Petrophysical Challenges and Triumphs in the Gippsland Basin*

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Abstract

Early explorers did not appreciate initially, the fact that many of the large gas reservoirs and smaller oil accumulations were underlain by a large wedge of fresh water that extends from onshore to some considerable distance offshore into the basin. The fresh water aquifer made it difficult to differentiate hydrocarbons from fresh water bearing intervals, and led to an underestimation of the calculated hydrocarbon saturation. Careful analysis of the logs, combined with extensive formation pressure testing and sampling, and integration of special core analysis were used to show that the formation salinity of the connate water within the hydrocarbon intervals was significantly higher than that of the underlying aquifer. Re-evaluation of the logs has led to the significant upward revision of the hydrocarbons-in-place volumes in several fields. Another of the greatest challenges in the Gippsland Basin has been the ability to distinguish on logs, oil bearing from gas bearing zones in the intra-Latrobe reservoirs where the sands tend to be thin, shaly, and lower porosity. The presence of gas can be identified in clean sands using density-neutron cross-over, but in shaly intervals the cross-over effect is completely masked by the presence of clay. The need to differentiate oil from gas sands in the production wells was critical to increasing oil production during extended periods of low gas prices. As the production wells were deviated which increased the risk of sticking the formation testing tools and possibly losing the wells, the running of formation testers for sampling was actively discouraged. Several other log based techniques were tried, with varying degrees of success. One of the greatest triumphs for petrophysics in this basin has been the use of pulse neutron capture logs for monitoring the movements of fluids in the reservoirs, given the low formation water salinity environment in the basin. However, using carefully planned time-lapse logging, contact movements have been successfully tracked in the oil fields. This approach has resulted in numerous re-completion opportunities and extensive infill drilling programs which have extended the life of several fields.

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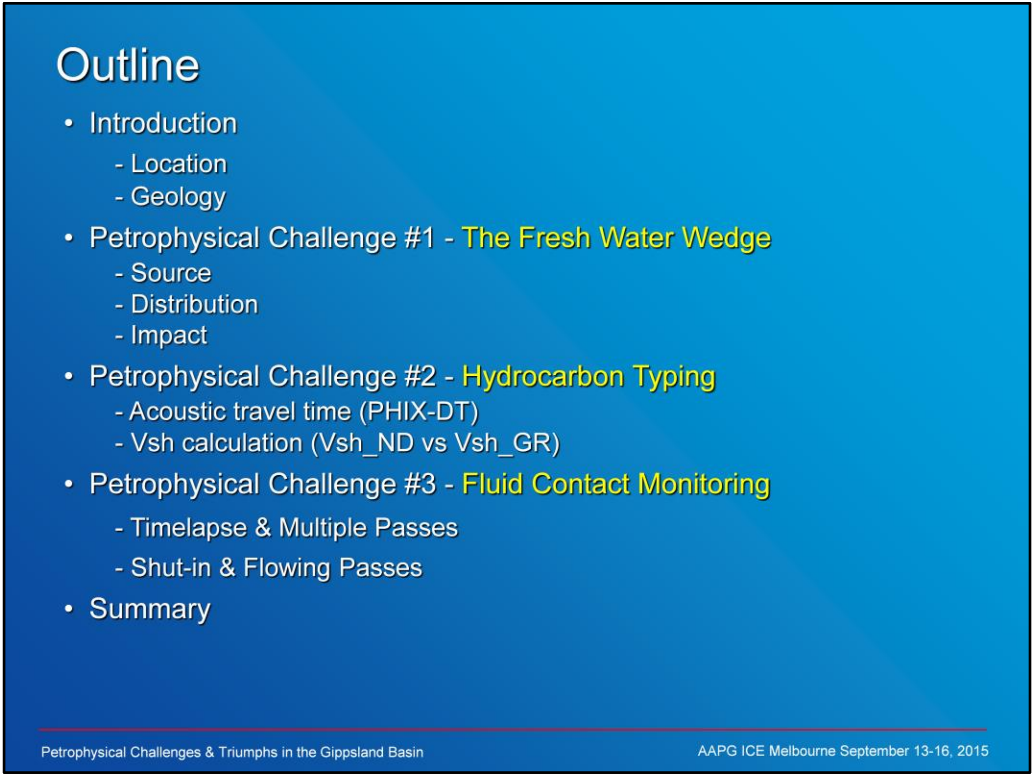
Petrophysical Challenges and Triumphs in the Gippsland Basin

Andy Mills & Kumar Kuttan
AAPG ICE Conference
Melbourne, September 13-16, 2015

Presenter's notes: Thanks Angie, and good afternoon ladies and gentlemen. Today my co-author Kumar Kuttan and I would like to share with you, a few of the petrophysical challenges and triumphs encountered over 50 years of exploration and production in the Gippsland Basin.



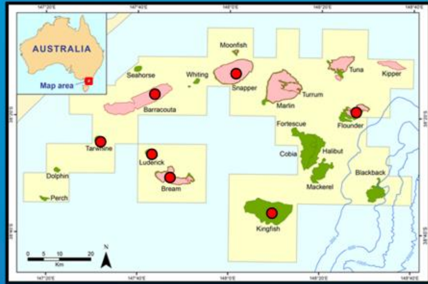
Presenter's notes: Following some brief introductory comments for orientation, we shall focus on three fundamental petrophysical challenges; why they can be difficult in the Gippsland Basin, and attempts to resolve them.

The first was a key challenge during the exploration phase of the basin, and entailed identifying and then quantifying hydrocarbons amid the fresh water wedge which sits on, and is interspersed with, the underlying more saline formation water. We will consider the source, distribution and eventual impact of the fresh water on the petrophysical workflow.
Having identified the presence of hydrocarbons, the second challenge of determining whether gas or oil is present can be exceedingly difficult. Many techniques have been tried with varying success. Today we will look at just two; the first related to the impact of hydrocarbons on acoustic travel time, and the second, its impact on shale volume calculation.

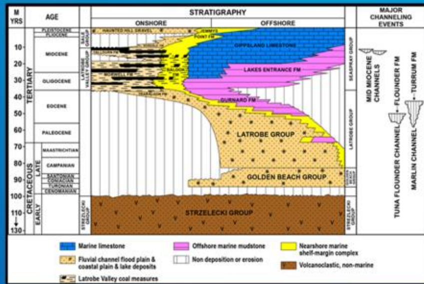
Finally, we'll move from the openhole to the casedhole environment, and discuss the challenges associated with fluid contact monitoring in a low salinity environment, and the evolution of associated analytical techniques with time.

Introduction

- Located on the SE margin of Australia between Victoria and Tasmania
- Gas & oil are produced from 23 platforms and subsea installations located on the shelf in 50-100m of water



- Rift basin formed during the break up of Gondwana during the Cretaceous and Tertiary
- Infilled with the marginal marine clastics of the LaTrobe Group
- Overlain and sealed by the marine Lakes Entrance Fm and Gippsland Limestone



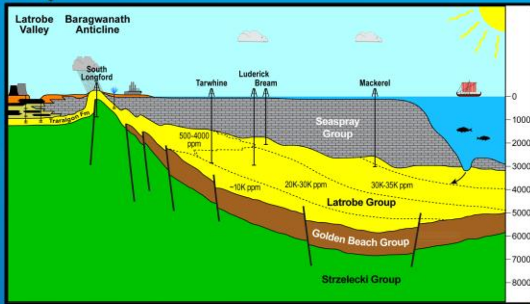
Presenter's notes: The Gippsland Basin is one of Australia's most prolific hydrocarbon producing provinces and is located at the south-eastern corner of the continent. ^^ Four-fifths of the basin is located offshore, and contains significant oil and gas reserves, with approximately four billion barrels of oil and eight trillion cubic feet of gas having been produced to date. Almost all of the hydrocarbon discoveries to date are contained within the Late Cretaceous-Early Tertiary LaTrobe Group. Location of examples in our talk today and the associated paper, are shown in red.

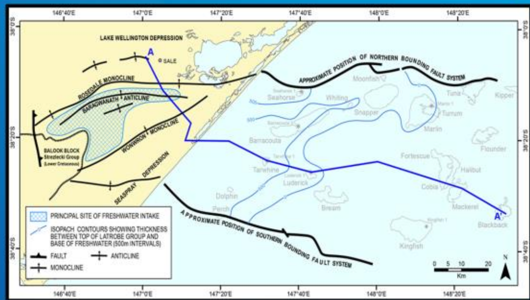
The rift basin which formed during the breakup of Gondwana, was infilled during the Cretaceous & Tertiary with several thousand metres of coastal plain, shoreface and marine sediments. The LaTrobe Group contains moderate to excellent quality fluvial and marine reservoirs, and is overlain by excellent quality shoreface sands.^^ This sand prone section is in turn overlain and sealed by the clay rich Lakes Entrance Formation.

Fresh Water Wedge (#1)

– Source & Distribution

- Compressional structuring post-LaTrobe deposition exposed the LaTrobe sediments in the onshore Baragwanath Anticline
- Meteoric water influx created a freshwater wedge of 500-4,000ppm floating on the underlying 10,000-35,000ppm formation water
- The freshwater wedge extends out under the major near shore gas & oil fields





Presenter's notes: Tertiary compressional structuring exposed the LaTrobe Group sediments in the on shore Baragwanath Anticline. Meteoric water intake here is interpreted to be the source of a large wedge of fresh formation water of between 500 and 4,000ppm NaCl salinity. ^^It floats on the underlying brackish formation water which varies in salinity from about 10,000 to 35,000ppm. The fresh water wedge has been mapped to extend out under the major near shore gas fields and several smaller oil fields. ^^It is the presence of this fresh water, which was the source of the first major petrophysical challenge identified during the exploration phase in the basin.

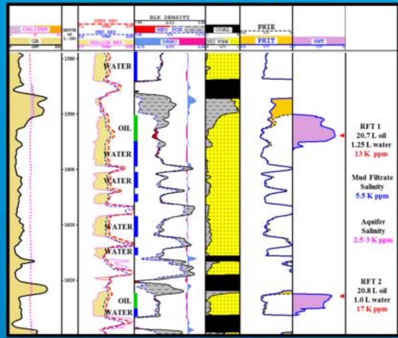
Fresh Water Wedge (#1)

– Impact (HC Identification)

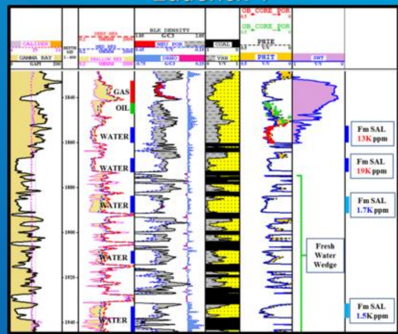
- Resistivity contrast between hydrocarbon and fresh water is subtle – easy to miss HC
- Multiple formation fluid samples were required to confirm hydrocarbons
- Water recoveries within small oil zones exhibited salinities 13,000-17,000ppm NaCleq
- Filtrate salinity = 5,500ppm
- Rwa salinity = 2,500-3,000ppm

- Luderick 1- only well to retain saline water above the wedge (19,000ppm)
- 57 fluid samples required to evaluate fluid content

Barracouta 5



Luderick 1



Presenter's notes: The following two examples illustrate some of the challenges thrown up by the wedge. Logs displayed include; gamma ray, resistivity, density-neutron, lithology, porosity, saturation, & RFT

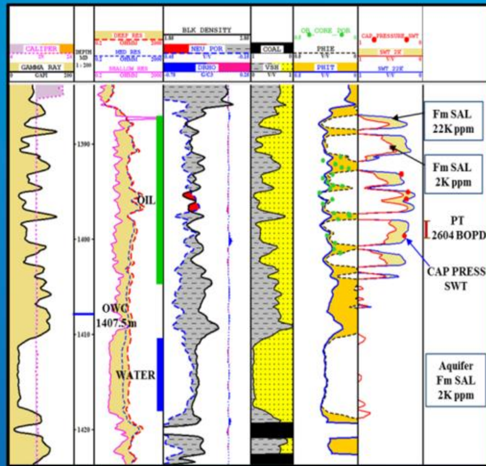
1) The first example from Barracouta 5 illustrates the difficulty in identifying thin hydrocarbon legs when interspersed with fresh water, and even more so when coals and dolomite cements are present. Multiple fluid samples were required to confirm the presence of moveable hydrocarbons. Recoveries from these two thin oil sands included water ranging in salinity from 13,000 to 17,000 ppm. As the mud filtrate in this well was only 5500ppm and the underlying acquifer salinity was calculated from logs to be 2,500 to 3,000ppm, the water samples were interpreted to be formation water of at least 17,000ppm salinity.^^^
2) The second example from Luderick 1 is the only well in the basin where salt water occurs above the aquifer.^^^ Here the water salinity calculated from logs is 19000 ppm,^ consistent with the fluid recoveries in the previous example. Notably, 57 samples were required to discriminate hydrocarbons from fresh water in this well.

Fresh Water Wedge (#1)

– Impact (HC Quantification)

- Further indirect evidence that water within the hydrocarbon leg is more saline than the freshwater is provided by Pc
- Capillary pressure data can be matched using 22,000ppm
- Standard usage of underlying freshwater leads to Sw >> Pc
- Quantification of HCIP is dependent on accurate Rw in the hydrocarbon leg

Tarwhine 1

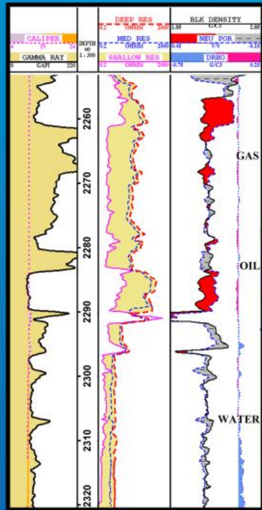


Presenter's notes: Further indirect evidence that the formation water salinity in the hydrocarbon legs is <u>more</u> saline than the underlying aquifer, comes from the comparison of water saturations calculated from both <u>resistivity</u>^ and <u>capillary pressure</u> data. In Tarwhine 1, the capillary pressure based water saturation can best be matched by resistivity based saturation shown in blue, using a formation water salinity of 22000ppm. Using the 2000ppm salinity from the underlying aquifer, leads to an over calculation of water saturation by about 20 su, here shown in red. This has a <u>significant</u> impact on the calculated hydrocarbons in place !!

Hydrocarbon Typing (#2)

– The PHIX-DT (Acoustic) Method

- Gas overlying high GOR oil in radioactive sands complicates fluid identification.

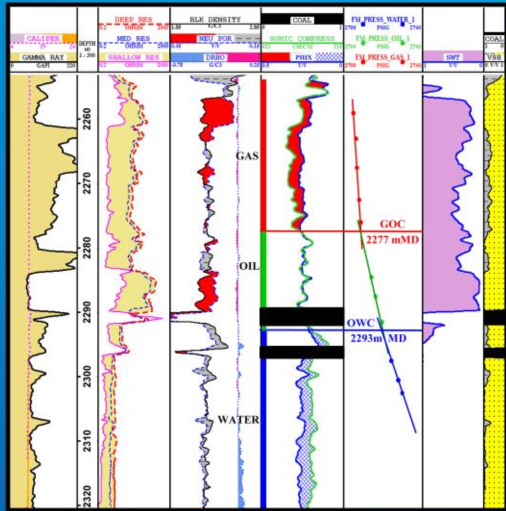


Presenter's notes: Having identified the presence of hydrocarbons, our attention turns to fluid typing. This is the second challenge we face.^^ In the Bream field, which lies <u>outside</u> the fresh water wedge,^ fluid identification is complicated by a combination of a wet gas cap, overlying a high GOR oil in a radioactive sand reservoir.^^^ In this example, it is evident that there is gas in the upper interval at 2260m,^^ and potentially gas in the thin interval at 2268m, ^^although the light hydrocarbon effect here is no greater than in the deeper, high GOR oil interval.^^^

Hydrocarbon Typing (#2)

– The PHIX-DT (Acoustic) Method

- Gas overlying high GOR oil in radioactive sands complicates fluid identification.
- PHIX-DT method was developed to assist:
  - overlay sonic on PHIX in oil
  - gas: DT separates to left
  - water: DT separates to right
- Less pressure data was required

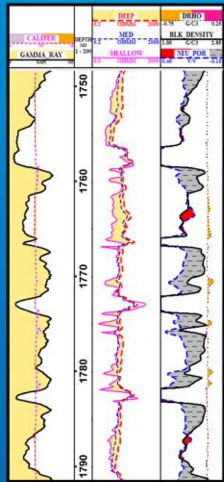


Presenter's notes: The PHIX-DT method was developed to take advantage of the light hydrocarbon effect on compressional sonic data.^^ When the DT curve is scaled to overlay the density-neutron crossplot porosity in the oil zone,^^ it separates to slower time in the gas leg ^^and faster time in the water leg, clearly defining the contacts. In this well the contacts were confirmed by pressure data, which was able to be dropped in later wells.^^^

Hydrocarbon Typing (#2)

– The Vsh Method

- HC effects are often masked in thin shaly fluvial reservoirs
- Comparison of Vsh_ND to Vsh_GR can indicate the correct fluid



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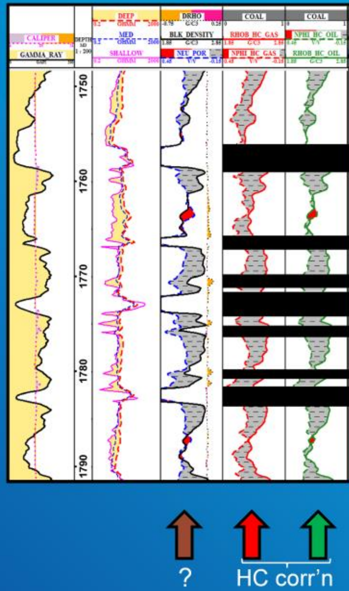
Presenter's notes: In the deeper, fluvial reservoirs, where radioactive sands are largely absent,^ fluid identification can be difficult because of the thin, shaley nature of the reservoirs. In this example, only the sand at 1765m has a well-defined gas effect on the density-neutron logs.^^ A petrophysical workflow has been developed which enables fluid identification through comparison of different GR and density-neutron Vsh estimates, in the <u>absence</u> of radioactive sands.

Hydrocarbon Typing (#2)

– The Vsh Method

- HC effects are often masked in thin shaly fluvial reservoirs
- Comparison of Vsh_ND to Vsh_GR can indicate the correct fluid
  - Density & neutron are HC corrected assuming gas and then oil

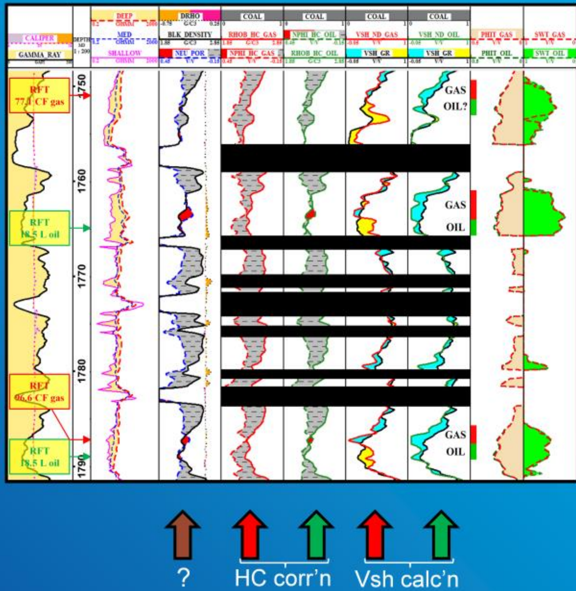


Presenter's notes: Initially, the density and neutron logs are hydrocarbon corrected, assuming firstly that all reservoirs are <u>gas</u> bearing,^ and then <u>oil</u> bearing.^^^

Hydrocarbon Typing (#2)

– The Vsh Method

- HC effects are often masked in thin shaly fluvial reservoirs
- Comparison of Vsh_ND to Vsh_GR can indicate the correct fluid
  - Density & neutron are HC corrected assuming gas and then oil
  - Vsh_ND is calculated using gas and then oil across all intervals
  - the closest match to Vsh_GR indicates fluid



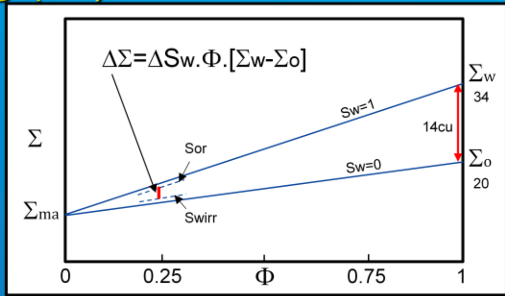
Presenter's notes: Shale volume is then calculated for both sets of hydrocarbon corrected logs, and the resultant curves are compared with the shale volume calculated from the gamma ray, shown here in black.^^^ Where gas corrected curves produce a better fit to the Vsh_GR than the oil corrected curves, ^^the fluid is assigned as gas, and vice versa.^^^ [RETURN] In this example, sufficient fluid samples were taken to verify the interpretation. ^^^Although an imperfect method, it is used regularly with good results.

At this stage, let's change our focus and look at some of the challenges associated with fluid contact monitoring in the casedhole environment.

Fluid Contact Monitoring (#3)

- Timelapse & multiple passes

- Low water salinity produces only a 1-2½ cu contrast to oil
- Timelapse logging required



Presenter's notes: In low salinity environments such as Bass Strait, carbon-oxygen logging is routinely used to monitor fluid contact movement. However, as the early 3 3/8" diameter tools would not pass through tubing restrictions, fluid contact monitoring has been pursued using a series of 1 11/16th inch pulsed neutron tools, which are designed for higher formation salinities. As a consequence, when we consider a porosity vs sigma plot, and the 14 capture unit contrast between oil and water ^^ is porosity weighted down to 25pu and lower, ^^ the resultant contrast between virgin and swept zones is only 1-2.5cu. These small contrasts can only be reliably interpreted by using the timelapse method, where logs are repeated every few years and compared to reveal changes.

Fluid Contact Monitoring (#3)

- Timelapse & multiple passes

- Low water salinity produces only a 1-2½ cu contrast to oil
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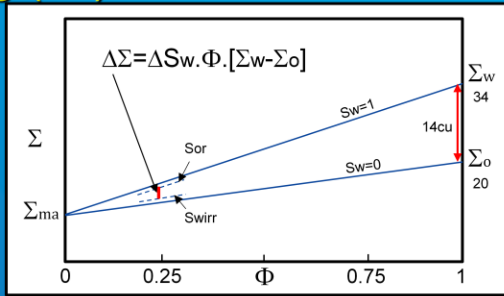
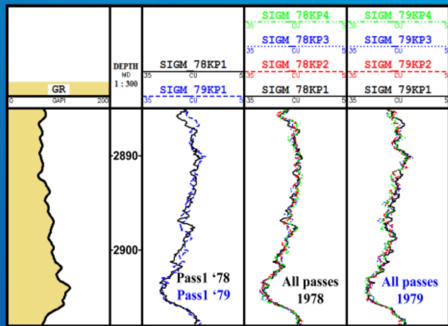


- Statistical repeatability of early tools was also ~ 1-2cu
- Multiple passes and lateral averaging required

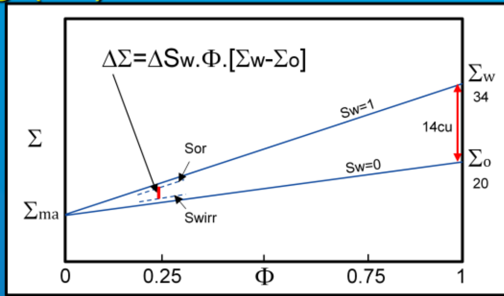


Presenter's notes: Unfortunately, the statistical repeatability of these early tools was also 1 – 2 cu. Thus we can see from track two, that no definitive contact movement can be determined between single passes of the 1978 and 1979 sigma logs because the signal is hidden in the noise.^^ To improve this situation, multiple passes were run each year and are here displayed in tracks 3 and 4.^^ These data clearly illustrate the poor statistical repeatability of the early tools.^

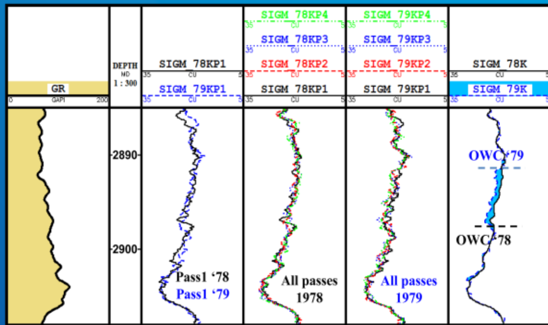
Fluid Contact Monitoring (#3)

- Timelapse & multiple passes

- Low water salinity produces only a 1-2½ cu contrast to oil
- Timelapse logging required



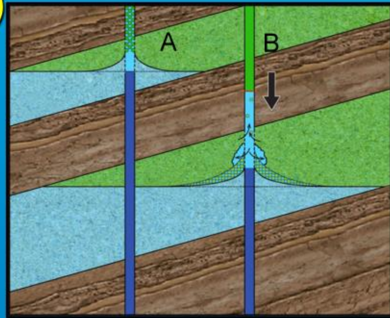
- Statistical repeatability of early tools was also ~ 1-2cu
- Multiple passes and lateral averaging was required



Presenter's notes: However, lateral averaging of these individual passes finally provides interpretable logs.

Fluid Contact Monitoring (#3)
– Multiple Passes Shut-in & Flowing

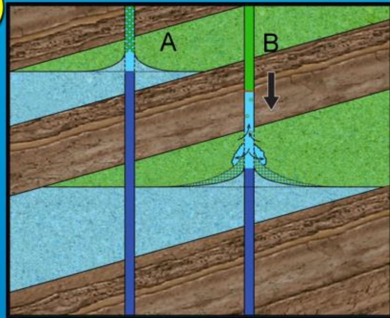
- Following water onset, produced water reinvades perforations while the well is shut-in to log
- A false OWC can be generated



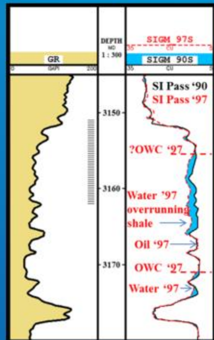
Presenter's notes: As the basin matured, when wells such as well "B" were shut-in to log, produced water would settle to the base of the perforations and re-invade the formation and create a false OWC.
^^^

Fluid Contact Monitoring (#3)
– Multiple Passes Shut-in & Flowing

- Following water onset, produced water reinvades perforations while the well is shut-in to log
- A false OWC can be generated

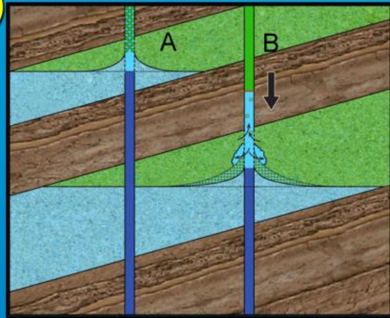


- Shut-in passes can indicate a potentially false contact



Presenter's notes: In this example we see in track one, a GR and perforations^^, and in track 2, a comparison between pulsed neutron sigma logs run in 1990 and 1997, both while the <u>well was shut-in</u>.^^ The black 1990 log was recorded with the reservoir full of oil.^^ In the red 1997 log, an increase in sigma indicates water encroaching in the base of the unperforated reservoir. This is then overlain by oil as indicated by no change in sigma,^^ and overlain again by water which has overrun a thin shale at 3166m. A clearly defined contact is seen in the middle of the perforations at 3155m.^^ Or is it?

Fluid Contact Monitoring (#3)
– Multiple Passes Shut-in & Flowing



- Following water onset, produced water reinvades perforations while the well is shut-in to log
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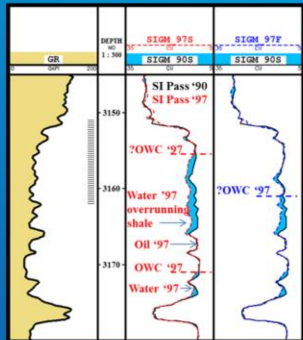
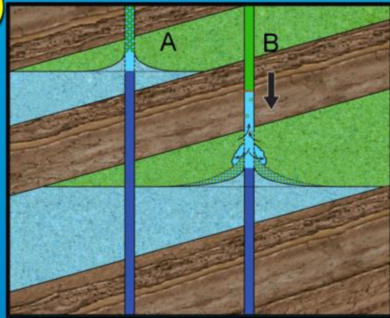


- Shut-in passes can indicate a potentially false contact
- Flowing passes can be used to clear the perforations of re-invaded water

Presenter's notes: In 1997, a second logging pass shown in blue, was run with the well flowing. A comparison with the 1990 shut-in log gives a very different interpretation with the OWC some 5m lower than indicated by the 1997 shut-in log.^^ Water which had re-invaded the perforations during shut-in was in the process of being flushed out again.^^

Fluid Contact Monitoring (#3)

– Multiple Passes Shut-in & Flowing



- Following water onset, produced water reinvades perforations while the well is shut-in to log
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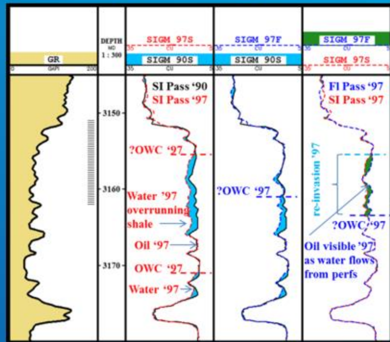


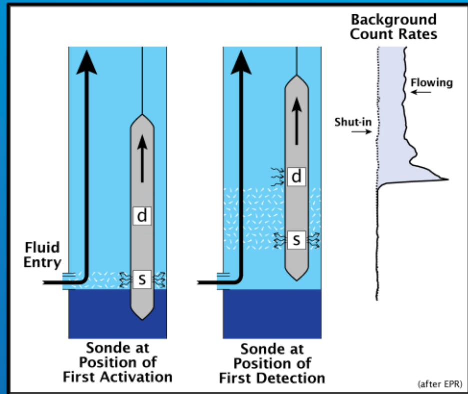
- Shut-in passes can indicate a potentially false contact
- Flowing passes can be used to clear the perforations of re-invaded water
- Reinvasion can be avoided by logging unperforated wells.

Presenter's notes: Finally, a direct comparison of the shut-in and flowing logs from 1997 alone, indicates a clear reduction in sigma as the water is replaced by oil and gives a final interpreted OWC some 8 1/2 m below the initial shut-in interpretation. Of course, careful planning can sometimes avoid dynamic effects such as these by logging in nearby unperforated wells such as well "A"^^^

Fluid Contact Monitoring (#3)

– Multiple Passes Shut-in & Flowing

- A PNC source will induce oxygen activation in water flowing past the tool during logging
- Oxygen atoms are activated to an unstable isotope of nitrogen which decays, ejecting GRs
- Comparison back ground counts from shut-in and flowing passes identifies first water entry points

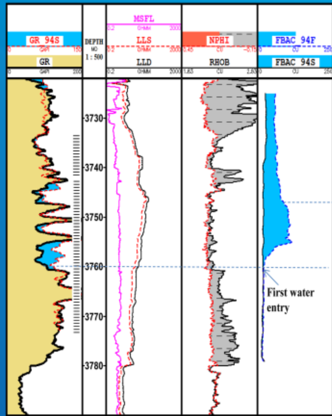


Presenter's notes: With the advent of shut-in and flowing passes in all wells, oxygen activation, a side effect of logging in flowing water columns, came into play. When water flows past a pulsed neutron source, the oxygen atoms are converted into an unstable isotope of nitrogen which decays with a 7.1 second half life, giving off excess energy as gamma rays.^^ As the activated water flows past the detectors, these gamma rays are counted in the background count rate channels. Comparison of back ground counts from shut-in and flowing passes indicates the first or deepest water entry point in the well.^^^

Fluid Contact Monitoring (#3)

- Benefits of Data Integration

- Increased GR relative to OH GR indicates water movement
- SI & F background counts indicate first water entry
- A reduction in background counts <u>MAY</u> indicate oil entry

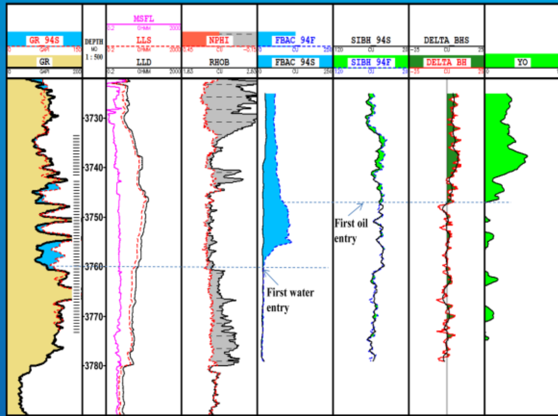


Presenter's notes: In this West Kingfish example, we see displayed openhole and casedhole gamma rays,^ resistivity,^ density neutron^ and background counts^. The entire interval of this radioactive marine sand is perforated. The increase in background counts on the flowing pass relative to the shut-in pass indicates first significant water entry at the base of the best quality sand.^^ This is consistent with the increase in the casedhole gamma gay relative to the openhole gamma ray, which is indicative of scale deposition associated with water flow.^^^
We can see also, an interesting reduction in the background counts at about 3747m, which has the potential to indicate less water and hence more oil in the wellbore stream.^^

Fluid Contact Monitoring (#3)

- Benefits of Data Integration

- Increased GR relative to OH GR indicates water movement
- SI & F background counts indicate first water entry
- A reduction in background counts <u>MAY</u> indicate oil entry
- Timelapsed borehole sigma curves confirm and quantify oil entry



Presenter's notes: The borehole sigma measurements reveal a drop in the borehole capture cross section under flowing conditions relative to the shut-in pass, consistent with oil entry at this point. The difference between the shut-in and flowing borehole sigmas can be processed and an oil holdup curve produced to quantify flow from the perforations.^^

Summary

- High porosity and permeability of the LaTrobe reservoir suggests simplicity….but
- All petrophysics is local
- Complexity takes different forms
  - the mixture of radioactive sands, mixed salinity water complicates the location, quantification and fluid identification of hydrocarbons
  - the overall low salinity complicates the casedhole monitoring requiring timelapse analysis which is then subject to various changes unrelated to the formation
- The requirement to find solutions to these challenges has led to the development of technology, techniques and petrophysicists

The Gippsland Basin Joint Venture

Esso

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resourcing the future

Presenter's notes: Although the high quality of the LaTrobe reservoirs would suggest a simple petrophysical environment, like politics all petrophysics is local. Complexity takes different forms with the mixture of radioactive sands and mixed salinity formation waters complicating the location, quantification and fluid identification of hydrocarbons. The overall low formation water salinities in the basin further complicates fluid contact monitoring. The required timelapse methodology simply measures change, and includes changes in borehole fluids and equipment, logging tools and software, ^^ all unrelated to formation fluid contact movement. However, over some 40 years, this complexity has driven the development of logging technology, interpretive techniques and indeed the petrophysicists who use them.

At this point, Kumar and I would like to conclude by thanking Esso Australia and BHPBilliton for their approval to share this information with you, and Louise Christensen for her assistance with our presentation today.

Questions?