CREWES

UNIVERSITY OF CALGARY

An empirical study of hydrocarbon indicators

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Introduction

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- The purpose of this study is to compare the generalized fluid method with other hydrocarbon indicators to see which is most sensitive to reservoir pore-fluid content.
- We will first review the various approaches that have been developed for hydrocarbon fluid indication, including the generalized fluid method.
- We will then review the work done by Dillon et al. (2003) on fluid indicators.
- We will next extend Dillon et al.'s results using the extensive core dataset measured by Han et al. (1986).
- Finally, we will discuss the effectiveness of fluid indicators using pre-stack seismic data.

Geology versus geophysics

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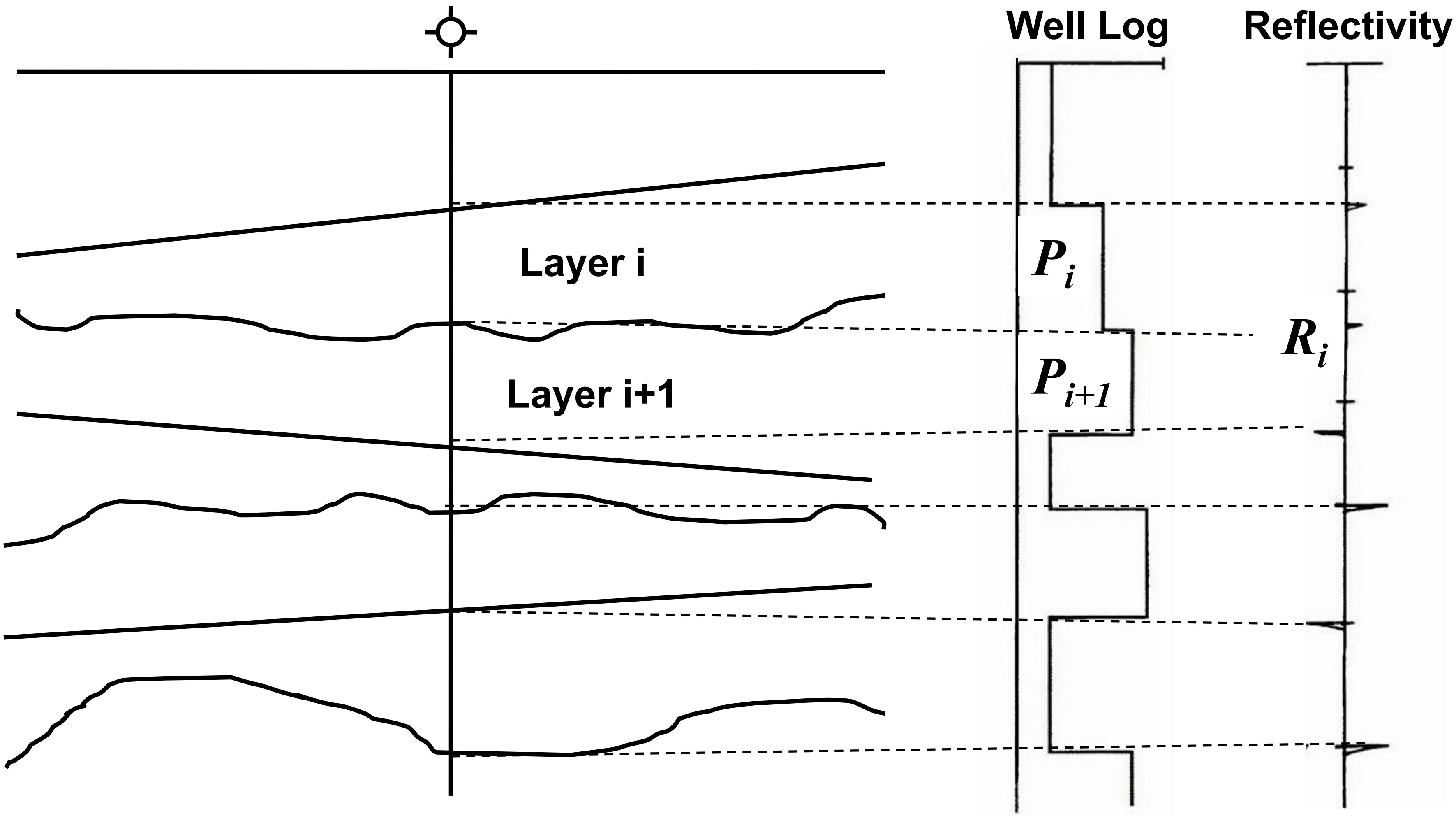

Geologists measure a property P for each geological layer, whereas geophysicists measure reflectivity R.

Hydrocarbon indicators

- Properties of interest as hydrocarbon indicators are:
  - P-wave velocity (V_P), S-wave velocity (V_S), Density (ρ)
  - Transforms of velocity and density such as acoustic impedance ($I_P = \rho V_P$), shear impedance ($I_S = \rho V_S$), velocity or impedance ratio ($\gamma = V_P/V_S$), and Poisson's ratio ($\sigma = (\gamma^2 - 2)/(2\gamma^2 - 2)$).
- These properties can be measured using well logs or laboratory analysis of cores.
- The reflectivity at each interface is found by dividing the change in the property value by twice its average:

$$R_i = \frac{P_{i+1} - P_i}{P_{i+1} + P_i} \approx \frac{\Delta P_i}{2\overline{P}_i}$$

Linearized AVO equations

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- Linearized AVO equations have been derived (e.g. Aki and Richards, 1982, Shuey, 1984, Fatti et al., 1994) which show that the pre-stack reflectivity as a function of angle can be written as a sum of three reflectivities:

$$R(\theta) = c_1 \frac{\Delta P_1}{2\overline{P}_1} + c_2 \frac{\Delta P_2}{2\overline{P}_2} + c_3 \frac{\Delta P_3}{2\overline{P}_3},$$

$$\text{where}: \quad \frac{\Delta P_i}{2\overline{P}_i} = \frac{\Delta V_P}{2\overline{V}_P}, \ \frac{\Delta V_S}{2\overline{V}_S}, \ \frac{\Delta \rho}{2\overline{\rho}}, \frac{\Delta I_P}{2\overline{I}_P}, \ \frac{\Delta I_S}{2\overline{I}_S}, \frac{\Delta \sigma}{2\overline{\sigma}}, \text{etc.}$$

$$\text{and } c_1, c_2, c_3 = \text{functions of } \theta \text{ and } \gamma = V_P / V_S.$$

- These reflectivities can be extracted and used as hydrocarbon indicators on their own, or can be inverted to produce velocity, density, impedance or the various ratios.

Other fluid indicators

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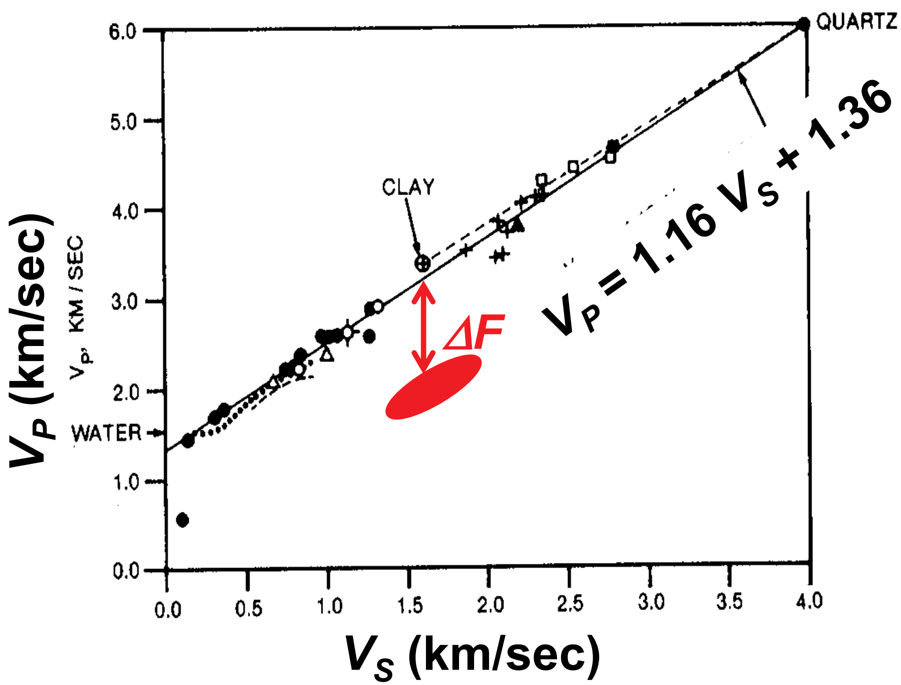
Smith and Gidlow (1987) defined Fluid Factor ΔF as the difference away from the wet trend, which should indicate fluid anomalies:

$$\Delta F = \frac{\Delta V_P}{2\overline{V}_P} - 1.16\left[\frac{V_S}{V_P}\right]\frac{\Delta V_S}{2\overline{V}_S}$$



Modified from Castagna et al, 1985

- Goodway et al. (1997) showed that we could extract the elastic parameters $\lambda\rho$ (fluid) and $\mu\rho$ (matrix) from inverted data as follows:

$$\lambda\rho = I_P^2 - 2I_S^2, \quad \mu\rho = I_S^2$$

LMR and poroelasticity

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- Russell et al. (CREWES, 2001, Geophysics, 2003) used poroelasticity theory (Biot, 1941) to generalize the $\lambda\rho$ term as follows:

$$\rho f = I_P^2 - cI_S^2, \quad c = \gamma_{dry}^2$$

$$\text{where: } c = \gamma_{dry}^2 \text{ is the dry rock } V_P / V_S \text{ ratio squared.}$$

- They showed that a reasonable value for *c* would be 2.233 for clean sandstones (Hedlin, 2000).
- Dillon et al. (TLE, 2003), from Petrobras, evaluated a number of fluid indicators on sandstones from offshore Brazil, using the fluid indicator coefficient:

$$\left| Mean_{dry} - Mean_{wet} \right| / \, Std\ Dev_{wet}$$

- They showed *c* values in the range of 2.6 to 3.0 for consolidated sediments, as shown in the next slide.

Brazil example (Dillon et al., 2003)

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			$I_P - I_S$	$\lambda\rho$	σ	V_P/V_S	$K-\mu$	I_P	ΔF
Cretaceous sandstones	water	mean value	4.23	35.0	0.285	1.822	36.9	9.4	0.006
		std. dev.	0.12	1.9	0.007	0.034	2.4	0.3	0.005
	oil	mean value	3.97	30.1	0.268	1.776	35.1	9.1	0.017
		std. dev.	0.12	1.6	0.006	0.017	2.5	0.4	0.004
Fluid indicator coefficient			2.2	3.0	2.8	2.7	0.7	0.8	2.8
Tertiary sandstones	water	mean value	3.26	21.0	0.368	2.183	16.9	6.0	0.008
		std. dev.	0.07	1.0	0.005	0.064	0.6	0.1	0.005
	oil	mean value	2.60	13.4	0.323	1.945	13.5	5.3	0.095
		std. dev.	0.10	1.0	0.007	0.061	0.7	0.2	0.014
Fluid indicator coefficient			6.4	7.4	6.4	3.9	4.8	4.2	6.2

The best of the above indicators is $\lambda\rho$. However:

$I_P^2 - cI_S^2$ is best if c is optimized (= 2.6 for Cretaceous, = 2.8–3.0 for Tertiary).

			$IP^2 - cIS^2$ [(m/s. kg/m^3)^2]$\times 10^{12}$				
			c=2.6	c=2.7	c=2.8	c=2.9	c=3.0
Cretaceous sandstones	water	mean value	19.1	16.4	13.8	11.1	8.5
		std. dev.	1.2	1.1	1.2	1.3	1.4
	oil	mean value	14.4	11.8	9.1	6.5	3.9
		std. dev.	0.6	0.7	0.9	1.1	1.3
Fluid indicator coefficient			7.7	6.7	5.4	4.3	3.6
Tertiary sandstones	water	mean value	16.5	15.8	15.0	14.3	13.5
		std. dev.	0.9	0.9	0.8	0.8	0.8
	oil	mean value	9.0	8.2	7.5	6.8	6.0
		std. dev.	1.0	1.0	0.9	0.9	0.9
Fluid indicator coefficient			7.9	7.9	8.0	8.0	8.0

Dillon et al. conclusions

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- Dillon et al. (2003), make the following conclusions:

1) In younger, poorly consolidated reservoirs, even the simple attributes, like acoustic impedance, are sufficient for good fluid discrimination.
2) In more consolidated reservoirs a combination of the elastic attributes calibrated locally becomes essential for the optimization of the fluid detection process.
3) It can be particularly observed that the indicator suggested by Russell et al., $I_P^2 - cI_S^2$, when used with the correctly calibrated c value, may be much more efficient than the other attributes.

Hong Feng's Thesis

- In a recently completed CREWES M.Sc. thesis, Hong Feng extended the work done by Dillon et al. by analyzing the following datasets for effective hydrocarbon indicators:
  - Hilterman's (2001) Class I, II, and III sand models derived from the Gulf of Mexico.
  - Han's (1986) dataset, which covers a wide range of cores with varying porosities and clay content at different pressures, both dry and wet.
  - The Blackfoot 3C-3D P-P dataset, recorded in 1995.
- We will now review the results obtained using De Hua Han's dataset, followed by a look at the Blackfoot data.

De Hua Han's dataset

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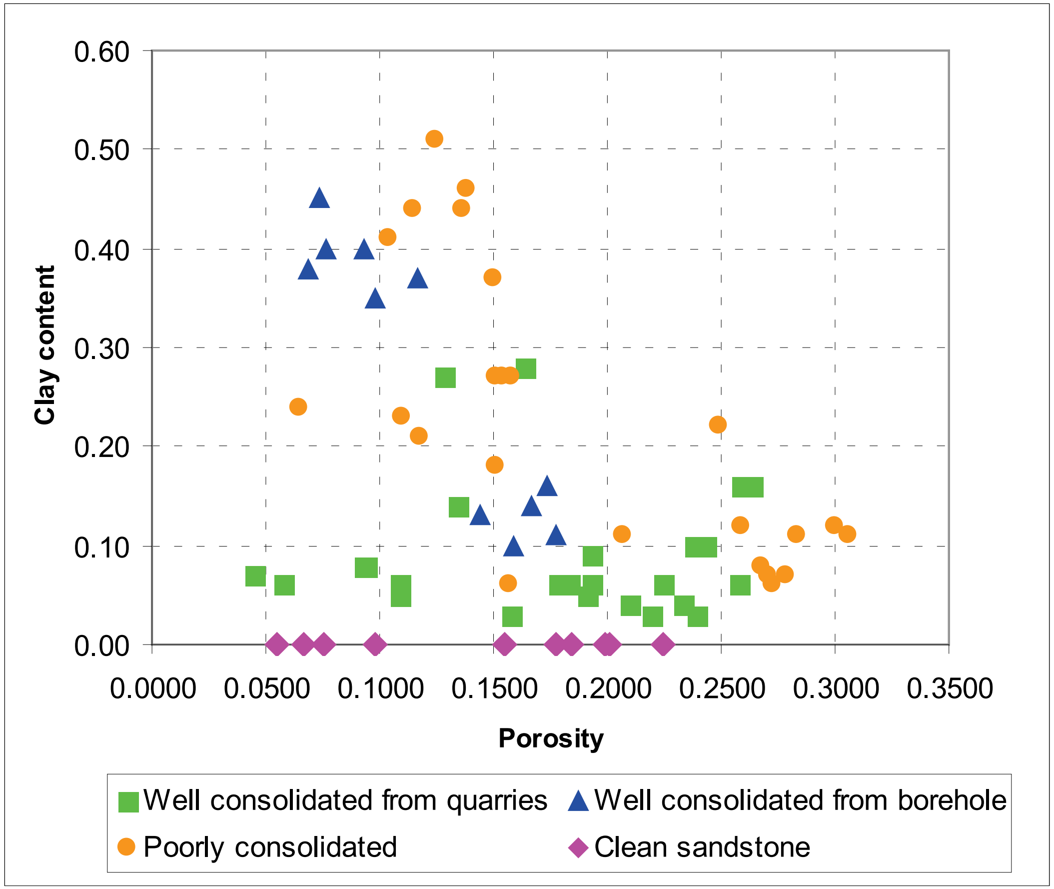

This figure shows a crossplot of clay content versus porosity for the 70 samples in Han's dataset, where:

- The porosities range from 4 - 30%.
- The V_{clay} ranges from 0 - 50%.
- The pressures are 5, 10, 20, 30, 40, and 50Mpa.

Green squares are well consolidated quarry sands, blue triangles are well consolidated borehole measurements, orange circles are poorly consolidated sands and purple diamonds are clean sands.

c value analysis vs. porosity and clay

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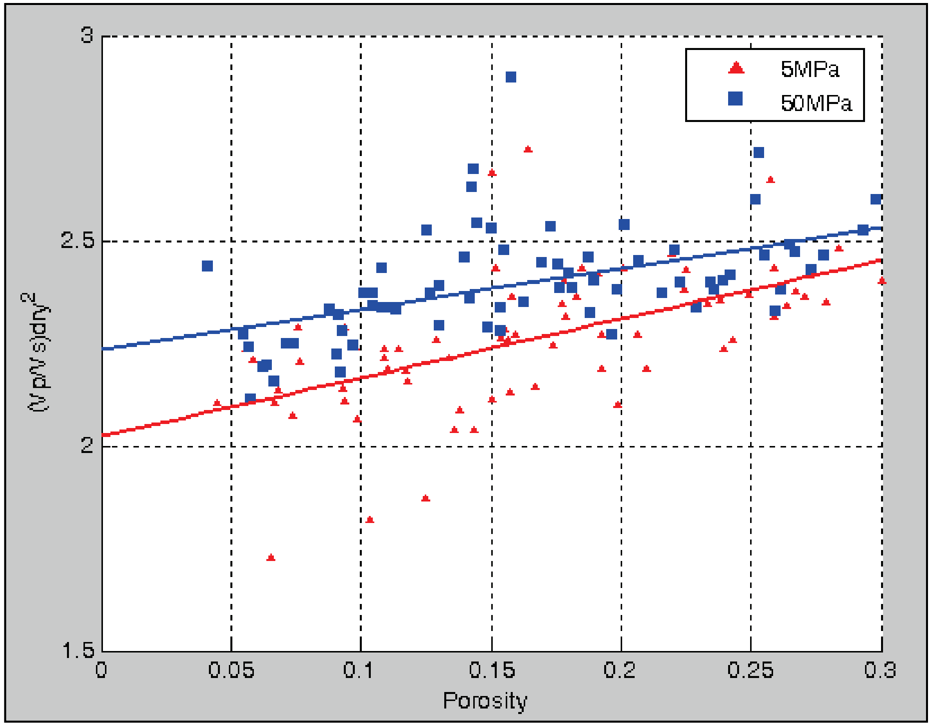
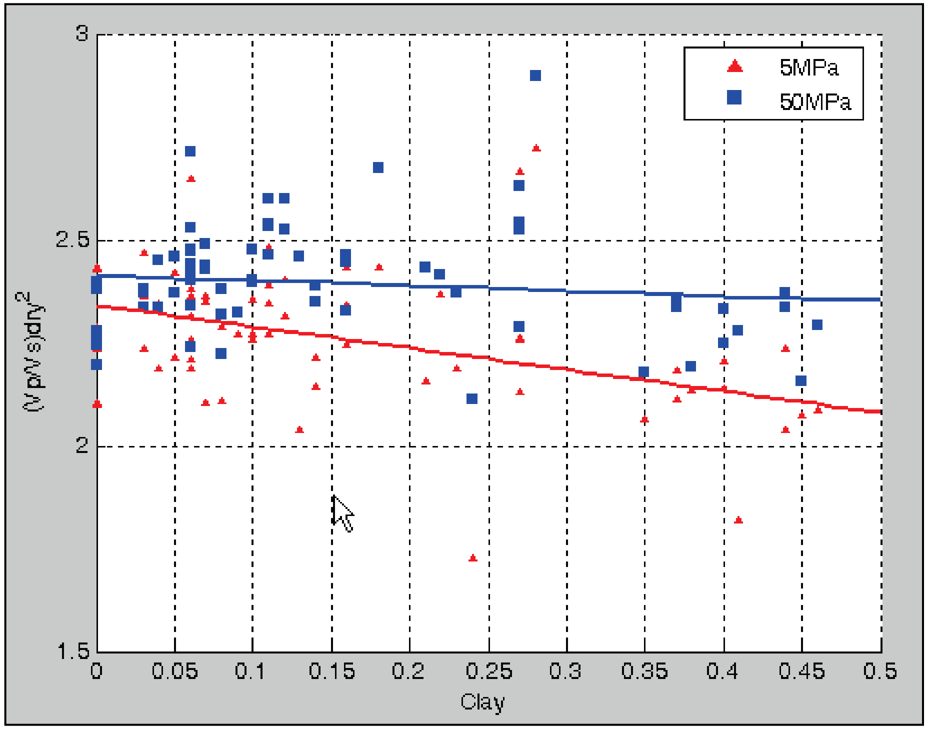


Correlation between *c* value and porosity for 5 MPa and 50 MPa. Note that *c* increases with porosity.



Correlation between c value and clay for 5 MPa and 50 MPa. Note that *c* decreases with clay content.

Han's dataset, 1986

c value analysis vs. pressure

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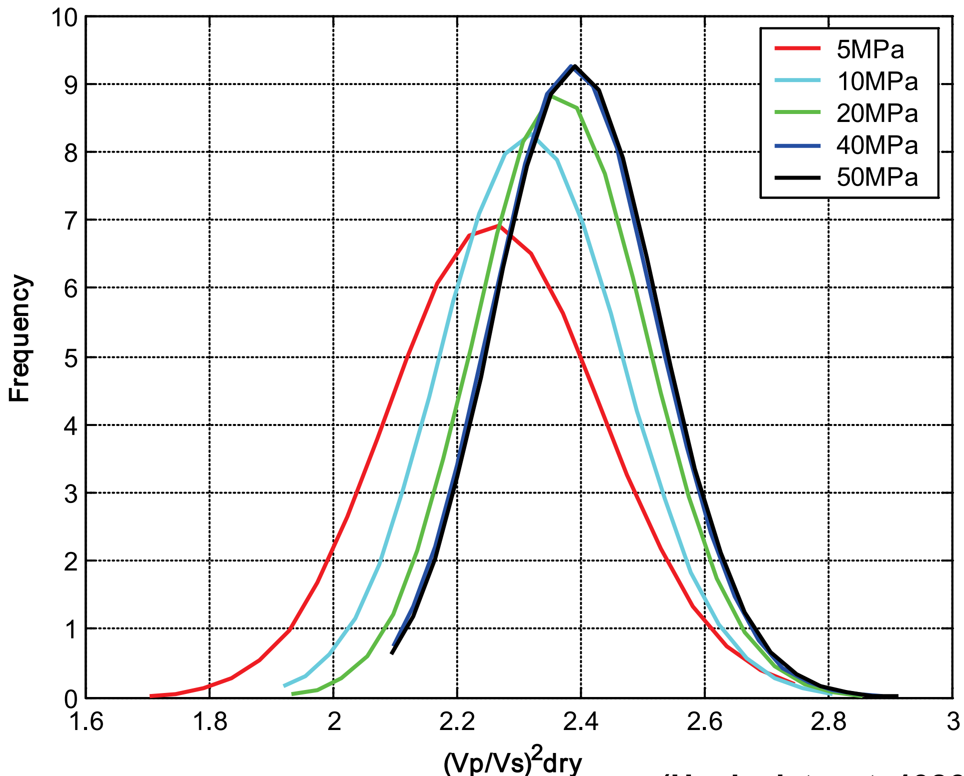

(Han's dataset, 1986)

Histograms of the *c* value for pressures of 5 MPa, 10 MPa, 20 MPa, 30 MPa, 40 MPa and 50 MPa. Note that *c* increases with differential pressure. This could also be seen on the porosity and clay content crossplots.

In Summary:

1. The dry rock *Vp/Vs* ratio increases with porosity.
2. The dry rock *Vp/Vs* ratio decreases with clay content.
3. The dry rock *Vp/Vs* ratio increases with differential pressure (i.e. depth), varying from 2.24 at 5 Mpa to 2.39 at 50 Mpa.

Hydrocarbon indicator study

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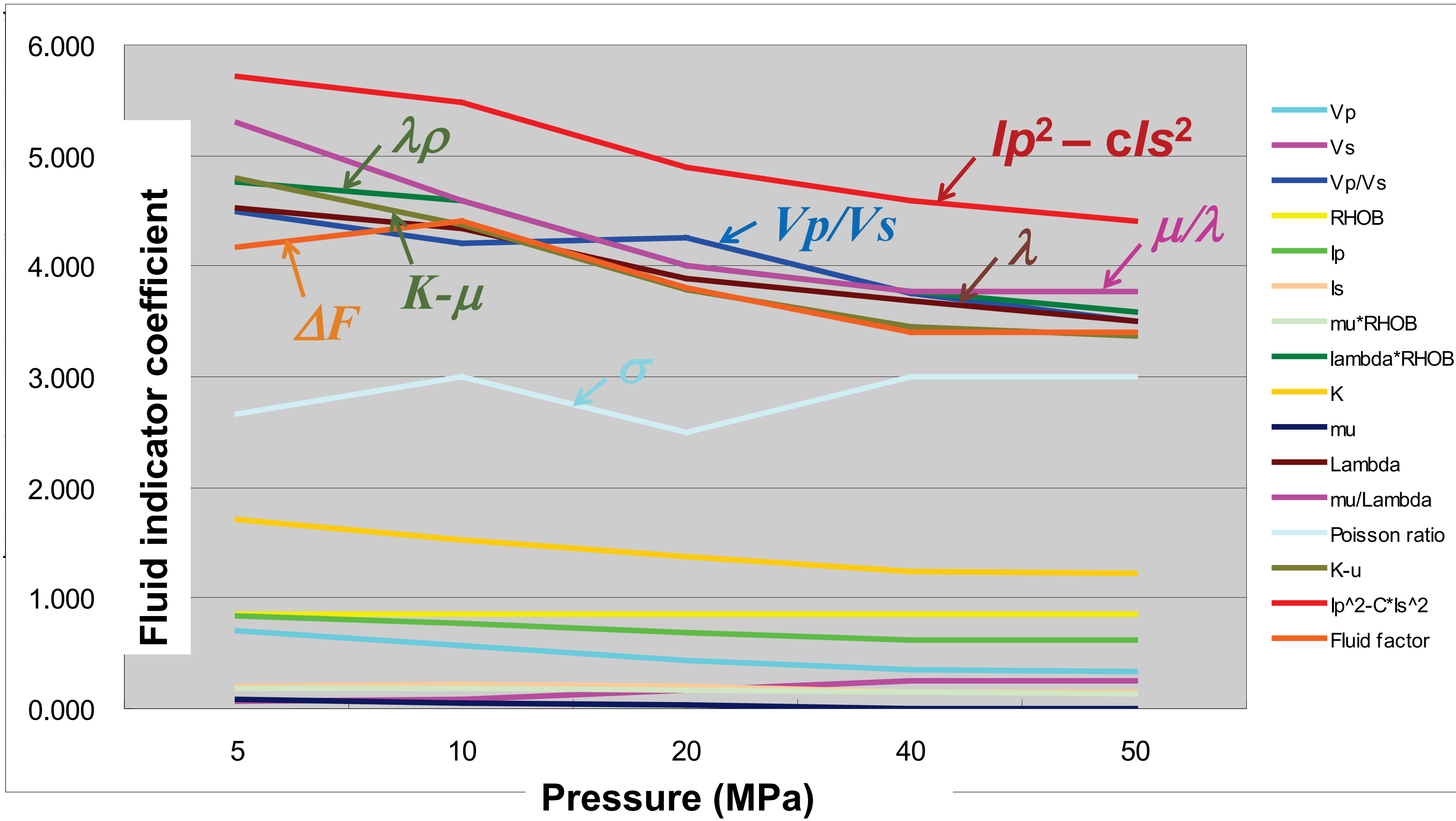
- Hong Feng then analyzed the effectiveness of the following sixteen hydrocarbon indicators, using Dillon et al.'s *fluid indicator coefficient* as his measure of success:
  - V_P, V_S, V_P/V_S, ρ, I_P, I_S
  - $\mu\rho$, $\lambda\rho$, K, μ, λ, μ/λ, σ, $K-\mu$
  - $I_P^2 - cI_S^2$, ΔF
- For the generalized fluid indicator, $I_P^2 - cI_S^2$, he used the computed values of *c* shown in the previous slides.
- The following slides show the results for both shaly sands and clean sands, first for 5 MPa and then over all pressures.

Fluid indicators - shaly sand



Fluid indicators - clean sand

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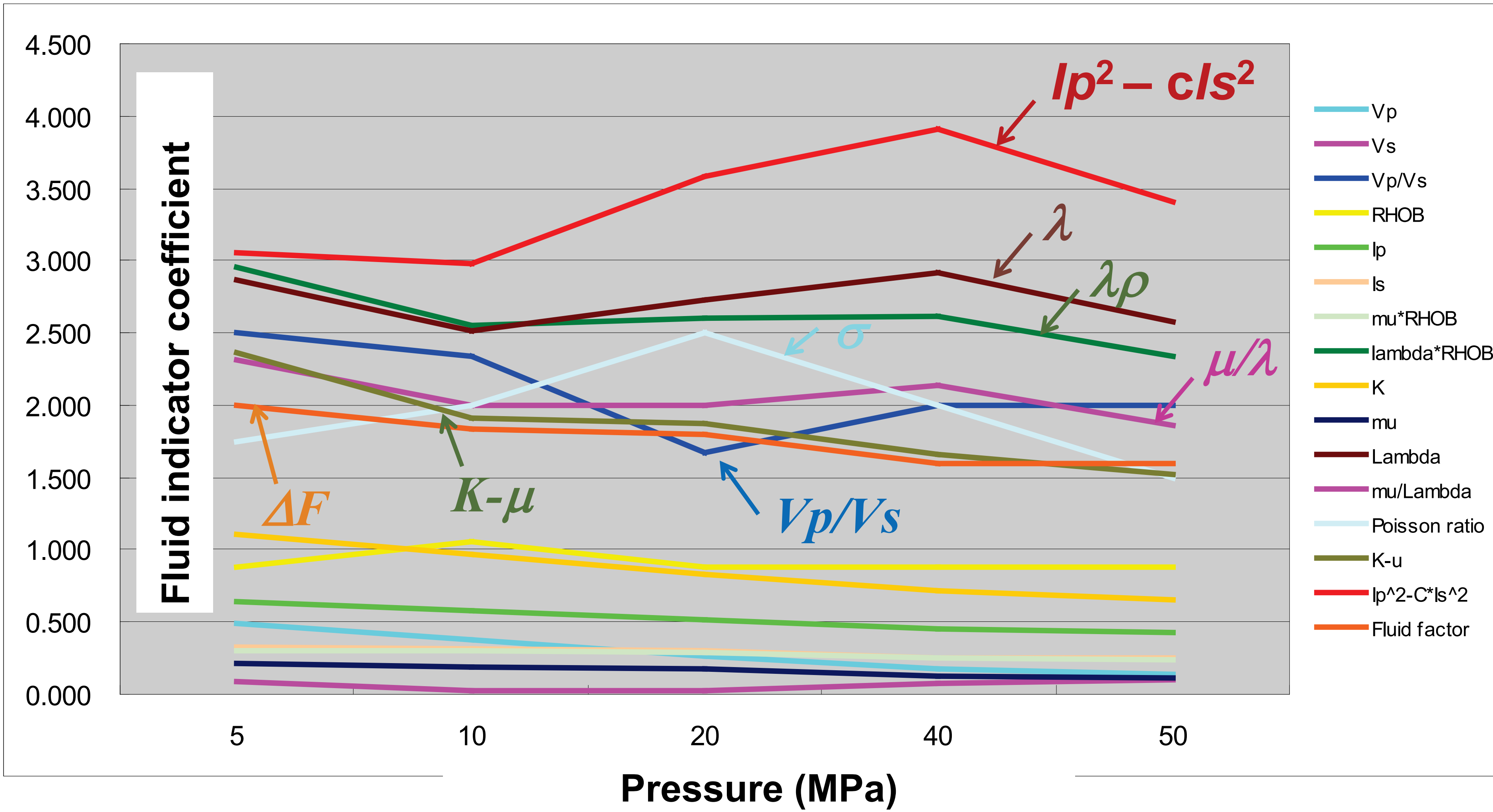
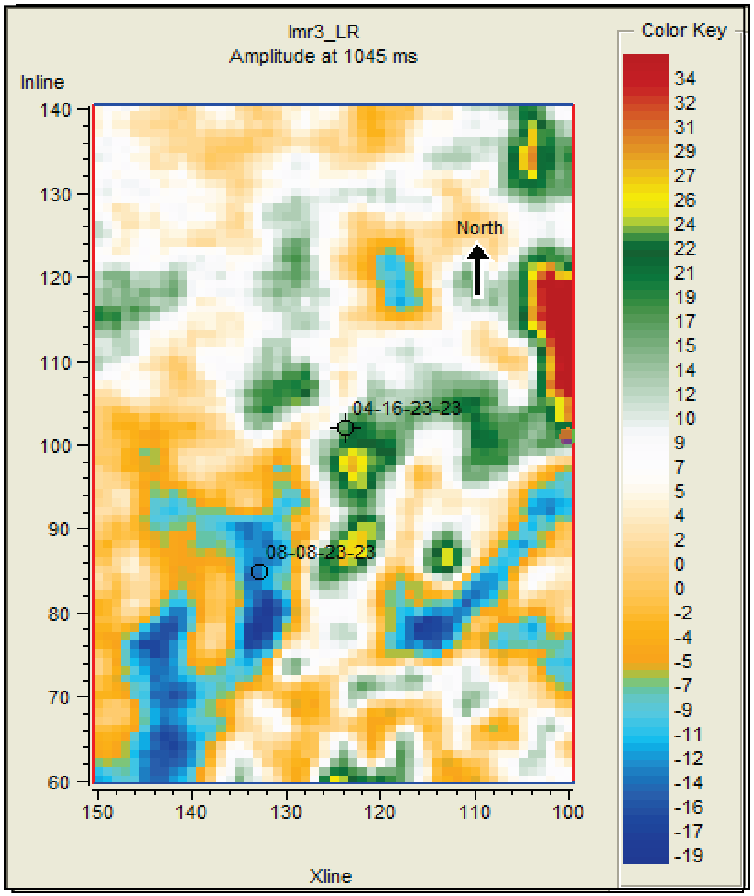


Blackfoot example



$$I_P^2 - 3I_S^2$$

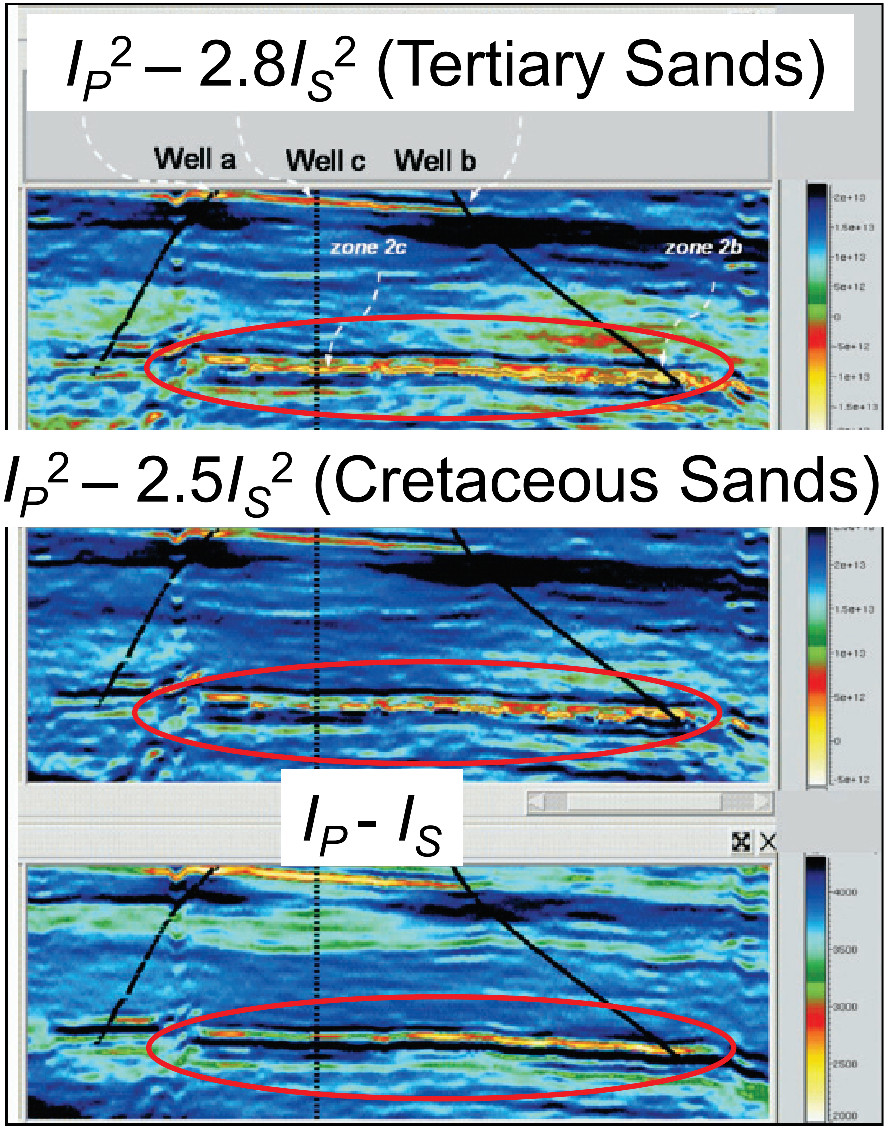
Hong Feng also applied the generalized fluid method to the PP data from the Blackfoot dataset, by inverting to P and S-impedance.

Here is the result of applying three different *c* factors to the impedances to derive the fluid term.

Note that there is little difference between $c = 2.0$ and $c = 2.233$ (which assumes that $K_{dry}/\mu = 0.9$).

We will next look at Dillon's results.

Data example – offshore Brazil



Dillon et al. (2003) make the following conclusions:

- At the seismic scale the $I_P^2 - cI_S^2$ attribute does not perform as predicted at the rock scale, due to the deterioration of the S/N ratio in the squaring operation.
- The $I_P - I_S$ attribute has the advantages of being less noisy and showing similar results.
- This can be seen in the figure from their paper shown here.

Linearized AVO equations

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- Gray et al. (1999) derived two new equations, one for λ, μ and ρ, and one for K, μ and ρ:

$$R^{(1)}(\theta) = c_1^{(1)} \frac{\Delta\lambda}{2\overline{\lambda}} + c_2^{(1)} \frac{\Delta\mu}{2\overline{\mu}} + c_3^{(1)} \frac{\Delta\rho}{2\overline{\rho}}, \; R^{(2)}(\theta) = c_1^{(2)} \frac{\Delta K}{2\overline{K}} + c_2^{(2)} \frac{\Delta\mu}{2\overline{\mu}} + c_3^{(2)} \frac{\Delta\rho}{2\overline{\rho}}$$

$$\text{where}: c_1^{(1)}, c_2^{(1)}, c_3^{(1)}, c_1^{(2)}, c_2^{(2)}, c_3^{(2)} = \text{functions of } \theta \text{ and } \gamma_{sat} = \left(V_P / V_S\right)_{sat}.$$

- Russell, Gray et al. (CREWES, 2006) generalized these two equations using poroelasticity theory:

$$R^{(3)}(\theta) = c_1^{(3)} \frac{\Delta f}{2\overline{f}} + c_2^{(3)} \frac{\Delta\mu}{2\overline{\mu}} + c_3^{(3)} \frac{\Delta\rho}{2\overline{\rho}}, \quad \text{where}:$$

$$c_1^{(3)}, c_2^{(3)}, c_3^{(3)} = \text{functions of } \theta, \gamma_{dry} = \left(V_P / V_S\right)_{dry} \text{ and } \gamma_{sat} = \left(V_P / V_S\right)_{sat}.$$

- It is our feeling that this parameterization may get around the processing issues described by Dillon et al.

Colony sand – Fluid result

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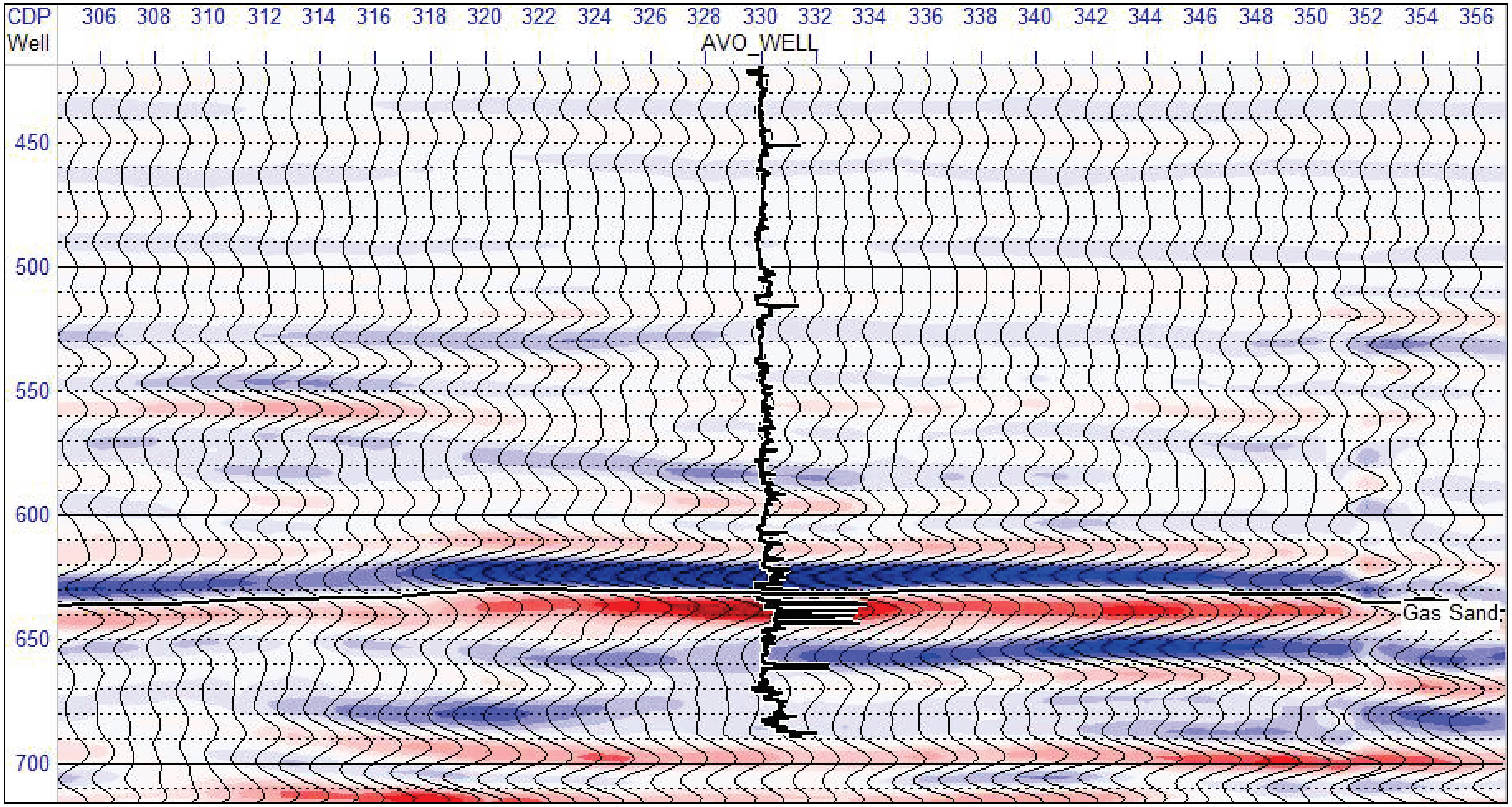

The extracted fluid term ($\Delta f/2f$) for a Colony sand example. We used a dry velocity ratio squared of 2.333.

(From Russell et al., CREWES, 2006)

Conclusions

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- This paper has been an empirical study of various fluid indicators.
- We first looked at the results given by Dillon et al. using offshore examples from Brazil.
- We then extended their results using the core dataset measured by Han et al. (1985), including factors such as porosity, clay content and pressure.
- Our results showed us that the generalized fluid method, with a calibrated dry rock velocity ratio, seemed to give the best results at the rock scale.
- On seismic data, processing issues can lessen the effectiveness of this method.
- We recommend extracting the fluid parameter itself using a modified version of the Aki-Richards equation.

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