Testing, Testing, 1, 2, 3

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In times past, presentations often started with 'testing, testing, 1 2 3' to ensure that the electronics were properly configured and the audience could indeed hear the speaker. In today's world of generally reliable electronics, the practice is not nearly so common, but the applicability of the phrase to formation evaluation remains.

Wireline formation pressure profiling is usually straight-forward, and at the simplest level can ***complement our other petrophysical tools in the three following areas.***

- Fluid typing, via determination of the fluid pressure gradient
- Fluid contact placement, via observation of pressure gradient changes
- Reservoir continuity, via identification of similar, but offset, pressure gradients

Pressure profiles are a vertical series of discrete formation fluid pressure measurements, from which a fluid pressure gradient (and hence a fluid density) may be calculated. These fluid pressure gradients, and the corresponding densities, are directly related to capillary pressure concepts (nicely summarized by Vavra et al), which is another important attribute for our petrophysical tool box: Exhibit 1.

Fluid Pressures and Capillary Pressure

•***Fluid pressure gradients, and the corresponding fluid densities, are directly related to capillary pressure concepts.***

•Vavra et al have provided us with a ***nice review of cap pressure basics***

•C L Vavra, J G Kaldi and R M Sneider. Geological Applications of Capillary Pressure: A Review. AAPG V 76 No 6 (June 1992)

•***Capillary pressure*** (P_c) is ***the difference in pressure across the meniscus in a capillary***.

•This pressure is ***associated with*** the ***contrast in fluid pressure gradients*** resulting from the ***different densities*** of the ***non-wetting*** (ρ_{nw}) and ***wetting*** (ρ_w) phases.

$$P_c = (\rho_w - \rho_{nw}) * g * h = \Delta \rho * g * h$$

Figure 1

Capillary pressure (P_c) is the difference in pressure across the meniscus in a capillary. This pressure is associated with the contrast in fluid pressure gradients resulting from the different densities of the non-wetting (ρ_{nw}) and wetting (ρ_w) phases, according to

$$P_c = (\rho_w - \rho_{nw}) * g * h = \Delta \rho * g * h$$

In these days of deviated well bores, it's worth pointing out that 'height' must be TVD. And when dealing with a legacy database, we should also remember that 'vertical' wells may not have in fact been surveyed, and that furthermore the surface elevations may not themselves be perfect. Not to be negative, but rather only aware of the back ground issues that can sometimes surface during an evaluation.

In the case of a single (mobile) fluid, the relation between (measured) pressure in psi and (calculated) density in gm/cc is (Figure 2).

Fluid Density = Pressure Gradient / 0.433

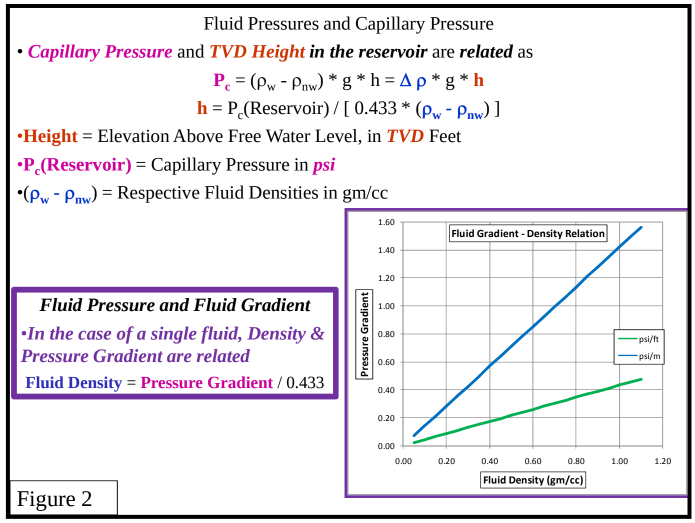


Figure 2

As is so often the situation, there is the 'ideal' profile, and the 'real' profile. In general, the profile high in the hydrocarbon column will correspond to the density of the hydrocarbon, while the pressures below the water contact will reflect the brine: Figure 3.

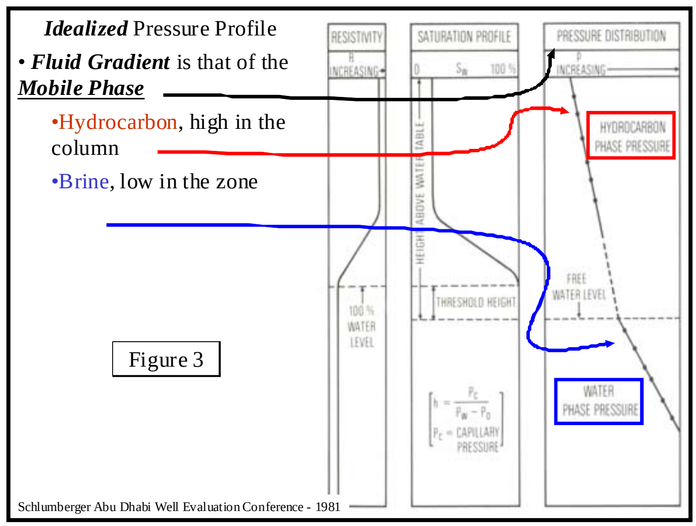


Figure 3

The brine gradient infers a salinity which can, and should, be compared against all other information: Figure 4 (more on this exhibit later).

It's ***important to recognize the difference between the hydrocarbon - water contact, and the capillary pressure free water level*** (Figure 5). In good quality rock, the two datum will be about the same, but as pore throat size decreases, ever more pressure will be required in order that the non-wetting phase penetrate the pore system, and the two datum will then deviate.

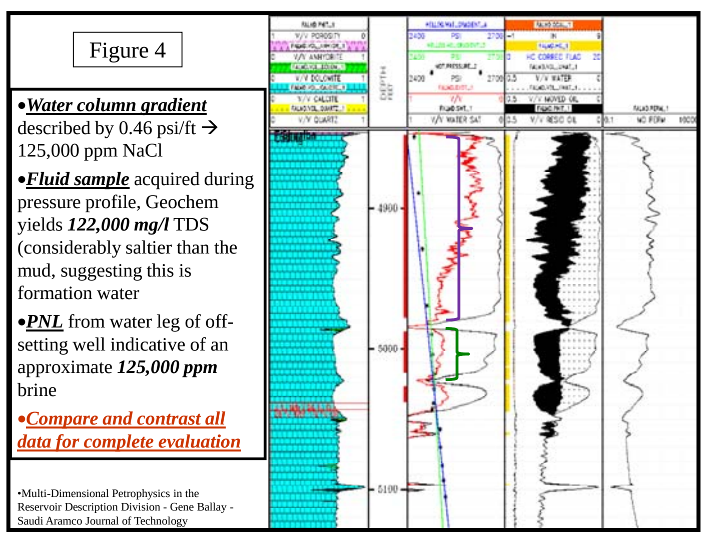


Figure 4

Above the transition zone, it's the hydrocarbon phase that is mobile, and the measured pressure profile will reflect that gradient. Extrapolate the hydrocarbon and brine gradients towards one another, and the intersection will identify the Free Water Level.

Many more details can be found in Hartmann and Beaumont's article "Predicting Reservoir System Quality and Performance", on-line at the link given in the References.

In most cases, this basic interpretation will be sufficient, but complications can arise. In Y2000, the SPWLA Conference had an entire session devoted to Wireline Testing, during which a number of issues were addressed. ***Additional relevant material may be found in Elshahawi et al and Griffiths et al*** (see References)

In addition to reservoir fluid typing, the ***pressure profile can identify hydrocarbon phase contacts, even in the absence of a distinct wireline signature***: Figure 6. In this example, and others from personal experience, there can be either no wireline signature, or an erroneous wireline signature (false contact), while the profile-based contact is consistent with independent information (off set wells, etc).

On the other hand (Figure 7), one must keep in mind that in order that the pressure be measured, the fluid must be mobile, and so it is possible for genuine differences to arise between pressure profile and wireline log interpretations. That old phrase "there is no free lunch" can be applicable to pressure profiles.

Pressure profiles also allow investigation of reservoir continuity, or vice versa, the interpretation can be complicated by a lack of continuity. Three distinct pre-production profiles are seen in Figure 8, one is oil and the other two are water. The two water profiles have a similar gradient, but are offset in pressure, across the limestone interval of about 12 pu porosity.

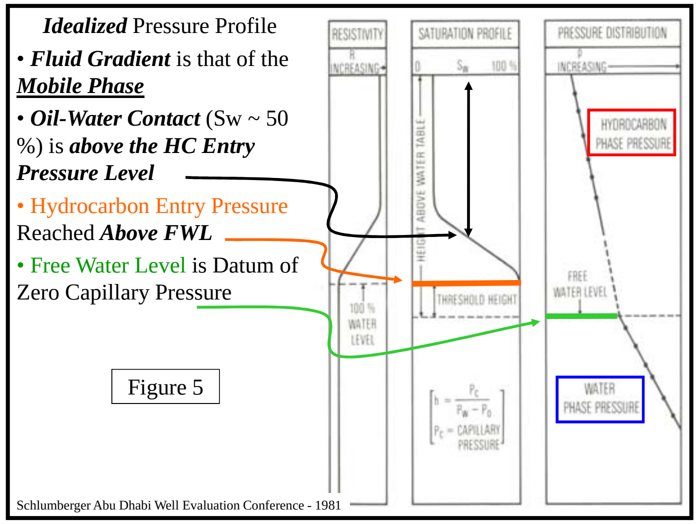


Figure 5

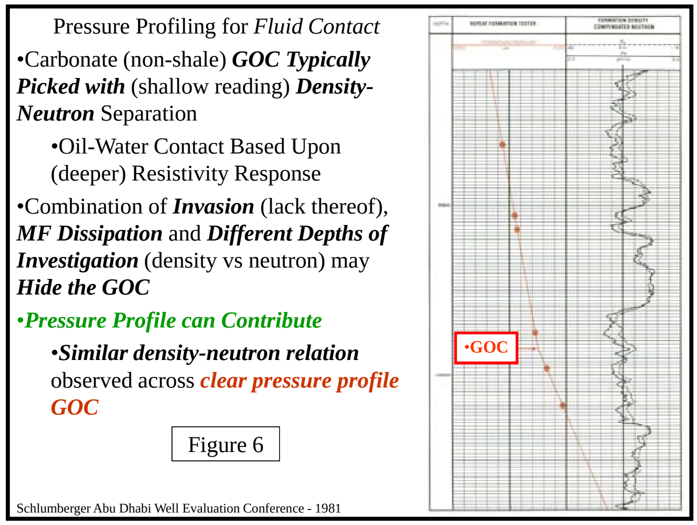


Figure 6

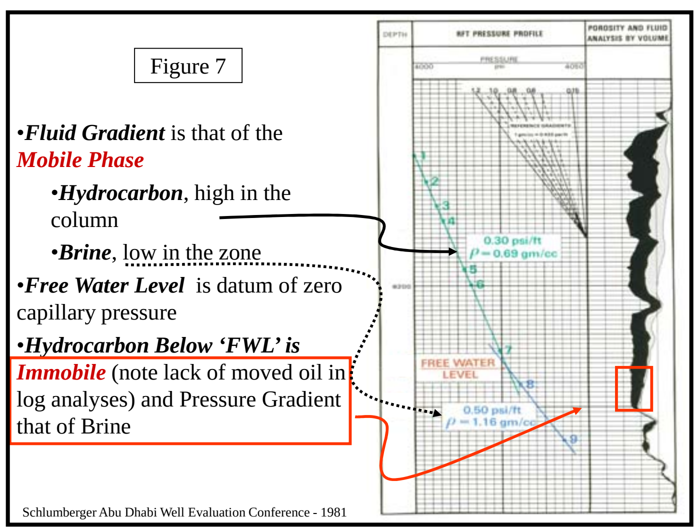


Figure 7

The interval at 5,120 to 5,160 constitutes (Figure 9) constitutes a barrier. The water above and below has the same density (gradient), but the lower zone is offset to a higher pressure. Pressure maintenance injection, into the lower interval, will not be effective in the hydrocarbon column. Furthermore, such barriers may (this one does) extend up into the hydrocarbon column, and thereby additionally impact primary depletion.

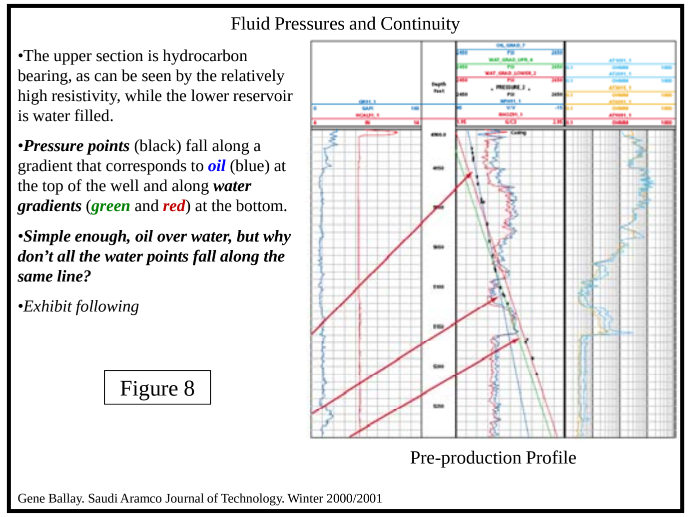


Figure 8

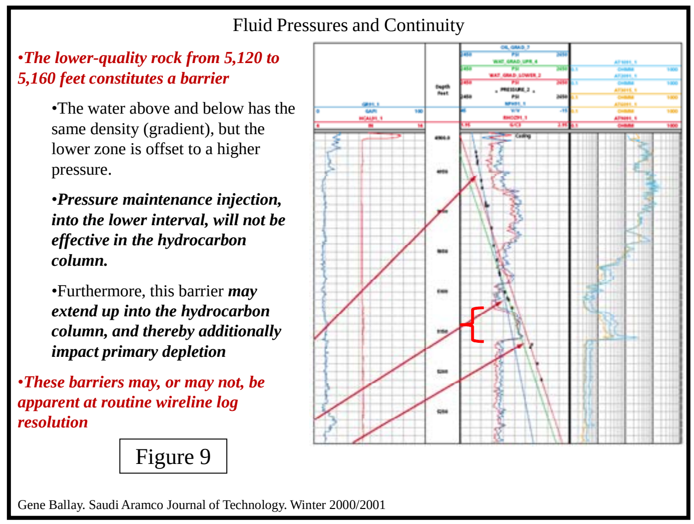


Figure 9

These barriers may, or may not, be apparent at routine wireline log resolution. When pressure profiles separate in this fashion, in the absence of a wireline signature, ***high resolution wireline logging*** is an option, and in the case of ***alpha processing can even be done with routinely acquired data, after the fact***: McCall et al, Galford et al, Eyl et al. Our experience, in good borehole conditions, was that alpha processing of routinely acquired wireline bulk density data could double the vertical resolution. Higher digitization rates and slower logging speeds offered yet more resolution.

If the profile is ambiguous, and the logging job has already terminated (the normal case, since profiles are often run last), alpha processing of the routine data may contribute.

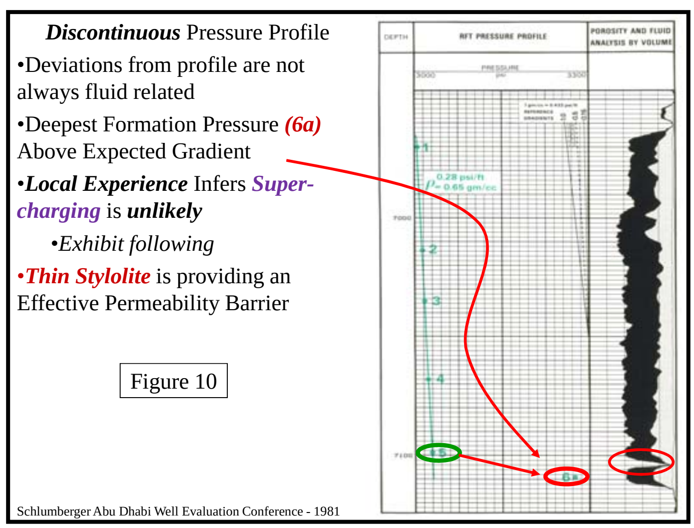


Figure 10

Barriers and / or baffles can result in a less obvious effect on the profile, to the point of shifting the gradient away from the (actual) baseline, and towards an (apparent) baseline: Figure 4. The pressure points across 4985 ➔ 5020 fall nicely along the field oil gradient line, while the points above are deflected (this is a post production profile) towards the water line. We once encountered a profile of points which crossed multiple baffles / barriers, with an apparent net gradient that was brine, even though the wireline evaluation clearly indicated hydrocarbon (as was expected from field geology considerations). ***Be aware that baffles and barriers may not be apparent in the wireline evaluation, and yet be having a significant effect on the pressure profile.***

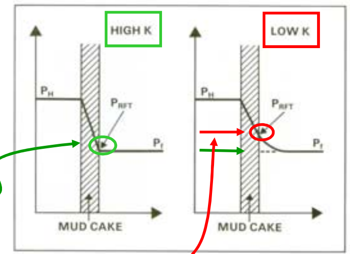
Super-Charging

•Zone Initially Over-charged by Mud Filtrate Invasion

•Mud-cake Eventually Accumulates and Forms Seal

•Over-pressure Gradually Dissipates

•***Pressure Fall-off Slow in Low Permeability Intervals***



•***Establish Local Guidelines*** for Avoiding / Recognizing Super-Charging

Figure 11

Schlumberger Abu Dhabi Well Evaluation Conference - 1981

While unexpectedly high pressure points (Figure 10) can signal the presence of a permeability barrier, it's also possible that the measurement is reflecting ***super-charging***: Figure 11.

Wells are typically drilled over-balanced and the invading mud filtrate will thus locally increase the fluid pressure. Mud cake builds up, and this over-pressure dissipates, gradually. In high quality rock, the dissipation is relatively quick, while in low quality rock the non-representative pressure may yet be present at the time of profiling. The phenomenon is best addressed with local experience and guidelines.

Routine wireline Sw estimates often assume that the brine in the water leg, is the same as the brine in the hydrocarbon column, and this is not necessarily the case: Figure 12. It's not uncommon to deduce a water leg Rw from an Rwa calculation, or SP deflection, and then base Sw calculations in the hydrocarbon column, upon that result.

Figure 12 **FORMATION EVALUATION IN AUSTRALIA** Figure 12

Hugh Crocker & Lan Strecker

SPWLA 9th Annual Logging Symposium, 1968

•The geologically ancient land mass of ***Australia*** has approximately the same size as the United States and has a large continental shelf area. It encompasses all known geological conditions; thus a survey of interpretation in Australia covers a ***wide range of problems. Typical cases*** of sedimentary basins ***have been selected and examples developed*** to demonstrate interpretation problems met and methods of interpretation used.

•In the ***Surat Basin*** (sub basin of the Great Artesian Basin) the problems are ***fresh formation waters*** and the ***difficulty of establishing formation-water resistivity*** and hence of evaluating water saturation. In the Cooper"s Creek Basin the problem is tight shaly sands with difficulty in establishing formation water resistivity and porosity. In the ***Otway and Gippsland Shelf Basins*** the problems are: 1. Massive quartzose sandstones with clay minerals and coals, and ***variable or unknown formation water***

Freshwater Influx in the Gippsland Basin: Impact on Formation Evaluation, Hydrocarbon Volumes and Hydrocarbon Migration

K. Kuttan, J.B. Kulla, and R.G Neumann

The APEA Journal, 1986

•Identification and evaluation of hydrocarbon zones in the Gippsland Basin is complicated by a ***freshwater aquifer system, below the hydrocarbon sands*** which leads to

- •difficulty in distinguishing hydrocarbon from the water sands,
- •difficulty in determining accurate water saturation values.

•Calculated ***water saturations using the salinity of the water sands are inconsistent with*** capillary pressure, wireline formation tests, and production test data.

•All available evidence suggests that the ***formation water salinities in the hydrocarbon zones are significantly higher*** than in the (freshwater) aquifers.

•Saline formation waters within the hydrocarbon zones suggest that ***hydrocarbons were present prior to the freshwater aquifer system***.

- •subsequent freshwater influx did not flush these hydrocarbons.

Figure 13 Figure 13

It sometimes happens that hydrocarbon first migrated into the reservoir, after which a water exchange took place in the water leg, resulting in the water leg Rw being different (fresher) than the hydrocarbon column (Rw). Our personal experience with this is in Central Arabia, and when this situation arises, the customary protocol of determining Rw per water leg calculations, for use in hydrocarbon column Sw calculations, can lead to very erroneous results.

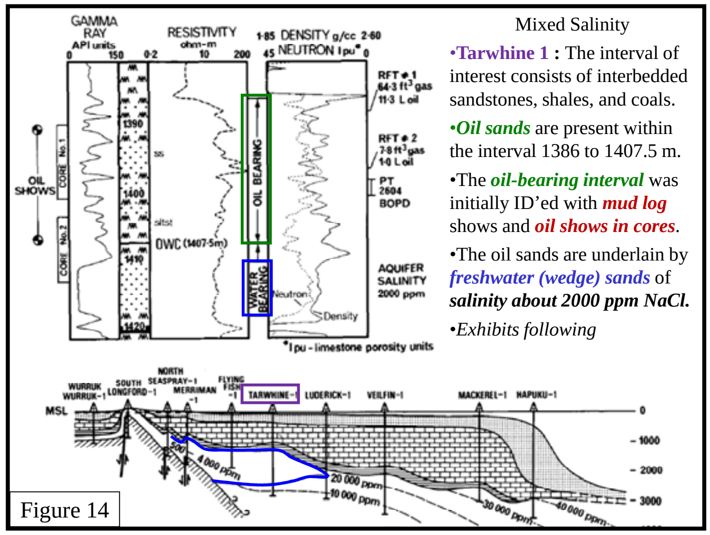


Figure 14

Kuttan et al have given us a nice, comprehensively evaluated example of exactly this situation: Figure 13, and my regards to Andy Mills of Esso Australia for bringing this article to my attention.

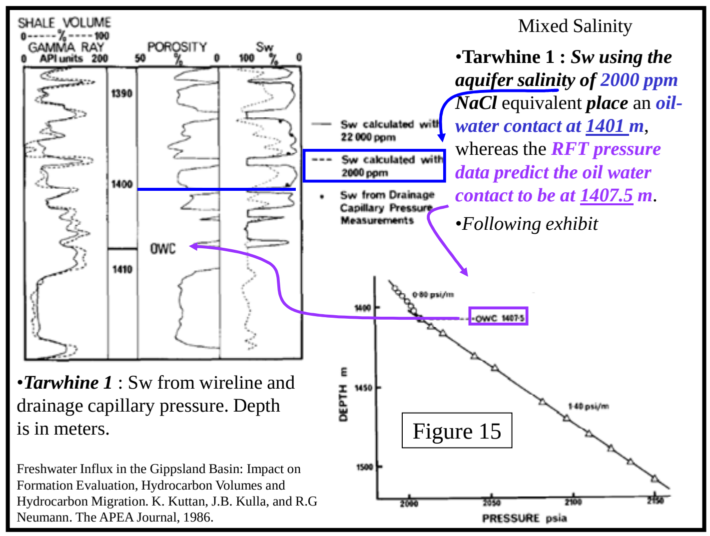


Figure 15

Not only is the water leg brine different than the hydrocarbon column connate water, but the salinity of the water leg brine is variable (Figures 14, 15 & 16). The Rwa approach to Sw estimation will be completely misleading. Each time I come across a situation such as this, I wonder about the individual(s) who first noticed the possibility of pay, and then had the fortitude to further investigate (and request Management approve additional data). Also, one cannot help but notice the contribution made by the (old fashioned and low tech?) mud log.

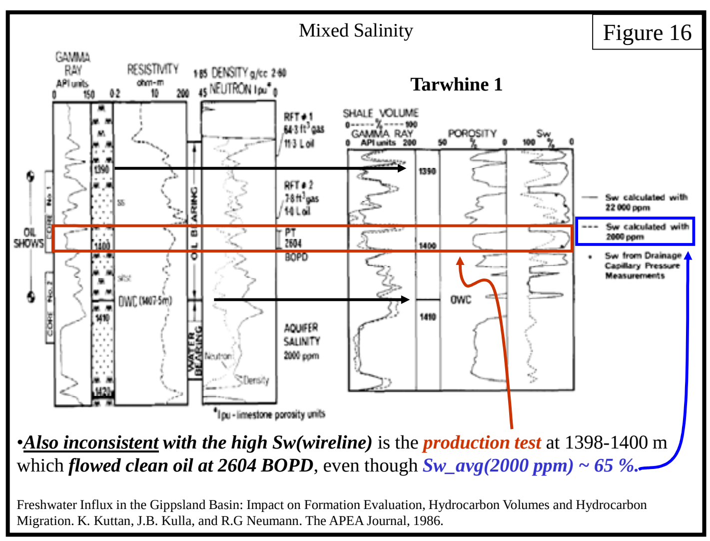


Figure 16

Kuttan et al advise: ***The Gippsland Basin is not the only area where the occurrence of freshwater underlying hydrocarbon zones complicates formation evaluation.*** It has previously been recognized in

- Mahakam Delta in Indonesia (Lalouel, 1972),
- Niger Delta (Ancel et al., 1974),
- Lake Maracaibo in Venezuela (Holbroook, 1982).
- The Eromanga, Surat, Canning, and Bonaparte basins of Australia are potential candidates.

Saline formation waters in hydrocarbon zones must be considered a possibility wherever hydrocarbons are underlain by a freshwater aquifer system.

In the typical pressure profile analyses, TVD Depth is plotted along the vertical axis, and pressure along the horizontal. Since the actual pressure magnitude is typically far larger than the precision of the pressure gauges (which are very accurate), this format does not draw upon all the information that is actually present in the profile.

In order to better utilize the precision of the gauges, Brown develops the 'excess pressure' concept. Excess pressure is calculated relative to some specified reference fluid (gas, oil water, select as appropriate) density and is defined as: Excess pressure, the difference between the measured pressure and the pressure expected from the specified fluid, between the datum and the depth of pressure measurement.

The magnitude of the excess pressure has less meaning than excess-pressure differences calculated using the same datum and fluid density. The excess pressure scale is expanded by a factor of about seven relative to the pressure scale: contacts and barriers become more obvious.

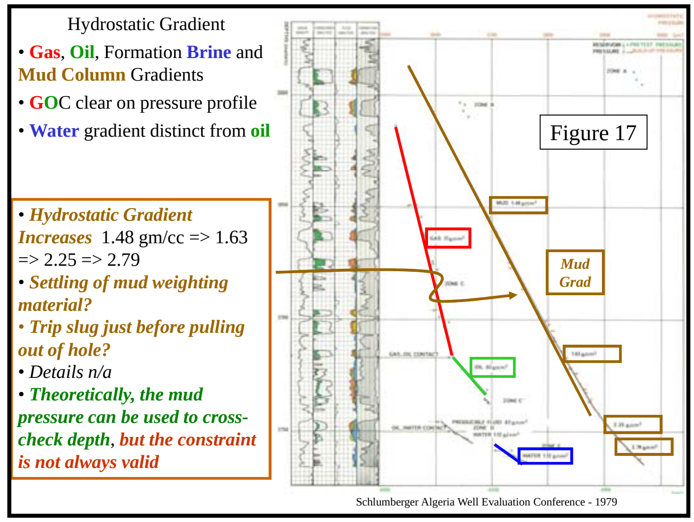
As one focuses on smaller pressure details, it's important to keep in mind the role that depth control is playing. A depth error of 1 ft will result in an approximately 0.4 psi excess-pressure error in water-bearing sections.

Brown observes that while, the mud pressure can be theoretically used to correct the depth, the approach has not proved useful unless depth errors are great, for the following reasons.

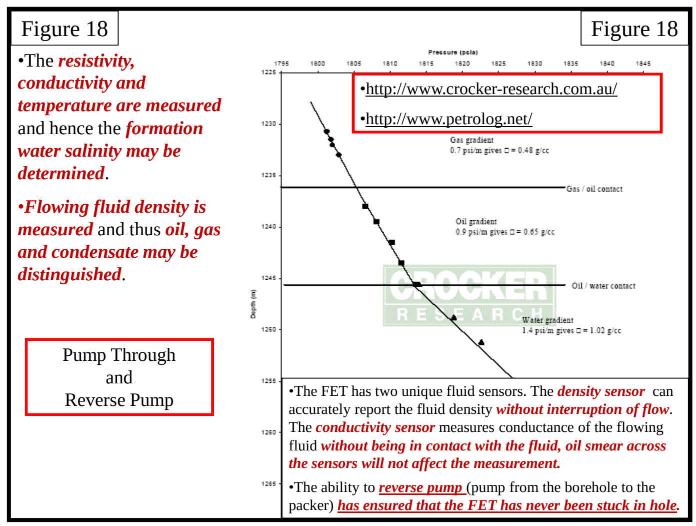
- Hydrostatic (mud) pressure measurements are rarely allowed to stabilize before or after the pretest
    - Reported before- and after-test hydrostatic pressures may differ by as much as 1.5 psi
- Mud density changes during logging as mud changes temperature
    - A slight drift to the mud pressure at a fixed depth is present
- Mud pressure also changes as mud level in the borehole varies while logging

Similar observations about using the hydrostatic gradient for depth control are found elsewhere: Figure 17.

There are times, low permeabilities, fractured carbonates, etc when a probe-based pressure profile is not representative and in these circumstances modern tools offer a ***straddle packer***: ***The Application of Modular Formation Dynamics Tester (MDT*) with a Dual Packer Module in Difficult Conditions in Indonesia.*** M. P. Siswantoro, T.B. Indra & I.A. Prasetyo. SPE Asia Pacific Oil and Gas Conference and Exhibition. 20-22 April 1999, Jakarta, Indonesia.



If ***representative fluid samples*** are an objective, the ability to pump fluids becomes paramount: Figure 18 and ***An Improved Wireline Formation Fluid Sampler and Tester.*** Hugh Crocker, Crocker Data Processing Pte. Ltd. SPE Asia-Pacific Conference, 4-7 November 1991, Perth. Australia. By monitoring fluid properties, during the pumping process, one is able to watch for stabilization and thereby ensure that formation fluid, and not mud filtrate, has been sampled. If the pump can be reversed, the additional ability to pump off the formation is available, should a tool sticking problem arise.



Sample integrity, and operational considerations, two important issues, have been summarized by Myers: ***Operational Considerations for Openhole Wireline Formation Tester Sampling in a Prolific Gas Reservoir.*** C. Myers, S. Vera & S. Haq. International Petroleum Technology Conference, 21-23 November 2005, Doha, Qatar.

Finally, in today's LWD world, pressure profiling has not been idle, and we now have the ability to ***profile while drilling*** (***Formation Pressure Testing During Drilling: Challenges and Benefits.*** M. Meister, J. Lee, V. Krueger, D. Georgi & R. Chemali. SPE Annual Technical Conference and Exhibition, 5-8 October 2003, Denver, Colorado), with the assurance that if operations are conducted carefully, results consistent with wireline measurements will be obtained (***Formation Pressure While Drilling Data Verified With Wireline Formation Tester, Hibernia***

Field, Offshore Newfoundland. Vinay K. Mishra, Steven Pond & Fred Haynes. International Petroleum Technology Conference, 4-6 December 2007, Dubai, U.A.E.).

Depending upon the background of the individual performing the evaluation, pressure profiles may be executed within either a spreadsheet, or petrophysical s/w. For those using a spreadsheet, Excel Tips and Tricks can be found at the two following links.

- http://people.stfx.ca/bliengme/exceltips.htm
- http://www.mrexcel.com/

1 2 3 and More

Pressure profiles provide important, basic information on reservoir fluids and rock continuity, and in some locales are vital to an accurate interpretation.

- Fluid typing, via determination of the fluid pressure gradient
- Fluid contact placement, via observation of pressure gradient changes
- Reservoir continuity, via identification of similar, but offset, pressure gradients

In order that the most value be extracted, base profiles should be secured pre-production and available for time lapse comparison.

And More. In addition to the technical contribution that pressure profiles provide, I enjoy working with the data because it always brings to mind my friend Hugh Crocker, inventor of the pump-through FET, and that rare combination of a true gentleman with keen intellect.

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