رياضياً في نطاق التقدير الحسابي.

وتكمن الخاصية الأساسية للمنهاج في تطبيق نماذج صخرية ذات مسامية متعددة (3-5 مكونات) ونماذج درجة تشبع مكونات مسامية مختلفة. وقد تم تقديم مثال تطبيقي فعلي بالبئر V26 بحقل بالحيضان على صخور تكوين القرقاف الرملية التابعة لدهر الحياة القديمة ذات المسامية المتشققة والفجوية. وستشمل المرحلة الثانية من تطوير هذا المنهاج عام 2002 على تطبيقات بعض التقنيات الحديثة المستخدمة في تسجيلات الآبار مثل التسجيلات الصوتية متعددة الصفوف والصور الدقيقة لجدار البئر.

Abstract: *In the recent years, 1992-2000, a scientific well log analysis software has been developed by the Formation Evaluation Group of PRC. The objective was to cope with quantitative well log analysis of the Libyan Oil Sector from the very beginning, 1959.*

In the early wells only gamma ray (GR), neutron and resistivity (plus SP) logs were available, which restrict capabilities of the software to provide only porosity, Φ, shaliness, V_{sh}, and fluid saturations, S_w & S_o.

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In recently drilled wells a rich suite of well logs have been measured: GR, (sometimes SGR), Φ_n, ρ_b, Pe, Δt, Cal; Induction or Laterolog resistivities (SP), and sometimes MSFL. This collection gives an ample chance to derive sophisticated rock composition and determine a large number of petrophysical rock properties at fair accuracy even for reservoir simulation.

The software is flexible since it can suit both old and recent logging conditions; a high integration is involved because all the evaluation techniques are calibrated to core investigations, well test results, and, production history data; the software is statistical & probabilistic since it is mathematically overdetermined.

The basic feature of the software is the application of multiporosity (3 – 5 porosity components) rock models with more efficient fluid saturation models which distinguish between saturations of the different porosity components.

An example of practical application is presented in the Palaeozoic fractured/vuggy Gargaf sandstone of Belhedan oil field (well V26).

A second stage of the FlexInLog software development, will start in 2002, which will involve the application of some novel logging techniques, such as Sonic Array Tool, MicroImages of the wall of borehole, etc.

INTRODUCTION

Oil exploration and production in Libya reached a turning point at the beginning of the 21st century. Production in the old oil fields is declining. Maintaining the present level of production needs the following action:

- Continuation of oil production in mature fields with enhanced and improved oil recovery techniques (EOR, IOR).
- Exploration of new oil/gas fields in the south of the country (Murzuq Basin).

These developments present a new challenge for the formation evaluation activity of Libyan oil producing companies. Their tasks are:

- Re-evaluation of mature oil fields for preparing the application of EOR/IOR;
- Efficient application of the powerful new well logging techniques in new boreholes.

The Petroleum Research Centre (PRC) of Libya and Teknica Ltd., Canada, are prepared to answer the challenge by developing a new formation evaluation software – FlexInLog, the flexible and integrated well log analysis software. Flexibility means that the interpretation is adapted to the availability of well log and other input information. Integration means that formation evaluation is an essential part of the oil development process, utilizing information from geology, well logs, core measurements, well tests and production data. In turn, it provides indispensable results for reservoir simulation and production control.

MAIN GOALS OF FLEXINLOG

Oil exploration including industrial well logging started in Libya in 1959. Oil production started in the early sixties in the Nasser, Amal, Sarir and Gialo fields (among others). In this period well logging implied only

- Gamma ray, GR;
- Neutron;
- Induction resistivity;
- Spontaneous potential, SP.

Output results were simple and lacking any detail; they provided:

- Effective porosity;
- Shale;
- Matrix material (sandstone or carbonate).

The only petrophysical parameters supplied were water and oil saturation.

Later on, new types of well logs were developed and gradually introduced into the routine logging in Libya. The most important are:

- Bulk Density, ρ_b;
- Photoelectric Effect, Pe;
- Sonic Compressional Propagation Time, Δt;
- Spectral Gamma Ray, SGR
- Micro Spherically Focused Resistivity, MSFL.

Existing well logging instruments were also improved. New tool design, improved computerized control and on-line environmental log corrections increased the reliability of neutron and resistivity measurements. Spectral gamma ray is superior to the conventional gamma ray measurement in revealing mineral composition.

Lithological/mineral composition can be evaluated in much more detail. In sandstones, besides sand and clay, silt fraction can also be revealed. In carbonates, density and photoelectric logs enable the distinction between calcite and dolomite. The presence of ferroan minerals is indicated by photoelectric log.

Better lithology interpretation improves the quality of the determination of porosity.

More accurate lithological composition, improved well logs and calibration on core and lab. measurements resulted in a rich set of petrophysical parameters.

Porosity is divided into 3 – 5 parts (the latter in the case of fractured/vuggy rocks). Some of the porosity terms are useful for oil accumulation and production, while others are only water-bearing. Understanding the pore space composition enables more accurate calculation of petrophysical parameters.

Absolute permeability can be calculated if well log data can be integrated with core analysis and well test results. The equivalent pore throat size, r_{pth} is an important result; examining it helps understanding the complicated relationship between porosity and permeability.

In fractured rocks, fracture permeability is the most important factor. If relevant input data are available (*e.g.* good quality micro resistivity), it can be computed quantitatively. In less favourable cases, the fractured intervals can only be qualitatively delineated which are the candidates for perforations.

Fluid saturations namely water saturation, movable oil saturation and residual oil saturation are computed. In multiple porosity systems, each porosity term has a different water saturation level. (They have different pore size and pore throat size structure; lesser pore throat sizes mean greater obstacles for oil accumulation). Water saturation can be divided to irreducible water saturation and movable water saturation in some cases.

A rich set of special petrophysical and reservoir engineering parameters is provided by FlexInLog; if input data are available: good quality of special core analysis measurements are necessary. Calibrating well log analysis formulae on the core analysis results, values of some special petrophysical parameters, can be determined continuously *vs.* depth; these special petrophysical parameters are as follows:

- Wettability of rocks;
- Relative permeabilities for water, oil and gas only in two-phase systems;
- Water cut (at the beginning of production);
- Fractional oil flow.

AREAL PROCESSING OF THE RESERVOIR

Users of formation evaluation results are interested in the hydrocarbon producing potentials of reservoirs and fields. Therefore, parameters of individual wells should be extended to field level which is supported by the FlexInLog system.

Here the total depth interval of the well is divided into zones, namely:

- Lithological zones are determined by lithofacies analysis; for instance, in some Libyan oil fields the reservoir consists of carbonate and sandstone facies;
- Hydraulic zones are separated by barriers of fluid movement, which can be recognized by the FlexInLog.

Zones of the well are characterized by average and cumulative petrophysical properties. These values determine whether a specific zone of the well is producible or not.

The main average and cumulative parameters are:

- Average porosity and equivalent porosity height;

- Average permeability and transmissibility;
- Average oil saturation and equivalent oil column height;
- Average movable oil saturation and equivalent movable oil column height.

Areal maps of average and cumulative reservoir parameters are drawn in FlexInLog by a semi-automatic method which determines also the oil margin of the field.

Evaluation of oil/gas reserves is carried out by modelling the reservoir with triangle-based prisms, and summing up the hydrocarbon volumes of the prisms; this is a new technique provided by FlexInLog.

BASIC CHARACTERS OF THE SOFTWARE

Flexibility, integration and statistical/ probabilistic nature are the basic characters of the software.

Flexibility means that the procedures of formation evaluation are adapted to the completeness of available input information. Simpler methods are applied for the interpretation of only basic logs in older wells. More sophisticated methods are used in recent wells where a complete set of well logs is available. In field studies where older and newer wells are both investigated, the methods applied on the older wells are calibrated on the newer wells where input information is rich and reliable.

Integration means that well log interpretation is carried out not in isolation, but utilizing all available relevant information. In the following we list the most important data sources which should be analyzed for the calibration of well log analysis.

Routine and special core analysis provide data that can't be obtained by any other means. Petrographic investigations reveal not only the mineral content but also the texture of rock samples. Mercury injection describes the pore throat size and pore size distribution which is crucial in determining permeability and saturations. Lab. analysis of reservoir fluids is also necessary, *e.g.* salinity of formation water affects the interpretation of resistivity data.

In core analysis, great care is needed to restore reservoir conditions (temperatures, pressures, wettability, fluid saturations and streaming velocities) during lab. investigations as closely as possible. This principle assures that core data provide a solid base for the calibration of well log interpretation in reservoir conditions. Otherwise, contradictions may occur between results obtained from different types of investigation.

Well tests (PBU, production tests) give evidence about the presence of oil. If formation evaluation follows well logging by several years – as in the case of field studies – studying production history is essential. The volume of oil and the transmissibility estimated by formation evaluation should be in agreement with the actual production data.

The FlexInLog software is statistical and probabilistic. The process of well log measurement and interpretation is burdened with random errors. The FlexInLog system handles this situation by applying mathematically overdetermined systems. Statistical analysis of errors assures that the reliability of interpretation results can be expressed quantitatively (as by incoherence in the case of lithology).

Multivariate statistical methods are included in the FlexInLog system for the analysis of internal connections between input data and interpretation results. Principal component analysis (PCA) of input data is an unbiased tool for checking the results of more sophisticated human-made quantitative methods.

The name of the software: "FlexInLog" refers to the basic two features of flexibility and integration.

PETROPHYSICAL CHARACTERISTICS OF RESERVOIR ROCKS

The basic properties of rocks are determined by the lithology, mineral content, rock texture, grain size distribution, pore and pore throat size distribution and wettability (Fig. 1).

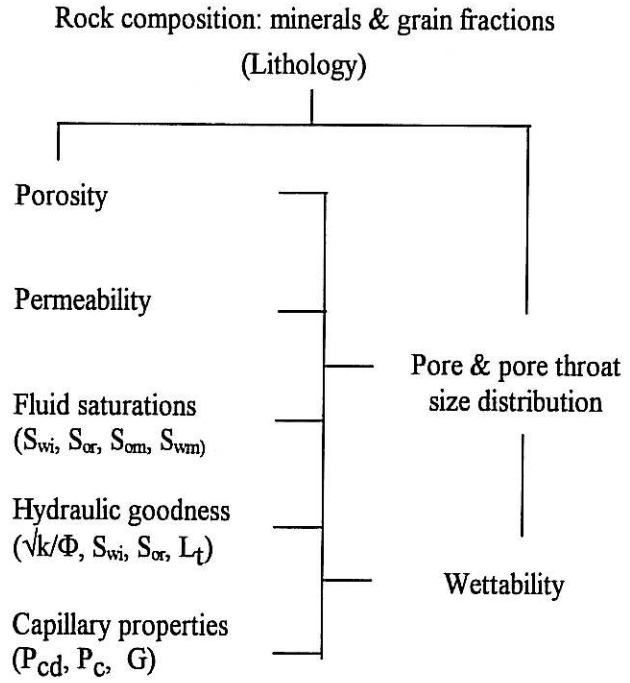


Fig. 1. System-pattern of relations between petrophysical characteristics.

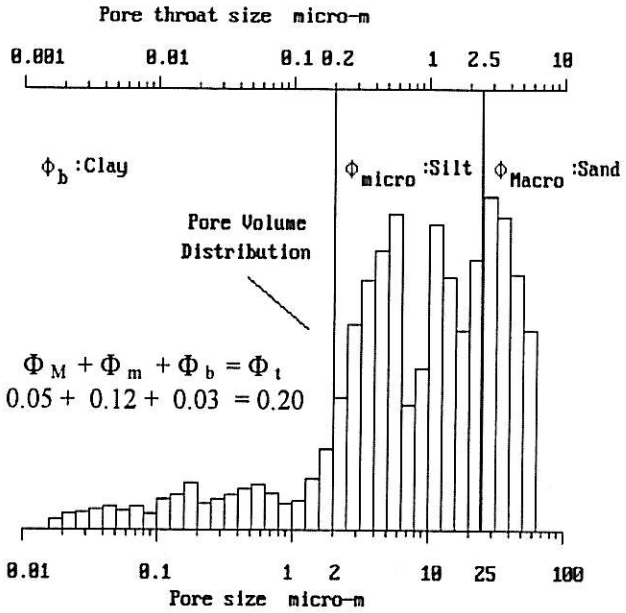


Fig. 2. Triple porosity system in shaly sandstones.

The most important controlling factor of petrophysical parameters is the pore & pore throat size distribution. Pore structure has greater effects on hydraulic properties than the quality of solid rock materials. Therefore, the more information is provided on pore structure, the better is the evaluation of petrophysical parameters.

Presence of reservoir fluids may also alter rock properties. Saturation with oil may also alter wettability: the originally water-wet rocks became oil-wet. Determining wettability of rocks is one of the most difficult tasks – integration of core and log analysis may give the best answer. Knowledge of wettability is crucial in the selection of proper improved oil recovery techniques.

POROSITY COMPOSITION OF SHALY SANDSTONES

In figure 2 a typical example of pore size and pore throat size distribution is shown in a shaly sandstone rock. Accumulation and movement of hydrocarbons are greatly influenced by pore throat sizes. Buoyancy forces push the oil through the pore throats; the smaller the opening, the greater the forces needed.

Well log analysis in itself cannot reveal the pore size distribution *versus* depth; however, in case of an adequate set of input well logs, breaking down total porosity into terms is possible; in shaly sandstones three porosity components can be revealed:

- Macro effective porosity (associated with sand fraction);
- Micro effective porosity (associated with silt fraction);
- Bound water porosity (associated with clay fraction).

POROSITY COMPOSITION OF FRACTURED/VUGGY ROCKS

Composition of porosity is more complex in fractured/vuggy rocks (Fig. 3). Tectonic movements create open fractures in the rocks. These fractures open the way for circulating fluids which in turn dissolve vugs in the rocks. These voids are large enough to accept hydrocarbons during accumulation. Smaller vugs are produced by secondary mineral alterations such as modification of calcite to dolomite. These three porosity components make up the useful (engineering) porosity.

Some other part of porosity has smaller pore throat sizes which prevents hydrocarbons from

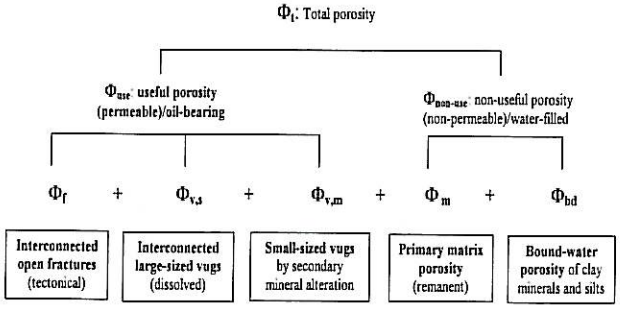


Fig. 3. Composition of the total porosity in fractured/vuggy rocks.

entering it. Primary matrix porosity is what has been left of the original porosity after diagenesis. Bound-water porosity is associated with clay minerals – similar is the porosity associated with micrite which is composed of very fine calcite crystals. These porosity parts do not contribute either to hydrocarbon storage (saturation) or to hydrocarbon movement (permeability), therefore they are called non-useful porosity.

The porosity components of figure 3 are displayed from right to left in order of increasing usefulness for oil production. Fractures are negligible in respect of oil storage but their contribution to permeability is decisive.

EXAMPLE OF FLEXINLOG APPLICATION

The formation evaluation principles of FlexInLog are illustrated by the example of an oil producing well in Belhedan field. The oil is produced from the Gargaf formation, a very old Palaeozoic fractured/vuggy quartzose shaly sandstone. The borehole was drilled in 1992, and a complete suite of well logs was measured, supported by core analysis and well tests. This wide range of input data produced a rich set of output results.

In figure 4 the lithological composition in the upper part of the Gargaf sandstone is shown. Here porosity rarely exceeds 10 %. Quartz is the main constituent; clay and silt are present in 5-20 feet thick intervals; carbonates and ferroan minerals occur in small volumes as accessory components; legend of the solid rock components is presented at the top-right of the figure.

Four components of the fractured/vuggy porosity system – excepting the open fracture porosity – are shown in the middle track:

- Effective porosity is the outcome of the quantitative lithology analysis.
- Matrix porosity is estimated by statistical analysis of effective porosity histograms as an average of the minimum of effective porosities.
- The difference of effective and matrix porosity is the useful porosity, which is divided into large-sized vuggy and small-sized vuggy porosity by application of the sonic Δt log. We utilized the property of the sonic log; that avoids large-sized vugs, so it reflects the sum of matrix and small-sized vuggy porosity.
- Bound water porosity is estimated from the volume fractions of clay, silt and ferroan minerals.

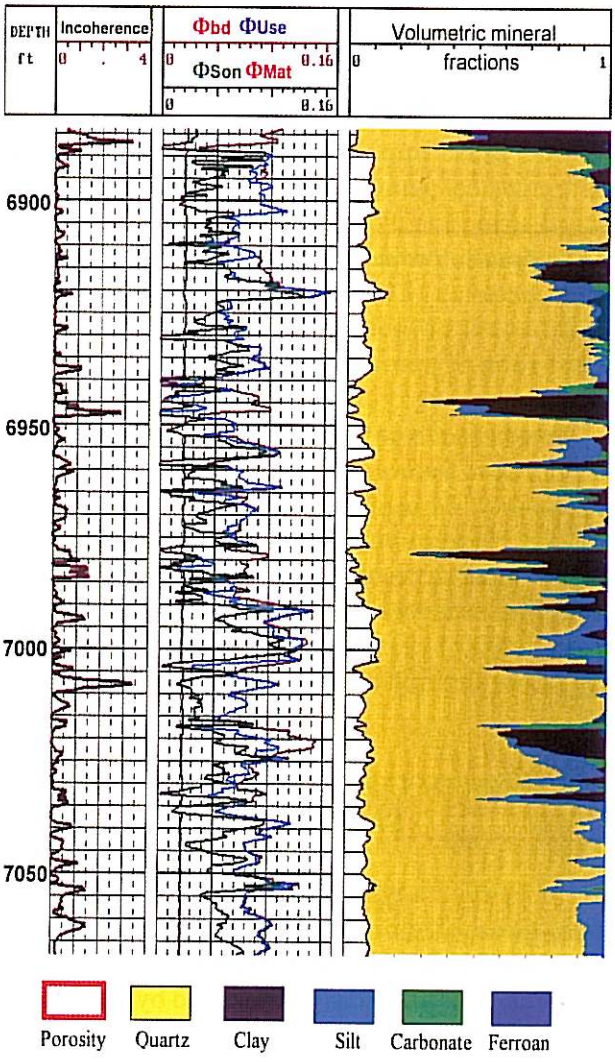


Fig. 4. Lithologic and porosity logs.

FlexInLog applies quantitative statistical lithology/mineral interpretation with a mathematically overdetermined system of equations solved at each depth. It provides – beside the rock composition – measures of reliability of the results. The incoherence is a compound quality indicator – its large values occur where harmony of the input logs is disturbed by measurement errors or other effects; the incoherence is displayed at the lower track.

The lower track of figure 5 shows again the four porosity components; in the middle track the fifth component, open fracture porosity is displayed. A logarithmic scale is applied because the involved quantities are small: the largest fracture porosity in this case is about 0.6 percent.

Fracture porosity was computed in this well from the Micro Spherically Focused Resistivity log (MSFL). Open fractures (filled with mud or mud filtrate) cause a drop in the value of micro resistivity compared to resistivity of fracture-free rock blocks. This method is specific in the FlexInLog system.

In the upper track the volumetric fraction of shale is displayed. Shale is the impermeable part of the rock; the shale is composed of clay, silt, carbonate and ferroan minerals. Presence of shale decreases the value of the rock for fracturing and hydrocarbon production.

In figure 6 those petrophysical parameters are presented which control the oil reserves. In the upper track two quantities are shown which are involved in the computation of water saturation: the deep induction resistivity log is used as an approximation of the true resistivity, R_t; its value is compared to the theoretical resistivity of water-bearing rock, R_0.

The resistivity model of fractured/vuggy rocks, applied in FlexInLog, has been developed by Prof. Z. Barlai; it assumes that the different porosity components form parallel channels of electrical conductances, and they have different water saturation levels.

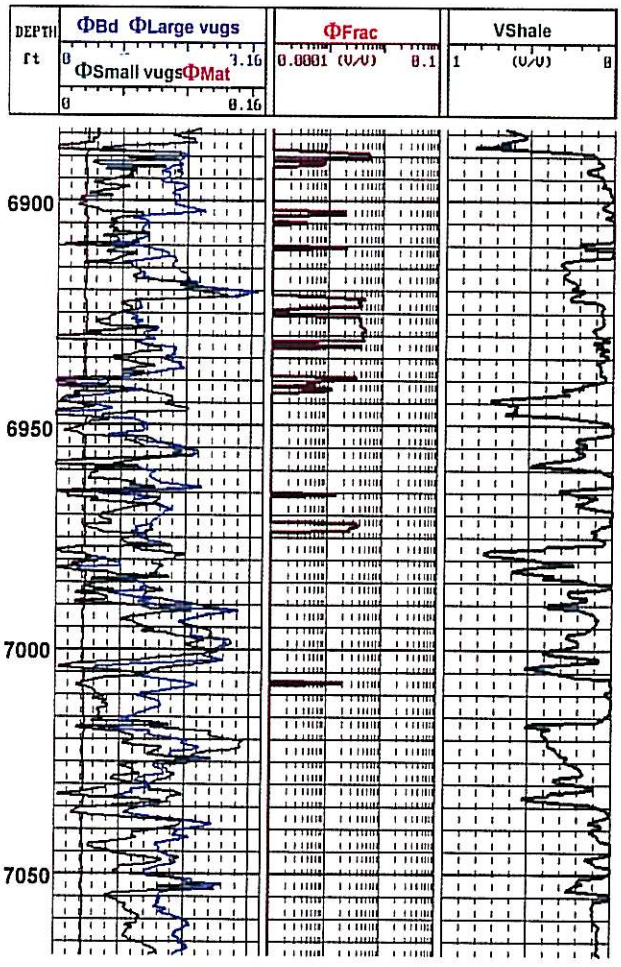


Fig. 5. Fracture porosity log.

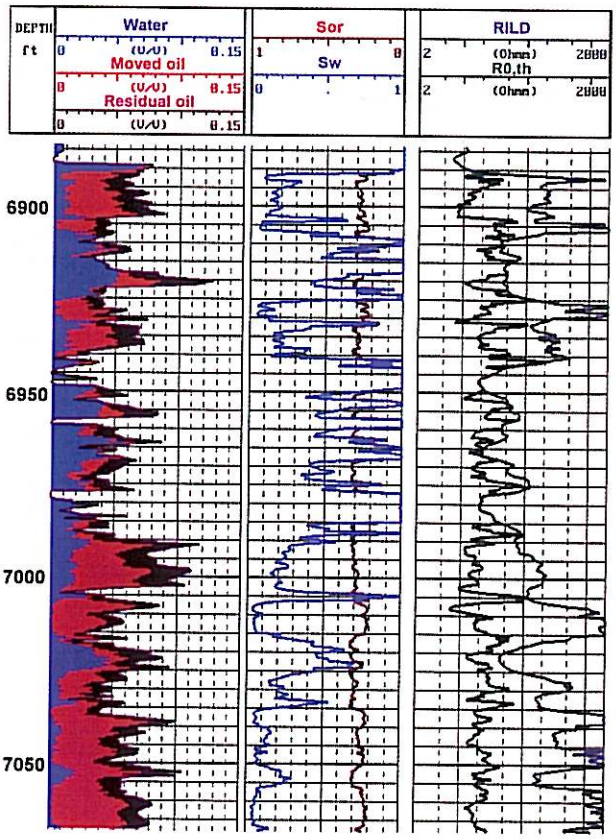


Fig. 6. Fluid volume and saturation logs.

In the middle track the fluid saturations are displayed; water saturation in blue and residual oil saturation in red. Only the porosity components included in the "useful porosity" are filled with oil, so the water and oil saturation values are related to the useful porosity (sum of vuggy and fracture porosity).

In the lower track the useful porosity is shown as filled up with reservoir fluids: water (in blue), movable oil (in light red) and residual oil (in dark red); in this depth interval the water saturation is close to the irreducible level since the oil-water contact (OWC) is at great depth.

In the upper track of figure 7 the total permeability and the block permeability are displayed. Total permeability is the sum of block permeability and fracture permeability. While block permeability is below five millidarcy, the largest values of fracture permeability (and hence total permeability) exceed 20 000 millidarcy i.e. 20 darcy. It is obvious that fractures have the greatest contribution to the total transmissibility.

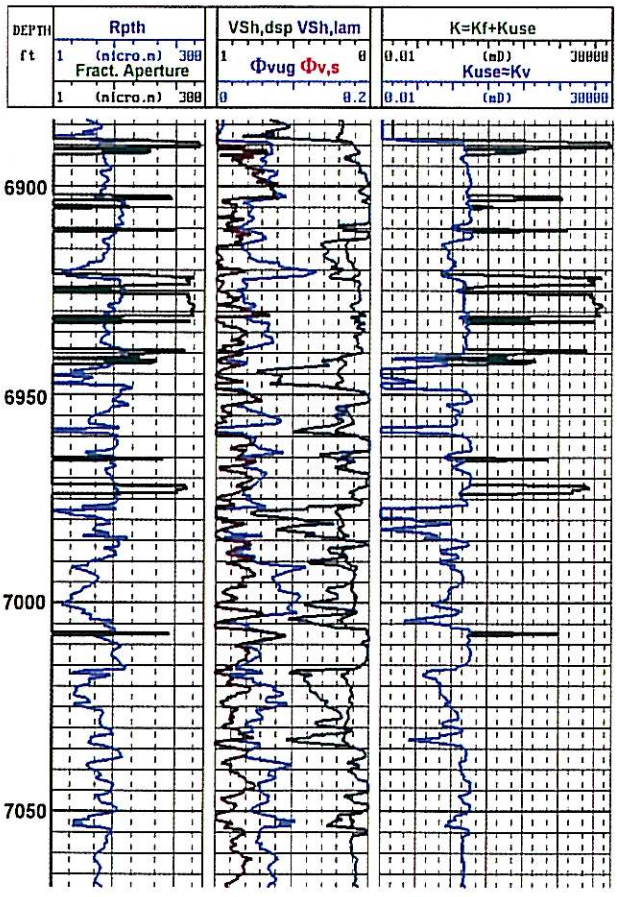


Fig. 7. Permeability and void-size logs.

In the middle track the vuggy porosity divided to large-sized vugs and small-sized vugs is shown together with volume of shale. The shale fraction is separated to laminated shale and disperse shale. Disperse shale has more detrimental effect on the oil producing potential of the rocks. Laminated shale development contain also sandstone laminae with good porosity, permeability and saturation values. FlexInLog applies proper methods for the evaluation of saturations and permeability in the case of laminated shale.

In the lower track equivalent pore throat size (in blue) and fracture aperture (in green) are presented in logarithmic scale. Here again it is apparent that fracture aperture may be 15 times larger than the equivalent pore throat radius (which is a characteristic of vuggy porosity).

The example of the selected well is a good illustration of the novel approach provided by the FlexInLog system. It is important to mention that in this well a rich set of input data were utilized, including core analysis, well tests, production data and Formation Microscanner. All this information was used for the calibration of FlexInLog formation evaluation in an integrated mode.

CONTRIBUTION OF FLEXINLOG TO RESERVOIR SIMULATION

Output results of well log analysis and formation evaluation are utilized in many areas of oil exploration and production. Information provided by FlexInLog is rich and reliable to create a solid base for decision making in reservoir engineering.

Technical and economical decisions about the future production in an oil or gas field are often supported by reservoir simulation. Success of simulation studies depends substantially on the quality of input data. Rock characteristics of the individual wells are provided by formation evaluation.

FlexInLog also applies the "history matching" principle: results of well log analysis should be in agreement with well tests and production results (including production rates and water cut).

During the process of formation evaluation, different sources of information are integrated. Their quality and reliability are evaluated, any contradictions are revealed and possibly resolved. This procedure is beneficial also in the preparation of data for reservoir simulation. Consequently, FlexInLog will improve the quality of reservoir simulations.

THE SECOND PERIOD OF FLEXINLOG DEVELOPMENT

In this stage the software will incorporate the interpretation of those kinds of well logs which are regularly used in Libya. A second phase of development will be started in 2002, in which interpretation of new techniques will be introduced into the software such as:

- Electromagnetic Propagation Tool (EPT);
- Sonic Array Tool (SAT) with full acoustic wave;
- Nuclear Magnetic Resonance (NMR);
- Thermal Decay Time (TDT);
- Geochemical Logging (GL) with energy-selective neutron measurements;
- Borehole wall imaging micro techniques;
- Dual dipmeter tool (SHDT).

SUMMARY

1. The FlexInLog software was developed in a scientific form by PRC in the period 1992-2000; its main goal is to cope with quantitative well log analysis and formation evaluation of Libyan oil/gas wells and reservoirs from the very beginning in 1959 up to now.
2. The basic character of FlexInLog is a flexible and probabilistic integration of well log analysis and all the related disciplines of geosciences into an up-to-date Formation Evaluation.
3. The new way of FlexInLog is to build up the total porosity of the rocks from a number of porosity components, – namely minimum 3 and maximum 5, – by taking into account the pore-throat and pore-size distribution and the fracturing of the rocks.
4. The different porosity components, contributing to the water saturation and to the permeability at different levels, is utilized in FlexInLog with the purpose of recognizing the presence of hydrocarbons even in sophisticated rock developments. Better understanding of reservoir rock behaviour will improve the production control and the quality of reservoir simulations.

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Emerging Technologies in Subsurface Monitoring of Petroleum Reservoirs

- a keynote lecture -

M.R. Islam*

تقنيات مستقبلية للمراقبة التحتسطحية للمكامن النفطية

م. ر. إسلام

إن أغلب الحقول النفطية لا تنتج أكثر من 45% من مخزونها الكلي حتى بعد إجراء عمليات الاسترداد الإضافي. كما أن أغلب الزيت غير المنتج يعتبر مفقوداً وذلك لأن التقنيات المستخدمة لاستخراج الزيت أثناء الإنتاج تهمل كميات كبيرة من المخزون الأصلي. وإن إسترداد هذا الزيت المفقود سيؤدي إلى مردود إقتصادي هام حيث أن البنية التحتية اللازمة لاسترداد الزيت الإضافي موجودة أصلاً بالمكان ولم يبقى إلا كلفة الإنتاج التي سوف تكون بسيطة.

لقد تم في هذه الورقة مراجعة جميع التقنيات المتوفرة للمراقبة بما في ذلك استخدام المجسات السيزمية ذات الأربع أبعاد والمجسات داخل البئر بالإضافة إلى مراجعة شاملة لجميع التقنيات المستقبلية للمراقبة التحتسطحية. تتضمن هذه التقنيات تطبيق الموجات السيزمية والرسم الطيفي للمقاومة الكهربائية وصور الموجات الصوتية وفوق الصوتية والكهرومغناطيسية والألياف البصرية بآبار متعددة، بالإضافة إلى الليزرية/فوق الحمراء وذلك للنظر في المنطقة القريبة من جدار البئر.

Abstract: *Most oil fields do not produce more than 45% of the oil-in-place, even after enhanced oil recovery schemes have been applied. Most of this unproduced oil is missing because most displacement techniques by-pass significant portion of the original reserve. Finding this missing oil can lead to significant economic windfalls because the infrastructure for additional oil recovery is already in place and the cost of production is likely to be minimal. In this paper, all existing monitoring techniques, including 4D seismic and downhole seismic sensors, are reviewed. This is followed by a comprehensive review of emerging technologies in subsurface monitoring. These techniques include multi-well seismic, electrical resistivity tomography, electromagnetic and ultrasonic imaging, acoustic and fibre-optic imaging, as well as laser/infrared or MRI/NMR visualization near the wellbore region.*

INTRODUCTION

A detailed analysis indicates that for an accurate reservoir engineering analysis, geostatistical models should have information of 1m scale. This is the only scale that would satisfy the representative elemental volume (REV) requirement of an enhanced oil recovery (EOR) system. This scale length is orders of magnitude higher than that of core samples and at least an order of magnitude lower than the conventional seismic data. This data gap constitutes the weakest link between geophysical information and

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reservoir engineering. Any attempt to reconstitute the reservoir without information regarding petrophysical properties and fluid saturations in the 1m level, one would risk falling into the trap of multiple solutions – a typical problem of history matching through reservoir simulation. To obtain a resolution of 1m scale, one must investigate the possibility of using 50-2000 Hz seismic frequency range. While this seismic range cannot be used with vertical seismic profiles (VSP) because of the travelling distance constraints, multi-well imaging can be used with multi-component receivers. This system, in combination with borehole seismic sources, can provide one with the desired resolution. The same system can be used in combination with resistivity tomography, a method that has recently given satisfactory results for tracking ground-water contamination. The images can be further refined with acoustic and fibre-optic imaging techniques. These techniques can provide satisfactory details to track viscous fingering, wormholes, and other time-dependent properties of an active reservoir. Finally, infrared/laser or MRI/NMR imaging of a wellbore is still in its nascent state of development, but holds great promises for the future applications of real-time monitoring and eventual dynamic reservoir management.

4-D SEISMIC

The fourth dimension is time. This time is measured in months and years for any reservoir application. This is in contrast with measurements in millisecond as commonly used in seismology. Typically, new survey results are compared with original and previous survey results, in order to monitor changes in fluid content or even rock characteristics.

Reservoir Characterization

Improving reservoir performance and enhancing hydrocarbon recovery while reducing environmental impact are critical to the survival of the petroleum industry[1]. Proper reservoir characterization has been directly linked with growing reserve[2]. In order to achieve these objectives, one must start with characterization of reservoir parameters[3], including fluid properties and their changes with time[4-6]. This constitutes the essence of dynamic reservoir characterization. Recently, there has been a surge of three-dimensional (3D), three-component (3C) seismic survey activities[7]. Past experiences have shown that the time-lapse survey is necessary only when the reservoir is under some enhanced oil recovery scheme. Only recently, it has been recognized that time-lapse 3D can also be a reservoir characterization tool. If base-line data are already available, introducing time as the fourth dimension, new time-lapse (4D), 3C seismology can become an effective tool for monitoring production processes and to determine reservoir property variation under changing conditions[8]. The introduction of 4D seismic is equivalent to adding many new points to the production history (when one makes an analogy to the history matching process). Using 4D, 3C seismic monitoring as an integral part of dynamic reservoir characterization, refinements can be made to production processes to improve hydrocarbon recovery. Refinements made to reservoir characterization techniques and their applications, dynamically with 4D seismic, are important new areas of research. Benefits of this method include better reservoir characterization, increased hydrocarbon recovery and lower operating costs due to improved reservoir management[9]. Recently, guided seismic waves have been introduced as a tool for continuity logging – to be used by geologists[10]. This, in turn, can help predict the continuity of shale markers between gas wells that are significantly apart. This method holds promise for gas reservoirs. In addition, innovative reservoir characterization must be performed in order to predict accurately the reservoir potential as well as to develop the optimal production scheme. In this regard, the use of artificial intelligence and expert system is worth mentioning[11].

Industry Attitude

The fundamental objective of 4D seismic is to monitor changes in a reservoir. It is necessary, therefore, to conduct 3D seismic surveys at a given location many times over the course of months or years. This would enable one to compare surveys to the original or previous surveys. It is easily understood that such an extended effort must come with a price tag – something oil companies might not be willing to pay unless the prospect of payback is clear. In this regard, some of the world's

largest oil companies are not yet convinced, especially when they have yet to realize the benefits of conventional 3D seismic. For instance, Saudi Aramco, with its reserve of 260 billion barrels of oil and 500 Sun workstations in its E&P center in Dhahran, still considers 3D seismic as its forte[12]. For the moment, Saudi Aramco is preoccupied with first 3D's in over 25,000 km over a productive area of 20,000 sq. km. This is not to mention that the benefits are less than spectacular. In fact, only in 1994, soon after some of the first series of 3D seismic surveys were finished, 2.9 billion barrels of reserve was added to the existing 250 bbl of Saudi Aramco. Saudi Aramco currently produces 8 million barrels of oil daily and has an ability to increase production to 10 million b/d within 60 days.

Shell has realized the value of 4D seismic. They have invested a great deal in improving the quality of 1st time 3D surveys. This is because, unless the state-of-the-art technique is applied to the original (baseline), it will be difficult to make use of new surveys that continue to see experimental growth in technical advances[13]. This view has been supported by BP Exploration[14] who admitted that many of the differences between old and new 3D surveys were not yet fully understood. Chevron, Amoco, Conoco, and Exxon developed a consortium with support from the US Department of Energy (US DoE) and the Gas Research Institute (GRI) to use seismology at higher frequency bands than the conventional ones. This really opened up the opportunity for using 4D seismic as a monitoring tool. It is true that ambient noise levels are much lower in the downhole than at the surface. For example, cross well surveying from deep in one well to receivers at corresponding depth in a nearby well should yield seismic data with measurable signals at frequencies approaching 1000 Hz. The resolution can be better than 10 ft[15-16].

Sceptics are critical of the fast pace in applying 4D seismic, comparing it to letting loose a novice to a Pandora's box. While the scepticism continues[17], the advancement in the last decade can assure one that the on-line monitoring of reservoirs is not an unrealistic dream[18]. Strenedes[19] reported that the average recovery factor from all the fields in the Norwegian sector has increased from 34-39% over 2-3 years, due to enhanced monitoring. He emphasized that North Sea production being on a decline, the needs for an improved technique is very important.

REMOTE SENSING AND RESERVOIR MONITORING

Reservoir and Tubulars

There is a need to improve the ability to depict phenomena occurring at three levels, namely, reservoir, wellbore, and wellhead. The conventional seismic technology has a resolution of 20 m for the reservoir region. While this resolution is sufficient for exploration purposes, it falls short of providing meaningful results for petroleum field development, for which 1 m resolution is necessary to monitor changes (with 4D seismic) in a reservoir. For the wellbore, a resolution of 1 mm is necessary. This can also help detecting fractures near the wellbore[13]. The current technology does not allow one to depict the wellbore with this resolution, especially when two or three phases are present in the wellbore[20]. A recent research study shows that resolution should be 1 meter in the reservoir, 1 cm near the wellbore, and 1 mm inside the tubulars[21].

Reservoir Permeability and Relationship to In-situ Conditions

Evaluation of sandstone permeability from recovered drill cores is done routinely as part of any hydrocarbon reservoir characterization program. These laboratory measurements usually involve mounting the prepared core specimens in a pressure chamber to enable permeability and acoustic measurements at simulated *in-situ* pressure conditions. However, current industry practice normally involves tests done under simulated overburden or hydrostatic pressures only, and recent works indicate that permeability under constant overburden pressure can vary significantly as lateral stress is varied[22-25]. Such lateral stress variations would be expected as a function of orientation in an anisotropic stress field and in response to production or stimulation procedures. As well, changes in reservoir gas pressure will alter effective overburden and lateral stresses by different relative amounts, a scenario which cannot be simulated using tests at hydrostatic pressures. Therefore, complete

characterization of the permeability and acoustic properties of recovered cores as functions of independently applied overburden and lateral pressures is required to estimate:

- Permeability and preferred flow paths in an anisotropic stress field;
- changes in *in-situ* permeability resulting from changes in lateral pressures due to production, stimulation operations, and others;
- changes in *in situ* permeability due to reservoir gas pressure variations;
- remote identification of any of the above reservoir properties from acoustic and seismic data.

Figures 1 and 2 show some of the experimental setup that can be used for collecting above data in a laboratory. Figure 3 shows an example set of data on permeability variation as a function of overburden pressure. Figure 4 shows changes in acoustic response due to overburden pressure changes. These data provide valuable information regarding monitoring of a reservoir that is currently under production.

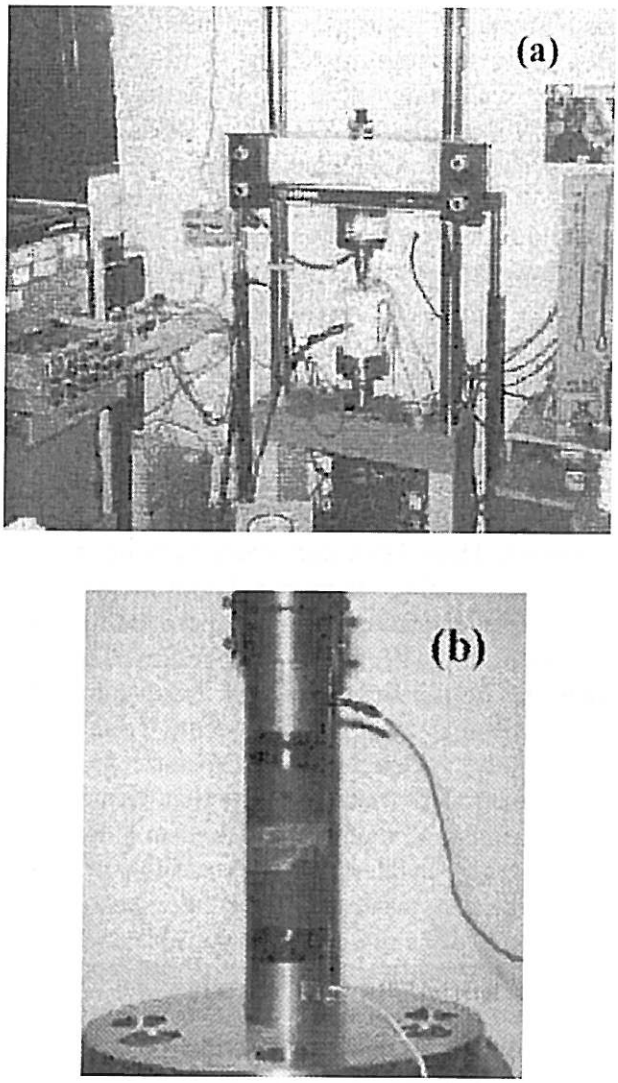


Fig. 1. Photograph of stress flow acoustic (a) and uniaxial (b) test facilities.

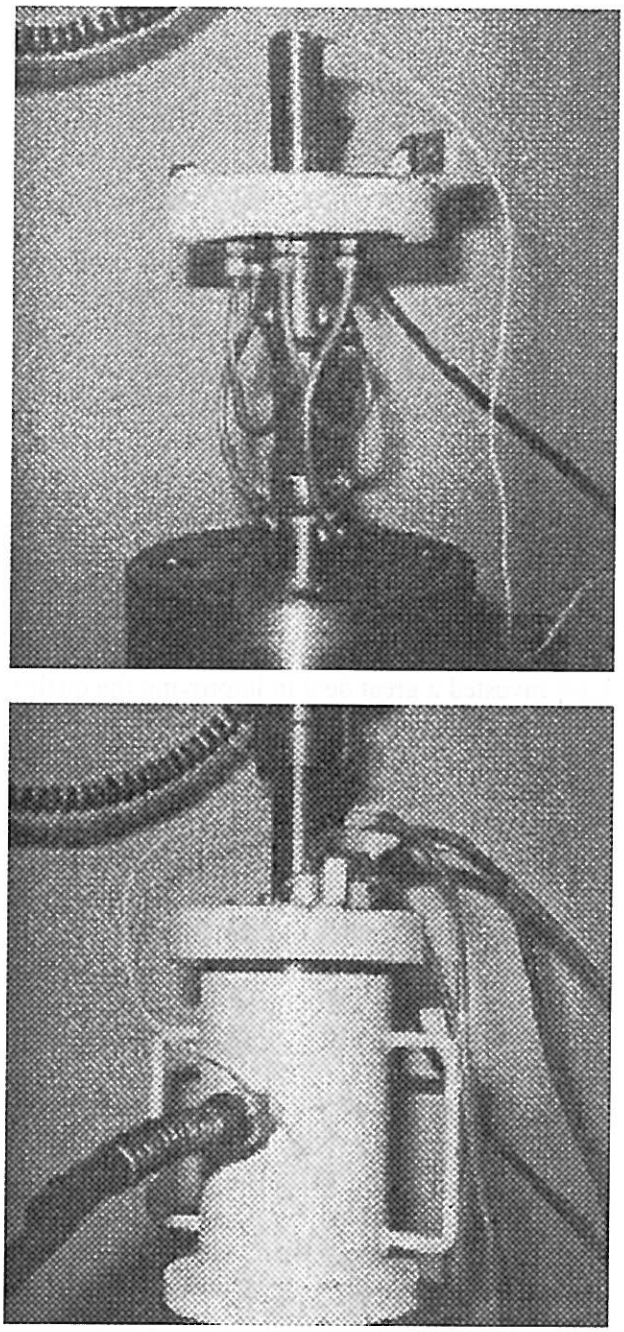


Fig. 2. Photograph of triaxial test facilities.

Infrastructures

In order to remain competitive in today's global economic environment, owners of civil structures

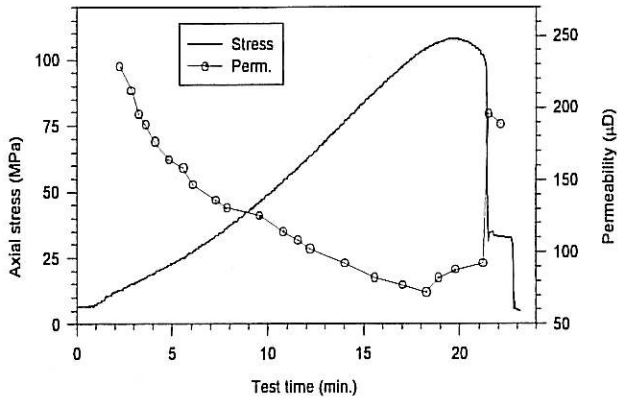


Fig. 3. Permeability variation with overburden pressure (vertical permeability as a function of varying overburden pressure – c.p. = 5 Mpa).

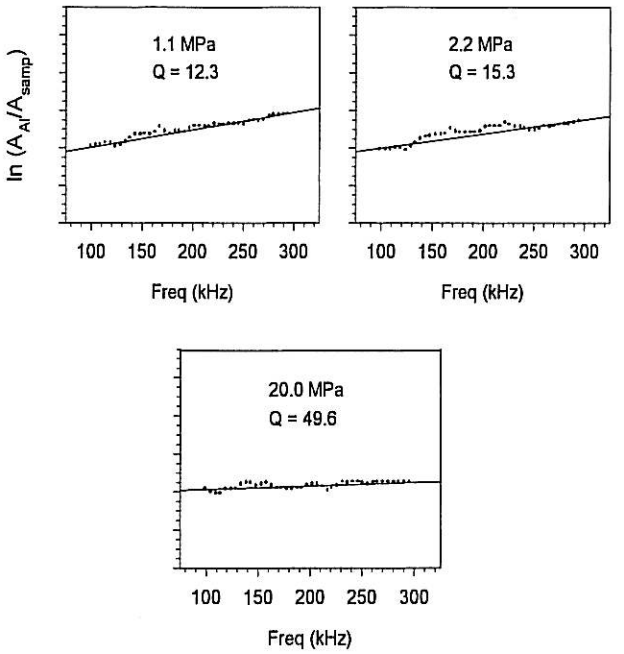


Fig. 4. Acoustic response for various overburden pressures (P-wave attenuation parameter Q as a function of overburden pressure (using spectral ratios method).

such as buildings, bridges, offshore platforms and reservoirs need to minimize the number of days their facilities are out of service owing to maintenance, rehabilitation or even replacement.. That is, they need to maximize the output of their system. Indicators of structural system performance, such as serviceability, reliability and durability are needed for the owner to allocate resources toward repair, replacement or rehabilitation of their structures. To quantify these system performance measures requires a structural monitoring system to monitor and evaluate the integrity of large civil structures while in service[26, 27]. The same applies to petroleum structures. Offshore structures are of particular significance in this regard for both structural monitoring and stress corrosion measurements.

FUTURE RESEARCH ACTIVITIES

Reservoir Characterization

The following steps should be taken in a 4D seismic research. 1) repeated acquisition of 3D, 3C seismic survey. Initial works have been done by Mari and Wicquart[28], who used acoustic log data obtained by dipole source imaging tool. 2) demonstrate the correlation between 4D, 3C seismology and rock/fluid property change associated with a production process. Past permeability-porosity correlations in this regard have used core data[29]. This offers a major drawback. Scaling criteria for upscaling core data to reservoir scale (resolution of meter) should be developed, using artificial intelligence. Initial efforts have made in this regard for upscaling well log data[30]; 3) incorporate geological, petrophysical, reservoir engineering, and other geophysical studies. Cross-well seismic should also be included. This can improve the resolution of reservoir petrophysical data [26-31]; 4) refine the reservoir models and recommend procedure for scaling; 5) link bulk rock/fluid property variation monitored by 4D, 3C seismic surveying to permeability, fluid saturations, flow characterization, and other dynamic attributes. The ratios of the P (pressure) and S (shear) velocities, Vp/Vs for both the fast and slow shear components can provide a tool for separating bulk rock changes due to fluid property variations from bulk rock changes due to effective stress variation. Also, changes in shear wave anisotropy may reflect varying concentrations of open fractures and low aspect ratio pore structures in both spatial and temporal sense across the reservoir. The permeability of a formation, or the connectivity of the pore space, will be the target for the 4D,3C seismology. This should be done in the following sequence: 1) Develop a technique that will be able to generate real time data that are compatible with the computer data acquisition system. Geological data should be used in reservoir characterization using factorial krigging analysis (FKA). This technique was first introduced by Matheron in 1982 and was successfully applied in integrating reservoir data with geophysical

data[32]; 2) Develop mathematical models, suitable for characterizing fractured and geologically complex reservoirs, using the theory of chaos, fractals, and solitons. An effective way of handling heterogeneity is to use multifractal statistics with some success[33]. 3) Couple these models with a compositional, integrated (with geomechanics and flexible wellbore model) simulator; 4) Develop an expert system for geological, geophysical, and reservoir engineering characterization. This integration of conventional reservoir engineering analysis with real-time monitoring, environmental impact and economic constraints has not been conducted in the past[10]. Even though expert systems (ES) and artificial intelligence (AI) did not live up to the expectations once touted a decade ago, they still offer an excellent tool for reservoir characterization[11,34-36]. The above reservoir characterization should be backed by fundamental studies of gas and gas condensate flow in porous media. Studies in this regard are still in their nascent state[37]. Several aspects of these need to be addressed with fresh approach. Conventional approach lacks depth in science and understanding of the fundamental. For the reservoir, new flow equations need to be developed for the following cases: 1) thermodynamics of gas condensates coupled with models capable of mimicking phenomena, such as condensate blockage; 2) geomechanics of fractured formations under thermal as well as mechanical stress; and 3) solid deposits (e.g. wax, asphaltene, hydrate) during gas production and its impact on wellbore blockage. Each of these factors can affect gas (or gas condensate) production significantly and should be predicted accurately in order to mitigate problems and optimize production strategies. However, to-date, coupled thermodynamic/ reservoir models have not been developed.

Effect of Dimensionality

Recent investigations have shown that dimensionality plays a role in modelling of complex rock/fluid interactions[38] or even during water flooding[39]. Figure 5 shows a schematic of the effect of dimensionality within a 3D system. It is conceivable that within a 3D system, dependence on grid size would be evident. Figure 6 shows how the grid size for 3-D cases would affect the prediction of oil recovery. Because no exact solution is available for

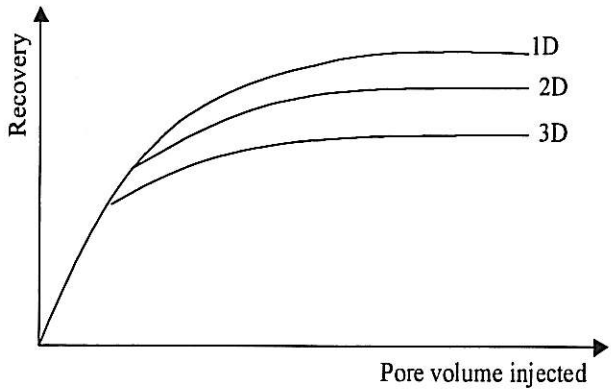


Fig. 5. Typical effect of dimensionality on predictions of recovery performance.

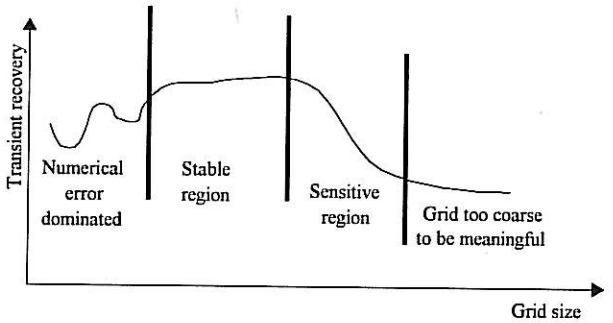


Fig. 6. Transient recovery (e.g. breakthrough recovery) for various grid sizes.

multiphase flow, it is impossible at this point to tell which ones are closer to the real solution. Experimental (both laboratory and field) observations are equally difficult to make under controlled and fully known conditions. Note that figure 6 pertains to uniform petrophysical properties. When heterogeneity dominates, the profile of Figure 6 becomes more complicated. It is well known that accurate knowledge of porosity is necessary for predicting fluid capacity of a reservoir. However, far more sensitivity is expected if prediction of a dynamic system with heterogeneity has to be made. Taking a simple case of known heterogeneity (Fig. 7), for which the permeability distribution (either shale streaks or higher-permeability zones) is known, one can show that the recovery prediction will be extremely sensitive to the grid size. For even this simple case, physical phenomena (related to Representative Elemental Volume, REV) overshadow the numerical problems, as shown in figure 8. Of course, one desires to operate in the stable region for which both physics and the numerical method are captured properly. This region is likely to be 1-10 m in the reservoir region, 1-10 cm in the near wellbore region, and 1mm-

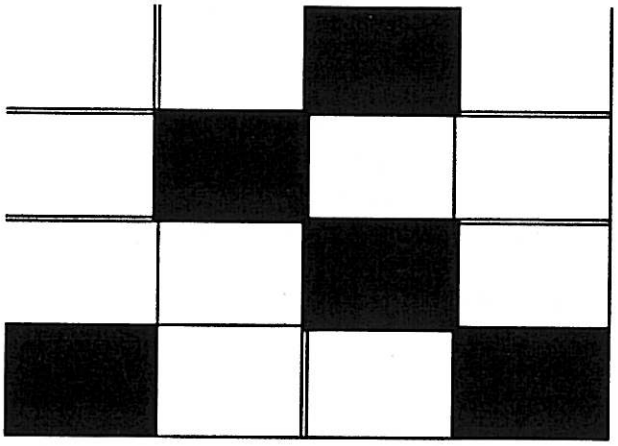


Fig. 7. A simple heterogeneity model.

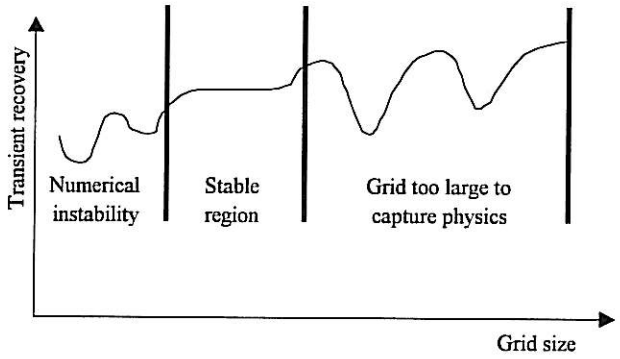


Fig. 8. Effect of grid size for heterogeneous formations.

1cm in the wellbore region, the latter two being significant only for reservoir simulators that are capable of modelling wellbore phenomena. A finer grid block would only increase numerical error, unless special techniques were used. For modelling viscous fingering in the reservoir, much smaller grid blocks are needed[40]. These sizes are so small that using such a grid distribution in the entire reservoir is unrealistic and calls for using dynamic refinement of the grid based on the location of the displacement front. Even though such an approach has been proposed in modeling in situ combustion, such method for modeling non-isothermal techniques has not been tested yet.

Another important factor is the fact that for refined grid blocks, petrophysical data are almost invariably absent for each block, owing to limitations in the data acquisition system. This problem is illustrated in figure 9. The upper part of this figure shows the number of faults resolvable per unit volume against the size of the fault that can be seen in meters. This figure clearly shows that a data gap of several orders of magnitude exists between the information provided by well logs or cores and information acquired through 3D seismic. With the currently available technique, the resolution of the data is limited by the highest frequency signal returning from the target that can be seen above the noise level. For a target depth of 2 or 3 km, the highest frequency is in the range of 50Hz which can yield a resolution of barely 20 m. If 1 m resolution in the reservoir is necessary, the current methods cannot provide one with this information. This problem is addressed by geostatistical methods that are used to generate required properties for each block of whatever size. Seismic data are downscaled while petrophysical data are upscaled. Seismic attributes analysis has been developed to obtain petrophysical parameters between wells. This method has some flaws. For instance, petrophysical properties (measured at cm scale) on a core are measured on the same core samples but with 1MHz frequency – 4 orders of magnitude higher than the one used in seismic surveys.

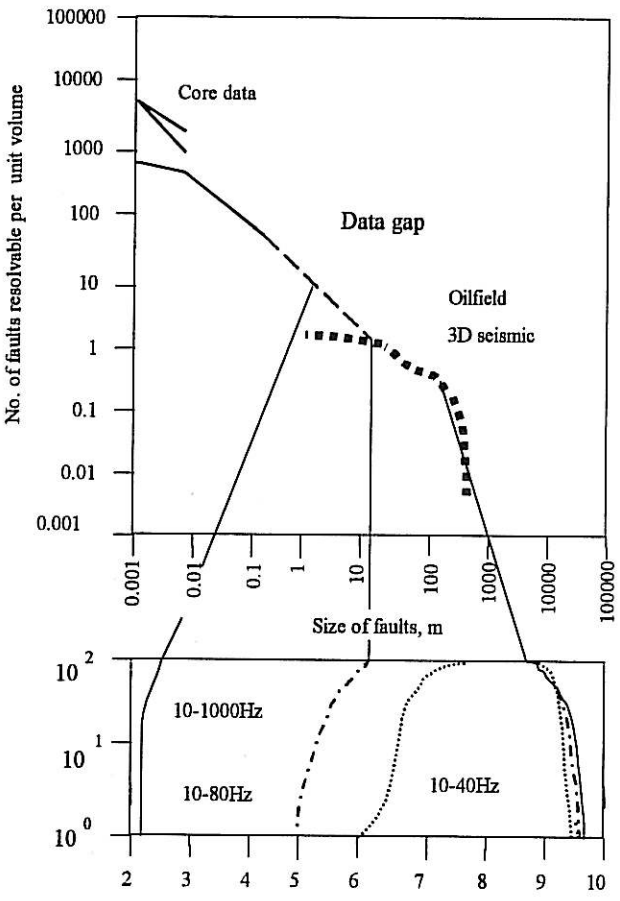


Fig. 9. Data gap in geophysical data acquisition

Seismic properties being frequency dependent, problems arise. The other problem is that the relationships, as derived in the laboratory, are assumed to be valid for seismic data, in which the smallest resolvable volume is six to nine orders of magnitude greater than the core samples. This latter aspect needs further investigation, as publications on the topic are rare.

Development of Technologies for In-situ Reservoir Monitoring

Current practice for monitoring reservoir performance is generally limited to pressure measurements and sampling at or near the well-head. Such well-head monitoring is limited because it provides little information regarding downhole conditions and for complex well systems (such as encountered routinely in off-shore fields) it is difficult to determine the relative production contribution from each well segment or production horizon. Further, when production problems are encountered, very little information regarding the location or nature of the difficulty is available, making remedial action difficult to plan and implement. To date, in situ monitoring has concentrated on high frequency seismic sensors to facilitate high resolution cross-well tomography and to monitor acoustic emissions from hydrofracturing and related enhancement procedures[41], but recent work has expanded to include high resolution imaging near the well bore using acoustic logging, ground probing radar, NMR, and even more traditional geophysical methods (*e.g.* electrical resistivity) calibrated for fine discrimination. However, limited battery lives, difficulties in maintaining communication/ power cables, and harsh operating conditions often result in short operational lives of this instrumentation, and there is a need to expand the scope of downhole measurements to include fluid temperature/pressure, chemical analysis, flow rate, etc. to better characterize in situ conditions.

Some measure of remote monitoring is provided by time-lapse seismics (Ref. 42), which uses laboratory data correlating reservoir conditions and seismic properties to identify characteristic changes in rock/fluid properties over time, but even this type of work would benefit from in situ data for the purposes of applying corrections and calibrating seismic results against measured reservoir conditions. However, under current practice (despite the clear benefits of expanded in situ monitoring operations as discussed above), most reservoir characterization and diagnosis of production problems must be done using production interrupting (and therefore very expensive) down-hole logging operations.

Improvement in Remote Sensing Ability

The current technology does not allow one to depict the reservoir, the wellbore, or the tubulars with acceptable resolution[32,43]. New techniques, which have seen applications in space research, can be used to develop more accurate techniques for mapping wellbores[44,45]. This technique, if successful, will become the most environmentally benign technique of all logging methods. The remote sensing research should also develop technologies for transmitting both downhole and wellhead data (chemical analysis of oil, gas, water, and solid) for real-time access from any desired location. Finally, methods should be developed to remotely conduct real-time control of various operations, in all locations, such as, the wellbore, production string, and pipelines. Recently, the use of NMR has been gaining popularity[46]. In this regard, service companies (e.g. Baker Atlas, Shlumberger are quite active in research). The objective in this regard is to develop an effective technique for improving resolution of wellbore imaging. In the next phase of this task, resolutions in the reservoir should be increased by using cross-well tomography[32,47]. In order to improve resolution within a wellbore, acoustic response should be analyzed. Such method has been attempted in the past in the context of wellbore mapping using sonic logs[28]. However, the possibility of using the technique to determine multiphase flow within the wellbore needs to be investigated. In addition, fibre-optic detection of multiphase flow should be investigated[21].

Recently, resistivity tomography has been proposed by Lawrence Livermore National Laboratories for developed improved images of the subsurface. The technique is based on the automated measurement and computerized analysis of electrical resistivity changes caused by natural or man-made processes. The inversion of the raw data is accomplished using a finite-element scheme. The technique can be coupled with the

4D seismic technology to develop finer resolution for subsurface mapping.

Instrumental Research

Video Logging

Recently, strides have been made in downhole cameras that can now operate in temperatures as high as 300°F and pressures up to 10,000 psi. It has an integral light ring to illuminate the wellbore and can perform in wellbores from 4 to 20 inches in diameter at depths up to 20,000 ft[48]. Currently, advances have been made in fiber optical transmission as an alternative to coaxial cable transmission. Fiber optics allow a superior quality of video transmission from downhole, irrespective of the length of the wellbore. Besides, a 7/32 inch diameter is far more flexible than a coaxial cable. Difficulties are encountered owing to imperfect transmission at high temperature and irreversible damage in a severed cable.

Videologging should not be considered as a replacement logging tool. It should be used to augment conventional electric logging. For instance, caliper and corrosion log results can be visually verified through a video log to plan a remedial operation.

Acoustic Logging

Medlin and Schmitt[49] reported acoustic logging based on wellbore resonance. This relatively new modification of conventional acoustic log uses stimulated Model Acoustic Long (SMAL) that relies on driving an acoustic transmitter at a selected frequency that corresponds to wellbore resonance, which is demonstrated by means of excitation logs. Remarkable signal enhancement was reported using the SMAL method. Recently, there has been a surge in using ultrasonic for wellbore logging. This medical technology (Ultrasonic Doppler) appears to provide one with a visualization tool for both dynamic[50] and static[51] systems. For the dynamic system, an ultrasonic signal emitted from a transmitter is reflected by scatters in the path of the beam. The velocity difference between the scattered and the transmitted signals results in a frequency shift (Doppler shift) of the returned signal. This frequency shift is proportional to the scatterers' velocity. For downhole applications, ultrasound is scattered at phase boundaries, such as oil/water droplets, gas bubbles, sand grains, fines or fluid turbulence. Although theoretically there is no upper or lower limit for velocity measurements, the measurement range is limited by the mode of signal interpretation scheme, and the geometry of the instrument[52].

Logging in Harsh Conditions

In order to keep up with drilling in increasingly deeper formations, research is being done to increase maximum operating temperatures of downhole well logging tools. Research in this area is focussed on developing special electronic circuits and in using high-performance materials. High-temperature applications specific integrated circuits (HTASIC's) are being developed to replace conventional logging tool electronics. These electronics are ultra compact, often taking as little as 5% of the space conventional circuitry. In terms of new materials, fibre optics are being proposed for transmitting data. Also, diamond and other heat and chemical resistant materials are being investigated for use in harsh environments, such as at high temperatures, H_2S, *etc*[53].

Fibre Optics Sensors

In the past, fibre optic sensors used to be considered only for measuring temperatures. They are now being extended to sense a wide range of additional parameters, such as, pressure, vibration, flow, and acoustic fields. In this, a distributed-temperature sensor is used for temperature profiling, an optically excited resonant-pressure sensor, an interferometric point sensor for pressure monitoring, and Bragg-grating-based sensors for range of parameters. This technology that finds its root in medical (chemical probes) and military (e.g. underwater acoustic arrays), is now being applied in civil-strucutural monitoring, industrial applications sensing (distributed spectroscopy), and security monitoring (intrusion detection). The advantages of this technology in oil and gas sectors are considered to be[54]:

- electrically passive;
- intrinsically safe;
- immune to elecromotive interference;
- operable at high temperatures;

- can be multiplexed or operated in a distributed mode;
- small cross-section and operationally flexible.

The scientific and industrial benefits of this work fall within the general scope of benefits of improved reservoir characterization. More specifically, however, accurate characterization of *in-situ* permeability and its relationship to gas pressure, lateral stresses and acoustic velocity/ attenuation is important knowledge for reservoir engineers and geoscientists regarding many aspects of reservoir analysis. These include, but are not limited to:

- Prediction of reservoir production over time;
- Correlation between drill stem test results and core data;
- Interwell communication/correlation;
- Analysis of shut-in tests and more reliable reserve estimation;
- Planning and implementation of stimulation and enhanced recovery schemes.

The tangible benefits of this research to industry will improve reservoir characterization, more effective use of technical facilities and expertise, and ultimately the potential for extended production from hydrocarbon fields at reduced operating costs.

In addition to the task of calibrating measurements with reservoir conditions, the greatest challenges in developing technologies for *in situ* monitoring are harsh operating conditions (*e.g.* high temperatures, corrosive fluids, *etc.*), instrumentation size limitations, and long-term difficulties maintaining power and signal cables. In light of these challenges, research efforts will concentrate on evaluating:

- Corrosion resistant materials (e.g. high temperature ceramics) for instrument components;
- Long life batteries and/or low power drain electronics;
- Transmitting electric or acoustic signals between in situ sensors and near surface receivers using steel casing and tubing;
- Piezoelectric sensors which generate their own high voltage signals in response to mechanical stimuli;
- Mechanical devices which "ping" the casing at a rate which can be correlated with pressure, flow rate, temperature, *etc...*;
- Techniques for differentiating between signals originating from multiple down-hole sensors;
- Passive acoustic sensors to "listen" for casing leaks, ruptures, and related production problems;
- Improvements to power/signal cables for long-term installation.

The most promising of these research components will be deployed in the field for *in situ* evaluation.

Regarding scientific and industrial benefits, the ability to monitor a reservoir *in situ* is a powerful tool for oil and gas companies and can assist with, among other applications:

- determining production contributions from various regions or well segments within the reservoir;
- facilitating more accurate surface and downhole time-lapse seismic monitoring;
- evaluating and monitoring stimulation and enhancement procedures;
- calibrating reservoir models and facilitating more accurate predictions;
- providing advanced warning of impending production difficulties to enable preventative and remedial action.

Monitoring of Petroleum Structures

Research should be dedicated to developing a structural monitoring system that will integrate, fibre optic sensor system, remote monitoring communication system, intelligent data processing system, damage detection and modal analysis system and non destructive evaluation system[26-27]. A similar system of monitoring devices, which will be capable of detecting signs of stress corrosion cracking should be developed. A fibre optic-based sensor system, and remote monitoring communication system will allow the monitoring not only of the internal operating pressures, but also the residual stress levels, which are suspected for the initiation and growth of near-neutral pH Stress corrosion cracking[55].

Real-Time Control System

The ultimate objective of monitoring is real-time control of an oilfield. This can be achieved if one can integrate reservoir models with vertical and surface network and monitoring systems [56]. Therefore, progress must be made in advancing the technology of remote sensing with data processing and continuous feedback systems. This aspect can benefit greatly from using artificial intelligence. Artificial intelligence should be used for solving both reservoir and production problems and to develop strategies for production optimization as well as smart design of enhanced oil recovery schemes. These analyses are incomplete without a decision support system that minimizes economic risk. A decision support system should be developed by integrating technical constraints with economical constraints as well as environmental impact. A fully integrated system that takes environmental constraints under considerations is yet to be proposed in the petroleum industry. Finally, one needs to develop virtual time travel capability in and out of the reservoir and couple monitoring systems with production control schemes. This will give petroleum engineers the long-desired ability to go for a site visit, the site being the reservoir and inside of various tubulars.

CONCLUSIONS

The need to monitor reservoirs and petroleum production systems is well recognized. Only recently, efforts are being made to integrate monitoring systems with reservoir characterization tools. Despite much scepticism, improved reservoir monitoring systems can increase the proven reserve several times in many instances. In this paper, the research opportunities in petroleum reservoir monitoring are identified.

ACKNOWLEDGEMENTS

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Defining Electrofacies from Logs and Core Data: Principles of Supervised and Non-Supervised Approaches

Gaël Lecante*, Pierre-Yves Dequirez** and Pascal Lavest*

معرفة السحنات الإلكترونية بواسطة السرود وبيانات العينات اللبية: أسس التطلعات الموجهة وغير الموجهة

ج. ليكانتي وبييرا ديكويرز وبسكال لافيست

إن التعرف على السحنات الصخرية المستنبطة من تسجيلات الآبار السلكية ومعايرتها باستخدام بيانات العينات اللبية يعتبر أحد مفاتيح التقييم الناجح للمكمن، وتحديد نوع الصخر حيث يمكننا من إشتقاق البيانات المدخلة واللازمة لبناء نماذج ثلاثية الأبعاد للمكمن.

إن التحليلات البيانية متعددة المتغيرات توفر الآلية الصحيحة التي تسمح بالآتي:

- تفسير تسجيلات الآبار السلكية وبيانات العينات اللبية.
- توقع السحنات الإلكترونية لعدد كبير من الآبار باستخدام مجموعة متكاملة من السرود.
- معايرة السحنات الالكترونية المستخلصة من سرود الآبار مقابل بيانات العينات اللبية.
- توقع السحنات الالكترونية في الأعماق التي لا تتوفر بها عينات لبية وكذلك الآبار التي لم تؤخذ منها هذه العينات.
- تحديد مقدار الريبة في تعيين السحنات باستعمال السرود.

هذه الورقة والتي اعتمدت على حالة دراسة حقيقية تصف طريقتين أساسيتين لتعيين أو توقع السحنات الالكترونية المستندة على التفسير البياني متعدد المتغيرات.

- الأسس غير الموجهة وهي تستند بدرجة أساسية على التفسير البياني متعدد المتغيرات لتسجيلات الآبار السلكية بغض النظر عن بيانات العينات اللبية.
- الأسس الموجهة هي التي تربط أو تدمج بين تسجيلات الآبار السلكية وبيانات العينات اللبية.

وكخطوة ثانية، فإنها تصف كيفية الربط بين هاتين الطريقتين بشكل ناجح وتكاملي لمعرفة أو للتوقع الأمثل للسحنات باستخدام السرود في الآبار التي توجد بها عينات لبية أو التي لا توجد بها هذه العينات.

- تفسير دالة الكثافة عديدة المتغيرات لتحديد تجمعات النقاط.
- تفسير هذه التجمعات لتعريف السحنات الإلكترونية باستخدام بيانات العينات اللبية.
- توقع السحنات الإلكترونية في المواضع التي لم تؤخذ بها عينات لبية وكذلك في الآبار التي تتوفر فيها هذه العينات.

Abstract: *The definition of log facies from wireline logs and their calibration against core data is one of the keys to successful formation evaluation and rock-typing. It allows to derive the input data that is essential for building accurate 3D geocellular reservoir models.*

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- *Multi-variate statistics provide the right tools that allow:*
- *to analyze wireline logs and core data;*
- *to predict electrofacies from a large number of wells and using complete sets of logs;*
- *to calibrate the detected log facies against core data;*
- *to predict the log facies at the non-cored intervals and non-cored wells;*
- *to quantify the uncertainty of the log facies determination.*

This paper, which is based on a real case study, describes two basic approaches for determining and predicting electrofacies, based on multi-variate statistical analysis:

- *A non-supervised approach, that is purely based on multi-variate statistical analysis of the wireline logs, regardless of the core data.*
- *A supervised approach, that integrates wireline logs with core data.*

As a second step, it describes how these two basic approaches can be combined to identify and predict optimal log facies at cored and non-cored wells, in an integrated and robust workflow:

- *Multi-variate density function interpretation and cluster identification*
- *Cluster interpretation and electrofacies definition, using core data*
- *Electrofacies prediction at the non-cored intervals and non-cored wells.*

INTRODUCTION

What is an Electrofacies?

Well data are a set of z values. A set of log measurements is associated to each z value. Data can be represented as shown in figure 1.

Samples are in a p-variable hyperspace, in which each axis is linked to a tool measurement (Fig. 2).

An electrofacies is nothing but a cluster of z values in the space. Its geological meaning is a priori known or it must be interpreted (from core data for instance).

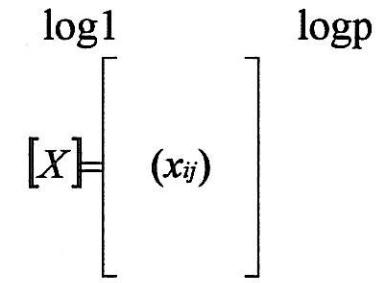


Fig. 1. Matrix of the data. (xij) = log j measurement at the point i.

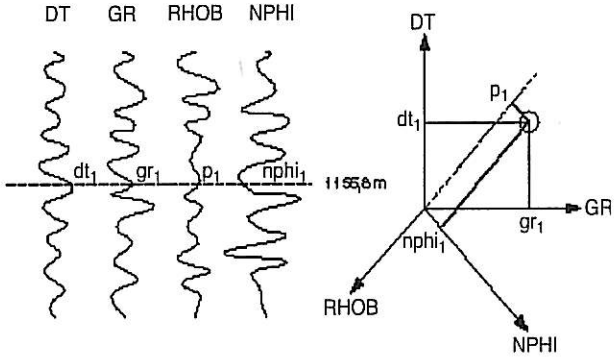


Fig. 2. Display of the samples in the log hyperspace.

The electrofacies gathering depends closely on the variables (logs) in use. The electrofacies definition and prediction presented in this paper combines a statistical analysis with the standard geological interpretation of logs (Fig.3). Logs and core data are both taken into account in order to generate facies logs that honour both pieces of information.

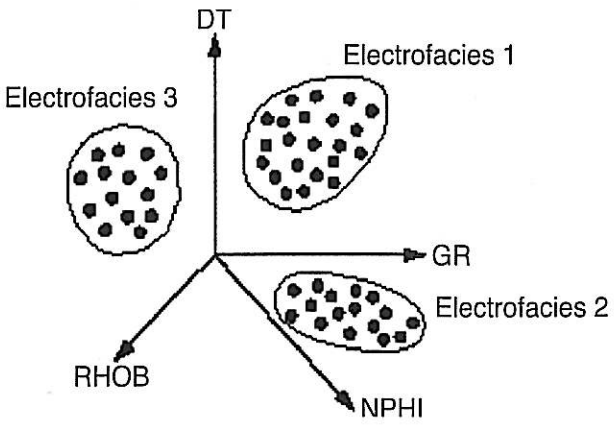


Fig. 3. Gathering into electrofacies.

Supervised or Unsupervised Approach?

Two different classification methods can be performed: a supervised and unsupervised. The supervised approach takes into account a priori data given by the geologist which constitute the "training sample". The number of classes and their log characteristics are determined by these data. When running unsupervised approach, the training samples are defined from the interpretation of the density function calculated on log data. The number of classes and the corresponding characteristic samples are decided and selected at this step. Their geological meaning will be interpreted from their location in cross-plots and/ or from core data.

In both cases, points not yet belonging to any class will be next assigned to a class according to a classification function created from the training sample.

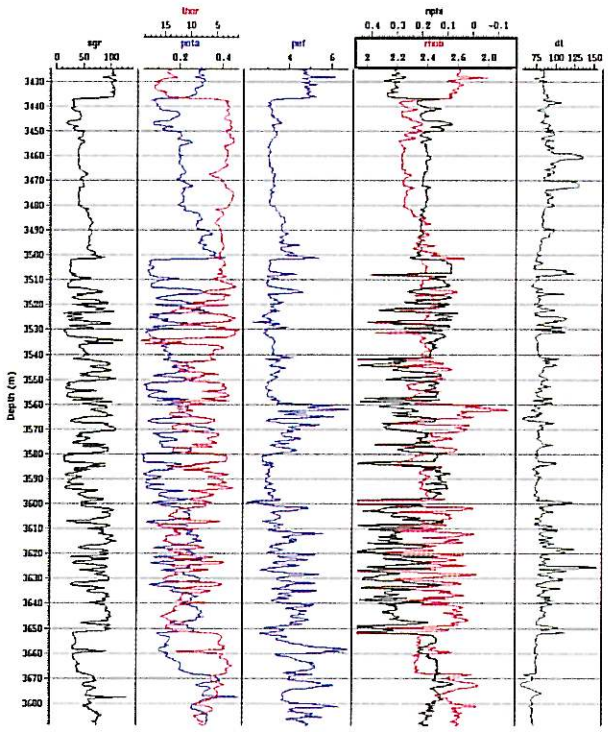


Fig. 4. Composite log

The two methods can be run independently or be linked together:

- electrofacies detected during an unsupervised approach can constitute a training population to add as a priori information to a supervised study;
- the geologist can add a priori supplementary class to these that have been interpreted during the unsupervised approach.

The study we use for showing the electrofacies definition methodology study takes place in a fluvio-deltaic environment. Figures 4 and 5 display the composite log and some classical cross-plots.

The Unsupervised Approach

The unsupervised approach can be divided into 3 important steps.

- density function estimation,
- density function interpretation: number of classes, creation of the training sample,
- data points assignment.

Density Function Estimation

An electrofacies is nothing but a gathering of points together in the log hyperspace. Electrofacies classes constitute a set of points separated by areas with low density of points. By detecting and analyzing the variation of the density in the log hyperspace, it is possible to detect these different sets. The number of density peaks defines the number of classes. Points highlighted in these zones of high density correspond to the most typical samples of each class.

The probability density function (PDF) describes the distribution of a variable and gives its associated probabilities. In a univariate case, the PDF is often described in a discrete manner with a histogram. However this histogram is not a good density function estimator. It does not give the number of samples for a particular value; it only gives the number of samples that fall into an interval.

In a p-dimension space (corresponding to the p logs which are used), the PDF is estimated using KNN (K nearest neighbors) or kernel techniques (Gaussian, Epanechnikov, *etc.*). If only one variable is used, the density function is a curve (that can be approximated by smoothing a histogram). If two variables are used, the density function is a surface with valleys and hills like a topographic surface. When more variables are

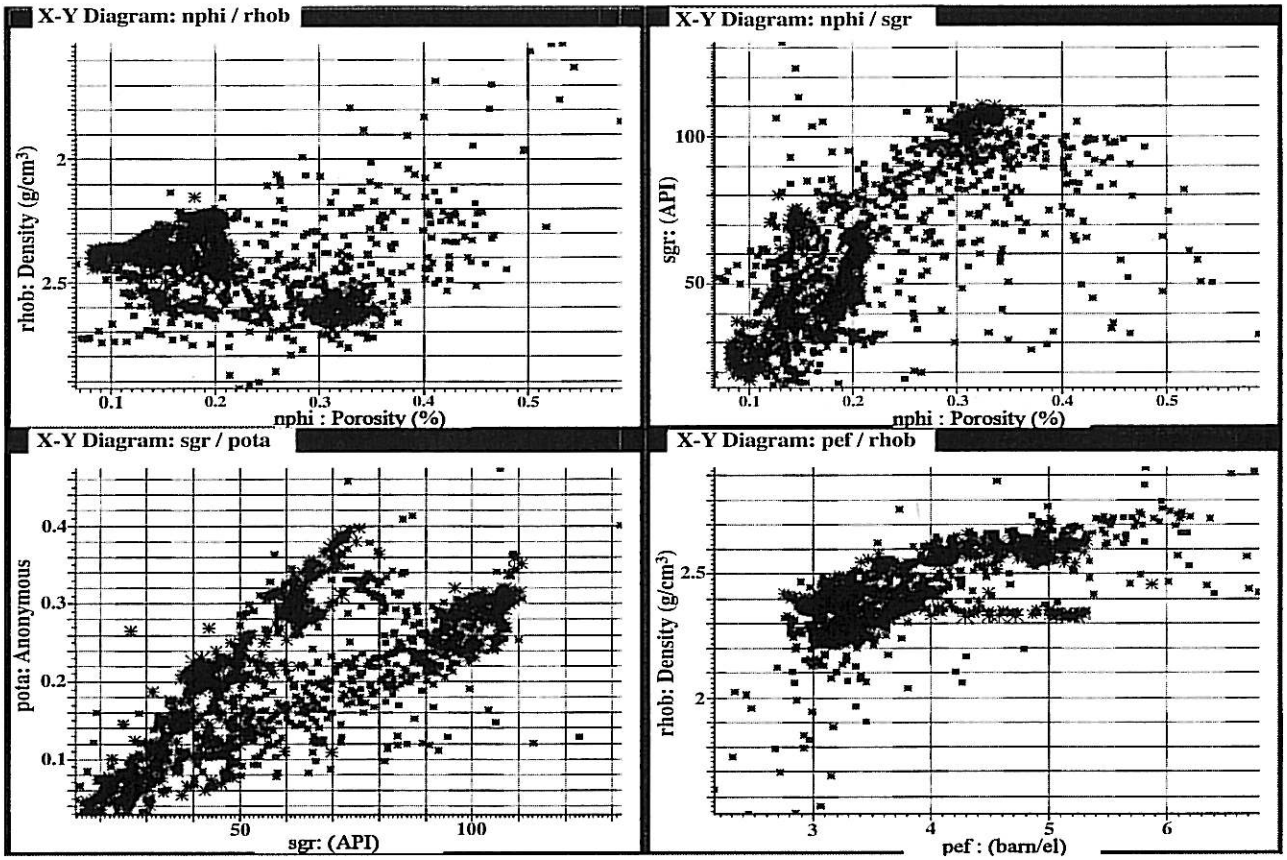


Fig. 5. Cross-plots

used, it is not possible to represent the PDF, however, we can analyze the peaks of the PDF using Kittler algorithm[1]. This technique is called the mapping of the PDF or PDF mode mapping (Fig. 6):

- A random point is chosen.
- A neighbouring is defined in order to calculate the slope in all directions.
- The next point is chosen from nearby in order to move as far uphill on the PDF as possible (*i.e.* the greatest slope is used)
- The process goes on until reaching a density peak.
- From this, the following points are selected in order to ensure that one moves as little downhill as possible until a minimum of the PDF.

This gives a path that climbs steeply uphill to a mode and then goes down slowly, visiting all points. The neighbouring, called « Mode mapping parameter », is the smoothing parameter to choose. If it is too big, you loose information about density. If it is too small, all the details are mapped, even the small ones, introducing noise in the interpretation.

Assignment of Samples to a Class: the Classification Method

The next step of the classification aims at classifying all log samples. At this point statistical techniques such as discriminant analysis or pattern recognition can be used. In the methodology presented in this paper, the discriminant analysis is used. It is fast, robust and has shown an unmatched efficiency and reliability on any type of environment (clastics and carbonates).

In a discriminant analysis, the probability of belonging to a class is computed for each sample. The point is next allocated to its most probable belonging class. This calculation uses the well-known Bayes formula. Various kinds of discriminant functions can be used for classifying the samples:

- The linear hypothesis: the covariance of each class is assumed to be the same,
- The quadratic hypothesis: for each class a distinct covariance is calculated from the training sample.
- Non-parametric hypotheses can also be made.

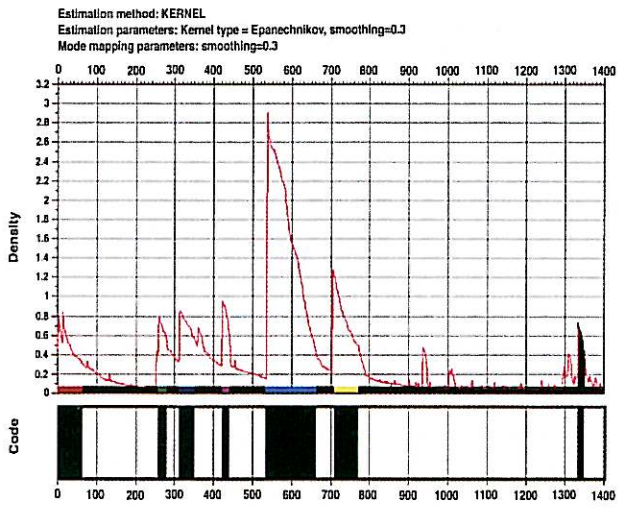


Fig. 6. Density function mapping

In such a case, the probability laws for each class have to be estimated using Kernel or K Nearest Neighbors methods. These laws are nothing but the PDF of each class.

Obviously, the less hypothesis on the model is assumed, the more closer we are to the reality. Ideally, the non parametric approach is the most promising, but with this approach, we need a lot of points in the training sample to obtain a reliable result

Once the assignment method is chosen, the training samples are stored as non allocated points (Fig. 7a & b). The method efficiency can be evaluated by computing the percentage of well-assigned samples (i.e. which are allocated to their actual class).

In the example displayed on figure 8, all samples are correctly assigned, whatever the method is chosen. However, this method is it underestimates the error rate because observations to evaluate the classification results are the same to build the classification rules.

For this reason, a second series of validations is carried out. A sample is taken out of the training sample before building the classification rules. It is re-allocated using this rule afterward. This is a more pessimistic but realistic measure of the classification efficiency (Fig. 9).

In the case displayed on figure 9, all the samples of the class 6 are not correctly assigned using the non parametric method. Quadratic and linear hypothesis give good results. Cross

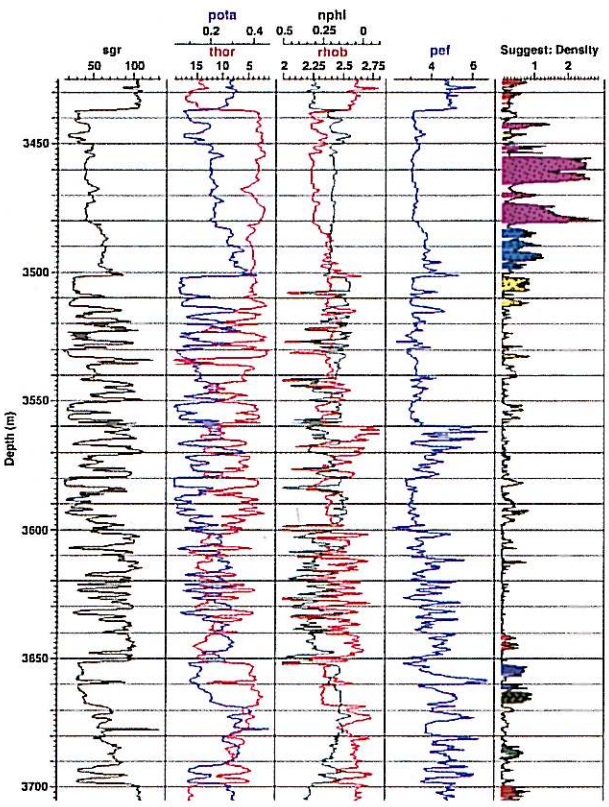


Fig. 7a. Highlighting the training samples on composite logs

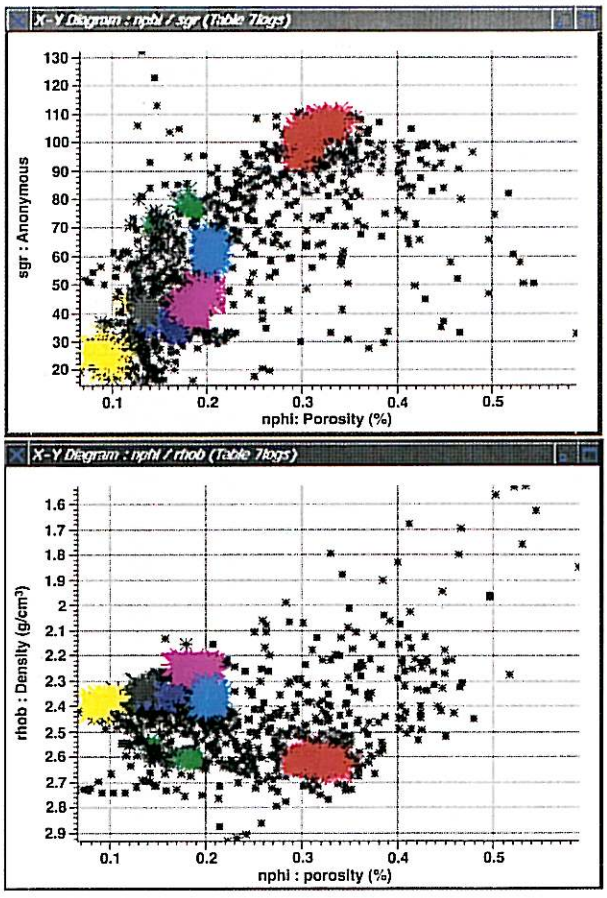


Fig. 7b. Highlighting the training samples on cross-plots

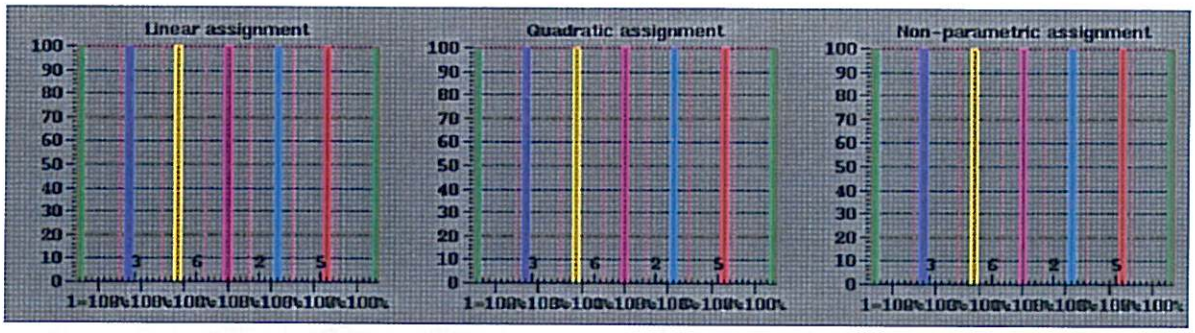


Fig. 8. Direct validation results.

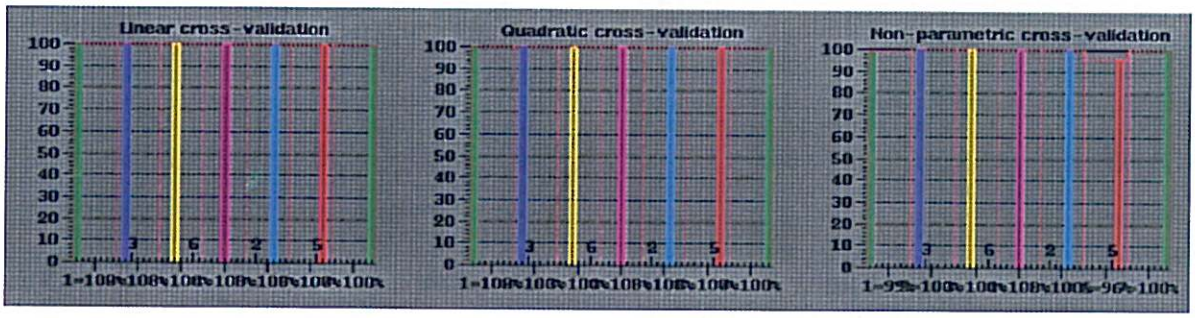


Fig. 9. Cross validation results.

validation is interesting, in the linear and quadratic case, only if the number of points is not too large. Otherwise, if you remove a sample from a lot of points, it has a little impact on statistical methods using only mean and covariance matrices. However, in a non parametric case, this diagram is always interesting to be consulted because removing even one point could affect intra-class density estimations.

The results, obtained with the linear hypothesis are displayed (Fig. 10a and b).

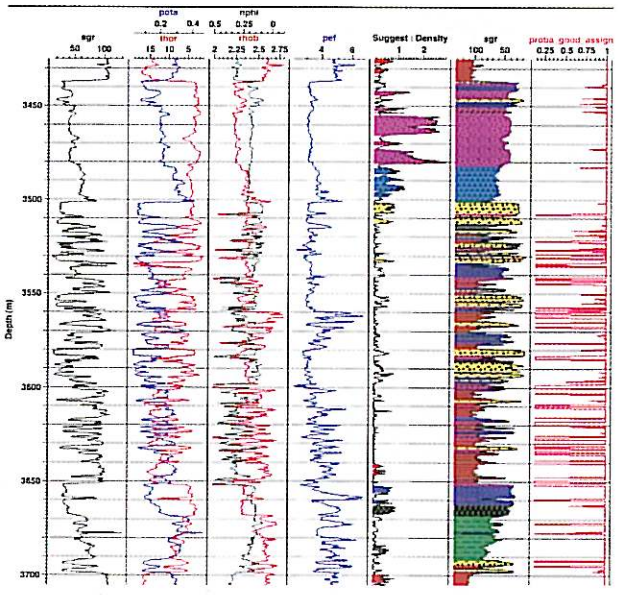


Fig. 10a. Assignments results: logs

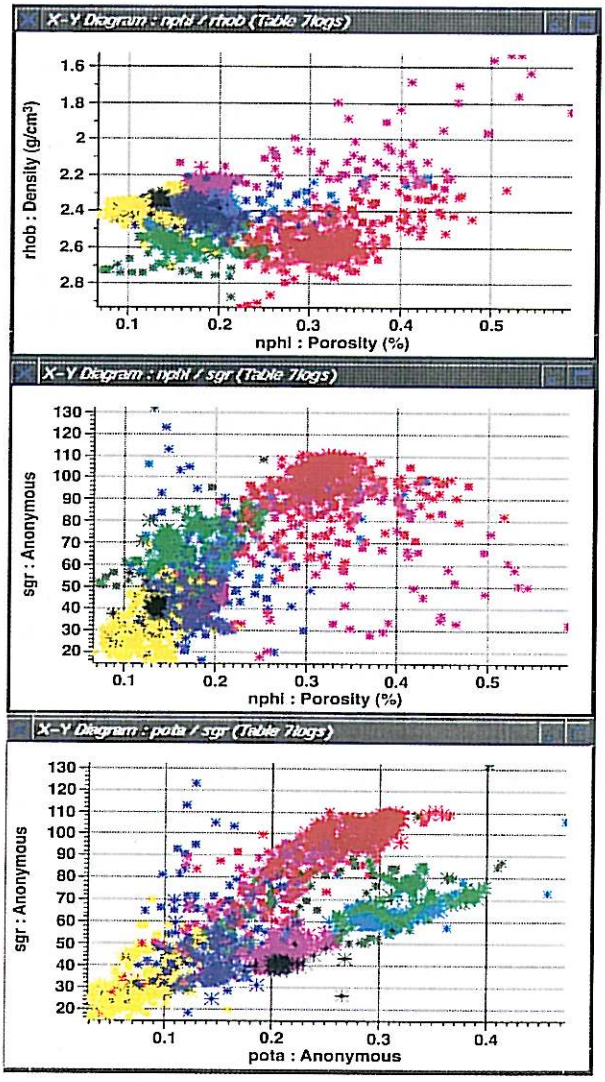


Fig. 10b. Assignments results: crossplots.

At this point, the probability of good assignment is also calculated. It quantifies the uncertainties and controls the quality of the newly built lithologic column. In figure 11a, 10% of the samples are allocated to a class with a very small probability. These samples are outlying as we can see on the cross-plots on which they are highlighted as triangles (Fig. 12).

Supervised Approach

In a supervised approach, we have a priori training sample coming from a geologist prior interpretation. The number of classes is given, it is a part of the geological a priori. The classification function is created from this a priori

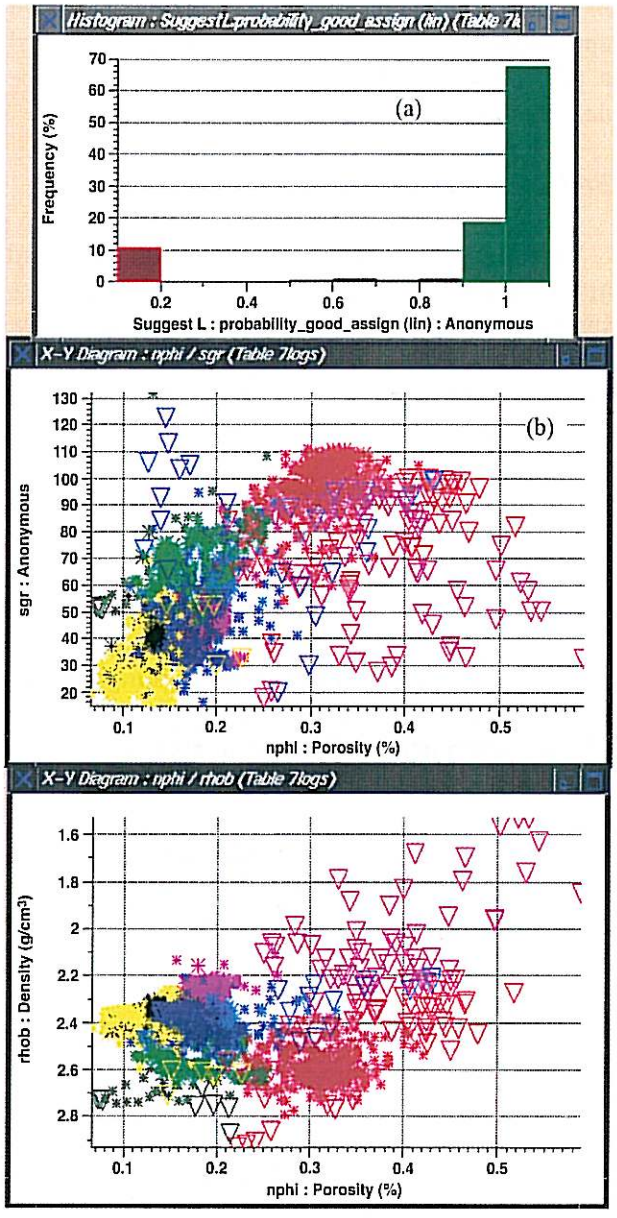


Fig. 11. Highlighting points with a not reliable assignment.

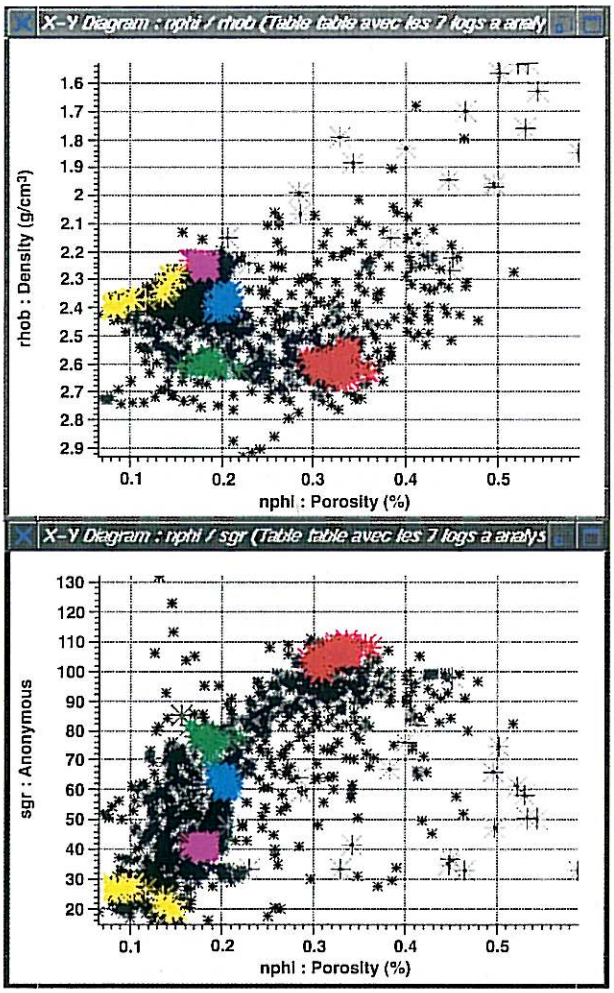


Fig. 12. Training samples displayed on cross-plots.

training sample. All the points will be assigned to a class using this classification function.

Everything is known since we have already discussed the discriminant analysis in the frame of the unsupervised interpretation: we have to choose the hypothesis (linear, quadratic or non parametric), in order to run the classification and check the results.

The Training Samples

In this case, we have to highlight a class of coal not discriminated during the unsupervised approach (Figs. 7a and b). In fact, a class can be identified if it forms a statistical population. Scattered points in the log hyperspace cannot be detected using a unsupervised approach. In the case of a supervised approach, samples with characteristics close to coal will be assigned to a coal class, which does not correspond to the real situation. As a consequence, the set of training sample is very important. The

confidence in the results depends on the confidence in the training samples.

Choosing the Discriminant Method

In the case presented here, the cross validation shows that the linear method does not allow a reliable identification of the coals. We cannot use the non-parametric method either, as we only have 205 training samples (20 to 50 per class), which is not enough. At last, if we use the quadratic assumption, almost 70% of anonymous samples were classified into the class of coals. This is not good but foreseeable, as Coals have very scattered log responses.

The quadratic method computes each class covariance from the training sample. If sample characteristics are very dissimilar, the class covariance will be very high and the attraction of this class will be very important. In our particular case, we want to highlight samples with no typical features. The quadratic assumption is not reasonable.

Consequently, we have to use the linear hypothesis, even though we know that the discrimination may be not as reliable as expected. The obtained results (Fig. 13) are assigned to the different classes in a way that is consistent with the geological expectation.

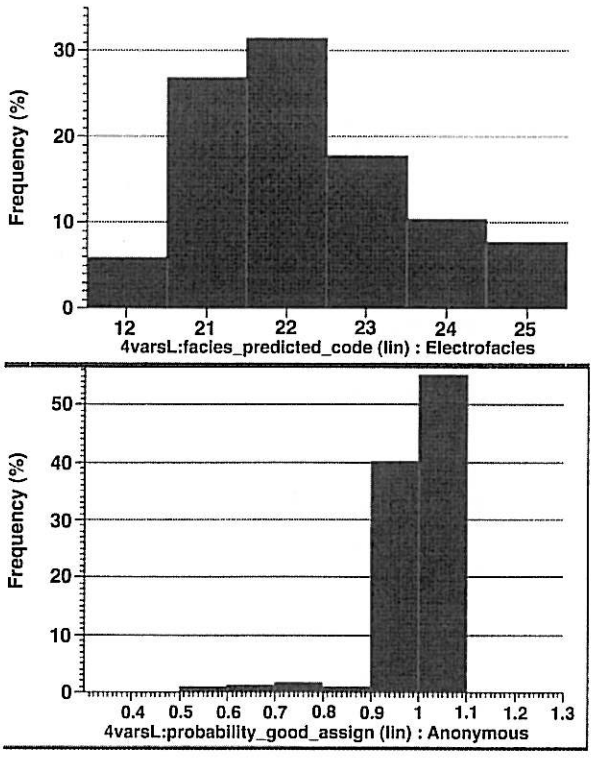


Fig. 13. Samples distribution and probability of good assignment.

As a result, an electrofacies log, calibrated to the geological model, are obtained. They have to be compared to the unsupervised log result.

Supervised or Unsupervised Approach?

Both of Them Can be Used Together

Even if you have an a priori information, both approaches have to be performed, to ensure a better control on the predicted facies. The unsupervised approach increases your knowledge about the sample distribution in the log hyperspace. The convergence in results of the two approaches is a way to confirm that the geological a priori used in the supervised method can be detected on the available logs.

Both of Them Can be Linked

In our particular case, the unsupervised approach did not identify the coals, which are very important from the geologist point of view. Conversely, the supervised approach did not take into account some classes that appear on the density function.

Samples allocated as coals can be used as constrains to unsupervised approach. The samples corresponding to coals can be picked on the PDF (Fig. 14).

The coals are now a part of our training sample, used in the unsupervised approach. The classification using a linear rule gives the results that we can see in figure 15.

The coals seem accurately identified. The seven classes discriminated during the unsupervised approach are consistent with the a priori information.

Automatic Interpretation of the Other Wells of the Field

The well that has been studied first is now used as the reference. The obtained classifier allows an automatic interpretation of all wells drilled in a similar geological environment in this reservoir.

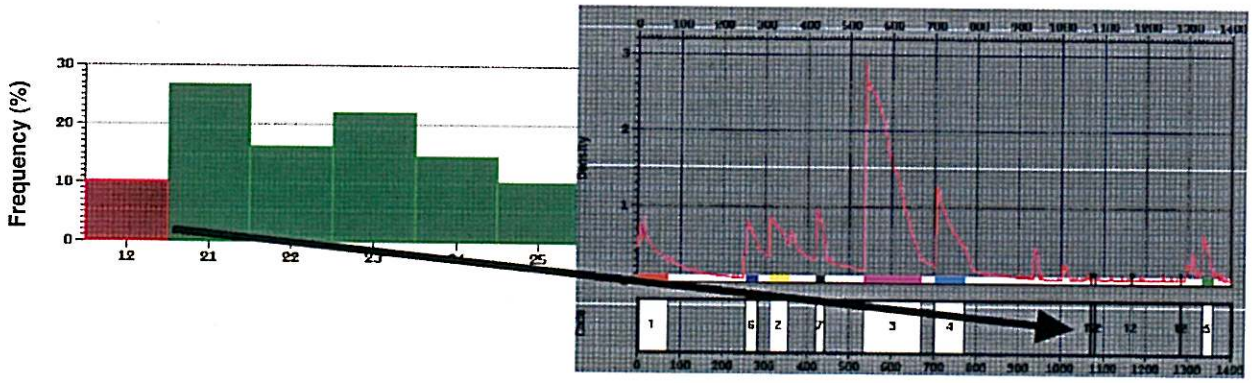


Fig. 14. The training coals are selected on the a priori histogram and a class is created.

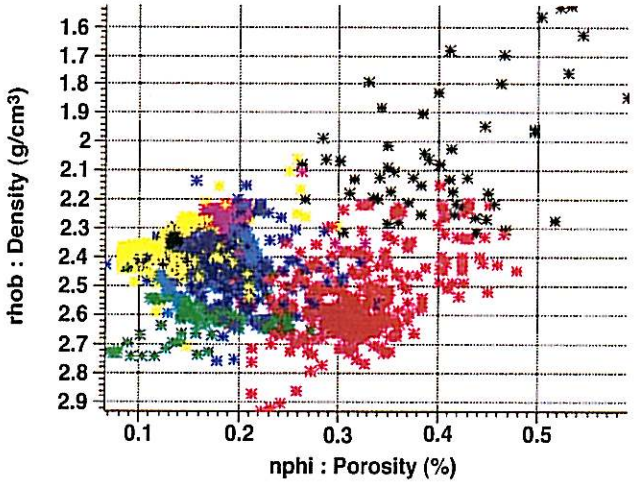


Fig. 15. The coals are identified.

If we consider a second well, where the spectral components of Gamma Ray was not acquired, the previous classifying rule cannot be applied directly. A new one has to be defined using all available logs as Nphi, Rhob and GR.

The new rule is instantly created using the unsupervised application with the training sample selected previously. The newly built classifying function allows the assignment of the samples of each well to classes.

The multi-variate statistical approach for accurate electrofacies determination at wells, within the non cored intervals and at the non cored wells is extremely robust and easy-to-use, and has been applied on a large number of studies, for both clastic and carbonate reservoirs. Thus, it is also used as a starting point of rock-typing, as it is far easier to infer rock-types from calibrated electrofacies at wells, than from raw wireline logs.

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Petroleum Res. J. Vol. 13 (2001); P. 57–64, 10 Figs.

The Role of Principal Component Analysis (PCA) in the Delineation of Lithofacies Based on Well Logs

Omar E. Suleiman* and Zoltan Kelemen*

دور تحليل المركبات الأساسية في وصف السحنات الصخري باستخدام سرود الآبار

عمر محمد سليمان وزلطان كيليمان

تم استعمال مجموعة من سرود الآبار في حوض غدامس للمقارنة بين فعالية الطرق المختلفة المستخدمة في تعيين حدود السحنات الصخرية بالبئر. وقد وجد أن التحليل الإحصائي الكمي للتركيبة الصخرية باستعمال ستة سرود أكثر فعالية، حيث أنه يستعمل المعلومات الجيولوجية خاصة المتعلقة منها بأنواع المعادن الداخلة في تركيبة الصخور أو التكاوين المختلفة.

وكنتيجة لذلك فهي تعطي الأحجام الجزئية للمعادن الداخلة في التركيبة الصخرية والمسامية، وحجوم الصخر الطيني ومعادن أكسيد الحديد. ويمكن تقسيم أي مرحلة من العمق إلى أجزاء من صخور مسامية وأخرى يتداخل فيها حجر رملي وطفلة على هيئة رقائق، وطفلة غير منفذة.

تم تطبيق التحليل البياني للمركبات الأساسية في نفس البئر لتحليل السحنات الصخرية. كما تم إختبار الأصناف المختلفة لهذه السحنات على أساس الرسم البياني التقاطعي بين المركب الأساسي الأول والمركب الأساسي الثاني ورسمت الحدود بين الطبقات أو التكاوين المختلفة بناء على ذلك.

طبقت طريقة التحليل الاحصائي الكمي في حالتين، أحدهما باستخدام ستة سرود، لتعيين التركيبة الصخرية، والحالة الأخرى باستخدام قياس أشعة جاما، وقياس التوصيل الكهربائي. وفي كلتا الحالتين تم تعيين السحنات الصخرية بناء على تحليل المركبات الأساسية.

وتمت مقارنة النتائج مع طريقة التحليل التفصيلي للتركيبة الصخرية، كما استخدمت هذه الطريقة أيضاً في تقدير الحجم الجزئي للمسامية والطفلة ومعادن أكاسيد الحديد.

Abstract: *A rich set of well logs were measured in a well in Ghadamis Basin, Libya. These data are used to compare the effectiveness of the different methods used to delineate lithofacies boundaries in the borehole.*

Quantitative statistical lithology analysis, based on six logs, is found to be the most effective. It utilizes geological information, particularly the knowledge of mineral types occurring in the formations. It provides volume fractions of minerals including porosity, volumes of shale and ferroan minerals. The depth interval can be divided into segments of porous reservoir rock, sandwich-type development with alternating sand and shale laminae, and impermeable shale.

The statistical method of principal component analysis (PCA) is applied for lithofacies analysis

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in the same well. Lithofacies categories are selected on the crossplots of the first principal component, (PC1) vs. the second principal component, (PC2). Formation boundaries are delineated based on lithofacies analysis.

Two PCAs were applied: one from the six logs, also used for lithology interpretation, the other from two inputs: gamma ray and conductivity. Lithofacies were delineated based on both of the PCAs and compared with the results of detailed lithology interpretation. PCA is also used for volumetric estimation of porosity, volumes of shale and ferroan minerals.

THE TASK OF LITHOFACIES ANALYSIS

Lithofacies are typical associations of rock forming minerals, *e.g.* sandstones, shales, carbonates, shaly sandstones *etc.* Recognition and understanding of lithofacies are important in geological research and oil exploration. Well log measurements, supported by cores, provide information on lithology. The delineation of lithofacies categories *vs.* depth creates the base for the determination of formation boundaries which is crucial in basin and reservoir analysis.

The methods applied for this task are exhibited in well A1-NC162 in the Ghadamis Basin of western Libya. A rich set of well logs was measured in this well, and subsequently a detailed analysis of lithology was performed. Statistical qantitative lithology interpretation, based on six input well logs, was carried out. The input logs are: bulk density (ρ_b), neutron porosity (Φ_n), photoelectric effect (Pe), sonic Δt, potassium and thorium content (the last two are components of spectral gamma ray measurement).

In the lithological interpretation 12 different minerals or lithological rock components were determined. Different rock models were applied with five or six components simultaneously; at each depth site the model, minimizing the statistical error (incoherence) was selected. The lithology (in simplified form) is displayed on the upper track of the strip log (Fig. 1a and 1b). Porosity, sand, calcite, laminated shale, dispersed shale (clay), ferroan minerals (oxides

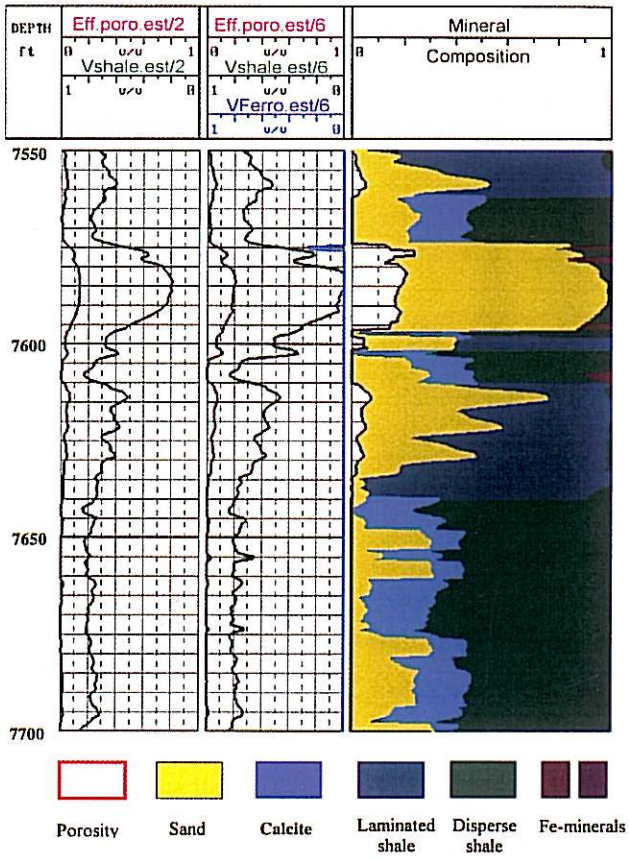


Fig. 1a. Strip log of lithological interpretation (well A1-NC162, 7550′ - 7700′).

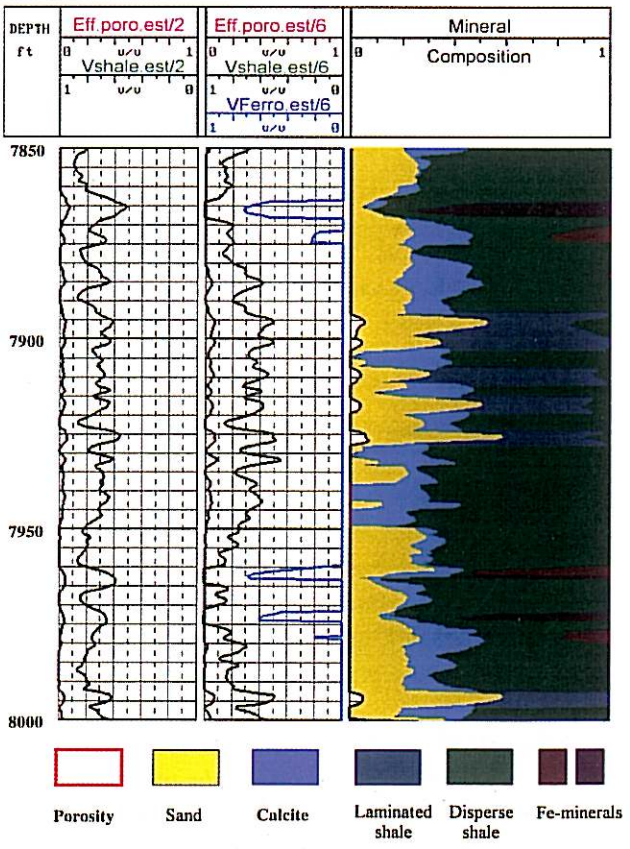


Fig. 1b. Strip log of lithological interpretation (well A1-NC162, 7850′ - 8000′).

& hydroxides) are displayed in variation diagrams.

Some typical rock developments can be recognized on the strip log. Clean sandstone with 15 – 20 % effective porosity and subordinate shale appears at the drill depth of 7575′ – 7595′. A strip of shale with no porosity, 50 – 60 % dispersed clay with some calcite and silt is positioned above it. Sandwich-type development of alternating layers of sand and impermeable shale are present in the interval 7610′ – 7640′. Porosity increases upwards from 1 % to 7 %, while the amount of shale decreases from 95 % to 25 vol. %, the rest consisting mainly of sand.

Investigating another section of the well, a rock development typical of high concentration of ferroan minerals occurs; the volume fraction of ferroan minerals reaches 60 % at 7962′ and 7974′ and even 80 % at 7866′.

PRINCIPAL COMPONENT ANALYSIS

In basin analysis studies, where several thousand feet thick intervals of a large number of wells (over hundred) are studied, the detailed lithology interpretation is not practical. The set of available input well logs may be very heterogeneous. Other information (geological description, core data) may be inadequate and the amount of necessary work is enormous. For this task, a simpler, but more efficient way of lithofacies analysis, was developed (Marriott, 1980) in the Petroleum Research Centre.

The multivariate statistical method of PCA Marriott, 1980 is used to extract the information contained in the well logs input and is capable of revealing some hidden factors which are reflected in the values of the well logs. These factors depend on the geological environment and on the set of input data. In well A1-NC162 the same six well logs are used as inputs which were applied for the statistical lithology interpretation. Therefore, the dominant factors are porosity, shaliness and presence of ferroan minerals.

Table 1 presents the most important mathematical parameters involved in the principal component analysis in the well of this study. The matrix of correlation coefficients reveals the internal relationships between the input variables. Strong correlations occur between ρb and Pe, Φn and Δt, thorium and potassium *etc.*

Table 1. Principal component analysis from 6 input logs (well A1-NC162)

Variable	Mean	St. dev.
RHOB	2.5721	0.1306
PEF	3.6727	1.3271
NPHI	0.2523	0.0594
DT	69.2614	4.5393
THOR	11.6414	3.6456
POTA	0.0189	0.0070

Correlation matrix

Variable:	RHOB	PEF	NPHI	DT	THOR	POTA
RHOB	1.000	0.617	0.555	-0.049	0.680	0.569
PEF	0.617	1.000	0.509	0.301	0.356	0.118
NPHI	0.555	0.509	1.000	0.628	0.736	0.575
DT	-0.049	0.301	0.628	1.000	0.306	0.131
THOR	0.680	0.356	0.736	0.306	1.000	0.735
POTA	0.569	0.118	0.575	0.131	0.735	1.000

Eigenvalues and eigenvectors

	PC1	PC2	PC3	PC4	PC5	PC6
	3.373	1.189	0.947	0.220	0.164	0.108
RHOB	0.433	-0.407	0.338	-0.097	-0.276	0.669
PEF	0.342	0.158	0.747	0.287	0.338	-0.321
NPHI	0.488	0.266	-0.103	-0.076	-0.713	-0.408
DT	0.248	0.781	-0.185	0.086	0.194	0.500
THOR	0.484	-0.143	-0.234	-0.654	0.482	-0.177
POTA	0.403	-0.330	-0.478	0.684	0.176	-0.048

The other section of this Table contains the eigenvalues (reflecting the importance of the principal components) and the eigenvectors (describing how the PC-s are constructed from the inputs). It is clear that the first three principal components concenrate more than 90 % of the information contained in the inputs.

DETERMINATION OF LITHOFACIES BY PCA

All points of the investigated depth interval are shown on the crossplot of principal components PC2 *vs.* PC1 (Fig. 2). The points are colour coded according to the lithofacies categories shown on the legend of the figure.

The methodology behind creation of the lithofacies categories is the following:

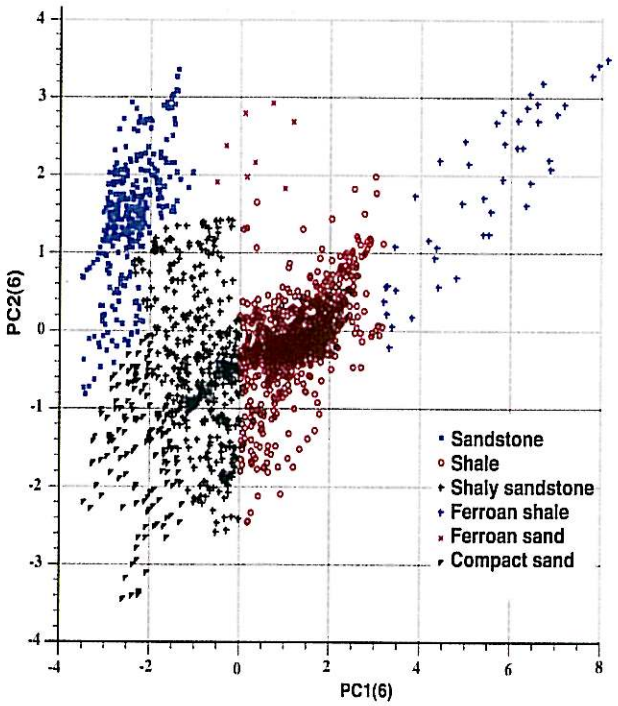


Fig. 2. PC2 vs PC1 (6 logs) (well A1-NC162).

- Recognize the clusters of concentrated points on the crossplot of PC2 *vs.* PC1;
- Identify some typical points of the crossplot on the strip log of detailed lithology evaluation; if necessary, check values of input logs;
- Determine the basic lithology type of the clusters - *e.g.* sandstones, shales, ferroan shales *etc.*
- Carefully draw the discriminating lines between categories.

The crossplot of PC3 *vs.* PC1 is presented (Fig. 3). Here the main categories of shale, shaly sand and sandstone can be distinguished, but less clearly, on a compressed scale. However, the group of ferroan shales is well separated.

Lithofacies analysis is also carried out in older wells where the set of measured well logs is poor. An experiment was made in well A1-NC162 with a two-input PCA involving only gamma ray and deep induction conductivity. Figure 4 shows the crossplot of PC2 *vs.* PC1 in the investigated interval; the points are colour coded by lithofacies categories. Here the categories of shale, sandy shale and compact sand are somewhat mixed, however, the facies of clean sandstones is well defined. This combination is not favourable for the separation of ferroan mineral concentrations.

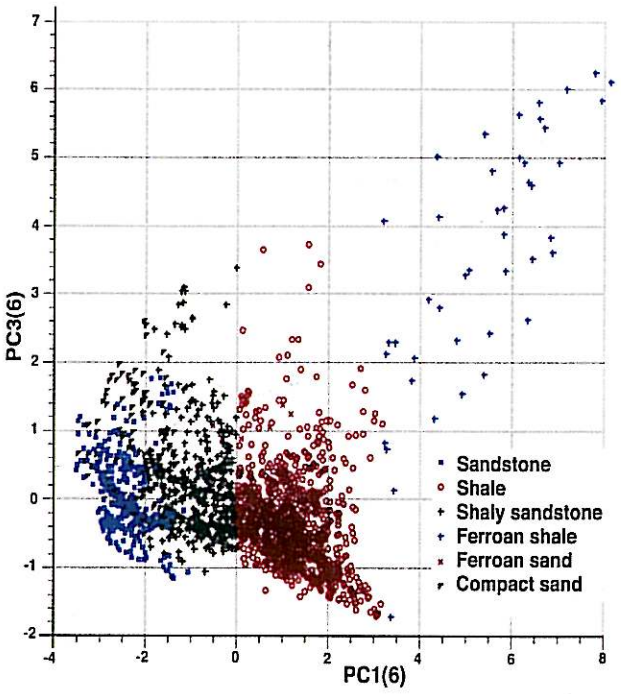


Fig. 3. PC3 vs. PC1 (6 logs) (well A1-NC162).

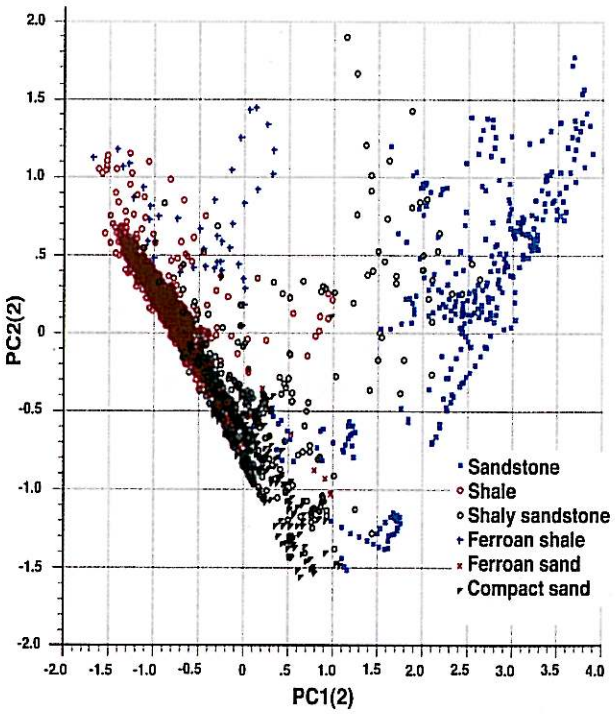


Fig. 4. PC2 vs. PC1 (PCA from conductivity +SGR) (well A1-NC162).

ESTIMATION OF ROCK COMPONENTS FROM PCA

On the previous figures, it has been shown that, there is a strong relationship between the values of principal components and the lithological

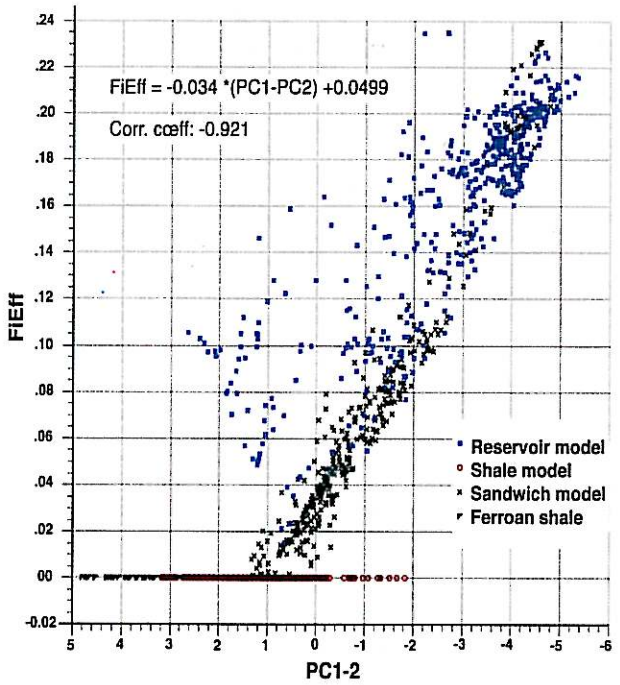


Fig. 5. Effective porosity vs PC1-PC2 (6 logs) (well A1-NC162).

composition of the rock. In particular, the main trend from impermeable shales through shaly sandstones to porous clean sandstones is clearly visible on the crossplot of PC2 *vs.* PC1. This strong relationship encourages us to estimate the value of porosity and shale from the principal components.

The trend of increasing porosity and decreasing shaliness is going from the lower right to the upper left (Fig. 2). This direction corresponds to the decreasing values of the difference PC1-PC2. Indeed, if the crossplot of effective porosity *vs.* PC1-PC2 (increasing from right to left) is constructed (Fig. 5), then a strong correlation with a coefficient r = – 0.92 is achieved.

Applying the line of regression for the estimation of effective porosity from PC1-PC2, the crossplot of figure 6 is achieved. The shape is similar to that of Fig. 5 but the possibility of negative porosity values, from the estimation, is eliminated. The error of the estimation is 0.0237 which is a relatively small value.

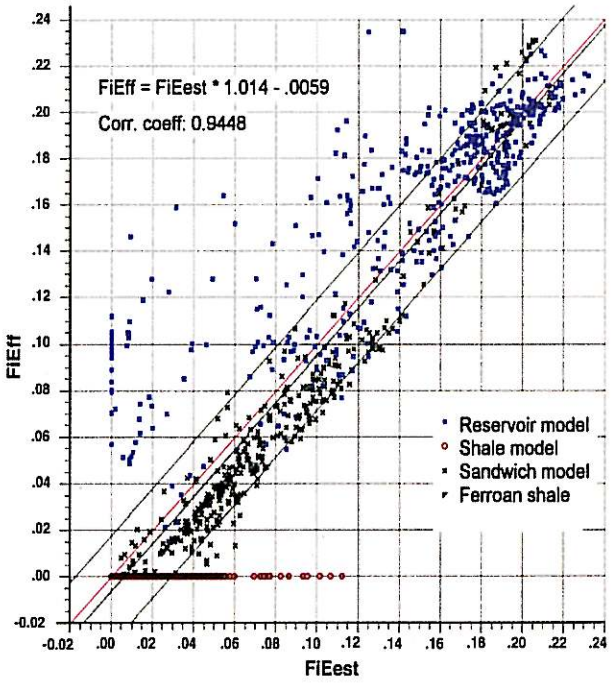


Fig. 6. Effective porosity vs. its estimation from PC1-PC2 (6 logs) (well A1-NC162).

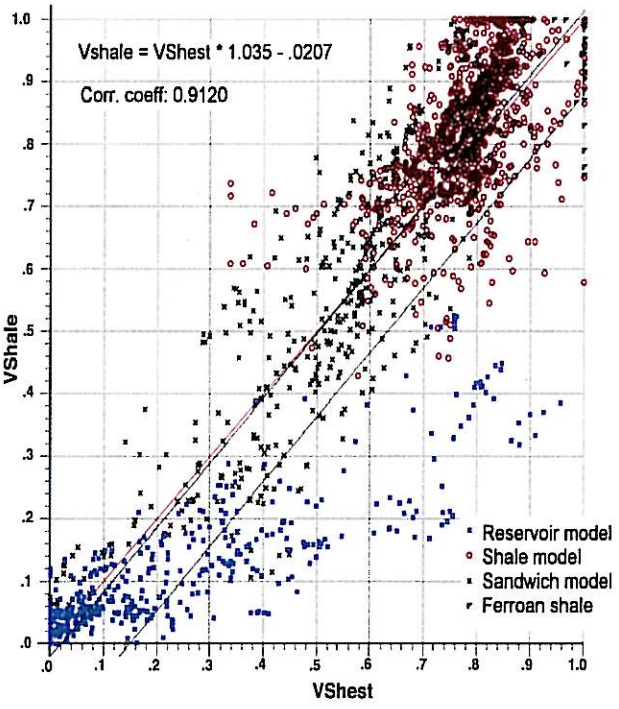


Fig. 7. Volume of shale vs. its estimation from Pc1-PC2 (6 logs) (well A1-NC162).

Estimation of the volume of shale from PCA has also been carried out. Here the difference of principal components PC1-PC2 is applied as the base of the estimation. The line of regression is used for the estimation of shale volume with the necessary restrictions (Vshale >= 0 and Vshale <= 1). Figure 7

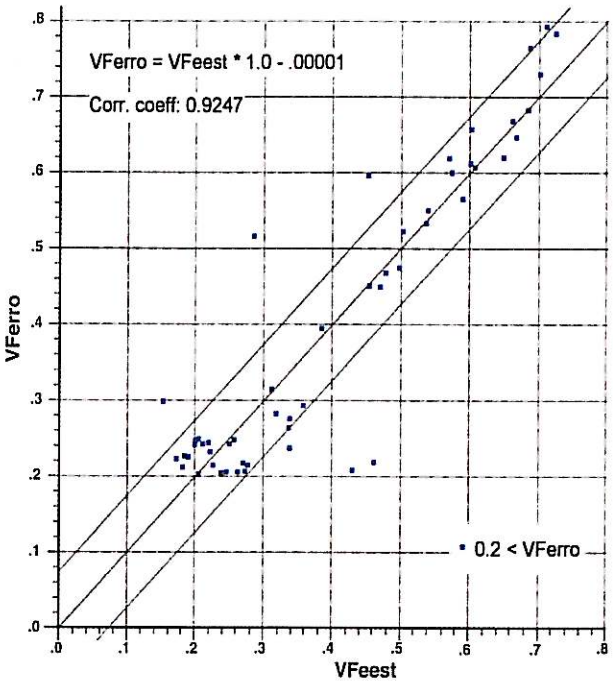


Fig. 8. Volume of ferroan minerals vs. its estimation from PC3 (6 logs) (well A1-NC162).

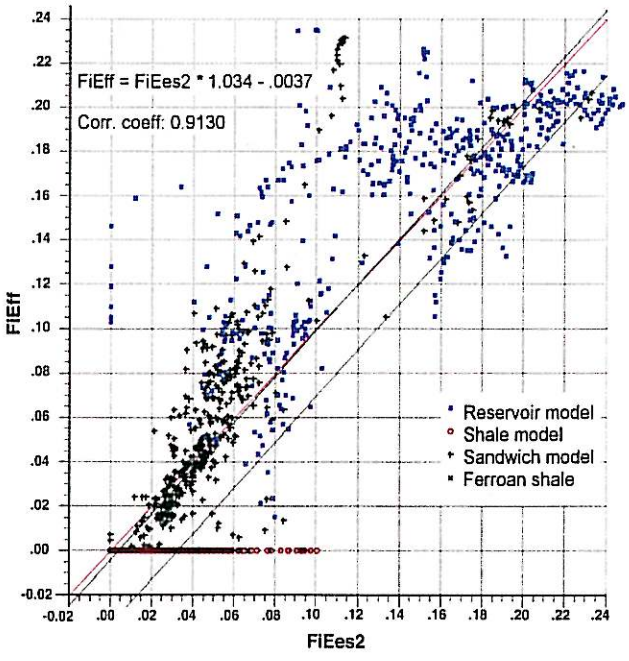


Fig. 9. Effective porosity vs. its estimation from PC1 (2 logs) (well A1-NC162).

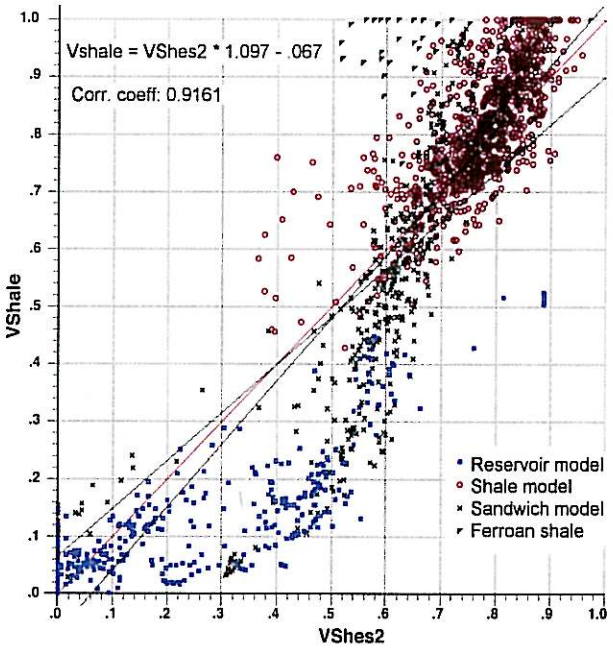


Fig. 10. Volume of shale vs. its estimation from PC1 (well A1-NC162).

shows the crossplot of volume of shale vs. its estimation from PC1-PC2 . The correlation coefficient is positive: r = 0.912 .

As the crossplot of PC3 *vs.* PC1 (Fig. 3) suggests, the third principal component PC3 shows the largest effect of ferroan minerals. This indicates that PC3 is the best estimator of volume of ferroan minerals. In this estimation we restricted the estimation only to the depth sites where the amount of ferroan minerals exceeded 20 %. The results are shown on figure 8.

Figure 4 shows that 2 input PCA from gamma ray and conductivity are suitable for the separation of porous clean sandstones. This suggests that quantitative estimation of porosity and shale volume from PCA is effective. The technique of estimation is similar to that applied from 6-input PCA, however, the correlation coefficient is weaker. The result is shown in figures 9 and 10.

CONCLUSIONS

The method of principal component analysis for lithofacies determination is extensively used in Petroleum Research Centre, Tripoli for basin analysis. Its advantages are:

- High productivity;
- Simplicity: no sophisticated rock models are necessary;
- The method is robust; effects of assumptions of the user are minimal.

In practical use, the method of PCA should be calibrated on detailed quantitative analysis of lithology. In a comprehensive analysis of a hundred wells in a basin with similar geological conditions, a few wells should be selected where the set of input well logs and other geological information is the richest. In these wells quantitative lithological interpretation as well as principal component analysis should be made. The selection of lithofacies categories is based on the lithological interpretation. These categories are recognized on the crossplots of principal components. In other wells, only PCA is carried out and similar patterns are searched for on the crossplots to determine lithofacies categories, porosity and shalines from PCA alone.

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Petroleum Res. J. Vol. 13 (2001); P. 65–74, 11 Figs.

Mineralogical Identification and Depositional Environment Estimation of Lower Nubian Sandstone Formation Using Wire-line Logs Analysis

M. Barghut*

التعرف عن المعادن واستنباط بيئة الترسيب بالجزء السفلي من تكوين الحجر الرملي النوبي باستعمال تحليل تسجيلات الآبار

محمد البرغوث

تم تحليل العينات اللبية المتوفرة من صخور المكمن النفطي العلوي بالجزء السفلي من تكوين الحجر النوبي بالبئر 82-001 الذي تم حفره بتراكيب 00 الواقعة بالجزء الجنوبي الشرقي من حوض سرت من حيث عمليات الترسيب والوصف البتروغرافي ونواتج النشأة المتأخرة، كما تمت مقارنة التحاليل المتوفرة بالنتائج التي تم الحصول عليها من تفسيرات السرود، وأمكن التعرف على المحتوى المعدني (خاصة الطينية منها) وتقييم بيئة الترسيب من خلال تحليل تسجيلات السرود وتدعيم ذلك بالمعلومات البتروغرافية والنشأة المتأخرة.

يوضح الفحص البتروغرافي أن الرمل ناضج من حيث المحتوى المعدني والنسيج وأن عمليات النشأة الكيميائية المتأخرة قد أدت إلى نمو موضعي لعدة مواد لاحمة كالمرو والكاولين مع كميات ضئيلة من معادن الآلايت والكلورايت. يتميز الرمل الناعم والرمل الغريني بقراءات عالية لتسجيلات سرود النيوترون والكثافة وتسجيلات منخفضة لتسجيلات السرود الصوتية ومنخفضة ومتوسطة للسرود الجيمية. أما الرمل الخشن والمتوسط الحبيبات، فهو على العكس من ذلك بالإضافة إلى أنه يعطي تسجيلات منخفضة لسرود الجاما. ويعزي هذا التباين في القراءات إلى وجود معادن المرو والكاولينايت بالنوع الثاني من الصخور، واحتواء المجموعة الأولى من الصخور على معادن تتكون من كربونات الحديد والبيرايت. وقد تم التأكد من هذه الخواص باستعمال الرسومات البيانية ROMA مقابل UMA. كما أكدت الرسومات البيانية لمعامل الامتصاص الكهروضوئي ضد القيمة اللوغاريثمية لعناصر الثوريوم على البوتاسيوم (Th/K) أو البوتاسيوم أن الكاولينايت هو أكثر معادن الطين شيوعاً. وتوضح عدة رسومات بيانية أخرى ناتجة عن تحليلات السرود أن الحجر الرملي الغني بعنصر الثوريوم والشحيح في عنصر البوتاسيوم مع تواجد لعنصر اليورانيوم أحياناً يعتبر مؤشراً لترسيب هذا الجزء من التكوين في بيئة قارية نهرية. أما وجود تركيزات أكثر قيمة لعنصر البوتاسيوم في حجر الطين (النوبي الأوسط) فإنه يعطي دلالة أن هذا الأخير قد ترسب في بيئة البحيرات.

Abstract: *Available cores cut in the upper pool of Lower Nubian Sandstone Formation of OO1/82 well drilled in OO structure, located in the southeast Sirt Basin, are analyzed according to their sedimentology, petrography and diagenetic products. The analyses are correlated with the results obtained from wire-line log interpretation. Analysis of these logs on the basis of different cross plots results, with the support of petrographic and diagenetic investigation, allows analysis of the mineralogical composition, particularly clay*

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minerals, and estimation of the depositional environment. Petrography examination shows that the sands are mineralogically and texturally mature. Diagenetic processes resulted in different cements such as authigenic quartz overgrowth, authigenic kaolinite with subordinate minor amounts of illite and chlorite. High readings of neutron and density logs plus low sonic and fair to medium gamma-ray reading characterize the very fine to silty sandstone while the opposite, with low gamma-ray readings, is true for medium to coarse sands. These values reflect quartz/kaolinite composition of the latter and presence of iron carbonates (e.g. siderite and/or ankerite) and pyrite in the former. These characteristics are confirmed by cross plots of ROMA (matrix density) versus UMA (absorption photoelectric cross section of matrix). Plotting of PEF (photoelectrical absorption index) against log Th/K and/or K confirm kaolinite as the most common clay mineral. Various cross plots obtained from analysis of spectral gamma-ray logs show that the sandstone are characterized by abundant thorium, minor amounts of potassium and locally uranium, interpreted as indicating fluvial continental environment. Higher amounts of potassium and uranium in the middle shale define a lacustrine environment.

INTRODUCTION

Classically core and/or cuttings are considered to be the most important well data source for lithology and sedimentary structure identifications, and hence depositional environment interpretation. However, a number of difficulties that are experienced in drilling operations such as lost circulation, and stuck drilling pipes can some times result in non-recovery of some cuttings. This can obviously complicate geological interpretations. Moreover, the time consuming and hence high cost of coring limits its general application resulting in a shortage of accurate identification of lithology and reservoir characteristics. On the other hand, wire-line log tools usually display a continuous survey of different lithology characteristics penetrated in the drilled well. Analysis of the different log curves generated, can provide valuable information about potential reservoir rocks and their characteristics, such as porosity and the nature of fluids present (Rider, 1986; Hurst, 1990; Doveton, 1994). Lithology and/or mineral identification, and correlation between drilled wells according to their log curve responses, are additional valuable information streams which can be obtained from logs analysis (Doveton, 1994; Schlumberger, 1989). Furthermore, estimation of depositional environments by applying different log technique analysis, has been documented during the recent decades (Rider, 1991; Selly, 1976, 1985; Schlumberger, 1989).

Aim of the Study

The upper pool of Lower Nubian Sandstone Formation, represented by the OO1/82 well, is the main subject of this study since it has long continuously cored section, and different wire-line logs are available. Hence, a valuable and accurate study expected to be achieved. Some other wells, surrounding the above mentioned well, such as OO2, OO3, OO4 and OO5, are included in this particular study as different logs types are available as well.

The aim of the study is to estimate the depositional environment and identification of the mineral composition types (especially clay minerals), which are distributed in the Lower Nubian Sandstone Formation represented by some wells drilled within OO structure. This is very important in the petroleum industry because knowledge of the relationship between clay content, types, texture, and water saturation enhances reservoir evaluation (Figs. 1, 2).

Methods of the Study

- The cored sections in the OO1/82 well were studied sedimentologically and petrographically in order to identify the lithofacies and their mineralogical contents. These results are compared with the different log responses, such as curves shape of the gamma ray logs and their relations of sediments grain size
- Analysis of the mineral composition of the formation according to the different logs responses such as density logs (LDL, LDT), neutron logs (CNL), sonic logs (DT). The analysis was compared with data obtained from the accurate mineral compositional analysis of the core section, determined from different application of petrographic techniques

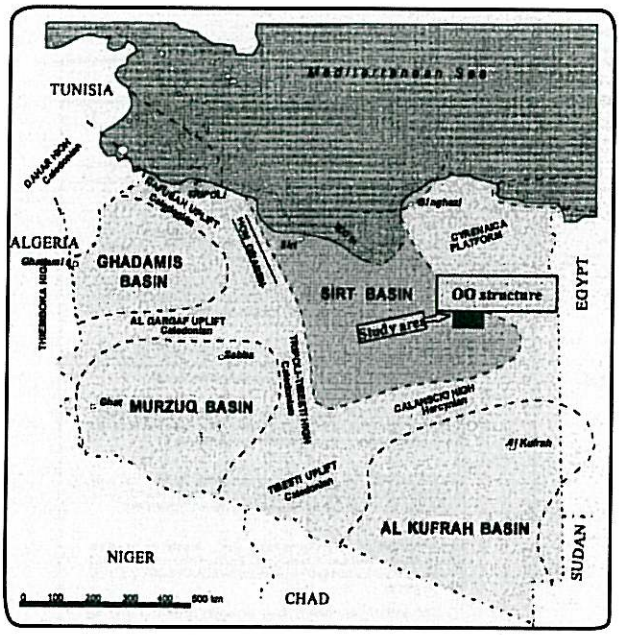


Fig. 1. Location map

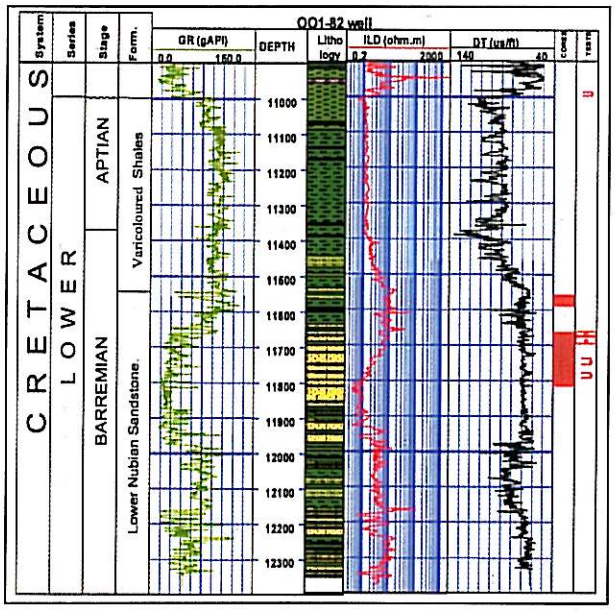


Fig. 2. Lithostratigraphic column defining LNSST and varicoloured shale, included the core interval and logs curves of OO1-82

- Analysis of the natural spectral gamma ray logs according to their natural radioactive elements (Th, K, U), which are available from some wells drilled within OO structure, and using different types of cross plots of these data for mineral identification and depositional environment estimation.

RESULTS OF THE STUDY

Lithofacies Analysis From Rock Samples

The upper pool of Lower Nubian Sandstone Formation, as represented in the OO1/82, well can be subdivided, according to hand specimen rock observation and petrographic analysis, into two main lithofacies as follows:

Fine to Very Fine-graind and Silty Sandstone

This type of lithofacies is characterized by very fine to fine quartz grains, moderately sorted and strongly indurated in most parts. It is occasionally characterized by moderate amounts of altered carbonaceous materials, presence of considerable percentage of pyrite in the form of cubes and/or poikilotopic cements and iron carbonates (ankerite and/or siderite). Low angle to horizontal laminations is the common structures identified.

These deposits could be represent overbank facies deposited under low energy conditions (Figs. 3, 4).

Medium to Coarse-grained Sandstone

This lithofacies is considered as the common sediment texture characterizing the OO1/82 well samples. It consists of moderately sorted, medium to coarse quartz grains, commonly characterized by sharp and/or erosinal surfaces containing mud-clasts conglomerates, and some times upward fining grain size profiles. Sedimentary structures presented as medium to small-scale cross laminations as well as gently dipping cross bedding. The multiple upward-fining units and the sedimentary structures, noted above, suggest that this lithofacies was deposited in channel environment under high-energy conditions (Figs. 3, 4).

Lithofacies and Mineralogy From Different Logs Responses

As Schlumberger (1989) reported, combination of different logs, such as NGS, neutron, density, and sonic logs can permit acceptable mineral identification, particularly within those formations characterized by less complex mixtures. Accurate mineralogical analysis was made on some

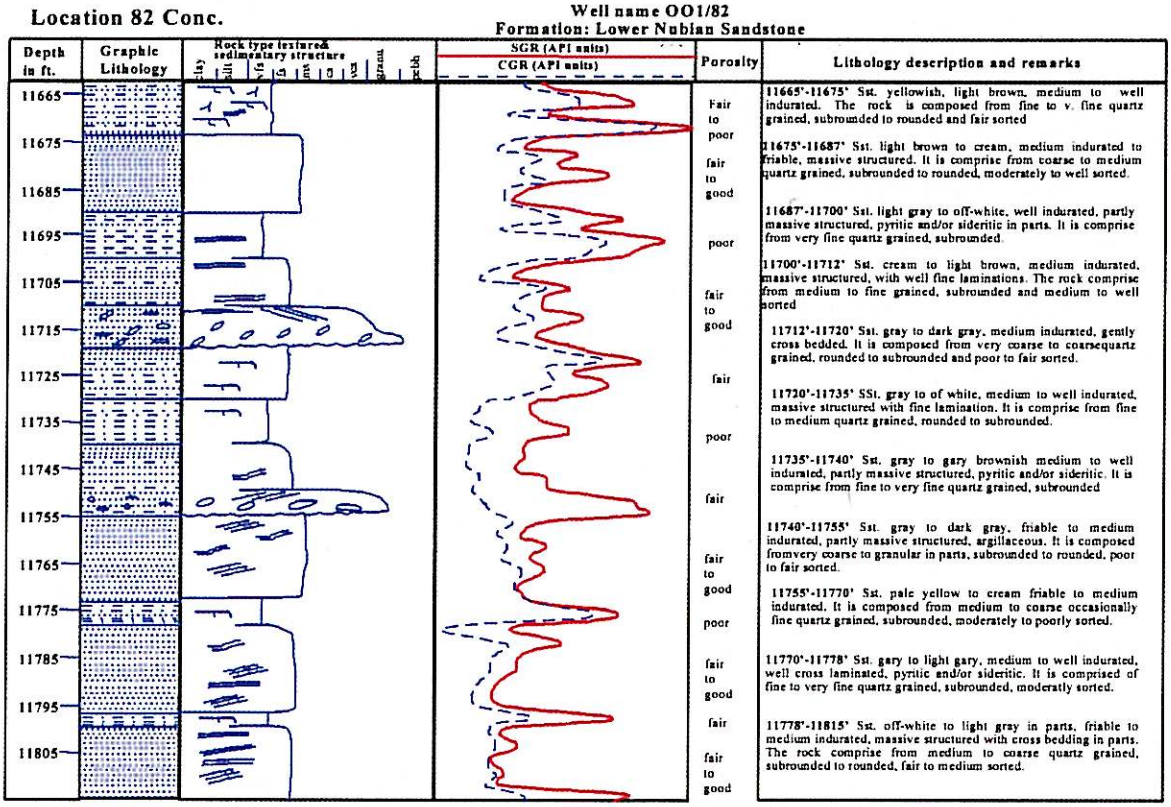


Fig. 3. Lithology and sedimentary structures of the OO1-82 core section (XX665'-XX815').

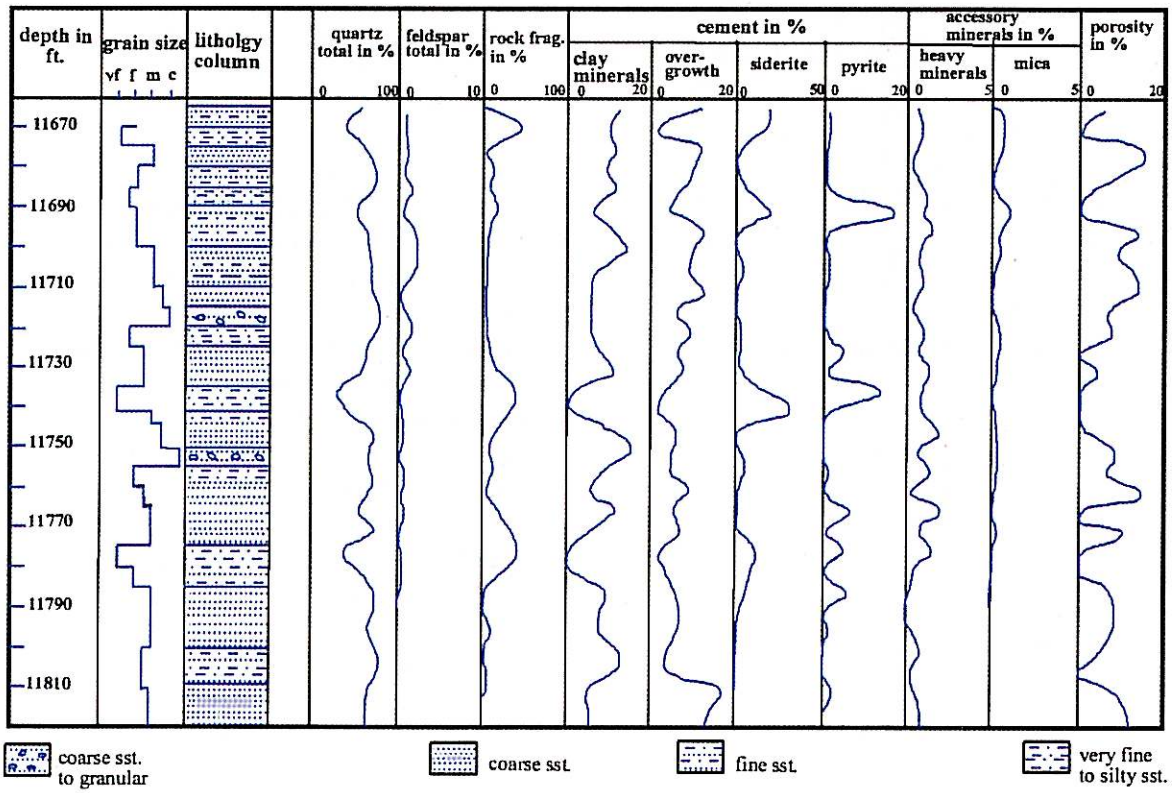


Fig. 4. Mineral distribution in percentage of the core section (XX665'-XX815') OO1-82 represented the upper pool of LNSS.

interesting samples selected from the core section and carefully correlated with the log responses. XRF was also used to identify the characteristics and to quantify the different minerals representing this lithology. Correlation of log curves with core samples in the OO1/82 well supported the subdivision into the two main lithofacies identified earlier. Distinct log responses of the different log curves define the two lithofacies. The characteristics of log responses related to the two identified lithofacies could be explained as follows:

Lithofacies one shows squashed quartz grains, and abundant matrix and cements possibly comprising detrital clays, so considerable percentage of bound water is present and hence a higher hydrogen index that is reflected by quite high readings in neutron curves in front of these lithofacies. Sonic logs on the other hand show quite low reading (about 58 us/ft. Density log is usually expected to give higher readings in front of very fine to shaly sandstone (Hurst, 1987; Rider, 1986). This is recognized in this lithofacies with higher bulk density pecks (approximately 2.65-2.70 gm./cc). These values do not, however, record shale lithology but result from the concentration of iron carbonates and/or pyrite, which are present and confirmed from petrography and chemical (XRF) analyses (Figs. 5, 6).

Log responses of lithofacies two, which is characterized by medium to coarse-grained sandstone, are mostly significant in that the neutron log responses show quite low readings compared with the values in lithofacies one. This might be explained by the presence of authigenic kaolinite filling part of the pore space and hence causing low fluids content (fair to poor hydrogen atoms). The hydrogen content within fine sand to shale lithology is higher than in medium to coarse-grained sediments (Hurst, 1987). Sonic logs, on the other hand, displays higher values compared with lithofacies one (about 70 us/ft.). Density log display lower values compared with lithofacies one. This can be explained logically as due to the abundance of quartz framework grains and authigenic kaolinite, which partially fills the pore space (Average grain density of quartz and kaolinite, documented in literature, ranges from 2.60-2.68 gm/cm3). Moreover, the minor amounts of iron carbonates and /or rarity of pyrite possibly control the low readings of density logs in this lithofacies (Figs. 5, 6).

LDT AND NGS LOGS EVALUATION

The log data in this analysis are derived from the two logs curves, the natural gamma-ray spectrometry (NGS), which is measuring Th, K, U, radioactive minerals and from the lithodensity log (LDT), which records the bulk density of a formation (apparent density) and photoelectrical absorption index (PEF). It records the absorption of low-energy gamma ray by the formation in units of barns per electron, and is commonly scaled on a range from 0 to 10 barns per electron on its log curves (Schlumberger, 1989; see log curves in Fig. 5).

Accuracy of NGS Data

Before accepting the NGS data, examination of their accuracy must be made (Hurst, 1990). Precision of the NGS log data is assessed by comparing the main runs of logs, displaying thorium, potassium and uranium data, with the repeat run section. The values of the NGS logs are obtained directly from the recorded curves (Schlumberger, 1989). To expand examination of the accuracy of analysis as a mineralogical indicator and as a parameter for deposition environment interpretations, some other wells (OO2, OO3, OO4, OO5) surrounding the OO1/82 well are included in this study. However, lack of core samples from these wells limits the study to log analysis only, but with the core section of OO1/82 well as reference. According to the data, which are derived from the study wells, fair to good correlations were achieved referring to 1:1 line. A few of points, however, are positioned quite a way from the main trend. These ambiguous values could be attributed to wireline stretching during logging operations. Also, the emission of natural radioactivity is random in any examined formation, therefore, many case studies show that measuring radioactivity of minerals within the same formation, over different times, often gives slightly different readings (Hurst, 1990).

Analysis of LDT and NGS Logs

Clay minerals identification according to the photoelectrical index is a function of their content

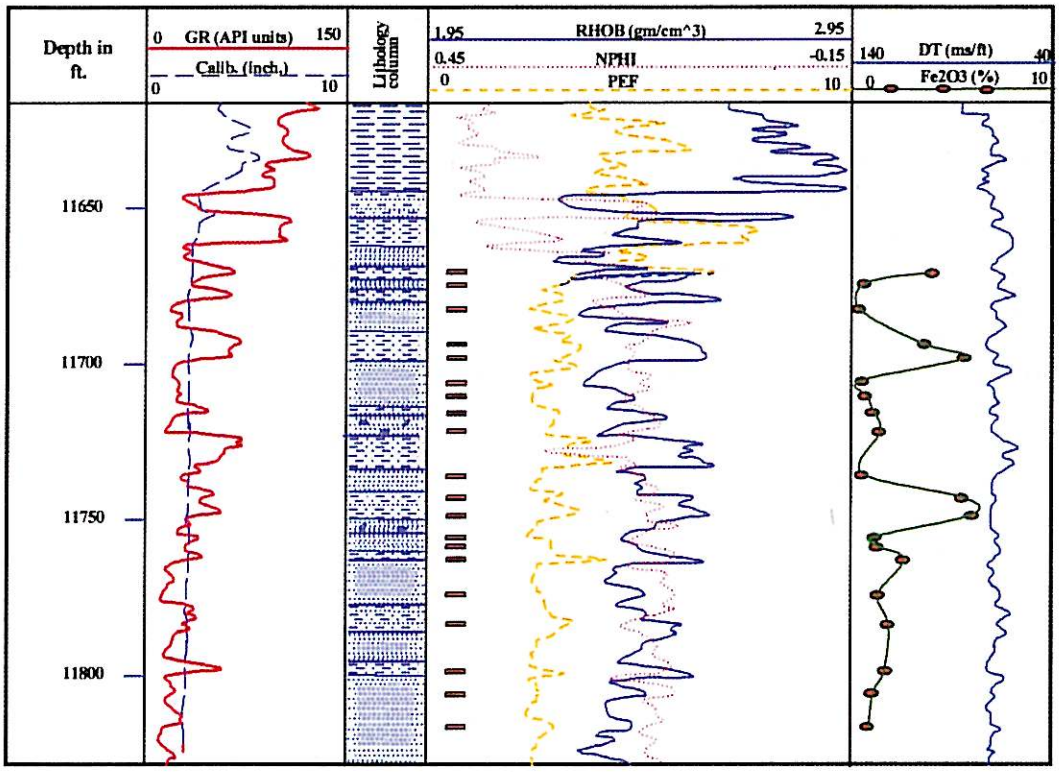


Fig. 5. Variation of different log curves (OO1-82 well) according to mineralogical and fluid composition. Note the positions of the selected thin sections related to log curves.

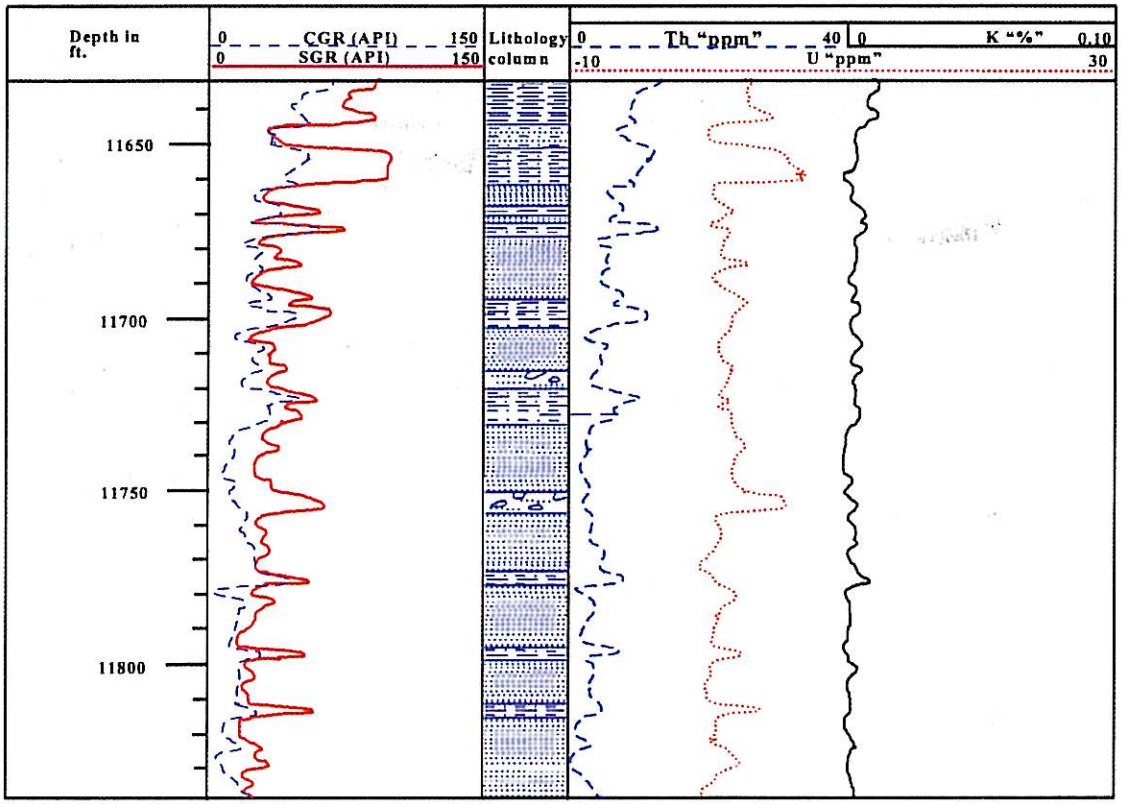


Fig. 6. Distribution of the radioactive elements (Th, K, U) within the OO1-82 well, Upper Pool of LNSS.

of iron, in which clays characterized by free iron (e.g. kaolinite) often have values similar to quartz. Preveraro and Russel (1984), Shlumberger (1989) and Doveton (1994) have discussed clarifications of these raw data, which are obtained from the above-mentioned logs. They propose that cross plots of these parameters can help in the identification of mineral composition. By identification of the data from different logs analysis (NGS, LDT logs), cross plot methods are made for minerals descriptions which are represented by known selected points and/or clusters on the cross plots (Preveraro and Russell, 1984; Schlumberger, 1989 charts).

Cross plot of ROMA versus UMA is used to separate lighter minerals such as pure quartz and kaolinite from heavier ones, which often contain iron concentrations, for instance, iron carbonates and/or pyrite. In this cross plot, the clean zones, which are characterized by medium to coarse quartz sand grains and authigenic kaolinite cements, appear to be concentrated in the left side of the cross plot confirming quartz and/or kaolinite minerals. The intervals characterized by fine to very fine-grained, display very high values of UMA, which are attributed to the presence of iron carbonates and/or pyrite (UMA>20). Minor scattered points represent mica, mixed clay, and heavy minerals (Fig. 7).

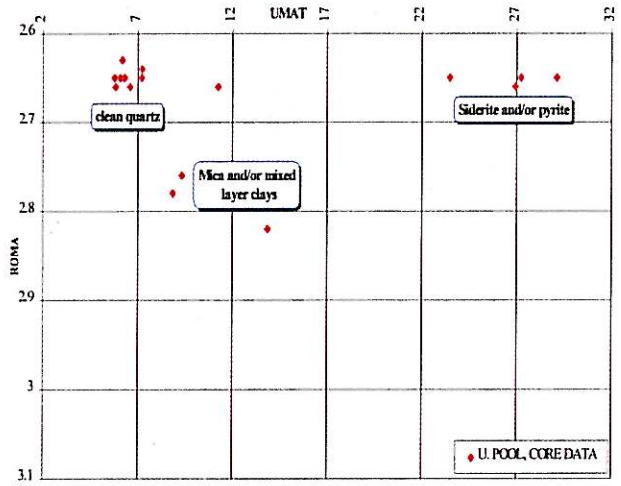


Fig. 7. Apparent matrix volumetric cross section versus apparent matrix density defining the distribution of the main minerals within the OO1-82 core section.

PEF data versus log Th/K and/or K cross plots are on the other hand, used to identify clay minerals types. Comparison of the cross plot data with the results obtained from petrographic studies show that reliable results can be obtained and clearly confirm the abundance of kaolinite, which is the most common clay minerals of the upper reservoir of the Lower Nubian Sandstone Formation (Figs. 8, 9)

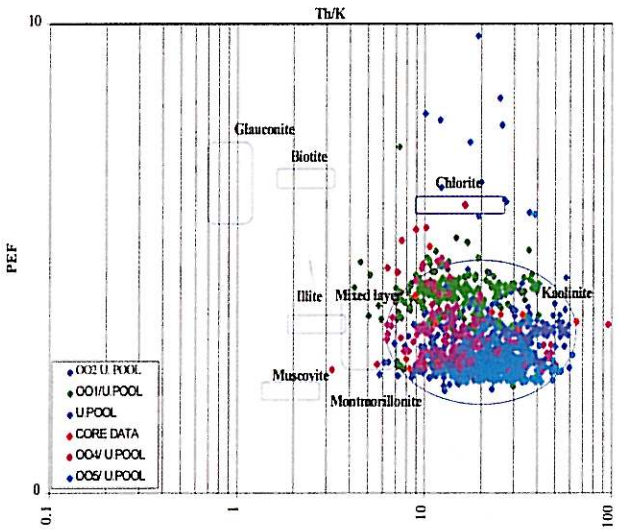


Fig. 8. Cross plot of Th/K ratio versus PEF (barn/electron) for identification the main minerals represented the upper pool of LNSS - OO1-82 wells

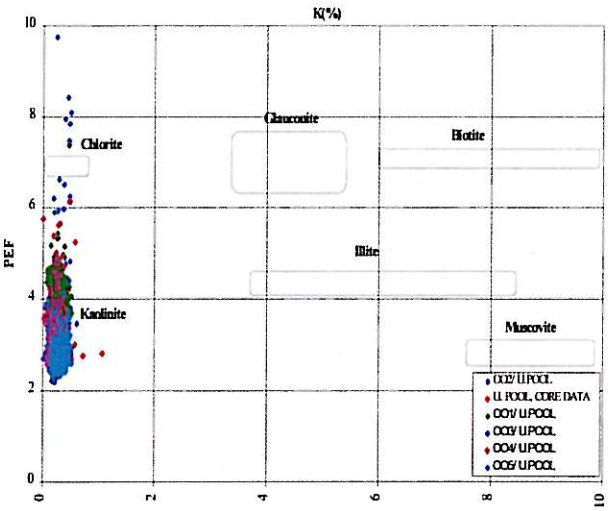


Fig. 9. Cross plot of potassium (K) versus photoelectric cross section (PEF) for identification of clay minerals within OO1-82 wells.

Spectral Gamma-ray Analysis

Introduction of natural spectral gamma-ray logs (NGS) has provided valuable information in geological studies, dealing with reservoir evaluation (Schlumberger, 1989). For instance, identification of clay minerals within drilled oil

well is considered important in the petroleum industry because knowledge of the relationship between clay contents, types, texture, and water saturation enhances reservoir evaluation (Hurst, 1987). Spectral gamma-ray log was run in OO1/82 well as is shown in figure 6. Interpretation of these logs on the basis of different cross plots results, with the support of petrographic and diagenetic analysis, allows analysis of the mineralogical composition, particularly clay minerals, and estimation of the depositional environment of the Lower Nubian Sandstone Formation. Three members represent this formation; the lower member comprising interbedded sandstone and shale intervals. The middle shale member, separating the two sandstones. The upper member, comprising the major sandstone intervals. This possibly forms the bulk of the reservoir rocks (Figs. 2, 3). Most of the radioactive sources in this case study are obtained from thorium and, locally, uranium, where as potassium shows a minor but constant amount through the whole of the upper sandstone member. The middle shale member, however, accommodates fair amounts of potassium. Support for these observations are confirmed in petrographic analysis on the available rock samples of the OO1/82 well, which show rare, or almost absent potassium feldspar, traces of mica, and absence or poor amounts of illites (Fig. 4). Data of thorium, potassium, and uranium were identified from analysis of spectral gamma-ray logs in OO2, OO3, OO4, and OO5 wells, and plotted on the same cross plots of the OO1/82 well to identify any data variations related to the mineralogical compositions.

Potassium-thorium cross plot

This plot was introduced by Quirein *et al.*, (1982) for recognition of different clay minerals types and also for identification of the accessory radioactive materials responsible for the quite high gamma ray reading in front of clean formation (e.g. sandstone reservoir). This is usually attributed to potassium feldspars, mica such as muscovite and, in some parts, to concentrations of accessory minerals (heavy minerals) such as rutiles, and zircon.

Application of this technique on Lower Nubian Sandstone presented by OO wells of concession 82 clearly separate the main minerals. It can be seen that the majority of plots are concentrated along the kaolinite track. In contrast the middle shale section plots are mostly a mixture of illite and kaolinite with subordinate amounts of smectite and/or mixed layer clays (Figs. 10a, 10b). As mentioned earlier, confirmation of these results has been obtained from petrography, and diagenetic analysis.

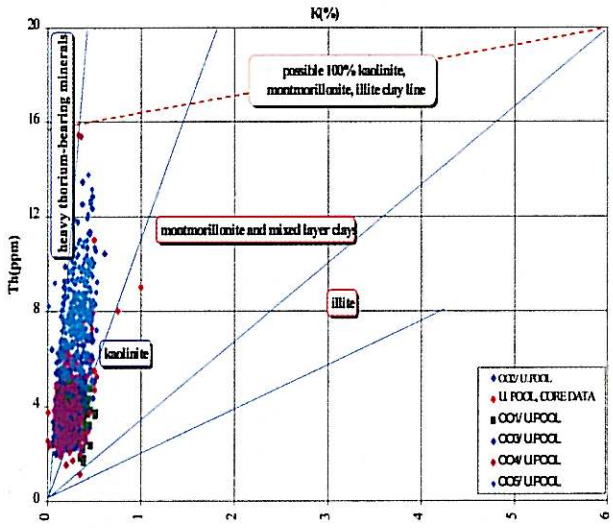


Fig. 10a. Distribution of clay minerals concentration within the upper pool of LNSS. - OO1-82 wells

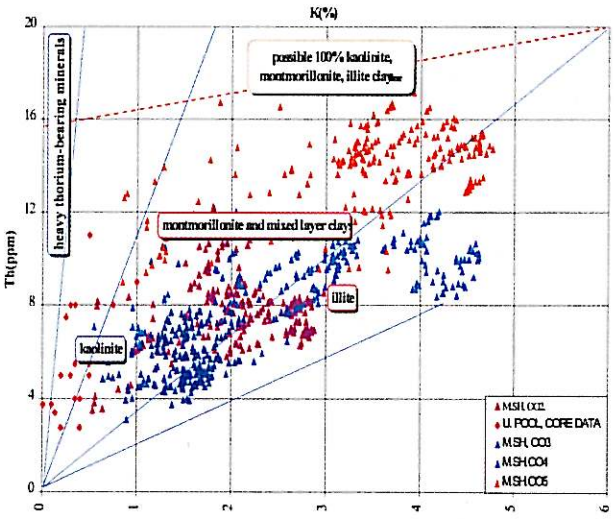


Fig. 10b. Distribution of clay minerals concentration within the middle shale of LNSS. - OO1-82 wells.

Thorium- uranium cross plot

Thorium, potassium and uranium are documented as helpful indicators for environment identification and hence, natural gamma ray spectral logs (NGS) can be used for environment

analysis (Adams and Weaver, 1958; Doveton, 1994). The suggested basis recommended for differentiating between marine sediments and continental ones is that the marine are characterized by a low Th/U ratio (reducing conditions) and vice-versa for continental sediments (oxidizing conditions). Clay minerals concentrations can also assist in distinguishing marine, transitional, and non-marine environments. This analysis in general shows that non-marine deposits commonly contain kaolinite as the abundant clay minerals, whereas illite is greater within marine sediments (Harron, 1986; Doveton, 1994; Lonnie, 1982). Application of this approach to the upper reservoir and the middle shale of Lower Nubian Sandstone, involved cross plots of Th/K versus Th/U. The plots show that most of the data related to the upper reservoir fall in the zone defining kaolinite and heavy thorium bearing minerals (Th/K >10) and (Th/U>2). A combination of the abundance of kaolinite and Th/U ratio is higher than two has been interpreted in as a very strong indicator of terrestrial depositional environment (Doveton, 1994). A few points are positioned along the area characterized by Th/U<2, these attributed to intervals characterized by presence of considerable amounts of uranium as recognized from NGS log analysis (Figs 3, 6). Explanation to these anomalous readings is that these intervals accommodate amounts of organic matter, which are attractive sites for uranium concentration (Doveton, 1994; Rider, 1986). The middle shale cross plot are mostly characterized by Th/K ratio range from 2.5-7.5 defining that this section accommodates considerable amounts of illites and/or mixed layer clays displaying characteristics of lacustrine type (Figs. 11a, 11b).

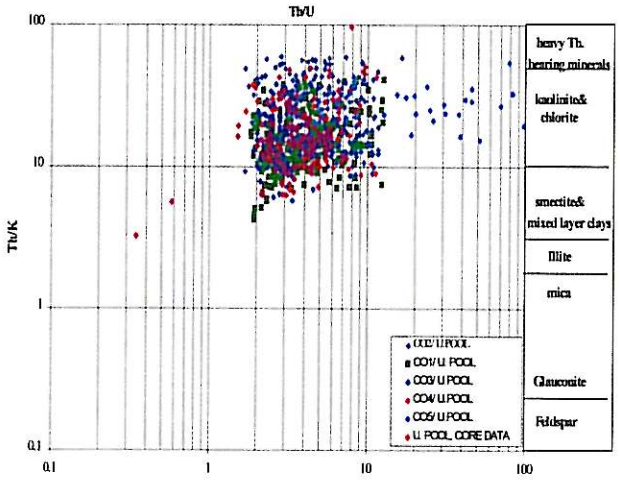


Fig. 11a Concentration of clay minerals within the upper reservoir of LNSS. Formation - AA/82 wells

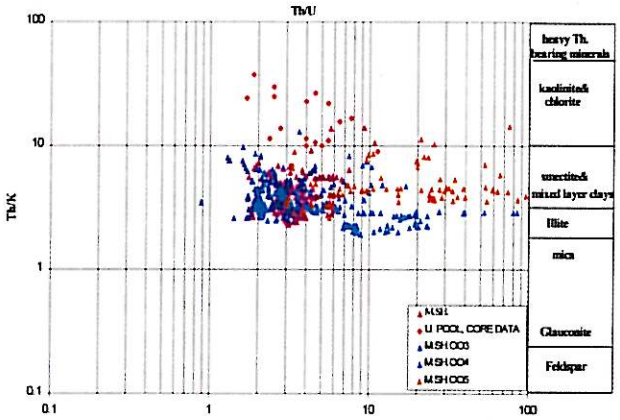


Fig. 11b Concentration of clay minerals within the middle shale of LNSS. Formation - AA/82 wells

CONCLUSIONS

Accurate interpretation of the mineralogy is obtained from application of cross plots of different data derived from log curves analysis. These are achieved and/or confirmed by careful selection of the same zones from the cores available and by analysis of some rock samples obtained from the core section of OO1/82 well sedimentologically, petrographically, and geochemically. The core section has been classified generally into two lithofacies; lithofacies one characterized by fair amounts of iron carbonates and/or pyrite minerals; lithofacies two shows clean quartz sand grains, and partially cemented by authigenic kaolinite. Moreover, the section documented intensive diagenetic processes in which most of the potassium feldspar and labile rock fragments containing muscovite were dissolved and replaced by authigenic clay minerals.

The dominant clay minerals characterizing the upper pool of the Lower Nubian Sandstone Formation is kaolinite with minor amounts of illites and chlorite. In contrast, illites and/or mixed layer clays characterize the middle shale. As a result, the gamma-ray values indicate quite low to fair API units within the whole sandstone section, except those intervals characterized by abundance of detrital clays and/or which accommodate amounts of iron carbonates and pyrite.

The different cross plots of thorium versus potassium and (log Th/K) against (PEF) are shown to be reliable means of estimating mineral types in the Lower Nubian Sandstone of the OO structure. This was achieved by recognition of abundance of kaolinite clay minerals, which is considered as a signature for the non-marine environment. Moreover, Th/K versus Th/U cross plots; on the other hand, show oxidizing conditions by displaying minor amounts of uranium.

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Predictive Modelling of Naturally Fractured Reservoirs Using Geomechanics and Flow Simulation

S.J. Bourne, A. Rijkels, B.J. Stephenson and E. Willemse*

التنبؤ بواسطة النمذجة للخزانات المتشققة طبيعياً باستعمال الجيوميكانيكا ومحاكاة تدفق السوائل

س. ج. بورني وأ. ريجكيلس و ب. ستيفنسون وأ. ويلمز

لزيادر كفاءة الإنتاج في الخزانات المتشققة طبيعياً يجب فهم وتقييم خواص الشقوق على مستوى الحقل. نقدم هنا طريقة شبه تقديرية لكي نتمكن من توقع وبطريقة منظمة توزيع الشقوق الطبيعية وتأثيرها على محاكاة تدفق السوائل. وهذا التوجه يمكن من حساب نماذج التشققات على مستوى الحقل حيث تمت المعايرة بواسطة الاختبارات الجيولوجية وبيانات إنتاج الحقل لتحديد توزيع الشقوق في الفضاءات ما بين الآبار.

لقد بدأنا أولاً بحساب توزيع الإجهاد أثناء وقت التشقق باستعمال أبعاد بنية الخزان الحالية حيث إعتمدت هذه الحسابات على النماذج الجيوميكانيكية الخاصة بتشكل الصخور كالصدوع المرنة مثلاً. ثانياً تم استعمال مجال الإجهاد المحسوب للحقل بهدف التحكم في محاكاة نمو شبكة التشققات، وأخيراً تمت زيادة حجم التشققات ديناميكياً بواسطة محاكاة تدفق السوائل من خلال شبكة التشققات المتميزة لكل كتلة على حدة لتمكين محاكاة الخزان متعدد المراحل على مستوى الحقل. وبواسطة توثيق ومعايرة النماذج مع المعلومات المستوحاة من التسجيلات السيزمية وسمك الآبار واختباراتها وإنتاجيتها، قلت الشكوك المصاحبة لهذه التنبآت كثيراً .

فإن تطبيق هذا التوجه الناجح على الصخور المتكشفة وصخور المكمن، يوضع وبدرجة عالية من التنبؤات خواص شبكة التشققات الطبيعية. وفي حالة محدودية المعلومات عندما تكون النماذج العشوائية غير فاعلة فإن هذه الطريقة تبقى هذ الأقوى.

Abstract: *To optimise recovery in naturally fractured reservoirs, the field-scale distribution of fracture properties must be understood and quantified. We present a semi-deterministic method to systematically predict the spatial distribution of natural fractures and their effect on flow simulations. This approach enables the calculation of field-scale fracture models. These are calibrated by geological, well test and field production data to constrain the distributions of fractures within the inter-well space.*

First, we calculate the stress distribution at the time of fracturing using the present-day structural reservoir geometry. This calculation is based on geomechanical models of rock deformation such as elastic faulting. Second, the calculated stress field is used to govern the simulated growth of fracture networks. Finally, the fractures are upscaled dynamically by simulating flow through the discrete fracture network per grid block, enabling field-scale multi-phase reservoir simulation. Uncertainties associated with these predictions are considerably reduced by constraining and

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validating the models with seismic, borehole, well test and production data.

This approach is able to predict physically and geologically realistic fracture networks. Its succesful application to outcrops and reservoirs demonstrates there is a high degree of predictability in the properties of natural fracture networks. In cases of limited data – where stochastical models typically fail - this method remains robust.

INTRODUCTION

Natural fracture systems have a dramatic impact on reservoir performance, as they act as highly complex and anisotropic flow conduits. Successful management of naturally fractured reservoirs is impossible without substantial knowledge of the properties of the fracture systems on the inter-well scale. This paper presents a new method to predict field-scale natural fracture distributions and their effect on oil and gas recovery (Fig. 1). By integrating fracture prediction and flow simulation, we constrain a single field-scale model using all the available geological and flow data. This significantly reduces uncertainty. For instance, standard ambiguities in borehole fracture data due to sampling bias can be overcome by the use of well

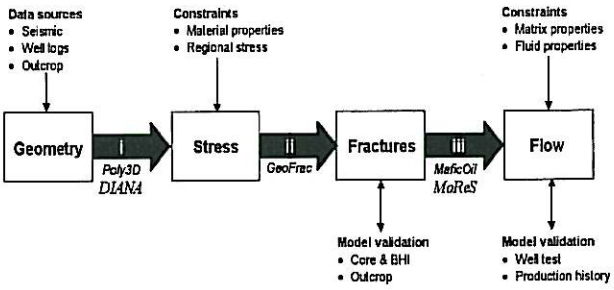


Fig. 1. Integrated model for naturally fractured reservoirs based on: (i) geomechanical models of rock deformation, (ii) fracture mechanics, and (iii) multi-phase flow simulation. This workflow incorporates all the available static and dynamic data in order to constrain the model and minimise uncertainty in fracture prediction and flow forecasting.

inflow data. Because the fracture model is field-scale, information from every well reduces the model's uncertainty across the whole field and not just around wells. These improved fracture models improve field development through: (i) better assessment of the recovery mechanism, (ii) more reliable production forecasts, (iii) well placement for optimal drainage, (iv) minimal water-cut, (v) recognition of drilling hazards associated with fractures.

The following sections describe how structural geometry is used to predict stress, how stress is used to predict fractures, and how fractures are used to predict flow. We finish by presenting one example of an application of this method to a producing carbonate reservoir.

STRESS AND FRACTURE PREDICTION

Faulting is typically the primary deformation mechanism of a reservoir and is therefore expected to be the dominant control on the distribution of fracture networks. The simplest approach to determine the stress field within a faulted reservoir is to assume the rock behaves as a homogeneous, isotropic, and linear-elastic material. The faults are modelled as traction-free surfaces in three dimensions, whose slip in response to a remote stress determines the deformation. We obtain numerical solutions for fault slip and the corresponding stress field using *Poly3D*[1], a boundary element analysis based on the method of Comninou & Dunders[2]. *Poly3D* uses a large number of triangles to represent the complicated three-dimensional fault geometries found in seismic data. Figure 2 illustrates the calculated

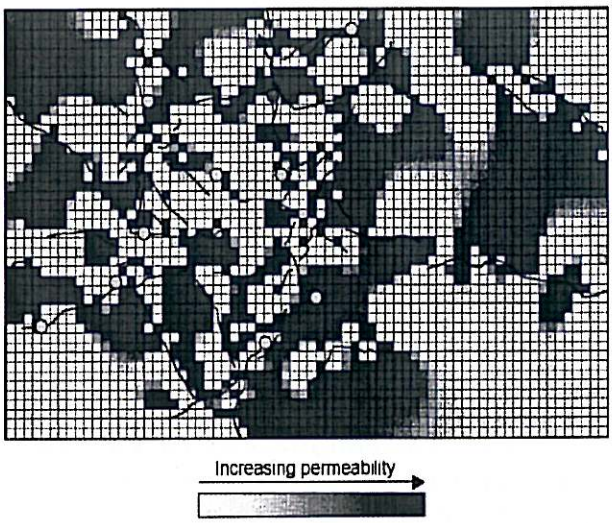


Fig. 2. Example of an elastic stress field calculated for a three-dimensional network of right-lateral strike-slip faults. The faults are embedded in a linear elastic, isotropic, homogeneous rock body which is subject to a remote stress (a). The resulting stress field (b) governs the distribution of small-scale tensile and shear fractures shown in (c).

distribution of elastic stress around a simple hypothetical network of right-lateral strike-slip faults. Even this relatively simple fault geometry produces a complex stress field indicating that fault geometries can dominate the distribution of stress. We predict fracturing related to this stress field according to the Griffith stress criterion for tensile failure[3], and a Coulomb stress criterion for shear failure[4]. Whichever criterion is met first as the stress field changes during faulting determines the mode of first failure.

The overall shapes of fracture clusters correspond to contours of the elastic stress field, which depend only on fault geometry and the orientation of the remote stress. The lateral extent of fractured areas depends on rock strength relative to the remote stress: increased rock strength results in fractured areas shrinking towards the faults, and vice versa. We include fracture formation mechanisms such as fluid pressure increase, diagenesis, cooling, and erosion of the overburden as isotropic reductions in compressive stress. There are two fracture model parameters available for history matching: (i) local strength versus remote stress, and (ii) the isotropic body force. These parameters can be constrained and the model validated by a small number of wells distributed across the field.

Once the distribution and mode of brittle failure has been determined the actual geometry of fracture networks can be simulated by growing fractures in the brittle-elastic stress field using the program *GeoFrac*. Fractures initiate in areas of brittle failure, propagate within mechanical layers orthogonal to the direction of least compressive stress, and terminate before entering regions with stable stress states. Fracture spacing and interaction is controlled by a forbidden zone around each fracture which represents an overall reduction in local stress due to the presence of the fracture. As a result other fractures are less likely to nucleate within these zones, which limits the ultimate spacing of fractures. Furthermore, when the propagating tips of two fractures approach each other their mechanical interaction may lead to the fractures turning towards each other and connecting[5,6]. This is an important mechanism affecting fluid flow as it produces connectivity between essentially parallel fractures.

FLOW SIMULATION

To simulate oil and gas recovery from a predicted fracture network, it must be upscaled to a dual-permeability grid. Dynamic upscaling is possible with MaficOil[7], a finite-element code which simulates single-phase flow through the discrete fracture network inside each grid block, and computes its equivalent fracture permeability tensor. MaficOil also determines the effective fracture spacing, which is used by *MoReS* (Shell's proprietary dual-permeability simulator[8]) to accurately describe the complicated recovery processes in fractured reservoirs[9]. The upscaled fracture grid is then used to obtain a history match on a field-scale, and also to forecast development scenarios.

APPLICATION TO A PRODUCING CARBONATE RESERVOIR

This method has been applied successfully to both single – and multi-phase fields. As an illustration, we present results from a fractured oil reservoir in a tight carbonate.

The fracture model predicted for this field is consistent with both fracture orientations and relative intensities as measured from image logs (UBI and CBIL) for 14 wells. Simulations based on the predicted effective fracture permeability grid (Fig. 3) matched the production history from all 9 of the producing wells (Figure 4). In the simulation, wells were constrained by historical flowing bottom hole pressure data, whilst stimulations and mechanical integrity problems were modelled as a skin change.

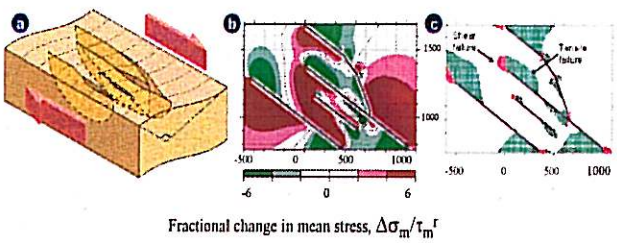


Fig.3. Map showing effective fracture permeability around seismically imaged faults (black lines) based on dynamic upscaling of a predicted, discrete fracture network. The single-phase, dual-permeability reservoir simulation results in Figure 4 are based on this fracture permeability grid and an independent grid for matrix permeability. Grid block dimensions are 200 m by 200 m.

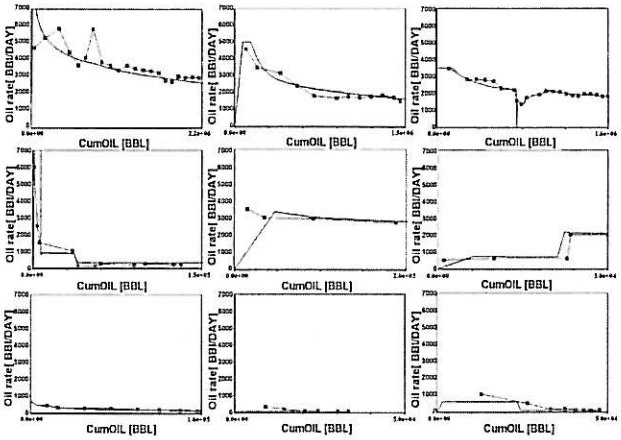


Fig. 4. History match for the wells shown in figure 3. Each graph shows the production rate versus cumulative oil produced. Note that the vertical but not the horizontal scale is equal in all graphs. Actual production history is denoted by black squares and the simulation result by the other line.

All plots in figure 4 have the same vertical scale. The plots show two classes of wells: (i) wells that tap fracture clusters with high rates (top row) and an ultimate recovery (UR) that is effectively determined by fracture cluster size; and (ii) wells located in unfractured regions with low rates (bottom row), whose UR is determined by matrix properties alone. The middle row shows wells within fracture clusters that were stimulated, or that experienced integrity problems.

Our geomechanical fracture model matches the (decline) rates in 9 wells, and pressure readings in 6 observation wells. This match is obtained using a single field-scale model without any local adjustments. Sensitivity studies show that the model is constrained very tightly. Well re-completions have confirmed the predictive capabilities of this fracture model, and production rates from all wells (including those recompleted) are, to date, consistent with the flow forecast from the fracture model. The ability to predict fracture distribution and hydraulic properties on a field-scale has a clear business impact, as it increases the probability of success of a new well significantly.

CONCLUSIONS

In short, rocks obey physics, and physics can be used to predict fractures that affect flow across entire naturally fractured reservoirs. As the model parameters are field-scale (*i.e.* mean rock strength, remote stress, *etc.*), information from each well constrains the whole fracture model and not just the areas close to wells. This makes the model suitable for fracture prediction and flow forecasting in all parts of the reservoir and not just those parts around existing wells. Traditional methods of fracture modelling are geostatistical and somewhat different to the model described above. They rely on stochastic realisations of the large numbers of fracture networks consistent with borehole fracture data to explain inflow data. This approach is ultimately limited to near-well scales as it lacks information on how fracture statistics change away from wells.

In contrast, access to a predictive field-scale fracture model allows enhanced field development of naturally fractured reservoirs. Understanding and quantification of the fracture system helps to mitigate risks via improved flow forecasting, and optimal well placement and design.

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Improving the Success Rate of Development Wells in a Fractured Cretaceous Carbonate Reservoir

- a keynote paper -

Jean Borgomano, Stephen Bourne, Tony Cortis, Karen Foster, Lex Rijkels, Ben Stephenson, Julian Bessa, Marcel Braas, Julio Carrera, Henk Leegte, Eduardo Vargas, Antonio Vizamora.*

تحسين معدلات نجاح الآبار المطورة خلال صخور جيرية متشققة في مكامن العصر الطباشيزي

جين بورقومانو وستيفن بورني وتوني كيرتس وكارن فوستر وآخرون

الحقل الذي تمت دراسته يمثل مكمناً ينتمي إلى العصر الطباشيري ذا إمرارية منخفضة ومتشقق وغير متجانس. إن العامل الحاسم في نجاح الآبار المطورة والتي تستهدف مناطق الاسترداد الإضافي من المكامن ذات التركيبة الصخرية الملتحمة، أوجد الحاجة إلى اعتراض الشبكة الواسعة الانتشار من التشققات المفتوحة. ويمكّن الوصول إلى هذه الشبكة من التشققات جزءاً كبيراً من هذه الرواسب اللاحمة والمسامية من تفريغ محتواها.

تشرح هذه الورقة تقنية جديدة لتحديد: أولا مناطق الاسترداد الإضافي من المكمن ضمن مواضع مسامية غير سميكة. ثانياً مناطق ذات إحتمالية عالية لكونها تحتوي على تشققات واسعة الانتشار. إن توزيع مسامية الصخر الأصلية قد تم إستنتاجه باستخدام المؤشرات السيزمية التي تم دمجها في نماذج المكامن الساكنة ذات الثلاثة أبعاد. وبالتوازي، فإن خرائط إمرارية التشقق قد تم تعيينها من حسابات الجهد وبالتالي ربطت مع نماذج هذه الرواسب لأجل محاكاة ديناميكيته.

لإجازة اختبار النماذج التحتسطحية الممكنة، فإن معدلات الإنتاج من كل الآبار المنتجة تم مطابقتها تاريخياً بأحد النماذج التي تتفق مع البيانات الاستاتيكية المتوفرة، أجرى المشغّل إختباراً ناجحاً للنموذج عن طريق تنشيط وإعادة استكمال الآبار القديمة. وقد مكّن العمل شركة شل أن تتجاوز مستهدفات الانتاج لسنة 1999 ف، مما زاد بقدر كبير من إحتمالية نجاح التطوير المستقبلي للآبار وأن فلسفة بناء النماذج لها تأثيرات كبيرة لصخور جيرية مشابهة من ناحية كونها متشققة طبيعياً.

Abstract: *The Cretaceous field studied is a low-permeability, heterogeneously naturally fractured reservoir. A critical success factor for development wells, which target areas of enhanced reservoir matrix quality, is the requirement to intercept an extensive network of open natural fractures. Tapping into such a fracture network enables a larger volume of porous matrix to be drained. This article describes new technology to identify (1) areas of enhanced reservoir quality within a thin porous interval (ca. 10m) and (2) areas with a high probability of being extensively fractured. Matrix porosity distribution was derived from seismic attributes and incorporated into 3D static reservoir models. In parallel, fracture*

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permeability maps were determined from stress calculations and subsequently combined with matrix models for dynamic simulation. To validate and select possible subsurface models, rates from all producing wells (that vary by a factor 10) were history matched with one model that is consistent with available static data. Successful blind tests of the model through reactivation and re-completion of old wells have been carried out by the operator. These have enabled Shell to exceed production targets for 1999 and have significantly increased the probability of success for future development wells. The subsurface modelling philosophy has substantial implications for similar naturally fractured carbonates.

BACKGROUND

The studied field is located offshore and has been operated by Shell on behalf of the National Oil Corporation since 1993. A significant proportion of the in-place volumes (ca. 8,400 MMbbl) occurs within low-permeability fractured Cretaceous platform carbonates as a light (29° API), sour crude (1,000 ppmv-26,000 ppmv). Throughout 1999, the reservoir was the subject of an asset-focussed research program. This study had the following aims: (1) to achieve a 'short-term' operational/financial impact for the operating company, (2) to develop Shell technology applicable to complex carbonate fields; and (3) to deliver the higher potential business impact of the asset to the greater Shell Group. This paper summarises the important results of this asset study undertaken by an integrated team comprising SEPTAR and regional staff.

TECHNICAL CHALLENGES

The carbonate platform sequence is *ca.* 1000′ thick and found at a depth between ca. 15,000′ and 17,500′ TVDss. It comprises three distinct formations. These are deformed by a series of strike-slip faults to create a low-relief anticlinal structure. The uppermost formation is a laterally extensive deposit which forms a thin sheet (ca. 100′ thick) of low-porosity and tight carbonates (average $\phi < 3$ %; average $k < 0.01$ mD) representing the shallowest part of the platform sequence. The main flow unit within this formation corresponds to a 30 ft thick layer of leached, bioclastic packstones with moderate reservoir porosity (average ϕ = ca. 6.1 %). The requirements of a successful development well are to intercept a dense network of open fractures (production rate) connected to a large volume of porous matrix (connected production volume) (Fig. 1).

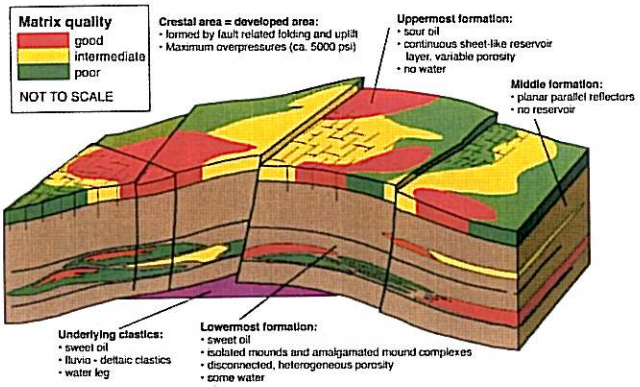


Fig. 1. Schematic picture of the field showing the major reservoir zones and flow units in relation to the stratigraphy, structure and fracture network.

To achieve this, the original development strategy was to target faults, as it was thought at that time that the intensity of tensile fracturing was likely to be greatest in the immediate vicinity of faults interpreted from seismic, with the width of the damage-zone related to fault displacement. This resulted in the "halo-concept" *i.e.* porous intervals inter-linked by a network of fractures with the highest density at the fault or fold related feature. To date, the operating company has drilled 12 dedicated wells of which four account for 92% of the total asset production. A 1996 review highlighted that the reservoir had to be appraised while being developed as there was still insufficient knowledge at that time to define in detail a proven development concept.

Subsequently in 1998, an asset-related study was initiated to increase the understanding of the sub-surface and to maximise the value of the asset. This asset-related study focussed upon developing new technology to achieve the primary subsurface critical success factors for development of a single formation. These were prediction of matrix reservoir quality and prediction of tensile fracture distribution. In the light of these data the development concept has undergone a paradigm shift from a focus on the entire interval to that of a manageable-risk uppermost formation-only

development. It is intended that development wells into the uppermost formation will target matrix "sweet-spots" and natural fracture networks developed away from faults.

INTEGRATED WORK FLOW

The overall strategy of the study was to identify regions of good matrix quality (porosity) and determine the open fracture distribution through forward modelling. Multiple alternative subsurface scenarios were validated through well-production history-matches of the models. The philosophy used in static reservoir modelling was to build voxel volumes of matrix properties (ϕ and k) that could be merged with fracture permeability predictions for dynamic simulation in Shell's dynamic simulation package MoReS (Fig. 2). The reservoir architecture models were based on

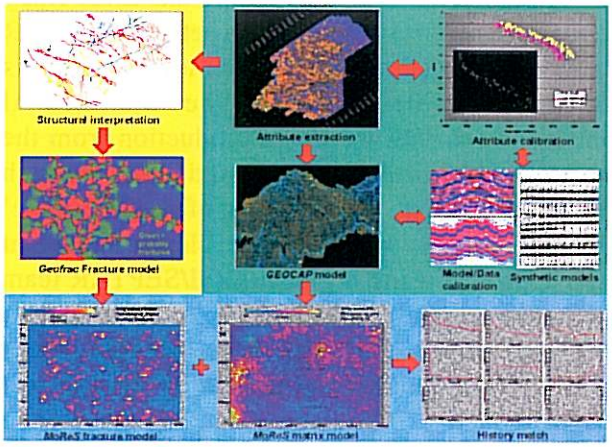


Fig. 2. Representation of the integrated workflow used to model the subsurface, which could also be applied to other fractured carbonates. The yellow, green and blue backgrounds represent the fracture, matrix and dynamic simulation (MoReS) workflows respectively.

stratigraphic correlation of 41 wells and rock fabric analysis of the 4 available cores.

Attribute analysis on the seismic response of the main reservoir from reflection and inversion cubes was carried out to provide a quantitative measurement of reservoir quality (ϕ*h). This was both integrated with and constrained by synthetic modelling. The ϕ*h map was imported into the static reservoir model and five different matrix property models were generated for reservoir simulation in MoReS: two different porosity scenarios (high & low) with each two permeability scenarios (high & low), based on possible ϕ/k relationships derived from recently acquired core data. An additional porosity scenario was generated by interpolating from well porosity logs in Shell's static reservoir modelling package (GEOCAP).

The fracture prediction methodology is based on a novel technique, which calculates the stress perturbation over the field due to slip on faults. This stress calculation predicts regions of effective tension, which are those most likely to be fractured. A fracture map is then "grown" in a semi-deterministic manner, constrained by BHI data from 12 wells, and rock-strength parameters. Different scenarios were modelled to address the uncertainty in remote stress, fault geometry and fracture type. These scenarios were upscaled to MoReS and combined with the matrix properties. Figure 3 shows how MoReS was used to discriminate between the matrix and fracture scenarios to find the optimum history match.

RESULTS

Only a few combined scenarios, from more than 25, match historical production data, as shown in figure 4. Both the matrix and the fracture model are important in the simulated well response, but only one scenario matches all wells. It is based on a seismic porosity map with a vuggy ϕ-k relation, and an extensive, well-connected, tensile fracture network (Figs 3, 4). That so many wells could be matched simultaneously without local adjustments greatly increases the confidence of predicting reservoir quality and fractures outside of the currently developed area. An initial

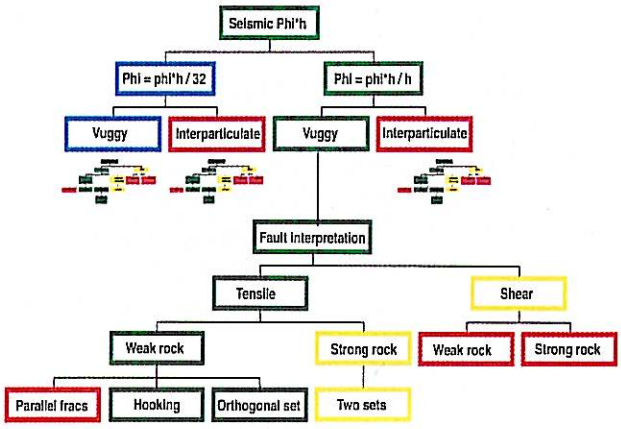


Fig. 3. Field-wide scenarios were used to match the production history of all wells, plotted here schematically as a tree of simulator ingredients. Green scenarios match and red do not.

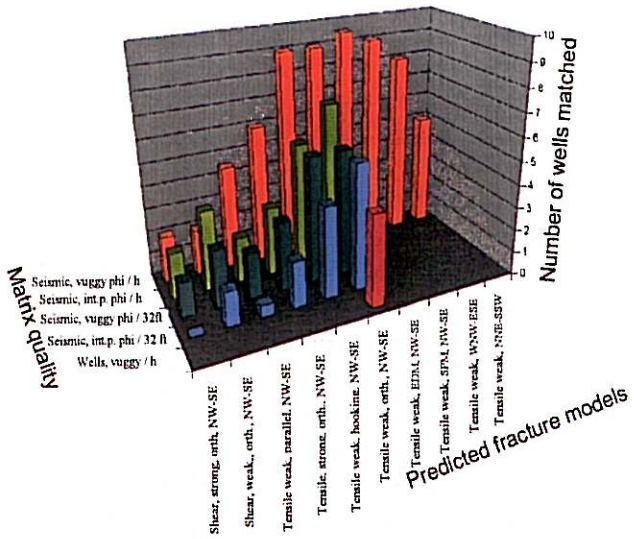


Fig. 4. Each bar represents one simulation scenario - a combination of a matrix ϕ/k model (one axis) and a fracture prediction (other axis). The height of the bar indicates how many wells are matched in the flow simulation (vertical axis). Its colour indicates the match of the matrix model with the well logs (hot colour = better match). The best history match is obtained with a matrix model based on seismic porosity prediction, and tensile fractures in a weak rock under NW-SE remote stress.

blind test of the model was carried out in July 1999 through a re-completion of an existing well. The test proved successful when an existing 30° well was perforated and stimulated to remove the skin. Post-stimulation production was predicted via simulation of the fractured matrix model and interpretation of a previous build-up. It is expected that the new subsurface model developed in this study will be further tested with a future appraisal well. Three potential locations were identified for new development wells in the field (Fig. 5).

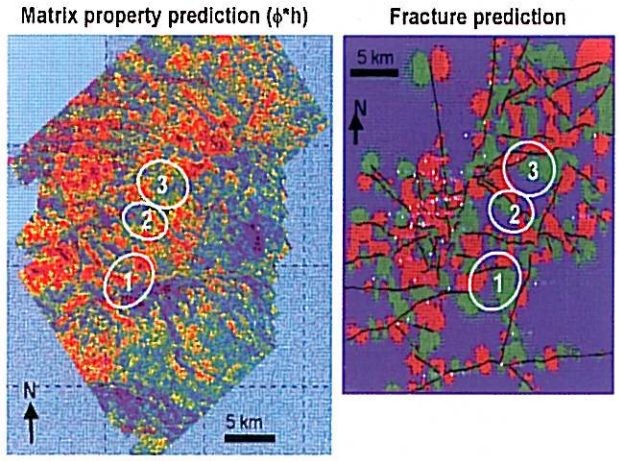


Fig. 5. Infill well ranking based on seismic attribute (ϕ*h) and fracture prediction maps. Wide areas of high matrix porosity (hot colours) overlapping regions of effective tension (green) away from major faults.

CONCLUSIONS

One of the main learning points from this study is that the integration of disciplines is crucial to the modelling of naturally fractured reservoirs as outlined schematically in figure 1. Through integration, all the critical subsurface parameters were combined in simulation models that were tested against production history. Both matrix and fracture distributions must be correctly described to obtain a history match. For instance, if the matrix model were based solely on well logs, the match between the logs and the model would be perfect, but a dynamic history match would never be achieved. It is only when we use the seismic ϕ*h map, combined with the effective fracture permeability map, both of which give a reasonable match individually, that the history match is good and consistent with the static data (Fig. 4).

A key factor in the success of this asset-study has been the close collaboration between SEPTAR staff in The Netherlands and the local staff. This success is measured in the operational environment with increased production from the reservoir with well re-entries, and in the research environment with the evolution of 'leading-edge' technology. The results to date, clearly show that the approach using a global/local/SEPTAR team represents a model for other assets requiring fast-track evolution of leading-edge technology that can be immediately applied in an operational environment.

Asset-focussed evolutionary-research on the reservoir is being furthered throughout 2000, with a drive to further 'sweat the existing asset' with new potential for stimulation and completion of old wells in the license area.

Petroleum Res. J. Vol. 13 (2001); P. 83–88, 4 Figs.

Induction Logging in Diverse Borehole Environments in the Elephant Field, Libya

Peter Elkington* and Christopher Skelt**

قياسات المقاومة التأثيري في حفرة البئر متعدد البيئات في حقل الفيل بليبيا

بيتر ألكينجتون وكريستوفر سكيلت

إن قياس المقاومة التأثيري الذي يجري في الآبار المحفورة باستخدام طين زيتي القاعدة يبين باستمرار أدلة على غزو سوائل الرشح. حساب قطر الغزو باستخدام لوحة الترنادو التقليدية يحتاج إلى قراءات مدخلة للمقاومة الضحلة باستخدام أجهزة المقاومة الدقيقة كقياس المقاومة المستعرض الدقيق، ولكن هذه القراءات أو القياسات غير متوفرة في حفرة البئر الذي يستخدم فيه وسط عازل. التقنية الجديدة التي تستخدم قياس المقاومة التأثيري بمفرده، رغم كونها بسيطة ومتينة، إلا أنها تحاصر هذه المشكلة.

لقد طبقت هذه التقنية أو استخدمت كذلك على بيانات من آبار محفورة بواسطة طينة موصلة. وفي هذه الحالة فإن جزءاً ذا قيمة من الإشارة الكلية قد يكون بسبب بيئة حفرة البئر، وهذا يتطلب استرجاع هذا الجزء لأجل إستنتاج درجة التوصيل الكهربائي لصخور التكوين وهذا يظهر درجة الشك في المنحنيات المحسوبة والتي تزداد بنقصان مقاومة طينة الحفر. ونحن نحدد أو نقيس هذا بالنظر في القيم النسبية للاشارات التي سببها مشاركة صخور التكوين أو حفرة البئر.

هذه الطريقة لها – وعلى وجه الخصوص – تطبيقات في التكاوين منخفضة التوصيل الكهربائي حيث الإشارات ذات المدى المنخفض.

إن المعرفة المتداولة أو المعتادة والتي في الغالب اكتسبت من أجهزة الجيل الأول، تقول بأن القراءات التي قيمتها أكثر من مائة أو مائتين أوم–متر، هي غير دقيقة أو غير موثوق فيها.

إننا نبرهن بأنه بتعريض السرود الكهربائية لعمليات معالجة مناسبة، يمكن أن نثق في القراءات التي تصل على الأقل إلى 1000 أوم–متر. وهذا قد ساعدنا على تمييز مكامن الزيت ذات المياه العذبة بالتكوين الجيولوجي.

هذه التقنية لها تطبيقات حيثما الجيوب البيئية التي يتم فيها التطابق بين قياسات المقاومة التأثيري والمستعرض أثناء تعود التيار على اختيار واحد ويرفض الآخر.

إن أفضل فهم لطريقة عمل جهاز قياس المقاومة التأثيري في التكاوين عالية المقاومة يساعد في شرح التضارب الواضح بين القياسات التي على هيئة خواص حقيقية للتكوين كما هو الحال في الخواص المتباينة حسب الاتجاه أو الانحرافات عن مظهر الغزو أو الغمر التدريجي.

Abstract: *induction logs run in wells drilled with oil based mud frequently show evidence of filtrate invasion. Computing diameter of invasion from a traditional tornado chart requires input from a shallow reading resistivity device such as a microlaterolog, but these are not available in non-conductive boreholes. A new technique using induction measurements alone circumvents the problem, while being both simple and robust.*

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The technique has also been applied to data from wells drilled with conductive muds. In these cases, a significant part of the total signal can be due to the borehole environment, and this must be backed-out in order to derive the formation conductivity. This introduces a degree of uncertainty in the computed curves that increases as the mud resistivity decreases. We quantify this by looking at the relative magnitudes of signals due to formation and borehole contributions.

The approach has particular application in low conductivity formations where signals are of low amplitude. Conventional wisdom, largely inherited from first generation tools, is that readings greater than one or two hundred ohm-m are unreliable. We demonstrate that, subject to appropriate processing, logs can be trusted to at least 1000 ohm-m. This has helped us characterise an oil reservoir with fresh formation water.

The technique has application where the environmental envelopes of laterolog and induction measurements overlap, and where current practice is usually to select one and reject the other. A better understanding of induction tool performance in highly resistive formations helps explain apparent discrepancies between the measurements in terms of real formation properties such as anisotropy or deviations from step invasion profile.

INTRODUCTION

Resistivity logs are traditionally run to derive a value of true formation resistivity, R_t, in order to derive water saturation, S_w. The emphasis is, therefore, on obtaining accurate estimates for R_t, but this is not necessarily the most important formation property that can be derived from the logs.

We present two field examples where induction logs have been processed to optimise diameter of invasion and variations in conductivity close to zero conductivity. The traditional approach of selecting either laterolog or induction log, according to borehole and formation properties, was appropriate when the measurements were first introduced, but technical improvements have extended the overlap between the operating envelopes of the two tool types. Although one of the two may be favoured, they are not mutually exclusive, and selecting only one can potentially deny the petrophysicist useful information about invasion and formation anisotropy. It is, therefore, worthwhile developing techniques to exploit the advances in logging tool technology.

Wells in which formation water is fresher than filtrate are often logged with induction alone. The borehole environment and radial resistivity profile encountered in the water legs are appropriate for deriving an accurate estimate of formation and water resistivity to apply in the hydrocarbon zones. However, the large increase in resistivity in hydrocarbon zones alters the radial resistivity profile so that resistivity increases with distance from the borehole, which favours the laterolog. The techniques we present here for working with induction logs in unfavourable environments are relevant to these frequently encountered circumstances.

Extending the Low Conductivity Limit

Formation resistivities in the reservoir of the Elephant field in Libya extend up to thousands of ohm-metres. Core analysis suggests that this is due to the formation becoming progressively more oil wet with increasing height above the contact. This is supported by the very low water saturations computed by the Archie equation applied to the highest resistivities.

While these high resistivities are easily measured by laterologs, they present a challenge for induction logs run in wells drilled with oil based mud. In these circumstances the priority switches from deriving a resistivity for use in saturation determination to optimising the description of the lowest conductivities with the aim of detecting small variations resulting from wettability changes.

The measurement accuracy for modern induction tools is claimed to be better than 0.001 S/m, which implies that computed resistivity logs should be accurate up to 1000 ohm-m. However, conventional wisdom is that induction logs are unreliable at formation resistivities above a few hundred ohm-metres, and that laterologs are preferred in these circumstances. The combination

of a massive high resistivity oil-filled sand and oil-based mud in the F3 well provide an opportunity to test the low conductivity limit of the tool's response.

Low Conductivity Signal Compression

The F3 logs are shown in figure 1. Curves in the rightmost track were processed using field default parameters. Field processing includes a curve "squasher" that prevents negative conductivities (from near-borehole conductive or magnetic anomalies) being displayed on a logarithmic resistivity grid. The process compresses displayed conductivity values progressively below a low conductivity threshold whose default value is 0.005 S/m (equivalent to 200 ohm-m). The effect of removing the squasher is also shown in figure 1.

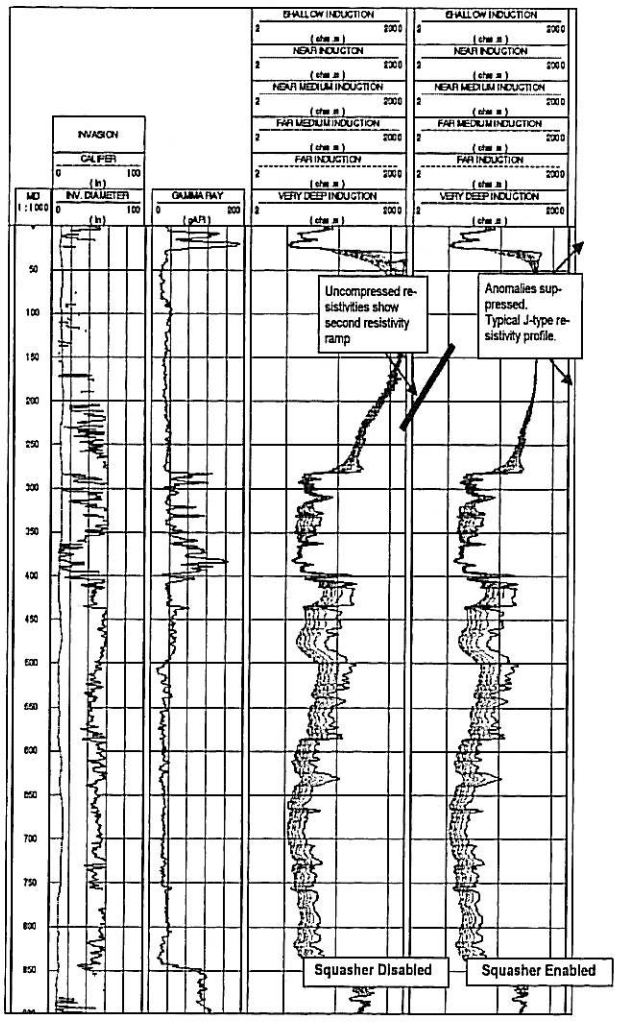


Fig. 1. Induction log low conductivity response, well F3.

The highest resistivities now approach 2,000 ohm-m with no obvious degradation in character, evidence that supports the claimed measurement accuracy. It is now possible to identify a change in the resistivity gradient close to x235 ft, at about the elevation above the contact thought to be associated with the onset of mixed and oil wet conditions. We conclude that the default display is unduly conservative in this favourable borehole environment.

Induction Log Borehole Effects

The apparent conductivity σ_a seen by an induction too transmitter-receiver coil array is given by

$$\sigma_a = g\sigma_m + (1\text{-}g)\,\sigma_f \qquad (1)$$

where g is an integrated radial geometric factor, and σ_m and σ_f are mud and formation conductivities respectively.

The magnitude of g tells us how much borehole correction has been applied, but is not necessarily a good indication of the size of the borehole effect. This is because g is determined under static conditions - it ignores the dynamic component of borehole effect arising from interactions between a moving tool and a non-constant hole environment. In low conductivity borehole fluids, the dynamic component can be ignored, but it becomes progressively more significant as the fluid conductivity increases.

Dynamic borehole effects constitute a source of noise that is inherently difficult to quantify, let alone remove. Nevertheless, they provide a framework for quantifying confidence levels for high resistivity values from real-world induction logs.

We cannot easily quantify all the individual sources of borehole-related noise and their complex interactions. It is reasonable to say, however, that as the size of the nominal borehole correction increases relative to the formation signal we are trying to extract, confidence in the computed formation signal will decrease. For example, we consider the situation of equal borehole and formation signal magnitudes.

From equation (1), for a single coil pair or sub-array the nominal signal due to the borehole is g_m and that due to the formation is $(1\text{-}g)\sigma_f$. These are equal when:

$$\frac{\sigma_f}{\sigma_m} = \frac{g}{(1\text{-}g)} \qquad (2)$$

Each sub-array is a source of borehole-related noise. Let us assume that the statistical distributions of the noise are independent, then the noise in any of the composite curves (such as the Deep and Medium, or other derived curve) is derived by taking a weighted RMS average of the individual sub-array noise levels. The weights are those used in the computation of the derived curves from the individual sub-arrays.

Figure 2 shows R_t/R_m as a function of bit size and standoff for deep and Medium curves processed from the array induction tool, for the condition of formation signal equal to nominal borehole signal. Scaling the condition (for example, borehole signal equal to 200% of formation signal) scales the maximum R_t/R_m value, but does not change the curve order.

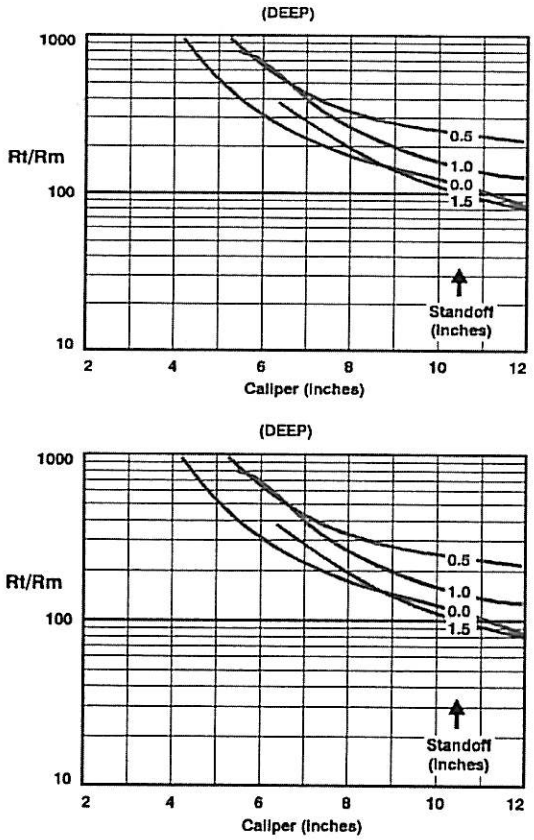


Fig. 2. Deep and medium curve signal to noise indicators. The curves connect points for which borehole and formation signals are of equal magnitude.

The practical interpretation of these curves is that they define resistivity envelopes above which borehole-related noise is likely to become intrusive. It does not mean that higher values of resistivity are unusable, only that care needs to be exercised in their interpretation.

Indeed, it would be wrong to regard the curves in figure 2 as delineating upper limits for R_t/R_m without regard for other aspects of the borehole environment. For example, experience suggests that in good wellbore conditions (on-gauge hole, no caves), R_t/R_m interpreted from figure 2 is pessimistic by a factor of at least 2. Conversely, in cases of extreme rugosity and irregular hole enlargement, the figures indicate maximum R_t/R_m values that are optimistic by a similar factor.

Invasion Diameter from the Array Induction

Well test results on a number of Elephant appraisal wells indicated high skin. A possible explanation was that the perforations had not penetrated beyond the zone damaged by filtrate in this hard formation. This put a high priority on determining diameter of invasion D_i, normally considered a by-product of true formation resistivity determination. Estimates of invasion diameter from laterolog and induction can be compared in the F2 well.

Diameter of invasion is defined in terms of the commonly assumed step invasion profile, and is normally computed as part of a tornado chart calculation. This chart allows the three step profile parameters R_t, R_{xo} and D_i to be computed from three input curves, normally two induction curves plus a shallow reading laterolog curve. In non-conductive borehole fluids, the laterolog curve is not available. The whole chart changes as a function of R_{xo} because of skin effect.

Although F2 contained conductive borehole fluid, we choose to use a technique for D_i determination that could also be applied to wells with non-conductive fluids. Our new method is set in the conductivity domain.

The new solution for D_i is derived from geometric factor theory. The apparent

conductivities from two differently spaced induction arrays for the case of step profile are:

$$\sigma_1 = g_1\sigma_{xo} + (1-g_1)\sigma_t$$
$$\sigma_2 = g_2\sigma_{xo} + (1-g_2)\sigma_t$$

where g_1 and g_2 are integrated radial geometric factors corresponding to particular values of D_i. Taking differences, we get:

$$(\sigma_2-\sigma_1) = \sigma_{xo}(g_2-g_1) + \sigma_t(g_1-g_2)$$

Re-arranging we get:

$$(\sigma_2-\sigma_1) = (g_2-g_1)(\sigma_{xo}-\sigma_t) \quad (3)$$

Adding a third measurement, and taking a second difference gives:

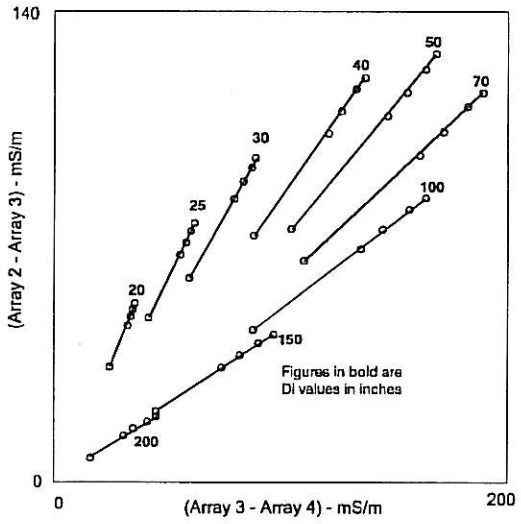
$$(\sigma_3-\sigma_1) = (g_3-g_1)(\sigma_{xo}-\sigma_t) \quad (4)$$

Dividing equation (4) by equation (3) eliminates σ_{xo} and σ_t:

$$\frac{\sigma_3-\sigma_1}{\sigma_2-\sigma_1} = \frac{g_3-g_1}{g_2-g_1} \quad (5)$$

If we ignore skin effect, the geometric factors in equation 6.3 depend solely on D_i. Moreover, apparent conductivity data from all invasion profiles with fixed D_i must appear on a straight line on a plot of $(\sigma_3-\sigma_1)$ against $(\sigma_2-\sigma_1)$. This has been tested by crossplotting data generated from analytical models. Figure 3(a) is a plot of the conductivity difference $(\sigma_3-\sigma_4)$ against $(\sigma_2-\sigma_3)$ using data from the $R_t>R_{xo}$ tornado chart. It is striking that the D_i values fall on almost perfect straight lines pointing to the origin, consistent with equation (5) the data points within each line correspond to different values of R_t/R_{xo}. This data set was generated for R_{xo}=1 ohm-m, and does, in fact, include skin effect.

The conductivity difference plots suggests a simple and robust method for extracting D_i information from array induction logs. Straight lines that pass through the origin of the conductivity difference graphs are defined solely by their gradients. In the case of figure 3(a), this is simply $(\sigma_2-\sigma_3)$ / $(\sigma_3-\sigma_4)$. This is plotted as a function of D_i in figure 3(b). Each point is actually a cluster of data values that span R_{xo}/R_t values of



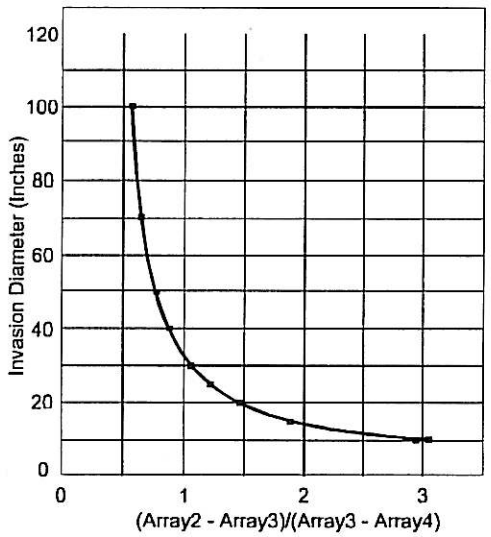


Fig. 3 (top). Computer model results showing points of equal Di fall close to straight lines on plots of conductivity differences. Fig. 3 (bottom). Slopes of the lines in figure 3 (top) are plotted as a function of Di. The model results exhibit that Di values computed in this way do not depend strongly on Rxo.

0.4, 0.15, 0.1, 0.05, 0.025, 0.02 and 0.01. It is apparent, therefore, that the function is practically independent of R_t/R_{xo}.

Using this method, D_i values were computed for the F2 well, and compared with those computed from a dual laterolog / microlaterolog combination run in the same well. F2 was drilled with an 8.5 inch (216 mm) bit and water based mud with R_m at bottom hole temperature of 0.39 ohm-m. The induction was run with 1.5 inch (38 mm) standoffs.

The analysis in figure 4 suggests these conditions are unfavourable for the induction tool

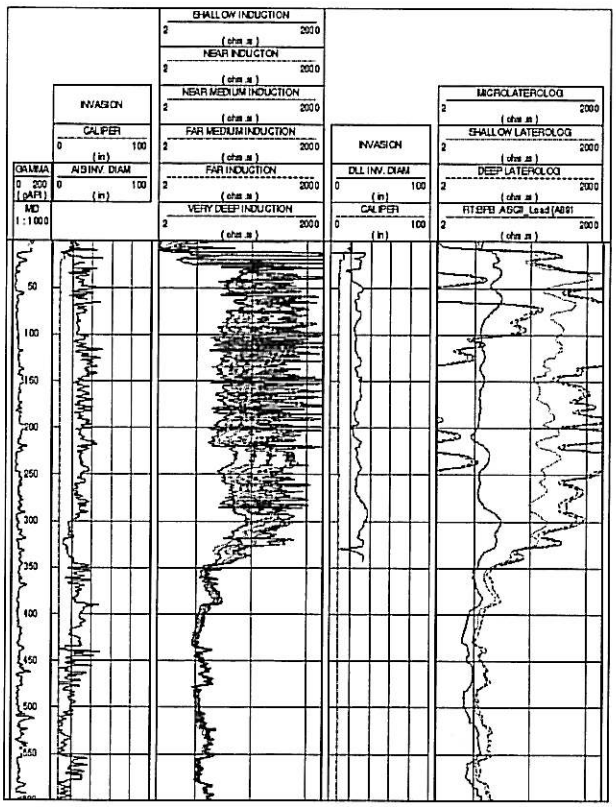


Fig. 4. Array Induction and Dual Laterolog data sets from the F2 well. The borehole environment was unfavourable for induction logs, but Di estimates generated from conductivity differences were stable, and comparable to those from laterologs.

over the oil leg, where the laterologs record high to very high values of R_t. This is reflected in the character of the induction curves, which appear to be very sensitive to small variations in hole quality and tool position when viewed on a resistivity scale. In the conductivity domain, however, the induction curves are much less active, and differences between induction curves are reasonably consistent. The D_i curve computed from conductivity differences is correspondingly stable, and in approximate agreement with that from the laterologs. The agreement suggests that the actual invasion profile may be step-like and that the method yields valid results.

CONCLUSIONS

The quality of induction log data in high R_t / R_m environments can be assessed by comparing signal amplitudes originating in formation and borehole regions. Where induction log borehole signals are small, for example in non-conductive environments, attention can usefully be paid to the parameters controlling the processing of low conductivity values in order to avoid unnecessary cosmetic distortion.

Invasion diameter values can be computed form the conductivity differences available from array induction tools even in unfavourable environments. The method is simple, independent of the Rt computation yields results similar to those obtained with laterologs.

ACKNOWLEDGEMENTS

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Petroleum Res. J. Vol. 13 (2001); P. 89–96, 7 Figs.

A Highly Integrated Logging Tool String Platform Express

Fabrice Uran†

عمود مجسات تسجيلات الآبار ذات الترابط العالي Platform Express

فابرايس أوران

لقد تم إعادة هندسة عمود المجسات في أجهزة تسجيلات الآبار السلكية، بحيث أصبح ذا طبيعة ترابطية أو تكاملية تحت اسم (Platform Express) وتم إدخاله إلى ليبيا حديثاً.

ويمتاز هذا العمود بتصميم يجعل حزمته الالكترونية وتصميمه الميكانيكي أكثر نجاعة، حيث أنه أسرع من عمود أجهزة تسجيلات الآبار السلكية المعتادة والمستخدمة حالياً، ويعطي إجابات اعتمادية أفضل، كما أنه أكثر كفاءة عند الآداء.

في الواقع، فإن قياسات المقاومة الكهربائية وقياسات المسامية قد تم تحسينها وزادت قدراتها الاستيعابية بحيث تشمل قياس المقاومة الدقيقة والصور الوصفية والقياسات المتحركة. وقد دمجت هذه المجسات الجديدة في عمود أقصر له نصف طول ونصف وزن الأجهزة المعتادة. كما تضاعفت سرعتها التسجيلية بحيث أصبحت ضعف سرعة الأجهزة المعتادة وبنفس وضوح المعلومات. حيث أن العمليات اللوغاريثمية الخاصة بتصحيح أخطاء السرعة والتعويض عن تأثيرات حفرة البئر، يتم إجراؤها في الحال، أي في نفس وقت القياس.

كذلك، فإن مجسات أو أجهزة قياس المقاومة الضحلة والكثافة، قد حُملت على لوح إنزلاق أقصر مزود بمفصل مرن يساعد على تحسين عملية التصاق الوسادة الحاملة لهذه المجسات مع جدار البئر، ويظهر جهاز قياس الكثافة، لاقطا ثالثاً لزيادة اعتمادية القياسات بقدر عال. بالإضافة إلى أن تسجيلات الآبار التقليدية والتي تستخدم في الاستنتاجات البيتروفيزيائية، ذات درجة وضوح رأسية عالية.

الجزء الأول من هذه الورقة يفصل خواص عمود المجسات ويبين مدى الاستفادة النوعية للبيانات من هذا التصميم الجديد ويتبع في ذلك تتابع المجسات، من أعلى إلى أسفل، جهاز أشعة جاما والنيوترون وجهاز الكثافة والمقاومة الضحلة وجهاز قياس المقاومة ذات الرؤية الرأسية العالية، والجزء الثاني من هذا البحث يركز على حالة دراسية حقيقية من ليبيا.

Abstract: *The standard wireline logging tool string has been re-engineered into an integrated string named the 'PLATFORM EXPRESS', introduced recently to Libya. The string features more robust electronic packaging and mechanical design. It is faster than the existing standard logging string, provides better answers and reliability and is much more efficient to run.*

Indeed the traditional suite of resistivity and porosity measurements has been upgraded and expanded to include micro-resistivity, imaging and tool movement measurements. The new sensors are integrated into a shorter tool string that is less than half the length of the standard one, weighs half and its logging speed is double for the same

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resolution of data. New algorithms such as speed-correction and compensation for borehole effects can be run in real-time. Shallow resistivity (R_{xo}) and litho-density sondes are mounted on a single shorter skid which is articulated by a flex joint for improved pad contact against the borehole wall. The litho-density tool shows a third detector that increases significantly the measurements reliability.

Also traditional logs used in petrophysical interpretation can be produced with a high vertical resolution.

The first part of this paper details the tool string features and shows how data quality benefits from the new design. It follows the string sequence i.e. from top to bottom the gamma ray-neutron tool (HGNS), the litho-density and shallow resistivity tool (HRGD*), and the high resolution resistivity tool (HALS*). The second part focuses on an actual case study from Libya.*

INTRODUCTION

Platform Express is the name of Schlumberger's re-engineering of wireline logging technology. The word Platform represents the concept of a platform of integrated sensors rather than a set of individual tools screwed together into a very long tool string. The new sensors are integrated in both the hardware itself and the measurement. The word Express refers to the tool efficiency. It results from higher logging speeds and faster well-site processing turnaround.

The string shows general features that improve significantly the acquisition reliability. In the meantime, each tool integrated in the string shows its own characteristics that also increase data quality.

TOOL FEATURES

From the operations standpoint, this new tool string brings major advantages. First, the Platform Express string consists of four major sections that make up a total length of 38 ft and which weighs 690 pounds – less than half the standard logging tool string. Figure 1 shows the relative lengths of the standard logging string and the Platform

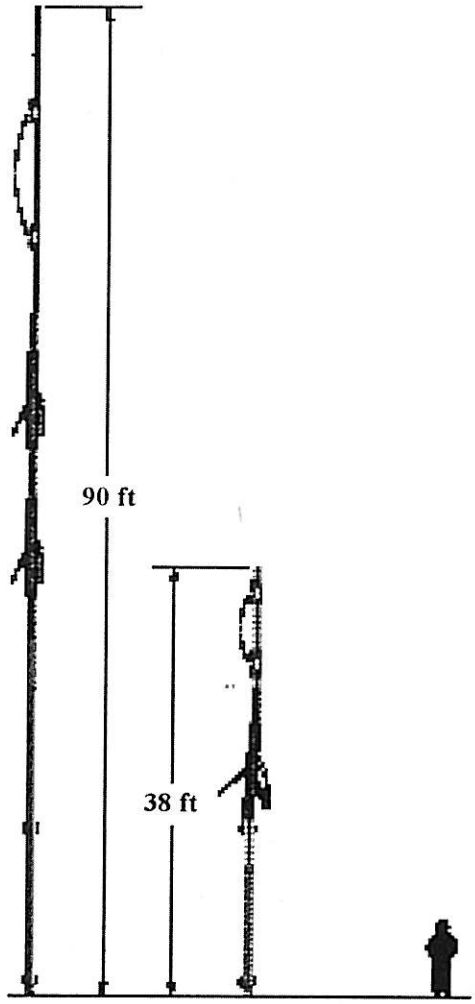


Fig. 1. Comparison of standard logging string with the Platform Express

Express. This shorter length allows it to successfully traverse short radius-of-curvature wells and wells containing severe doglegs. It requires, also, much less rathole than the previous generation of tools and helps reduce rig time in a significant manner[1]. The logging speed has also been increased to 3600 ft/h (double the speed of the standard logging suite limited to 1800 ft/h) without any loss in data quality.

Greatly enhanced reliability is an additional Platform Express benefit that reduces down time. New temperature and shock qualification standards have been achieved with the new design. Indeed, much more rigorous shock testing standards have been performed to qualify the Platform Express tool (as an indication, each tool has to survive 2000 shocks of 250 g's for 2 ms). The Platform Express is the only wireline tool in the industry that meets these standards for shock.

Over a wide range of environmental conditions in field tests conducted in Argentina, Canada, Indonesia and Saudi Arabia, Platform Express delivered almost failure free performance and reliability was over 3 times higher than the conventional suite of logs.

The Platform Express system implements the most advanced speed correction algorithms on the raw acquisition data, prior to any processing to provide basic outputs. This method ensures more accurate resolution matching of the measurements. Indeed, previous depth-matching techniques could not always perform correct depth-matching and resolution-matching of the data.

The integrated single-axis accelerometer measures acceleration along the tool's z-axis with a new and more precise acquisition method. This enables the depth along the borehole trajectory (measured depth) to be computed more accurately and for data to be indexed with respect to this speed-corrected depth. The speed correction is applied in real time to produce depth-matched data at the time of acquisition.

Environmental correction is also a service run in real time at the well site. Usually this type of correction is performed after acquisition and is often based on assumptions made about the well bore conditions instead of using direct measurements (temperature, pressure and properties of salinity, resistivity and density).

The Platform Express introduces environmental corrections with measured inputs rather than assumed values. An evaluation of the error on the correction is also computed to assess the correction validity. The environmental corrections are applied to speed-corrected data to produce high quality data.

Depending on the borehole conditions, the vertical resolution of the different measurements can greatly improve the log analysis. All of the Platform Express sondes are able to produce high-resolution measurements at a standard logging speed (3600 ft/h). The high-resolution data can help in a better indication of lithology, permeability and saturation changes in the formation.

A quick-look lithology indicator is also produced by combining a clay volume content (based on Gamma Ray – GR - or Spontaneous Potential – SP -) and the Photo-Electric Factor – PEF. This gives a type of lithology at each measured depth in order to observe lithology changes in the formation. This can be also used for effective well-to-well correlation. The tool string is also combinable with all of the other existing tools available in the wireline logging domain.

TOOL STRING

From top to bottom the Platform Express is made of the gamma ray-neutron tool (HGNS*), the litho-density and shallow resistivity tool (HRGD*), and the high-resolution resistivity tool (HALS*). Figure 2 shows the tool string and its measurements.

HGNS

The 9 ft, 5 inch long Highly Integrated Gamma Ray Neutron Sonde provides in one tool both standard gamma ray and neutron porosity measurements. Robust and shock-resistant packaging and new electronics have been added to improve reliability. The sonde includes the single z-axis accelerometer for speed correction. The HGNS also provides the telemetry interface for the entire tool.

The neutron detectors use an internal reference source for auto-calibration that eliminates the need for equipment at the well site. This enhancement saves time

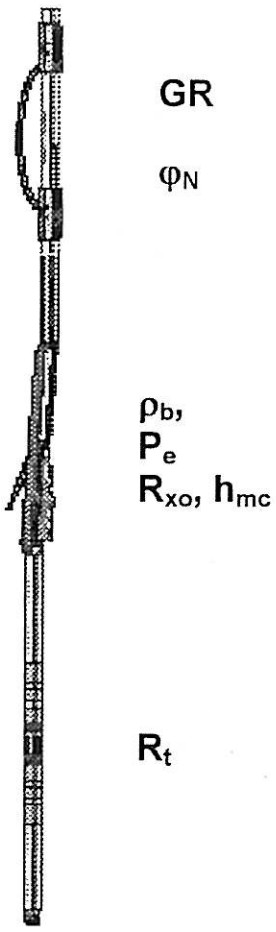


Fig. 2. Platform Express tool string.

and reduces the number of radioactive sources brought to the well.

HRGD

The High-Resolution measurements of the Platform Express include the three-detector density/PEF and the MCFL* (Micro-Cylindrically Focused Log) based R_{xo} (shallow resistivity) measurement. The sensors for both measurements are located on the same skid that is pressed against the formation. The pad is 30% shorter than the present generation Litho-Density tool.

Figure 3 shows the pad design. Flex joints are built in to allow the sonde to hinge or bend slightly as the tool travels into and out of rough hole sections. A second pair of arms is used to apply force directly to the back of the skid to keep its face pressed against the wall when the caliper arm hits a ledge. The upper link between the skid and the sonde body prevents the upper end of the skid from striking borehole restrictions abruptly and it also serves as a fishing link between the skid and the sonde body. Altogether the shorter pad, an additional back-up arm and the use of flex joints deliver significantly improved measurements in rough and deviated holes.

The MCFL electrodes are mounted on the surface of the pad, sandwiched between the short- and long- spacing detectors of the Three-Detector Litho-Density sonde (or TLD). Both sensors provide an estimation of stand-off (or mudcake) parameters, with the MCFL R_{xo} device providing a MicroLog-like measurement as well.

The TLD is called a backscatter density measurement because it uses a third detector located only 2 inches from the source. The response of this detector helps characterize the shallow zone of investigation in the presence of rugose hole or thick mudcake.

TLD logs are similar to conventional Litho-Density measurements but the higher statistics and superior pad application result in faster logging speeds and more accurate density and photo-electric factor data. The new mudcake density and tool stand-off estimates help improve the environmental corrections applied to the logs. Figure 4 shows the density and PEF measurements in a test pit where the true values are known (limestone and dolomite). Only high resolution logs show very good accuracy in thin beds.

The processing algorithm employed for the Platform Express Three-Detector density device

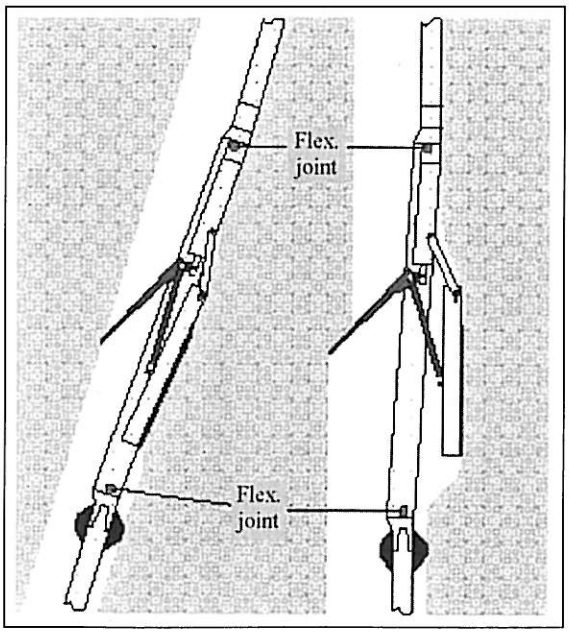


Fig. 3. HRMS pad.

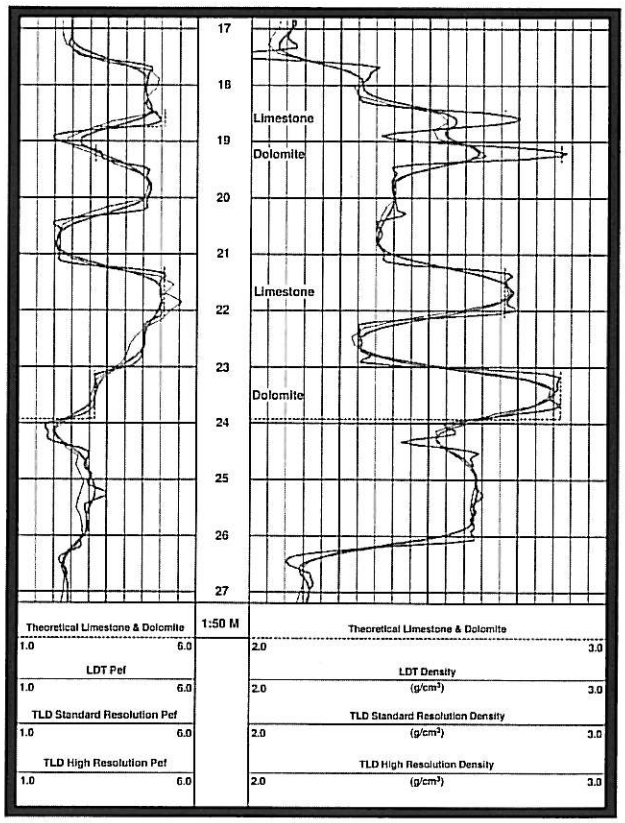


Fig. 4. Density in a test pit.

differs from the traditional spine-and-ribs approach of previous density tools. The spine-and-ribs algorithm is, in fact, a simple inverse model that permits the formation parameters (density and PEF) to be calculated directly from the count rate measurements.

However, with data from three detectors such a simple inversion is not possible. Instead a forward model is defined that is a prediction of the count rate measurements, calibrated and corrected for borehole effect, given the physical parameters (density and PEF of the formation, and PEF of the mud and mudcake thickness). Given this forward model the desired physical parameters are obtained through the resolution of an inverse model.

HALS

The 16 ft long High-Resolution Azimuthal Laterolog Sonde has an azimuthal array that bears overall resemblance to the previous resistivity laterolog tools, but rather than implement a scaled down version, the dimensions were re-optimized to minimize performance loss as a consequence of the substantial length reduction [2]. Four types of resistivity measurements are possible: conventional deep and shallow, and high-resolution deep and shallow resistivities. The tool delivers 12 " vertical resolution and a deep and shallow-reading azimuthal resistivity images of the formation, as well as the ability to estimate mud resistivity.

The main uses of the azimuthal images are determining formation dips and correcting true resistivity in dipping beds, detecting and evaluating fractures and estimating azimuthal anisotropy particularly in deviated/horizontal wells.

Borehole corrections to the High-Resolution Laterolog Sonde are available in real time at the well site. Figure 5 shows the corrections of borehole effects on the different resistivity logs (removing invasion appearance).

The importance of these real-time corrections is illustrated by this example from Indonesia, covering two different resistivity ranges. The standard- and high-resolution curves are presented

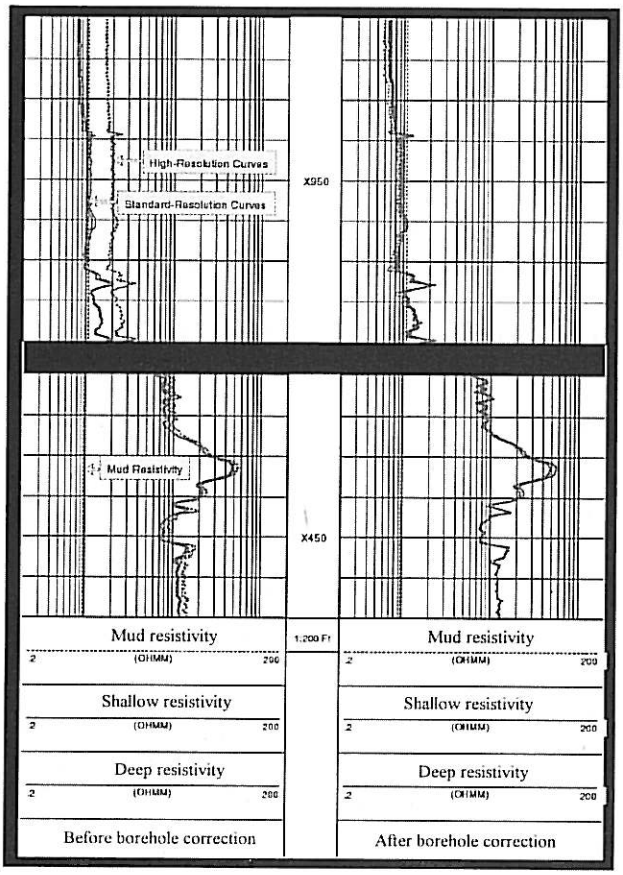


Fig. 5. HALS borehole corrections

both before borehole corrections, in the left track, and after, in the right track. The HALS mud resistivity measured is presented in both tracks.

Note from the data before borehole corrections that the separation between the standard- and high-resolution curves in impermeable zones, indicative of the magnitude of borehole corrections, increases as the ratio of apparent resistivity to mud resistivity decreases. Note, also, that in these low-contrast conditions, the borehole corrections to high-resolution data are very significant. After borehole correction, there is an acceptable overlay between the deep and shallow resistivities at both resolutions over these generally impermeable intervals.

EXAMPLE FROM LIBYA

Platform Express has been recently introduced to Libya. The example studied here was recorded with the same string as described previously but sonic measurements have also been added to the tools to provide the usual transit time log.

The general data set shows partially washed-out zones. Figure 6 shows the effect of speed correction on nuclear measurements in one of these zones. On the first track is plotted the caliper and both gamma ray curves (speed and non-speed corrected); the second track shows the cable tension; the third and fifth tracks are showing the nuclear curves (density and porosity) before and after speed correction. The lithology column logs in the fourth and sixth tracks follow the same logic.

The tension curve is clearly showing the tool sticking between X670 and X720 ft. The effect of speed correction is then clearly visible on the density curve. The lithology column is obviously

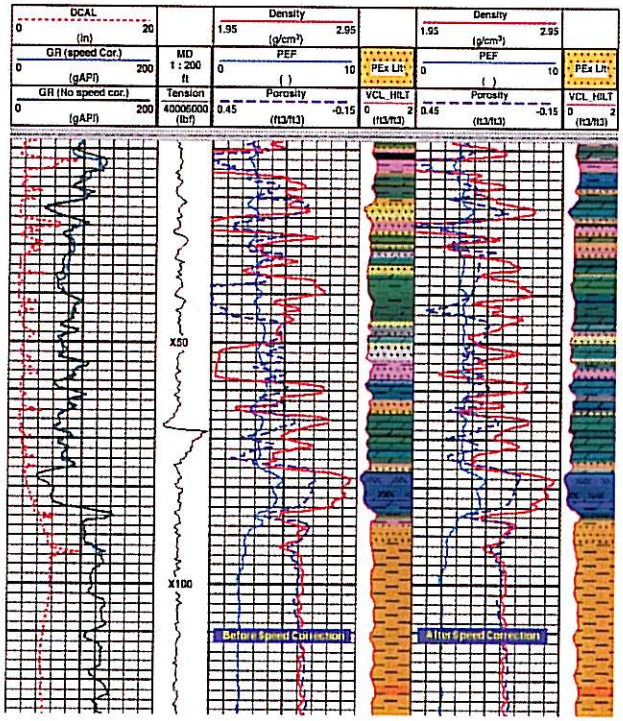


Fig. 6. Speed correction on nuclear data.

affected in the same manner: the first estimation of lithology shows non-negligible changes after speed corrections.

Figure 7 shows the recorded and recomputed logs along with formation volume analysis: the caliper and computed stand-off on the first track; shallow and deep resistivities with standard and high resolutions in the second track along with the R_{xo} curve; the deep resistivity image on the third track; the lithology quicklook on the fifth, the nuclear measurements (density-PEF, porosity) on the fourth and sixth track and the computed volumes in the last track.

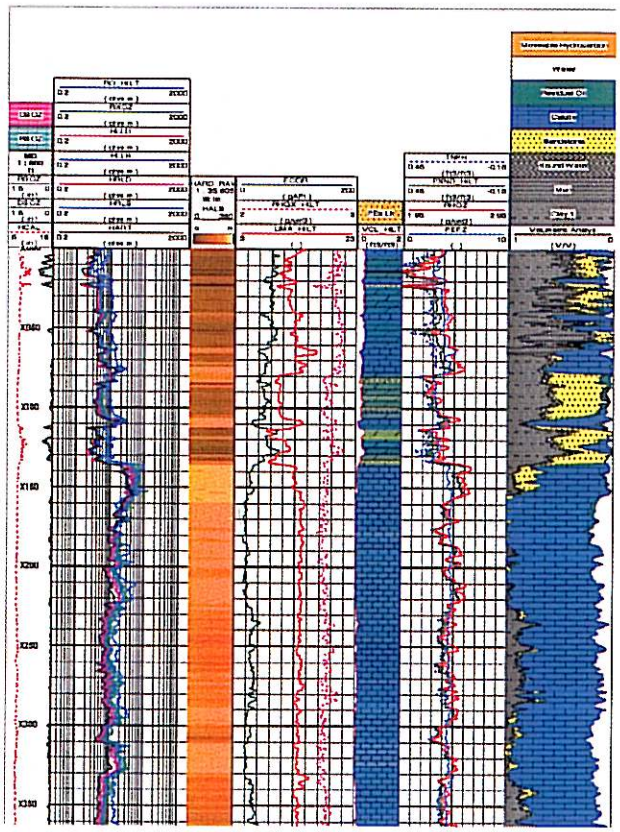


Fig. 7. Platform Express answer.

The lithological column shows good correlations with the formation volumes analysis. At the well site, both lithological column and speed- and environmentally corrected logs are available. It enables a quicklook interpretation with fairly reliable results.

CONCLUSION

The Platform Express tool string is designed to provide several services: First, it integrates the standard logging measurements in one string to provide the fundamental logs from a single run. The tool is designed in a robust way; its logging speed is double the standard one and the tool features shorter and lighter characteristics that allow data acquisition in hostile environments in a more reliable way (like short-radius wells).

Secondly new algorithms have been implemented that enable in real time speed and environmental corrections to produce ready-to-interpret data at the well site. A lithological column is also output at the well site to help identify the formations of interest.

Data quality also benefits from the Platform Express design: high-resolution logs enable thin beds analysis; resistivity images are produced; the pad integrating density and R_{xo} measurements give better answer owing to a flexible joint that improves the pad contact against the well-bore surface. The overall tool string is a new standard in Libya that already proved worldwide to be very efficient.

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Petroleum Res. J. Vol. 13 (2001); P. 97-104, 9 Figs.

Improved Resistivity Interpretation From a New Array Laterolog Tool

Ollivier Faivre and Roger Griffiths†

إستنتاجات متطورة في تفسير قياس المقاومة الكهربائية باستخدام الجهاز الجديد لقياس المقاومة المستعرض متعدد أعماق الاختبار

أوليفر فيفري و روجر جريفيثس

أحد الأسئلة الرئيسية في تقييم المكامن هي كيفية الاختيار الأمثل للتقنية التي تستخدم في حساب المقاومة الكهربائية لصخور المكمن. هناك تقنيتان شائعتا الاستخدام - قياس المقاومة التأثيري وقياس المقاومة المستعرض. ولقد راجعنا آخر ما طرأ من تطور على قياس المقاومة المستعرض. أن قياس المقاومة المستعرض متعدد أعماق الاختبار المستخدم حالياً يوفر عدة قياسات مسلطة على خمسة أعماق اختبارية وهي شبيهة بقياس المقاومة التأثيري عديد الأعمال المتحيرة.

كل هذه القياسات أو التسجيلات تستخدم التيارات الموجهة التي ترجع إلى جسم جهاز الرصد بدلاً من رجوعها إلى السطح. وبسبب قرب مكان رجوع التيار توجد مزايا جديرة بالاعتبار منها: تجنب ظاهرة التغير المفاجئ في سمك مسار التيار الكهربائي.

تم تفسير البيانات بواسطة برنامج الحاسب الآلي باستخدام نماذج للمكمن متفاوتة التعقيد للحصول على أحسن قيمة تقريبية للمقاومة الحقيقية لصخور المكمن، ففي موقع البئر تم الحصول على المقاومة الحقيقية باستخدام نموذج سريع أحادي البعد لهذا البرنامج والذي يأخذ في الحسبان تأثير الغمر. وهذه الطريقة بسبب محتواها المعلوماتي المتطور ودقة الرؤية العمودية لها، فهي تعطي قيمة أكثر دقة للمقاومة الحقيقية لصخور المكمن.

أما في المكامن التي تحتوي على طبقات رقيقة السمك، فقد تم عكس أو قلب نموذج ثنائي الأبعاد بحيث يحسب في نفس الوقت التغير في المقاومة الرأسية والمحورية، وقد لوحظ أن هناك تحسناً في حساب المقاومة الحقيقية عندما أخذ في الاعتبار تأثير سمك الطبقات.

إن التحسن الذي طرأ على تصميم الآلة وكذلك معالجة المعلومات نتج عنهما زيادة واضحة في معدل عمل هذه التقنية وأن الأمثلة من التقارير الحديثة تظهر وبجلاء فوائد هذه الآلة الجديدة.

Abstract: *One of the constant formation evaluation questions is that of selecting the optimal technique for determining formation resistivities. Two techniques are in common use, induction and laterolog. We review the latest developments in laterolog logging.*

A recent array laterolog tool, HRLA (High-Resolution Laterolog Array tool), makes several focused measurements, with five depths of investigation, in a way similar to an array induction tool.*

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* Mark of Schlumberger.

All measurements use bucking currents returning to the tool rather than to surface. The proximity of the current return has considerable advantages; it eliminates Groningen effects and significantly reduces shoulder effects caused by strong bucking currents returning to the surface, in particular the well-known "squeeze" effect. It also eliminates the need for a bridle, resulting in improved operational efficiency.

The data is interpreted by inversion software using formation models of varying complexities to best approximate the true formation resistivity. At the wellsite, Rt is provided by a fast one-dimensional (1D) inversion that only takes into account invasion effects. Improved information content and vertical resolution results in more accurate 1D Rt determination. In thinly bedded formations a two-dimensional (2D) model is inverted, which simultaneously accounts for both radial and axial resistivity variations. Significant improvements in Rt determination are seen when shoulder-bed influences are taken into account.

The improvements in tool design and in processing have resulted in significant increases in the operating range of the new laterolog. Examples from recent surveys clearly display the benefits of this new tool.

INTRODUCTION

Accurate R_t determination is critical in identifying and estimating reserves. As the industry evolves into the evaluation and production of more complex reservoirs, the importance of accurate resistivity data becomes increasingly apparent. Traditional dual laterolog measurements do not always supply sufficient information to achieve unambiguous interpretations. A review of the limitations of existing techniques and a rethink of both the acquisition and processing of laterolog data was undertaken in order to reduce the uncertainty on R_t and thus improve saturation estimations.

TOOL DESCRIPTION

The objective during tool design was to optimize the measurement information content while minimizing unwanted effects. It is better to minimize unwanted effects at the measurement stage than to compensate for them later.

Borehole and shoulder effects are minimized by the use of laterolog-style focusing, rather than unfocused measurements. Focusing involves injecting current from guard or bucking electrodes to ensure that the current from the central measure electrode flows into the formation rather than along the borehole.

By having all currents return to the tool body rather than surface, voltage reference effects are eliminated and shoulder bed effects reduced. In addition, the surface current return and insulating bridle are no longer needed.

Optimal focusing is achieved with a symmetric tool, which brings the additional benefit that all signals are measured at exactly the same time and logging position. This avoids horns and/or oscillations caused by irregular tool motion and ensures that the measurements are always exactly depth-aligned. Unfortunately the symmetric tool requirement conflicts with the need to achieve a practical tool length while retaining reasonable depth of investigation. This was resolved by using the conductive housings of the tools above and below the laterolog device as part of the array, increasing effective array length while keeping overall toolstring length to a minimum. The resulting tool has been named the High-Resolution Laterolog Array (HRLA) tool[6].

The HRLA tool uses segmented bucking electrodes and multi-frequency operation (ranging from 75 to 270 Hz) to acquire six simultaneous measurements. Two techniques are in common use, hardware and software focusing. The hardware injects the currents in a way that is as close to focused as possible. Hardware focusing alone, however, is subject to physical limitations which, in a dynamic environment such as well logging, result in slight voltage imbalances on the array. Software focusing, whereby mathematical superposition of signals is used to ensure that the focusing conditions are respected, is used to rectify any imperfections.

The result is six focused measurements with varying depths of investigation that are intrinsically resolution-matched and depth-

aligned. The shallowest mode, RLA0, is mostly sensitive to the borehole and is used to estimate the mud resistivity. The apparent resistivities RLA1 through RLA5 are all sensitive to the formation, becoming progressively deeper in investigation. The current patterns of these five modes, in a homogeneous 1-ohm-m. formation, are shown in figure 1.

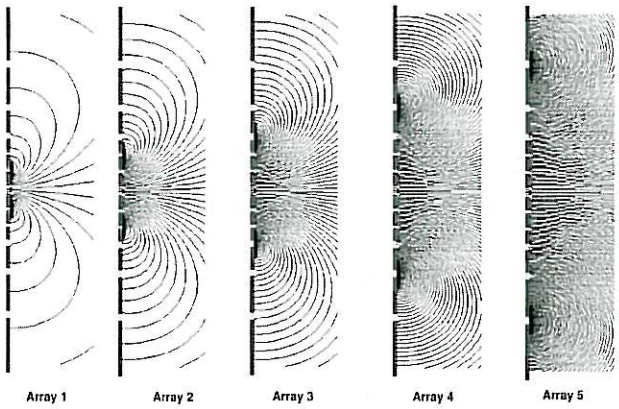


Fig. 1. Current distributions for HRLA resistivities RLA1 to RLA5 in homogeneous 1 ohm-m. formation.

Data from field tests of an experimental version of the HRLA tool was used to optimize the differentiation of the measurements by adjusting the array spacings. Figure 2 shows the radial response of the optimized HRLA tool compared to the HLLD and HLLS measurements from the High Resolution Azimuthal Laterolog Sonde (HALS) tool[5].

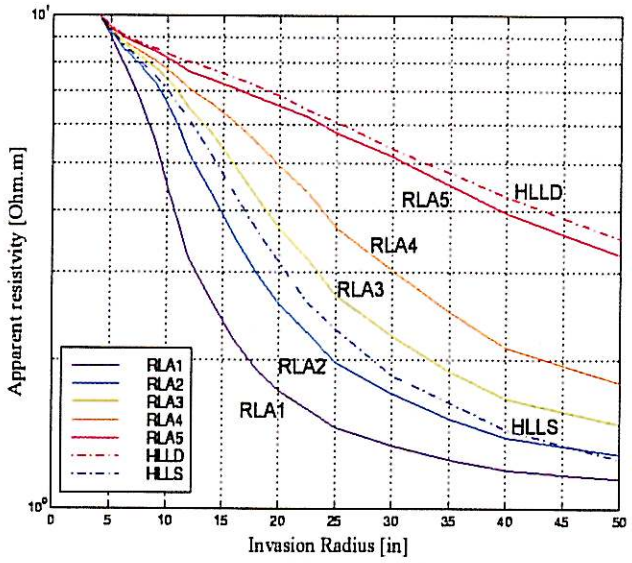


Fig. 2. Radial response of the HRLA resistivities compared to HLLD and HLLS from the HALS tool: Borehole-corrected apparent resistivities in a thick bed as a function of the invasion radius. R_t = 10 ohm-m, R_{xo} = 1 ohm-m, d_h = 8 in., and R_m = 0.1 ohm-m.

The borehole corrected resistivity readings are computed in an infinitely thick bed as a function of the invasion radius. The apparent resistivities, RLA1 through RLA5, from the HRLA tool, HLLD and HLLS from the HALS tool, all read true resistivity when the bed is uninvaded. When the invasion diameter increases the channels start dropping towards the R_{xo} value at a rate depending on their depth of investigation. The array laterolog tool response is very similar in character to that of the HALS tool, with the RLA5 measurement showing comparable response to that of the HLLD. The spacing of the array has been designed to optimize the information content of the data with respect to the invasion profile. The HRLA tool, with three additional curves, delivers greater detail about the invasion profile. This is especially important in thin beds, where "deeper" measurements tend to loose some depth of investigation and hence differentiation due to anti-squeeze effects.

FIELD EXAMPLES

Improvements in instrumentation have permitted electrode spacing reductions in recent sensors such as the ARI Azimuthal Resistivity Imager and HALS tools. This yields an improvement in vertical resolution which has been continued with the HRLA tool as is evident in the field log in figure 3 that compares the HRLA

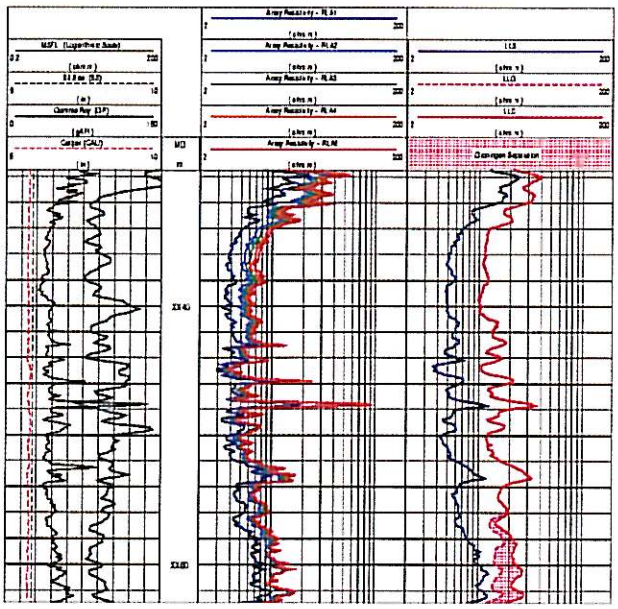


Fig. 3. Comparison of HRLA and DLL field data, showing improved resolution and the absence of Groningen effect on the HRLA response. Microresistivity is presented in the left track to confirm the high-resolution HRLA data.

response to the DLL response. The R_{xo} measurement is presented in the left track to show that the response of the array laterolog is verified by other high-resolution measurements. This well penetrates a sequence of thin beds overlain by a highly resistive anhydrite layer. This layer interferes with the deep mode current return of the dual laterolog resulting in Groningen separation as shown by the shading in the third track. The LLD reads too high over the entire interval. In contrast, the HRLA resistivities are not subject to Groningen effects. Toward the top of the interval invasion is indicated by the coherent spread of the array resistivities while the DLL data can not be used without further corrections[8].

Figure 4 shows a comparison of HRLA and DLL logs. The LLd and LLs separate nicely, which could be taken as an indication of hydrocarbon. This is in fact due to Groningen effect, and all the HRLA curves are stacked together indicating clearly a water zone.

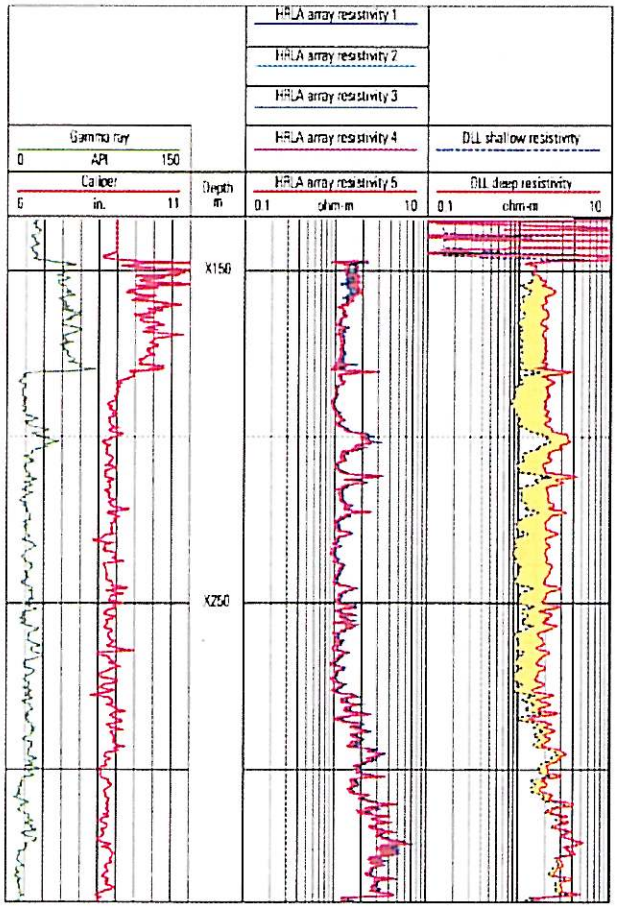


Fig. 4. Groningen effect visible on the dual laterolog is absent from the HRLA response shown in the middle track.

Figure 5 shows the wellsite-computed 1D R_t and d_i from both the HRLA and HALS tools. In resistive beds where the HALS resistivities are out of sequence owing to shoulder bed effect, the diameter of invasion is forced to bit size (i.e., no formation invasion). Over the same interval the R_t is equal to HLLD, as the input data is inconsistent with the 1D formation model. The additional information available from the array resistivities allows a realistic estimation of the invasion diameter, which in turn allows invasion corrections to be applied to find a more accurate R_t. The R_t computed in real-time at the well site (before shoulder-bed correction) from the consistent HRLA data will be more accurate than R_t computed from the HALS. For the peak around xx00 ft. the R_t found is about 45% higher: over the entire interval shown an increase in the reserves estimate of 16% was found compared to the HALS data. Note that shoulder corrections can be applied in post-processing to the HALS data (1D+1D), in which case a better R_t results, close to that computed from the HRLA data

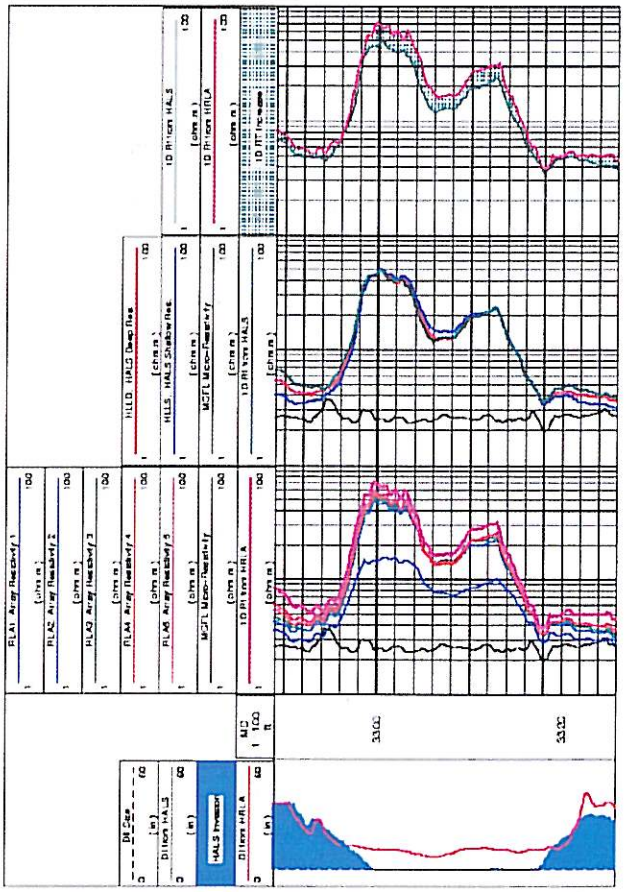


Fig. 5. Comparison of HRLA and HALS data, showing reduced shoulder bed effect and improved characterization of invasion which lead to better 1D inverted R_t.

2D INVERSION

Traditional resistivity determination by laterolog[7] involves a "deep" and "shallow" measurement in conjunction with a micro-resistivity pad device. The micro-resistivity device measures the resistivity of the near-wellbore zone invaded with drilling fluid filtrate. The separation of these three resistivities is taken as an indication of an invasion profile when the invading and connate fluids have different resistivities.

This one-dimensional (1D) approach, graphically represented in figure 6, only considers the radial effect of formation invasion. It does not address the fact that the reading in a bed may be influenced by the surrounding beds. This 1D assumption may be valid in thick homogeneous beds with relatively small resistivity contrast to

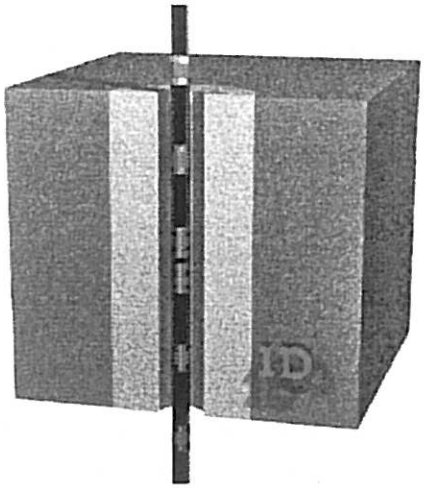


Fig. 6. Oversimplified formation model. The application of a 1D model that ignores 2D borehole and shoulder bed effects can lead to inaccuracies in formation resistivity estimation.

the surrounding beds, but in thin invaded beds the 1D assumption can lead to significant errors in resistivity determination.

It has been recognized that formation resistivity estimation can be improved by use of inversion techniques that take into account the true 2D or 3D formation structure[2,3,4,5,6]. The first step, then, is to define a formation model that more accurately reflects the subsurface. Figure 7 shows the two-dimensional, piston-invasion formation model proposed to represent the subsurface. An obvious extension of this is the construction of models that include dipping layers (2.5D) and azimuthal resistivity variation (3D).

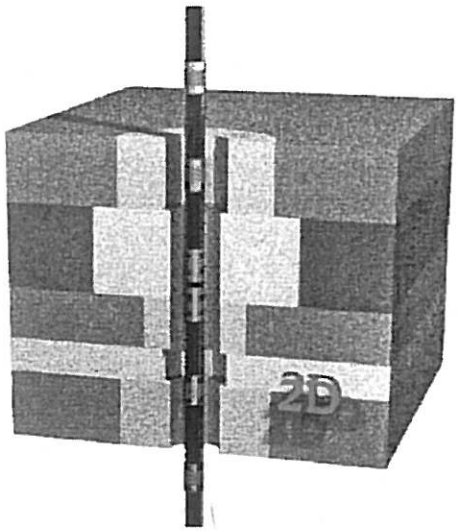


Fig. 7. The 2D-formation model takes into account the borehole, shoulder bed and invasion effects simultaneously.

In order to solve for these more complex formation models it is beneficial to increase the measurement information content by use of multiple-spacing electrode arrays similar in concept to the multiple-spacing induction arrays. A critical aspect of this approach is to ensure that the differentiation between the array measurements is larger than the uncertainties within each measurement.

The processing chain is outlined in figure 8. The first step is the definition of the formation layering. This is normally achieved by inflection point segmentation of the resistivity log. Initial

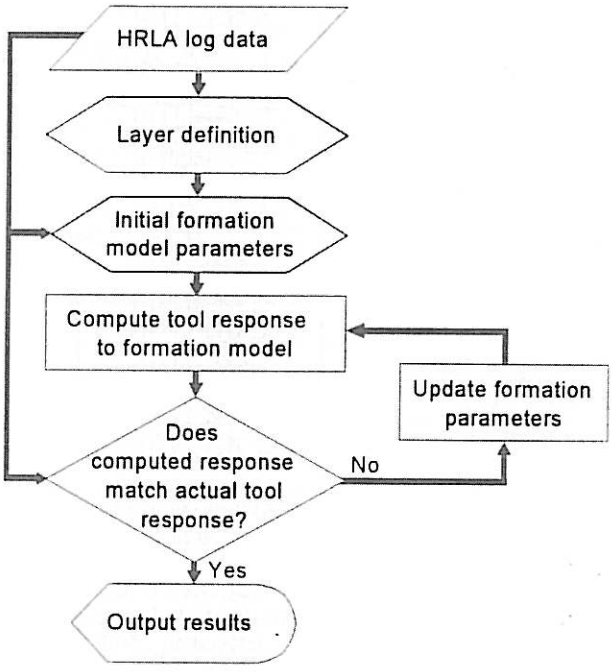


Fig. 8. 2D inversion processing chain.

formation parameters (R_t, R_{xo} and d_i) are then derived from the input resistivity data. A 2D Finite Element forward model is then used to compute the tool response to this initial formation model. The computed response is compared to the actual measurements and adjustments made to the formation parameters. This process of tool response modeling and formation model refining is iterated until a good match between the computed and actual tool response is found. By modeling the effects of the borehole, invasion and shoulder beds in two dimensions, their interdependent effects can be accounted for by the inversion process. Thus more accurate formation resistivity parameters, R_t, R_{xo} and d_i are found

Substantial improvements in estimated reserves have been seen during field testing of the tool and inversion. The field example shown in figure 9

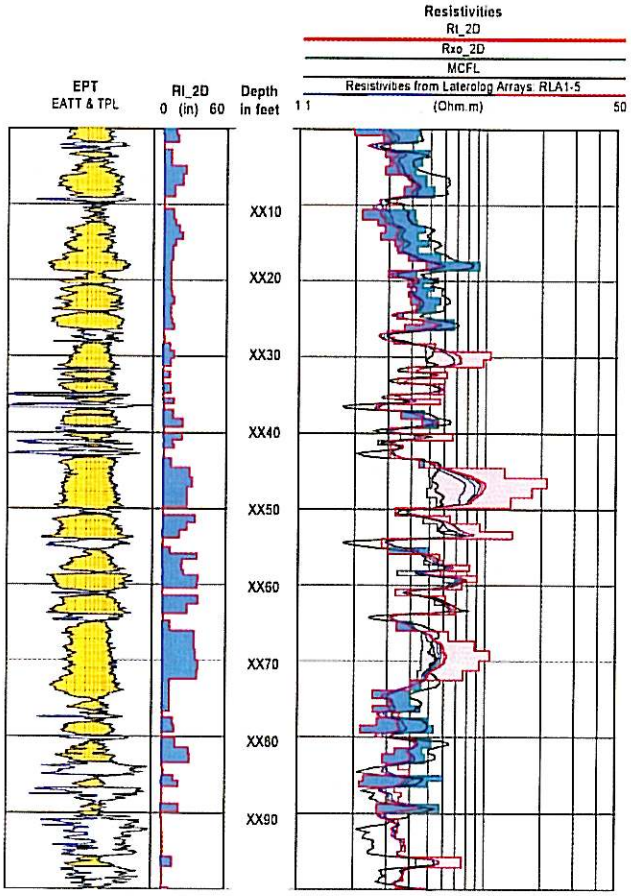


Fig. 9. 2D Inversion on HRLA field data showing significant R_t increases in the reservoir zones. Note the consistency between the R_{xo} extracted by the inversion from the HRLA data alone and the R_{xo} measurement, MCFL. Below XX80 ft the low R_{xo} measurements are due to hole rugosity and hence do not match the HRLA derived R_{xo}. Note also the stability of the inversion in handling both normal and reverse invasion profiles.

indicates a significant increase in the calculated R_t in the reservoir zones. The stability of the inversion is remarkable considering the high activity of the logs. Note the ability to handle alternating normal and reverse invasion profiles and the good match between inverted R_{xo} and the R_{xo} measured by the Micro-Cylindrically Focused Log (MCFL) tool except where the MCFL data is affected by borehole rugosity.

CONCLUSION

A new solution methodology, which combines an improved formation model with a mathematical inversion technique capable of extracting the enhanced information available from a new electrode array resistivity tool, provides better formation resistivity values.

The advantages of the HRLA tool, which minimizes unwanted effects, have been demonstrated both on synthetic benchmarks and several field data sets. Important advantages include the absence of voltage reference effects and reduced shoulder effect. These tests have shown high vertical resolution and improved invasion discrimination in thinly bedded formations, leading to an improved R_t estimate after inversion processing.

At the wellsite, operational safety and efficiency is improved by the elimination of the bridle and surface current return system. The real-time 1D processing benefits from the increased information content, reduced shoulder effects and the absence of Groningen and drill-pipe effects.

Application of robust inversion processing, based on a 2D formation model, to the array resistivity data yields improved formation parameter estimates. In many cases calculations of hydrocarbon saturations are considerably increased, particularly in thinly bedded formations.

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Petroleum Res. J. Vol. 13 (2001): P. 105–110, 8 Figs.

Imaging Tools are Much More Than Super-dipmeters

Arnaud Etchecopar and Eloy Diaz*

أجهزة التصوير الوصفي هي أكثر من أن تكون أجهزة قياس ميلان متطورة

أرنود إيتشيكوبر و إيلوي دياز

لقد تم تصميم أجهزة قياس ميلان الطبقات بحيث تعطي تحليلاً إحصائياً للميلان، وهي مهمة للحصول على معلومات بنيوية يُعوّل عليها داخل المكمن. غير أن هذه المعدات لا تعطينا وصفاً جيولوجياً واقعياً، وفي المقابل فإن أجهزة التصوير الوصفي التي استُحدثت في العقود الأخيرة مهدت الطريق لاعطاء معلومات حقيقية داخل البئر، فبواسطة الصور الفوقسمعية أو الكهربائية يمكن مشاهدة وتقييم التشققات والنسيج الصخري والبنية الترسيبية كما هو الحال في الصخور المتكشفة.

فبسبب هذه القدرة على المشاهدة المباشرة يمكن استغلال الطرق الجيولوجية المعتادة فمثلاً حساب الميلان التركيبي الفعلي يعتبر أكثر دقة من استخدام قياس الميلان البسيط، فعندما يتم فصل الميلان إلى مركباته الترسيبية والتركيبية فإنه يصبح بالإمكان إعادة تصميم أو إنشاء قطاع ترسيبي أو تركيبي بجوار البئر وكأنه قد تم من صخور متكشفة.

Abstract: *Dipmeter tools were designed to provide a statistical dip analysis. They were essential to obtain a reliable structural information inside the reservoir, but did not provide real geological description. On the contrary, the imaging tools developed during last decades provide the way to perform real geological observation down hole. On ultrasonic or electrical images, fractures, texture and sedimentary structures are directly observable, measurable and interpretable as on outcrop.*

Because of this direct observation capability, it is possible to take advantage of the standard geological methods. For example, the computation of the actual structural dip is much more accurate than from basic dipmeter. Once the dip has been split into its structural and sedimentary components it becomes possible to reconstruct structural or sedimentary cross-section in the vicinity of the well, as it would be done from an outcrop.

INTRODUCTION

Since dipmeter tools have been introduced in the field in the early fifties, geologists have extensively used them. Their main concern was to provide accurate structural dip in order to obtain consistent geological model at reservoir scale. However dip is not enough for an entire geological description. So many geologists attempted to extract sedimentological information, or fracture description from the dips and dipmeter curves. Many methods were proposed for such purpose. Some of them were successfully used in particular environments, however as long as the geologist cannot observe directly the geological features, the confidence level in such interpretations remains low. The development of imager tools has

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perfectly continuous and automatically oriented. If images allow detailed geological description they contain also quantified information that can be used to quantify the geological description. This is a great improvement for reservoir description. This paper will describe new methods that turn dipmeter curves and borehole images into quantified geological models. Three different uses of images or dipmeter curves will be examined in turn: the geological observation capabilities, the structural reconstitution, the facies determination and quantification. If most of these methods were developed to analyze images, many of them are also applicable to old dipmeter data, renewing interest for these logs.

GEOLOGICAL OBSERVATION ON BOREHOLE IMAGES

Images have totally modified geological interpretation in boreholes, as they make possible an observation of the borehole wall. This is true in vertical wells but even more in horizontal ones where dipmeters do not provide any help. Whatever is the image type, electric or acoustic, it makes possible to identify and classify the geological features as on a core or an outcrop. The goal of this document is not to establish a catalogue of different nice geological features visible on images, but to convince geologist that these features would have been either ignored or misinterpreted from conventional logs or dipmeters. This is particularly obvious on the following examples (Fig. 1).

One major interest of such digital images comes from the fact that they are easy to manipulate. Compressing the vertical scale allows figuring out events slightly oblique to the well. Playing with electrical contrast allows detecting features that are not obvious on the standard images. Figure 2. shows how the choice of the electrical contrast can enhance either sedimentary features or a secondary fault sealed by calcite. This image shows also that the calcite infilled differently the two fault sides.

Obviously the fact that images are perfectly oriented and indexed in depth allows determining the dip planes with a high accuracy. Based on such high quality dips it new methods have been developed to determine precisely tectonic and sedimentary structures.

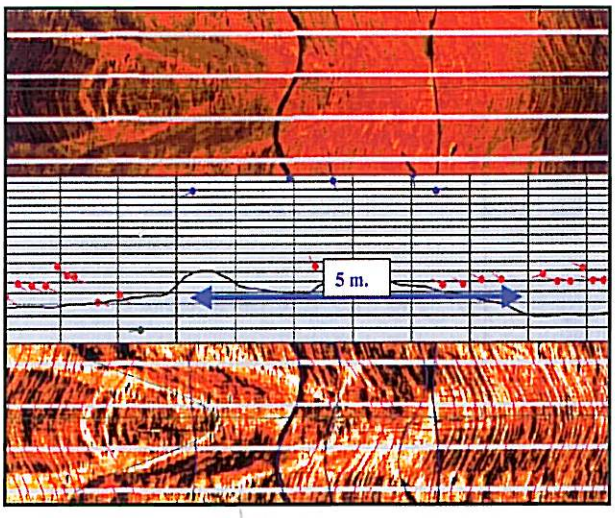


Fig. 1. Electrical images (FMI) in a horizontal well showing three different geological feature types: Layering (green); Foresets (red); Open fractures (blue). No other tool would allow such a differentiation.

RECONSTRUCTING STRUCTURES FROM IMAGE DIPS

The common mode of representing dips is the tadpole plot. This mode reflects the evolution of the dip inside the well but does not provide great help in splitting structural and sedimentary components. It neither provides a clear representation of sedimentary nor tectonic structures. So new methods have been developed recently to offer better structural dip determination

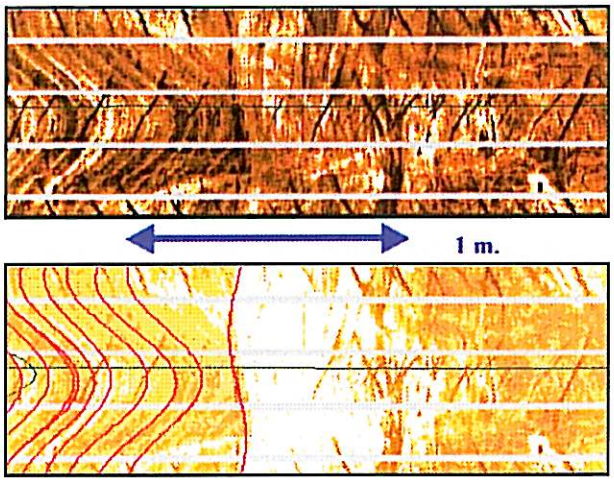


Fig. 2. Cemented fault (pink) identified using different contrasts of a FMI image.

and structure representation in the vicinity of the borehole. Such methods are complementary to seismic.

A New Method to Compute the Structural Dip Component: SediView

This method can be used whether the dips are computed from dipmeter curves or picked on borehole images. However when dips come from automatic processing of dipmeter curves, a filtering based on the continuity of the dip trend is applied prior to the structural dip determination. The method is not based on averaging but on the analysis of the local curvature axes (LCA). The local curvature corresponds to a change in dip organized around a single axis, as a piece of cylinder. The origin of such a curvature can be the deposition process, in a foreset for example, or deformation as flexures or drags.

The first step of the method consists in retrieving the different LCA through an automatic dip interpretation on the Schmidt net performed in a sliding window as shown in the second column of figure 3.

The second step is an interactive Schmidt analysis of the LCA. As long as the LCA inside the window open by the user, fit the same great circle the structural dip is constant (visually interpreted by noting that the great circles corresponding to each LCA cross each other at a single point on the net). When the user is satisfied with the fit on the screen, he releases the mouse button and the structural dip is automatically computed. The assumption behind this method is that the local curvature axes that are, in fact, sedimentary or micro structural axes, were initially horizontal. Only studies on present day structures could assess this point. However, when over long intervals, sometimes hundreds of meters, the LCA fit a single plane, it is difficult to imagine that this plane was initially inclined. This method allows detecting very low angular unconformities (Fig. 3).

Once the structural dip is computed, it is automatically removed. Allowing retrieving the initial sedimentary orientation and organization. It also becomes possible to create some elementary sedimentary cross-sections using the StrucView software originally designed for computing structural cross-sections (Fig. 4). The basic assumption behind this sedimentary cross-section is that during deposition, each new lamination would be nearly identical to the previous ones in

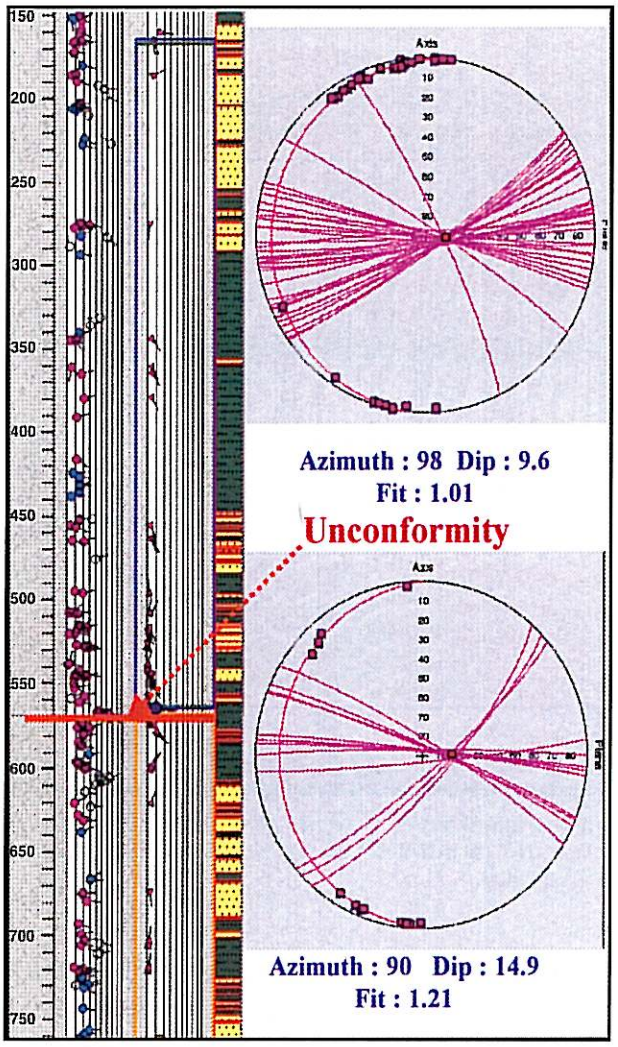


Fig. 3. Low angle unconformity detected using the local curvature method

- Track 1: depth
- Track 2: dips after filtering and automatic Schmidt net analysis. Hollow- dips rejected; pink- dips whose poles fit a great circle and contribute to a Local Curvature Axis computation; Blue- dip with good continuity but not fitting a great circle.
- Track 3: Local Curvature Axes
- Structural dip change at a main unconformity detected through an interactive Schmidt analysis of the LCA. Pink squares and great circles correspond to the LCA. The red GC and square correspond to the STRUCTURAL DIP best fitting the LCA. The value of the fit is a quality indicator of the structural dip determination.

parallel to the structural dip. This is a bit crude but provides a fast estimation of the sedimentary structure thickness and orientation.

A New Method to Model the Structure Around the Well: StrucView

StrucView is firstly a method to filter and regroup dips according to the structural axes

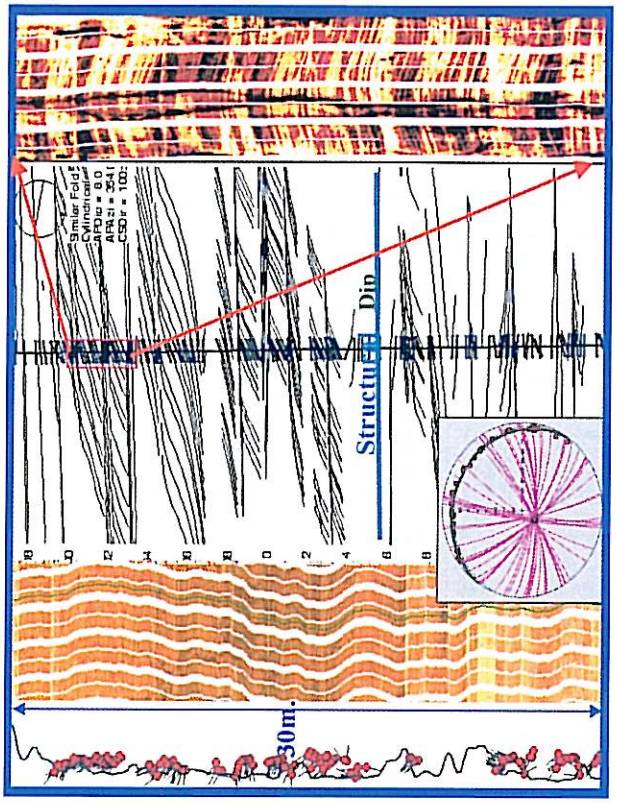


Fig. 4. Sedimentary cross-section obtained from dips in fluvial sands after the structural dip has been determined using the LCA method.

identified through an automatic Schmidt net interpretation. Secondly for each of these structures, Strucview creates cross-sections fitting dips at the well with respect to the structural model chosen by the user. This method can be used whatever the origin of the dips: computation on dipmeter curves, picking on borehole images or cores.

This method relies on the basic idea that structures such as fold, drag or rollover can be described in first approximation as part of a cylindrical or conical surface that correspond respectively to great or small circles on a Schmidt net. Based on this simple assumption, StrucView performs two tasks. The first one is an automatic Schmidt plot analysis that retrieves the different structures crossing the well; their axes and their corresponding dip sequences. The second task of StrucView is the cross-section construction itself after the user has chosen the structural model he wants to apply (Fig. 5). This construction relies on standard structural rules.

For each dip set corresponding to a same structural axis, the user has the choice in between the following models: Similar fold, Parallel fold, Normal fault, Reverse fault, Rollover, Monocline. According to the chosen model the user is asked for different parameters. For example, if he has chosen a model "fault" he will be asked to pick an undisturbed dip zone that will be used as a

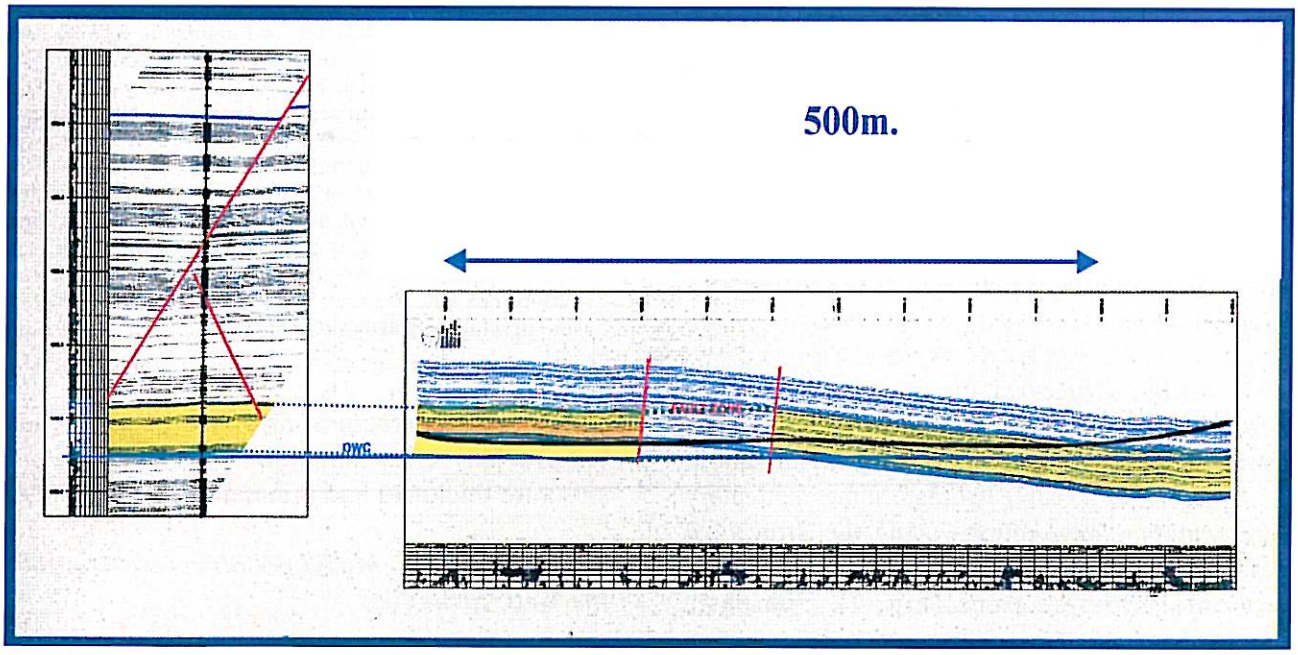


Fig.5. Cross section obtained from dips recorded in a vertical pilot hole and a horizontal well. The reservoir sand is yellow; the faults are coloured in red, their throws in the vertrical well have been computed from correlation to other wells.

reference. As the computation is very fast, it is always possible to perform multiple tries with different models. It is even possible to compute different cross-sections for the same zone of the well.

This structural approach using dips is perfectly complementary to the seismic one, as it is powerful when the structural dip is high or varies a lot, but limited in its lateral extension.

IMAGES AND FRACTURES

Fracture analysis is one of the main image applications, as they allow a full description of the fracture sets (Fig. 6). Each fracture can be identified, oriented and their aperture computed from the electrical contrast between the fracture trace and the matrix.

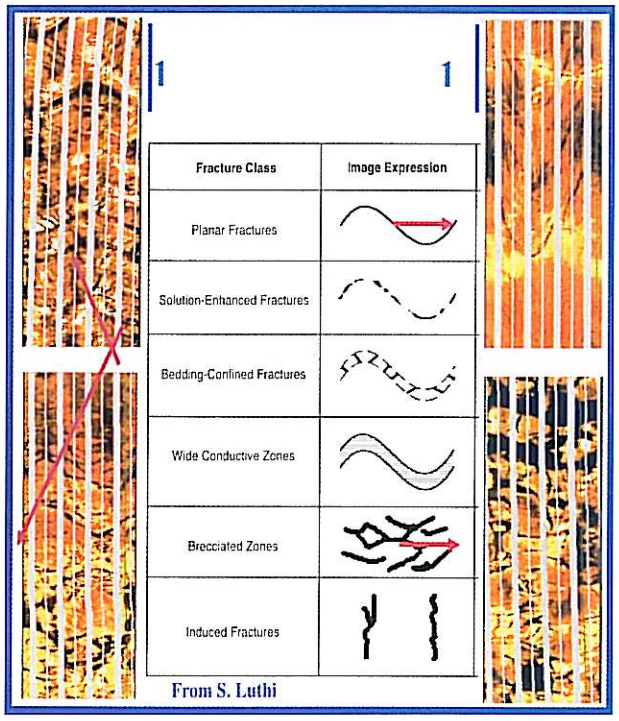


Fig. 6. Fracture classification in a carbonate well where dissolution occurred.

From such images it is obvious that the term "fracture" may cover extremely different features, particularly in carbonates where both dissolution and cementation occur. Many statistical tools exist now to provide a description of fracture at reservoir scale.

IMAGES AND STRESS

The in-situ stress regime appears more and more as a key factor for reservoir monitoring. Imaging tools may greatly help in stress tensor definition; particularly the ultrasonic tools that provide a very precise topography of the borehole wall (Fig. 7).

In a vertical well it is well known that breakouts or induced fractures indicate the minimum and maximum horizontal stress. What is less known is the fact that in a deviated well, the orientation of these features relatively to the borehole axis depend on the three main stresses. This means that the breakout or induced fracture orientation depends not only on the stress orientation but also on the ratio between their relative magnitudes. Shear movements at preexisting fractures can be detected from transit time images (Fig. 7). They correspond to micro-faults that can be inverted in terms of stress.

In favorable cases of deviated wells, using inversion method, it becomes possible to determine the main stress orientations, which stress is vertical, and the magnitude of the intermediate stress relatively to the maximum and minimum. Such information is fundamental for

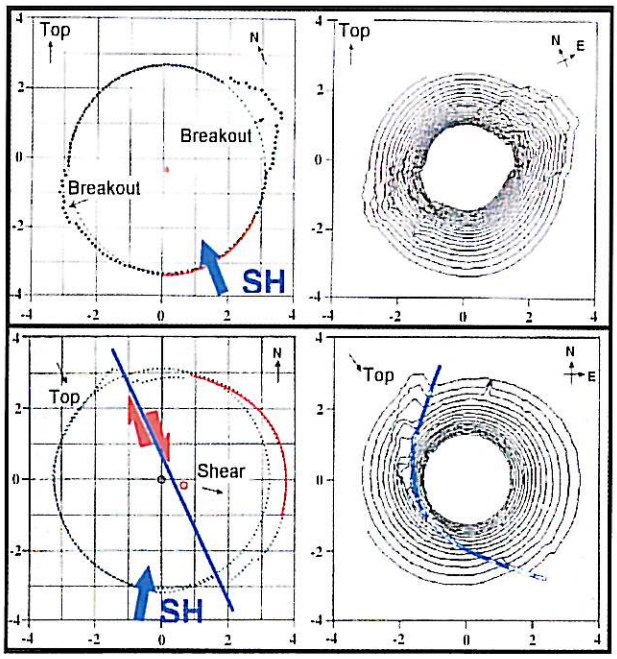


Fig.7. Stress induced damages at borehole wall from ultrasonic transit time:
Top- breakouts; Bottom- shear at preexisting fractures.

borehole stability, to predict fracture efficiency or to set injector wells relatively to producers. A lot of production problems come from misinterpretation of the state of stress at the present day. For example it has been recently observed in North Africa that fractures parallel to Shmax are sometimes 100 times wider than fractures perpendicular.

IMAGES AND FACIES

Another great interest of electrical images comes from the fact that they provide high-resolution measurement from which quantification of the image is possible. BorTex, a new method based on that concept, has been developed to extract morphofacies.

BorTex performs three tasks: firstly it provides layer delineation, secondly it characterizes heterogeneities, and thirdly it quantifies these results as summary logs. These steps are briefly described here below in a very simple way.

Layer Delineation

This delineation is obtained in two steps. The first step is the computation of the background conductivity after the image has been rescaled relatively to a shallow resistivity measurement. It is obtained by averaging the image conductivity with respect to the dip after removal of the elements that do not cross the image.

The second step is interactive. The user chooses a minimum resistivity contrast. Then the well is split into consecutive layers when resistivity contrast is greater than the chosen Threshold.

Heterogeneity Analysis From Images

This analysis is based on the same resistivity contrast principle rather than the layer delineation. The delineation of the heterogeneity is obtained by mapping the resistivity gradient in the image. If the resistivity contrast at the spot limit exceeds the threshold chosen by the user the spot will be classified into conductive or resistive heterogeneities (Fig. 8).

Summary Logs Computation

In order to use the image analysis in conjunction with open hole data, summary logs

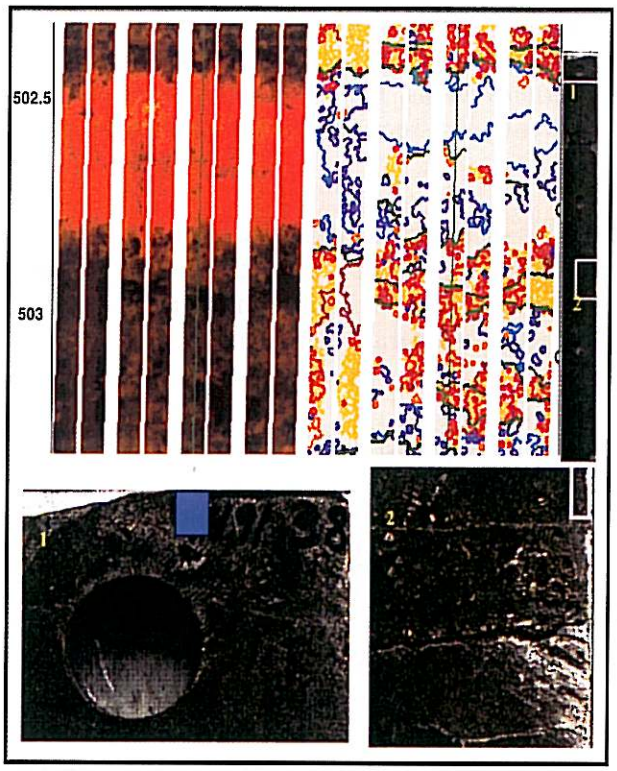


Fig. 8. Carbonate heterogeneity analysis from FMI image compared to cores.Note the fit between the vuggy zones of the core and the conductive anomalies (red/orange spots) in the BorTex display. The blue spot correspond to cemented zones due to diagenetic processes.

are derived from the image analysis. This is achieved by averaging, inside a sliding window the image parameters extracted during the previous phase such as: background conductivity; layer contrast; layer thickness; percentage and size of conductive/resistive anomalies...

This approach brings much higher resolution in facies determination than the use of conventional logs alone.

CONCLUSION

Images are much more than standard dipmeter tools for geological application. This is also true for many other applications. Through the cross-section computed from dips, seismic can take advantage of the images. The stress analysis is extremely important for drilling or for reservoir monitoring... Image is not a single application tool and should circulate much more in between the different services of an oil company.