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Estimating reserves in thinly-laminated sands with the help of Petrographic Image Analysis

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Abstract: Calculating hydrocarbon reserves in a reservoir sequence where the productive sands range from decimetres to only millimetres in thickness is very difficult using conventional downhole logging and core analysis methods. Petrographic image analysis (PIA) can be used to determine certain petrophysical parameters within these sands leading to more realistic estimations of both total and recoverable reserves.

Preliminary results from PIA analysis of twenty-four (24) samples from the Malay Basin are included to demonstrate how this new technology can improve reserves calculations.

INTRODUCTION

Thinly-laminated sands deposited in a near-shore to transitional environment dominated by storm sequences are abundant in Southeast Asian hydrocarbon reservoirs such as those in the Malay Basin and the Baram delta. The thickness of the interbedded sand/shale and sand/silt laminations range upwards from 2-3 millimetres.

The oil-bearing potential of such sands has often remained unassessed for a series of interrelated reasons:

- The sands remain undetected because of the inability of most downhole logs to resolve them. The log responses are strongly influenced by the shale laminae.
- The sands may have been detected by logs, shows during drilling or coring. However, they often occur in sequence with thicker producing zones and the oil they contain may have been considered residual due to the sharp decrease in log resistivity as the tool passes from the thick sand zones to the thinly-laminated zones.
- The sands may be suspected to contain additional reserves but lack of adequate analytical tools has made assessment difficult.

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Over recent years, there has been a growing interest among many oil companies operating in Southeast Asia to improve reserve calculations for thinly-laminated sands. One reason has been that material balance equations have indicated larger volumes of hydrocarbon reserves than originally calculated in place for a number of well-established producing fields. Possible explanations for these discrepancies have included:

- Inadequate geological and geophysical control over mapping of boundaries.
- Inadequate petrophysical parameters available for log analysis (e.g. "a", "m", "n", Rw).
- Improper shaly sand model to calculate Sw from logs.
- Logs not picking up thinly-laminated sands and/or isolated thin beds.
- Suppression of apparent Rt in thin sands by adjacent shale beds causing overestimation of Sw.

The last two points are relevant in the context of this discussion. A study of a thinly-laminated sand sequence would involve: identifying its existence; mapping out its extent; resolving bed thickness (net pay) and porosity; calculating Sw (So). These points are discussed below, with particular emphasis on the use of PIA.

ESTABLISHING PRESENCE AND AREAL EXTENT OF LAMINATED SANDS

Sedimentological, biostratigraphical and petrographic studies on conventional core material provide a good basis for creating a lithological depodiagenetic model for a thinly laminated sand sequence in a field. Correlation of available relevant data from downhole logs, sidewall cores, drill cuttings, production tests, pressure and seismic surveys would then allow mapping of the vertical and areal extent of the sands.

It is often possible to establish core correlated log signatures to facilitate mapping of thinly-laminated sands in uncored wells. However, care must be taken to distinguish thinly-laminated sequences and bioturbated sand/shale sequences which can appear very similar on logs. Although both types can be hydrocarbon-bearing, the former are potentially productive whereas the latter are commonly non-productive.

ESTABLISHING NET SAND IN A THINLY-LAMINATED SEQUENCE

New generation logging tools, such as high sampling-rate devices, have the ability to distinguish beds only a few centimetres thick. If a log/core correlation study has shown that the beds are too thin to be accurately distinguished by the logs, however, then corrective algorithms based on core studies might need to be generated to resolve net sand thickness.

ESTABLISHING Sw IN THINLY-LAMINATED SANDS

Conventional electric log interpretation in thinly-laminated sands is difficult due to apparent Rt suppression by adjacent conductive shale laminae.

A capillary pressure correlation derived from core based measurements has often been used for reserves calculations when electric log information has been difficult to obtain or difficult to interpret.

Traditionally, dry or brine-saturated core plugs representing the porosity and permeability ranges of the lithotypes in a producing formation are injected or desaturated by a non-wetting phase at incrementally increasing pressures to generate a series of capillary pressure curves (Fig 1). Capillary pressures are converted to height above the free water level in the reservoir and Sw (and therefore So) derived from a correlation such as that shown in Figure 2.

The core samples used to generate such a correlation should ideally be homogeneous. However, in many reservoirs, such as those in the Malay Basin, the sands may be too thinly-laminated for a homogeneous plug to be taken. Plugs comprising two or more laminations yield only average porosity, permeability and capillary pressure data which may be considered inadequate for proper reservoir characterisation. For such heterogeneous samples, PIA can provide relatively accurate laminae-specific petrophysical indices such as permeability, porosity, capillary pressure and formation factor. In addition to conventional cores, drill cuttings and sidewall cores representing thinly laminated sands can also be analysed by PIA techniques (Kinchu, 1987; Norman, 1987).

DISCUSSION OF PIA PROCEDURES AND RESULTS

A high quality thin section is made of the sample under investigation. Images recorded by a black and white video camera attached to the thin section microscope are digitised and processed to create binary image of the thin section. This image depicts rock matrix in white and pore space in black (Fig 3).

From the binary image, a number of first order parameters are measured on the pores (area, length, width, perimeter). Second order parameters are then calculated (eg. aspect ratio, length/width). First and second order parameters can then be used to calculate third order parameters such as pore-size distribution.

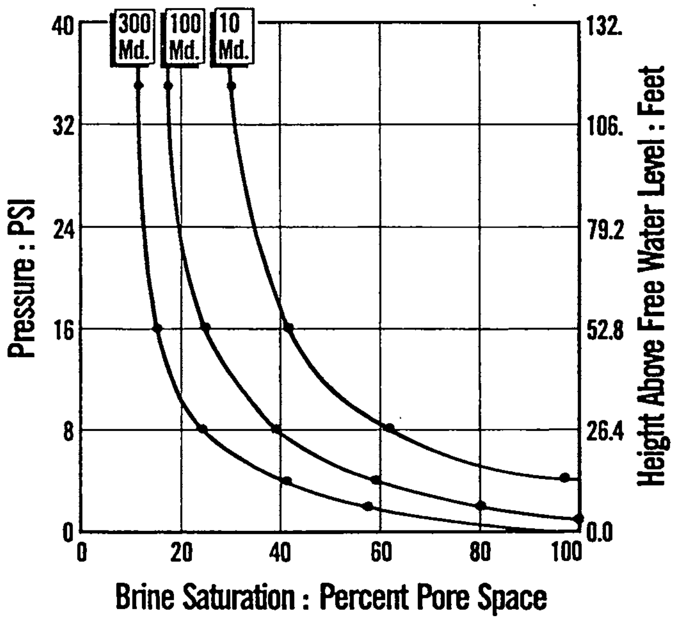

Figure 1: Connate Water Saturation vs Capillary Pressure and Height

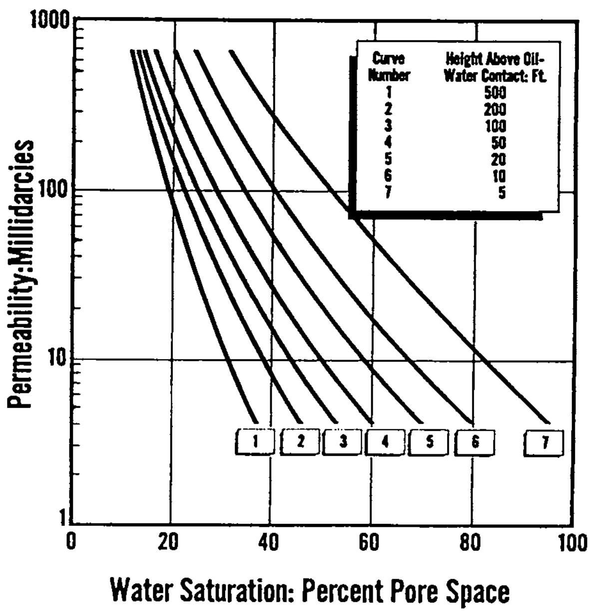

Figure 2: Correlation of Connate Water Saturation vs Permeability and Height

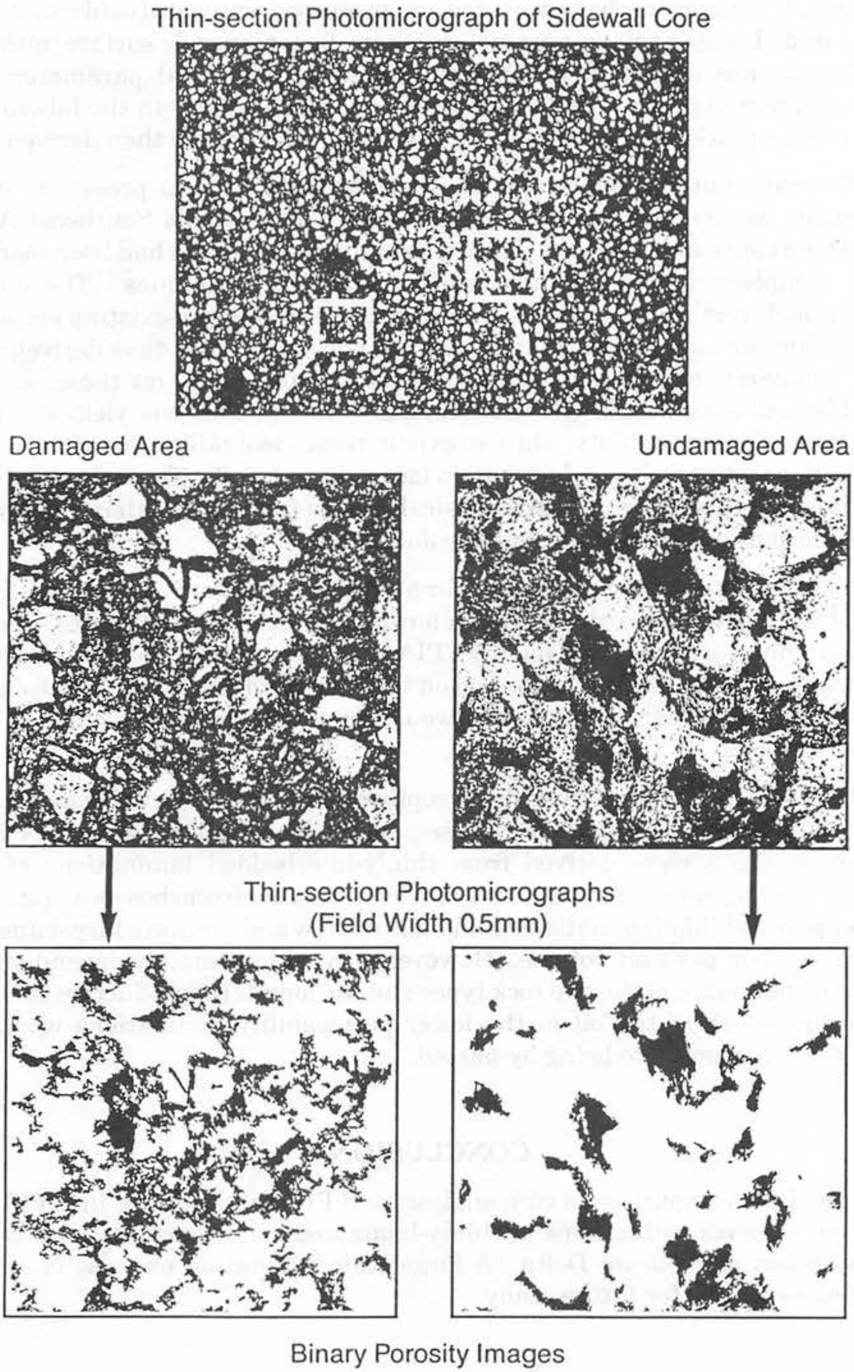

Figure 3: Binary porosity images derived from a sidewall core. Petrophysical indices would be determined on the undamaged areas by PIA.

Once the image has been acquired and processed, empirical calibrations are generated. Image analysis parameters (shape factor, specific surface, microporosity, etc) are identified which correlate to petrophysical parameters (for example, porosity) measured on homogeneous core samples in the laboratory. Empirical equations relating the two sets of parameters are then derived.

Several calibration sets currently exist (Garrison *et al.*, in press). As an experiment, twenty-four conventional core plugs from friable Southeast Asian sandstone cores were selected. Petrophysical measurements had been made on these samples which were then examined by PIA techniques. The images determined from the thin sections were processed using pre-existing empirical calibrations and a new fractal analysis. The petrophysical indices derived were then compared to the conventional measurements made on these, as yet, uncalibrated sandstones. It was found that fractal analysis yielded a good correlation for permeability, while an existing empirical calibration yielded good correlations for porosity and formation factor (Figs 4, 5, 6). These data indicate that it is possible to deduce petrophysical indices from rock material of uncalibrated formations using the available data base.

Insufficient data were available for a capillary pressure correlation. However, Fig 7 shows an example from a formation in the United States where a capillary pressure curve derived from PIA shows excellent correlation with one derived from core analysis performed on the same sample. A set of such curves derived from thin sand laminations would allow a correlation similar to that shown in Fig 2.

The fact that laminae-specific petrophysical parameters can be derived by PIA is particularly useful in sand/silt sequences. The capillary pressure curves shown in Fig 8 were derived from thinly-interbedded laminations of two distinctly different rock types, both of which were hydrocarbon-bearing. The higher permeability laminations would control flow and contain a larger amount of hydrocarbon per unit volume. However, it would ultimately depend on the relative abundance of the two rock types and the long-term production strategy as to how much of the oil in the lower permeability laminations would be recovered as opposed to being by-passed.

CONCLUSION

Results of the comparison of core analysis and PIA data indicate that PIA can improve reserves estimations in thinly-laminated sands such as those in the Malay Basin and Baram Delta. A large scale calibration exercise is recommended as a basis for future study.

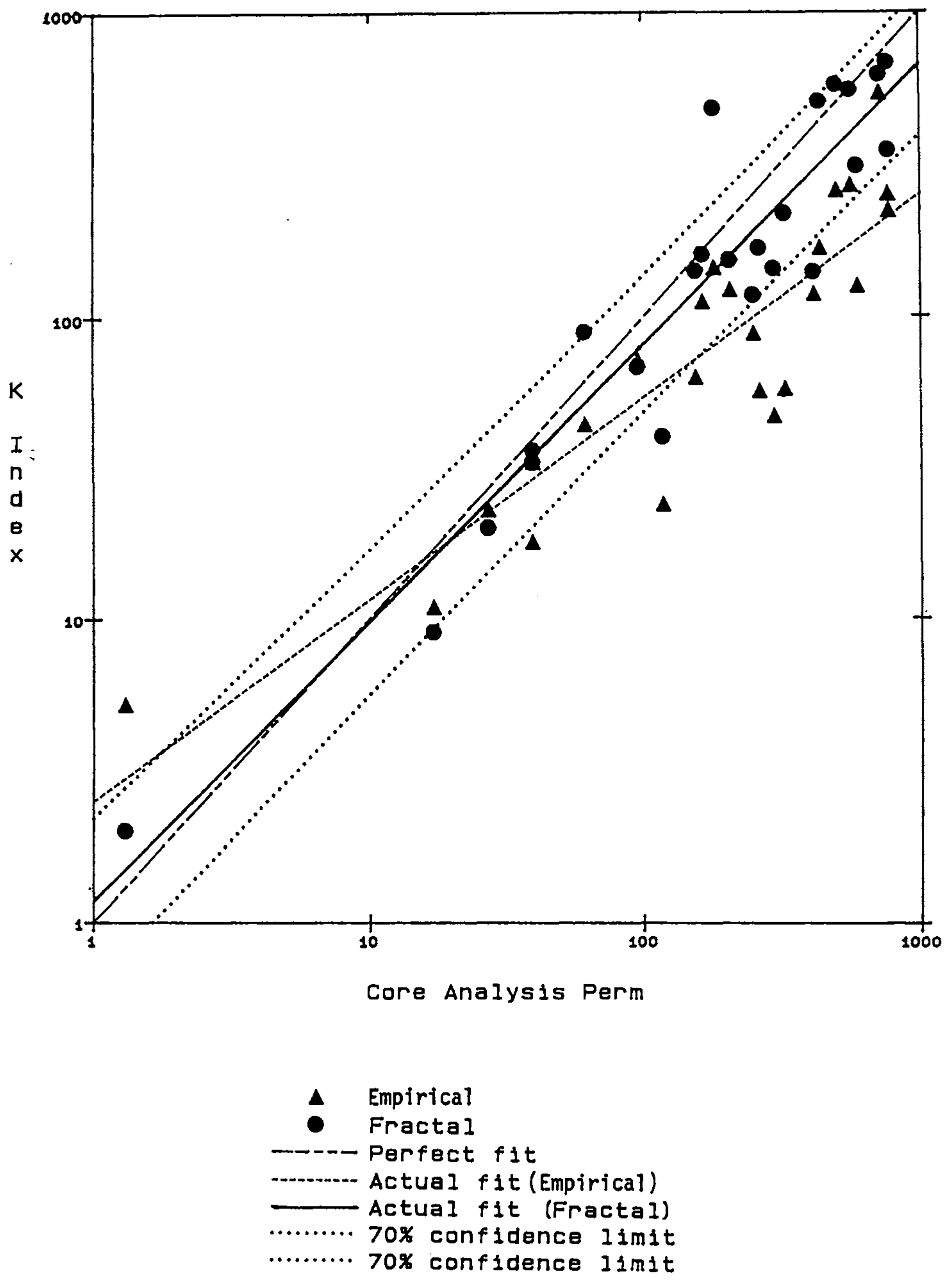

Figure 4: Comparison of permeability index from PIA and core analysis permeability.

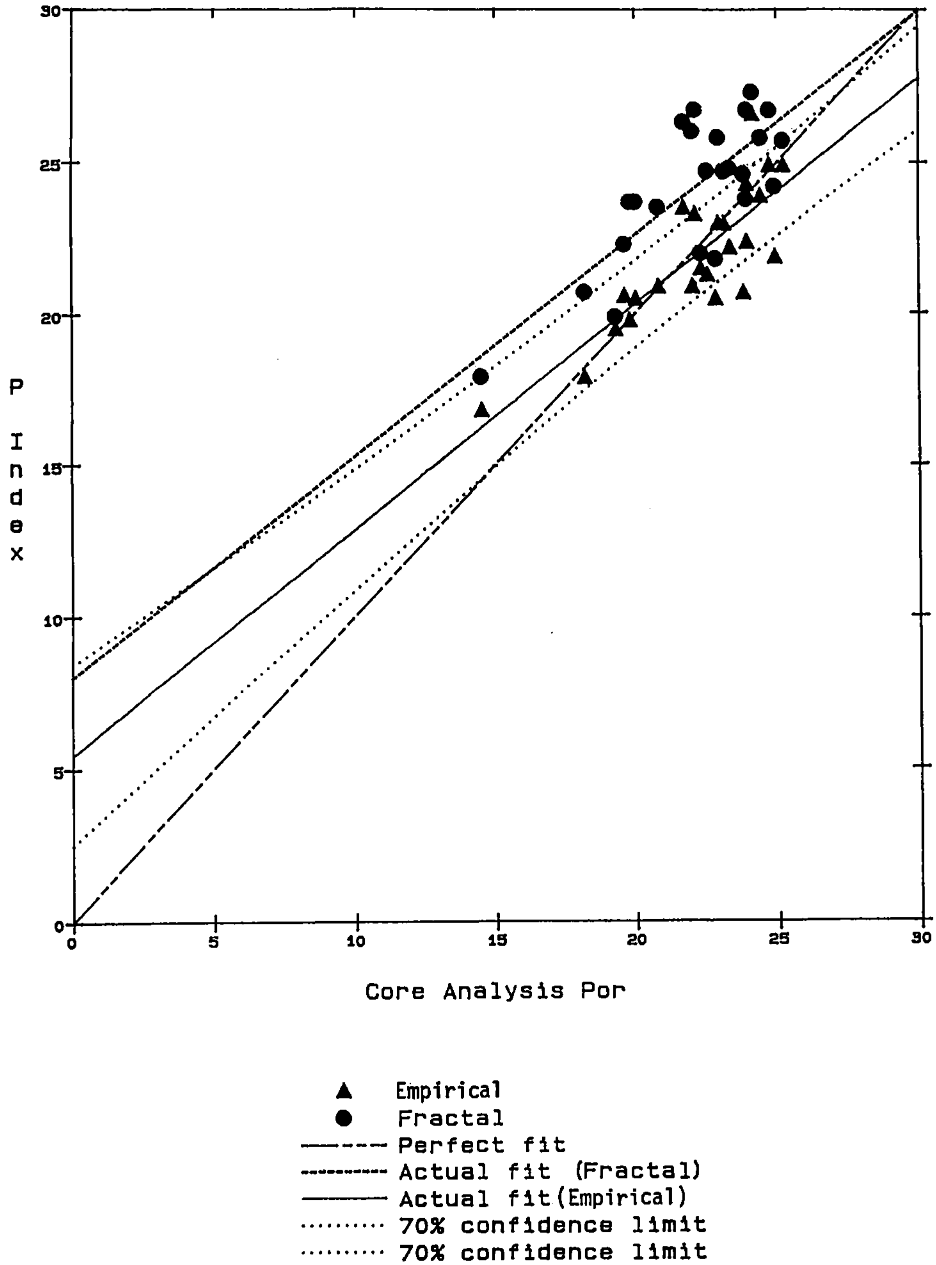

Figure 5: Comparison of porosity index from PIA and core analysis porosity.

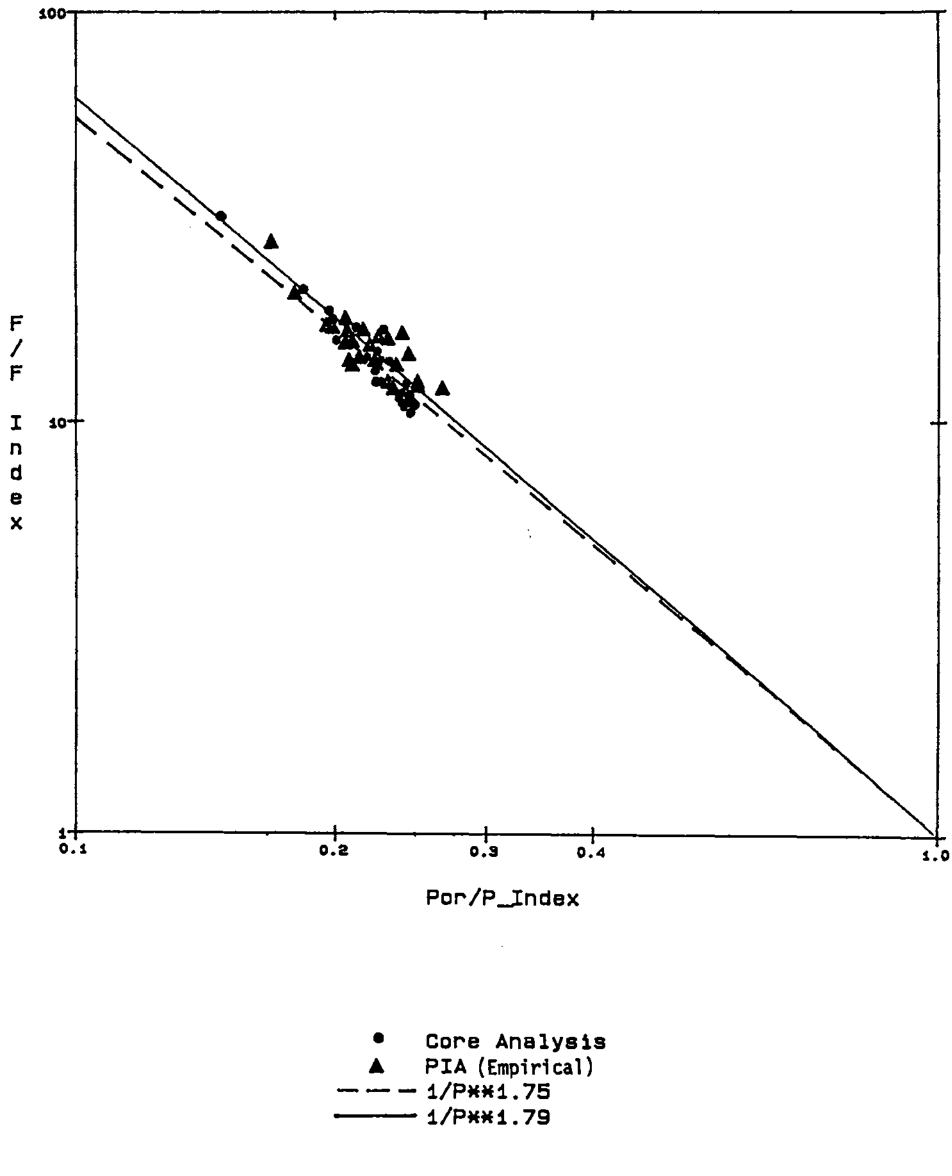

Figure 6: Comparison of formation factor index from PIA and core analysis formation factor.

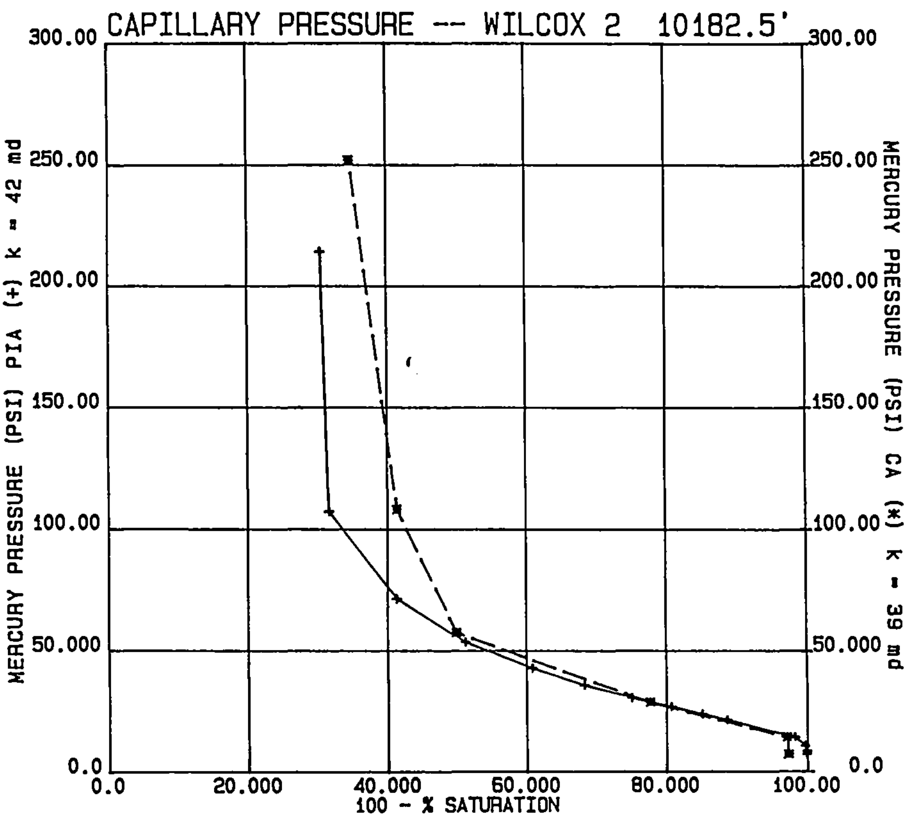

Figure 7: Comparison of capillary pressure index from PIA and core analysis capillary pressure.

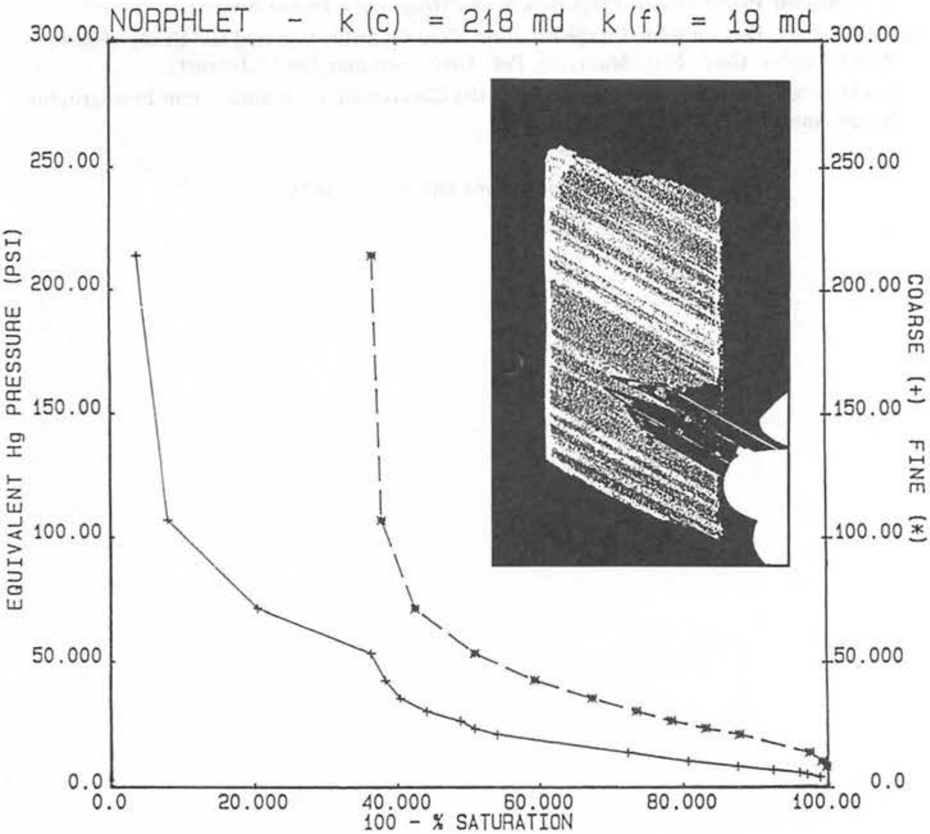

Figure 8: Laminae specific capillary pressure indices from PIA.

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