INTEGRATION OF STATE-OF-THE-ART WIRELINE RESERVOIR DELINEATION DEVICES WITH CORE DATA FROM AN OFFSET WELL TO OPTIMISE RESERVOIR MANAGEMENT: MAUI FIELD, NEW ZEALAND

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Abstract

State-of-the-art wireline measurements were obtained in the first development well, MB-(Z)11, which was drilled in the western culmination (B Area) of the Maui Field. Formation Micro Scanner (FMS™) images were interpreted with reference to core from the nearby appraisal well, M-07. These data, along with a full suite of standard open-hole wireline logs, were used to describe the reservoir layering. Formation pressures were measured using the Modular Formation Dynamics Tester Tool (MDT™) and show varying degrees of depletion from initial conditions, as a consequence of production from the eastern culmination (A Area) of the Maui Field.

By combining these data, it has been possible to define the effective layering of the reservoirs that will control drainage of the western (B) area of the field. This has enabled an optimum reservoir development and management strategy to be formulated prior to completion of the development drilling campaign. Additionally, FMS images have established the orientation of the principal horizontal stress within the field, to assist with subsequent deviated well drilling.

Introduction

The Maui Field is a giant gas-condensate field that lies some 40 km off the west coast of the North Island, New Zealand (figure 1). The field comprises two structural culminations, termed the A and B areas (figure 1). The field was discovered in 1969 by well Maui-1 (M-01) drilled in the westernmost culmination. Logging difficulties prevented the collection of a full suite of wireline logs, but the well nevertheless established two gas condensate accumulations underlain by thin oil rims (figure 2). Subsequent appraisal and development drilling was carried out in the A area until, in 1986, two appraisal wells, M-05 and M-07, were drilled in the B area (Zaborski et al, 1991).

After seven years of A area production, formation pressures, measured with an RFT tool in the 1986 appraisal wells, established that both the upper (C Sand) and lower (D Sand) reservoirs are compartmentalised by thin shales and carbonate cemented horizons. It was observed that uneven pressure depletion of the B area was occurring as the consequence of A area hydrocarbon withdrawal.

In 1992, eight development wells were drilled in the Maui B area. In addition to a full suite of standard open-hole wireline logs, Formation MicroScanner (FMS™) and Modular Dynamic Formation Tester (MDT™) tools were run in the first development well, MB-(Z)11. The objective of running these tools in this first (vertical) development well were to:

i) obtain new information concerning pressure depletion and fluid movement in the B area since information was last obtained in the 1986 appraisal wells
ii) obtain geological information to optimise the location and drilling of the remaining (deviated) development wells
iii) collect information to constrain construction and history matching of a new reservoir simulation model.

Tools and Processing

Formation MicroScanner Tool

The Formation MicroScanner (FMS) tool is a new generation dipmeter tool that provides all the traditional dipmeter information, but also includes an "array" of sensors on each of its four arms (figure 3). These are used to produce images of the formation that are derived from microresistivity buttons on four orthogonal pads. The data are sampled every tenth (1/10) of an inch and are used to produce vertical and horizontal resolution images of very high resolution.

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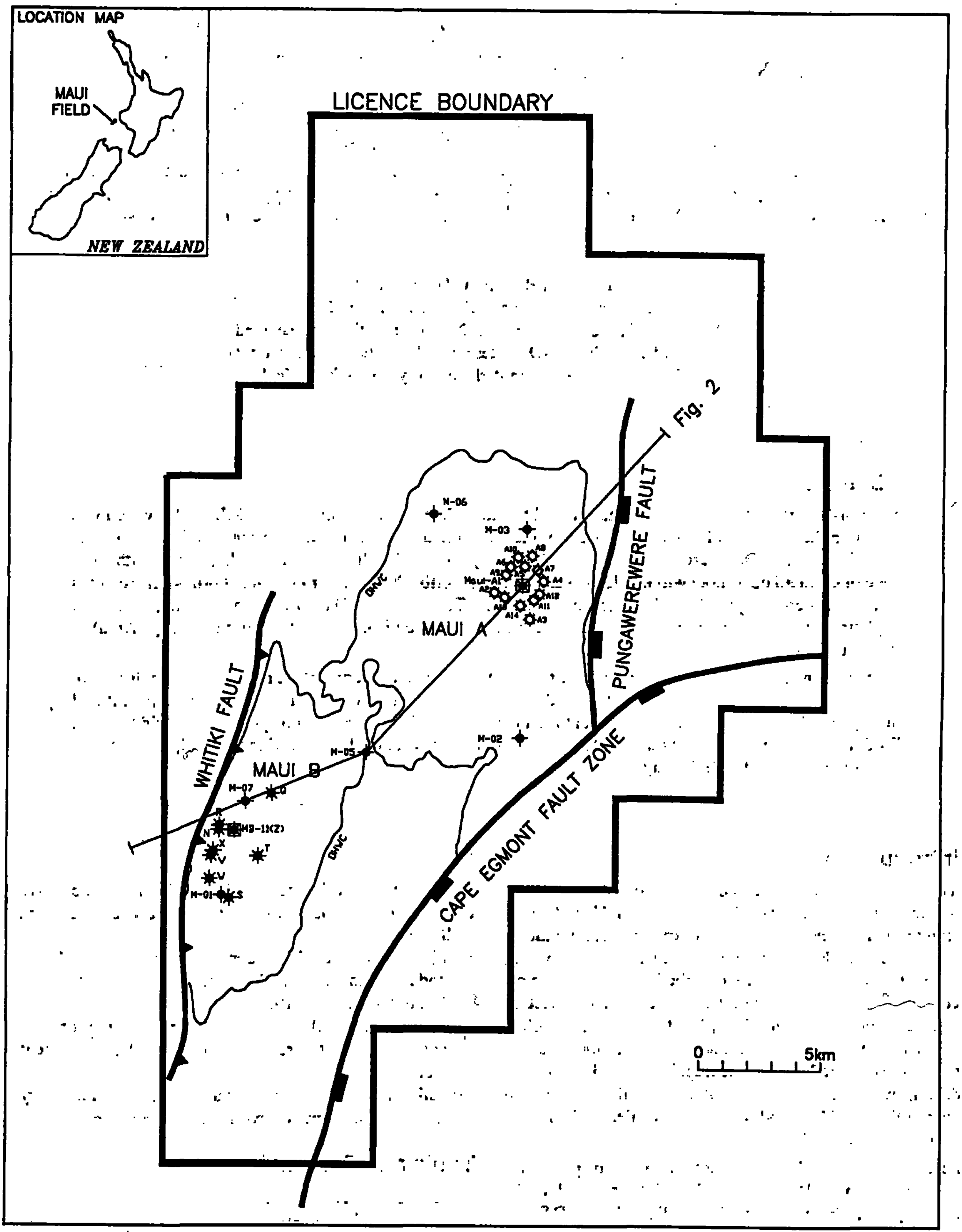

Fig. 1. Location map of the Maui Field showing the extent of the Cl Sands hydrocarbon accumulation at top reservoir and the location of the wells discussed in the text. The line shows the orientation of the cross-section illustrated in figure 2. Platform locations are indicated by squares. Appraisal wells are labelled with the prefix "M"; A Area development wells are prefixed "A" and B Area development wells are designated by other letters.

The processing and presentation of this amount of information requires special techniques that bear some discussion. Firstly, the images themselves are precisely oriented in three-dimensional space using solid state accelerators and

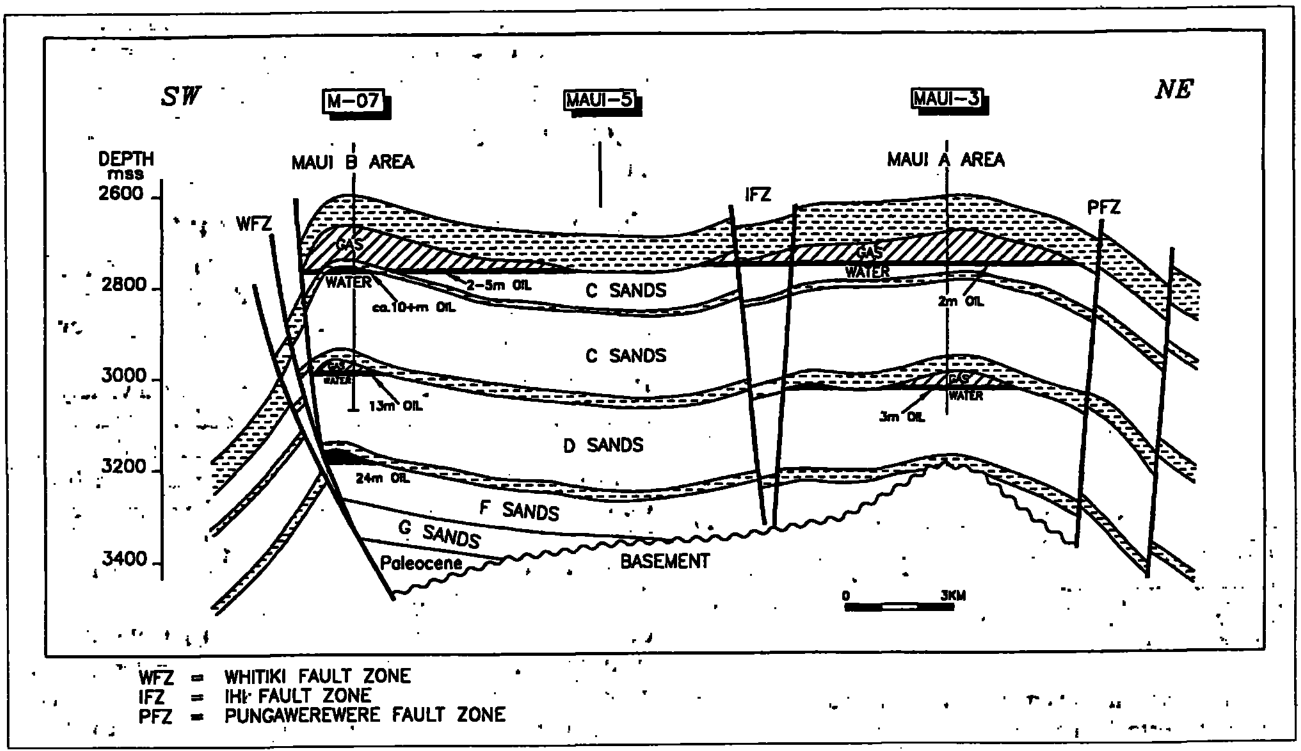

Fig. 2.. Schematic cross-section through the Maui Field to show the two structural culminations — the Maui A and B areas and illustrate the scaling of the C, D, and F Sands hydrocarbon columns by laterally continuous marine shales.

magnetometers as well as two pairs of orthogonal calipers. The data is recorded on magnetic tape along with the calipers, and with a gamma ray and any other conventional wireline logs desired.

While good quality images can be generated in the field with the new computerised units, the best quality images are generated at the regional computer centres. These images are fully analysed on workstations equipped with special software generated especially for that purpose. The examples shown later in this paper were generated with Frac View software on a Sun Sparc 2 computer.

The usual way to present three dimensional information is in a "log" format with depth on the vertical axis and an azimuthally oriented grid on the other. This "orientation" grid starts at true North (azimuth of zero) and displays the four images of the orthogonal pads properly positioned on the grid. Planar features, such as bedding planes, fractures and faults etc, appear as sinusoids on this presentation. The bottom of the sinusoid is the downdip direction (i.e. where the feature exits the borehole) and the higher the dip magnitude of the feature, the greater the amplitude of the sinusoid.

Fig. 3. Photograph of the Formation MicroScanner (FMS) tool to show the four pads that are pressed against the borehole wall. Each pad is equipped with 16 closely shaped buttons that measure the resistivity of the formation.

Various vertical and horizontal scales are available, but typically a scale of one to five (1:5) for both scales is used for detailed analysis. The range of magnitude of the microresistivity recorded in each data print is represented on the log with various colour schemes. The most common scheme normalises the data and uses darker colours for lower resistivities. The colour coding for the examples in this paper is from black to brown, orange, yellow, beige and finally to white as the "relative" resistivity increases. If the flushed zone resistivity of the sand is higher than the resistivity of the shales and lower than that of the cemented zones, the result is black and brown for shales, orange and yellow for sands and beige and white for tightly cemented zones.

Dynamic normalisation (which rescales the data every meter) is often used to emphasise the details. This greater detail usually obscures lithology. Therefore, both static and dynamic images are normally presented.

Being able to "see" the many features in the borehole greatly enhances the following applications, which were all put to use in MB-(Z)11 as described later:

1. Structural — structural dips, faults and unconformities
2. Reservoir description — thin beds, permeability barriers and trends, borehole stress analysis and sedimentary features (e.g. crossbedding)
3. Stratigraphic — determining depositional environments and sand body geometry and orientation.

Modular Dynamics Tester tool

The Modular Dynamics Tester (MDT) tool (figure 4) is a completely redesigned formation tester tool that has specially designed modules for fluid/PVT sampling and measurement of horizontal and vertical permeabilities. The basic MDT

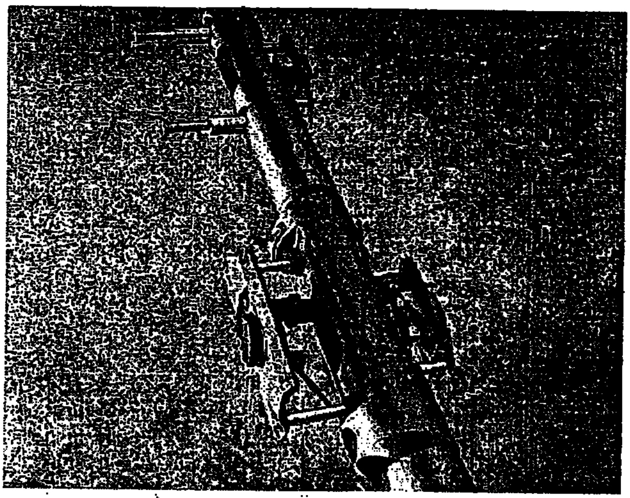

Fig. 4. Photograph of the Modular Dynamics Tester (MDT) tool. The upper assembly is the standard probe that was used to make the measurements in MB-11 (Z). (The lower assembly is a dual probe module that may be used to make more complex measurements.)

tool has several improvements over previous generation formation tester tools. These include a significantly improved pressure gauge, enhanced surface control of fluid flow (sampling pressure and pretest flow rate and volume) and surface readout of downhole resistivity of fluids passing across the probe.

The primary objectives for running the MDT tool in MB-(Z)11 were reservoir pressure characterization and to obtain downhole fluid samples. The high resolution CQG™ gauge proved to be very accurate with a much faster stabilisation rate than either the HP or strain gauges commonly run with the older type tools. In MB-(Z)11, a 60% time saving was realised over comparable runs in the appraisal wells using the older generation formation tester tools. Besides providing a considerable savings in rig time costs, the rapid gauge stabilisation time reduces operational risk by minimising the time the tool is stationary and at the greatest risk of becoming differentially stuck. The results of the detailed pressure profiles obtained with the MDT tool are discussed on page 112.

Formation MicroScanner Results

The data obtained from the FMS have provided useful information concerning stratigraphic details and borehole geometry. These aspects are discussed separately below.

Stratigraphic information

D Sands The D Sand reservoir comprises a variety of lower coastal plain sand bodies interbedded with shales and siltstones. Core interpretation and seismic data indicate that many of these sand bodies were deposited as channel-fill. Cores from M-07 indicate that the infill of such channels is frequently complex, comprising an early fill of flood-tidal dominated crossbeds overlain by ebb-tidal and/or fluvial deposited crossbeds (figure 5).

Careful processing of the Stratigraphic High Resolution (SHDT) Dipmeters, whereby processing parameters are set using core-derived information of cross-set thickness (cf. Hocker et al, 1990), has been used to establish the orientation of the crossbeds in M-07 (figure 5). Note, however, that the thin crossbeds in the upper part of the channel-fill are not resolved to give a clear dip orientation.

A channel-fill was encountered at a similar stratigraphic level in MB-(Z)11. In the absence of core in this well, any complex dip patterns calculated from standard dipmeter data would have been regarded as ambiguous. By contrast, the FMS images clearly indicate that the crossbedded sands show significant vertical changes in crossbed orientation (figure 6). Consequently, the dips calculated from the images are interpreted as representing infill of a channel oriented north–south by south-southeasterly oriented flood-

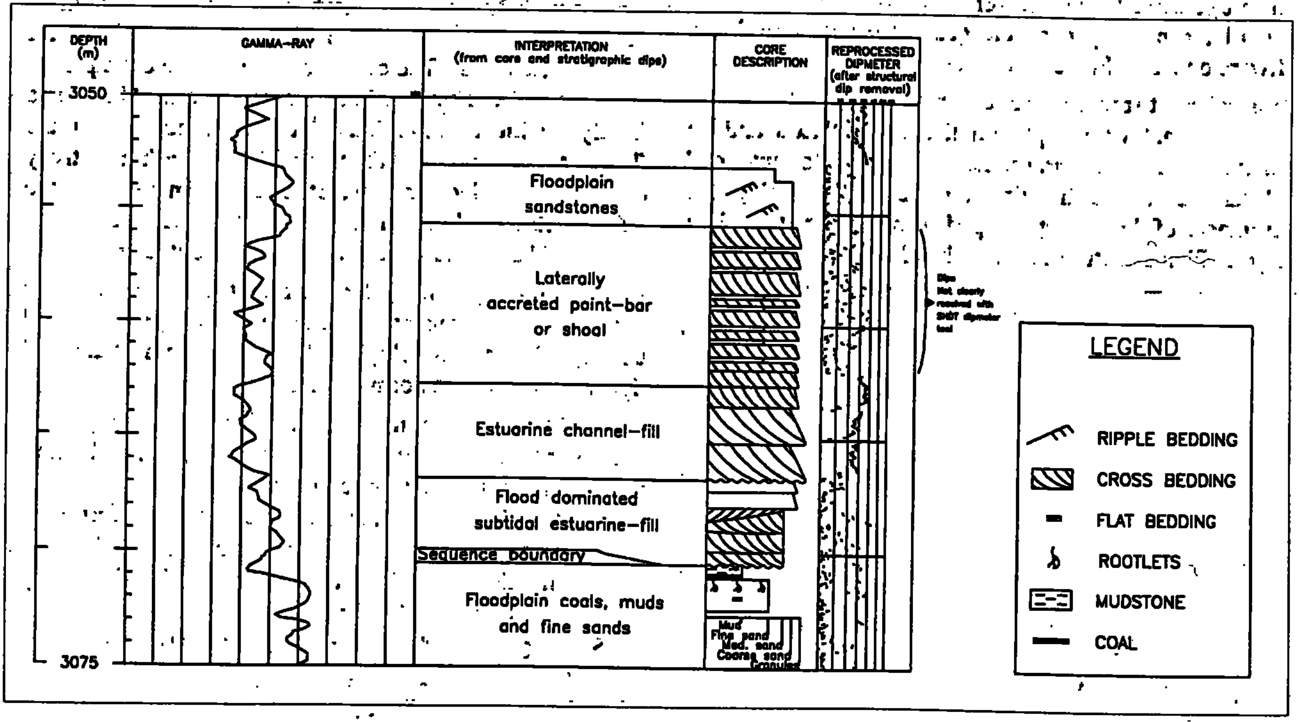

Fig. 5. Core description of the D Sands interval of M-07. Stratigraphic dips, calculated by careful processing of SHDT dipmeter data, are shown, after correction for structural dip, as tadpoles whose "tails" indicate crossbed azimuth. Confident interpretation of easterly directed crossbeds is only possible for the thicker bed sets. In absence of core very little confidence would be assigned to the scattered dips that are characteristic of the more thinly bedded intervals.

tidal currents overlain by northerly diverted ebb-tide and/or fluvial currents (figure 6). Consistent southerly oriented stratigraphic dips obtained within the upper D Sands (figure 7) supports the interpretation from core and 3D seismic that this unit comprises flood tidal estuarine infill sediments.

C Sands Understanding the vertical and lateral distribution of the various facies within the C Sands is critical to understanding the flow behaviour of the reservoir. The gas-bearing interval of the C Sands is subdivided into upper C1 and lower C1 intervals by a correlatable shale unit (figure 8). The lowermost part of the lower C1 Sands comprises prograding channel sands that erosively overlie lagoonal sediments. The remainder of the C1 Sands comprises coastal sands, inner shelf shales and conglomerates that were deposited as the shoreline shifted back and forth across the field area in response to minor changes in relative sea level (figure 8). The shales and conglomerates (which are frequently tightly cemented) form locally extensive barriers to vertical communication whilst reservoir quality varies within the sands. Channel-fill sands are crossbedded and show high reservoir quality; low-angle to horizontally laminated shoreface sands show moderate reservoir quality whilst bioturbated fine sands show low reservoir quality (figure 8). Stratigraphic dips and image textures on processed FMS logs from MB-(Z)11 provide similar information on the vertical distribution of these lithofacies to the cores from M-07 (figure 9).

Borehole geometry

MB-(Z)11 provides information on the ellipticity of the borehole, both from four arm calipers and the images themselves (figure 10). The images indicate breakouts on the north–south pads (slight blurring of the image) and vertical, open fractures on the orthogonal pads. These data indicate that the present minimum horizontal compressive stress is oriented north–south in the Maui field.

Modular Dynamics Tester Results

Comparison of the MB-(Z)11 MDT measured pressure gradients obtained in 1992 with pressures in M-07 obtained by RFT in 1986 indicate further pressure depletion as the result of continuing A area offtake. However, the observed pressure depletion is not uniform but shows slight offsets in the gradient over different stratigraphic intervals (figure 11). These offsets indicate how thin shales and carbonate-cemented zones have acted to reduce vertical communication within the C Sands reservoir interval. The most significant pressure discontinuity occurs across a thin shale that occurs at the base of the upper C1 interval. This shale is correlatable across the entire B area and is interpreted to represent a drowning of the entire area of the Maui field due to a relative sea-level rise. Less significant flooding surfaces are interpreted to give rise to the smaller pressure steps.

Application of the Results

Reservoir management

The indication of the sealing capacity of the shale at the base of the upper C1 interval (MDT pressure step) confirmed that the remaining development wells needed to be positioned to

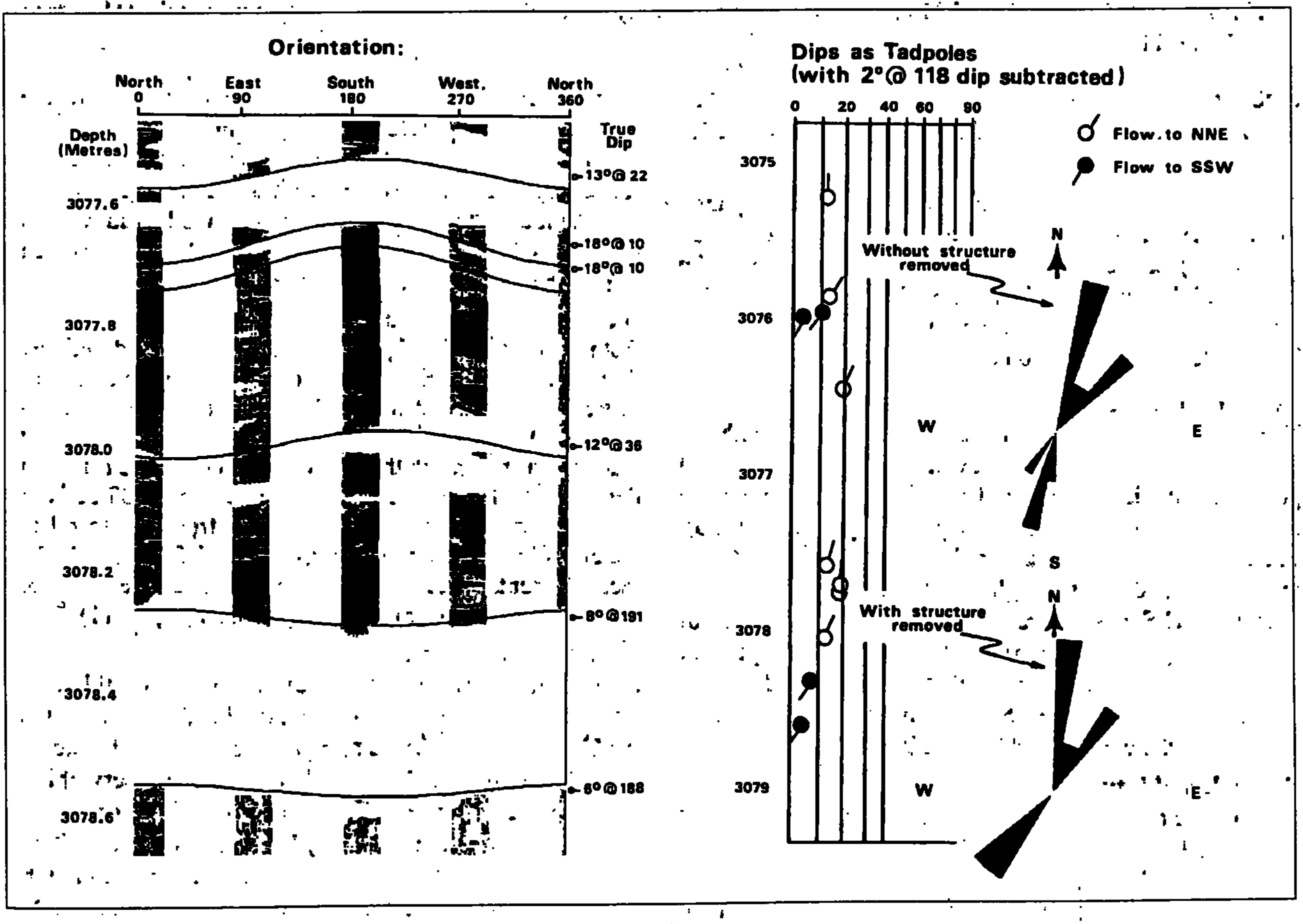

Fig. 6. Dynamically normalised FMS images from the D Sand interval of MB-(Z)11. The images allow confident interpretation of dips even in thinly bedded intervals. Southerly directed crossbeds in the lowest part of the interval are interpreted to be flood-tidally deposited. Northerly oriented crossbeds in the upper part of the interval are interpreted to be deposited by ebb-tidal and/or fluvial currents.

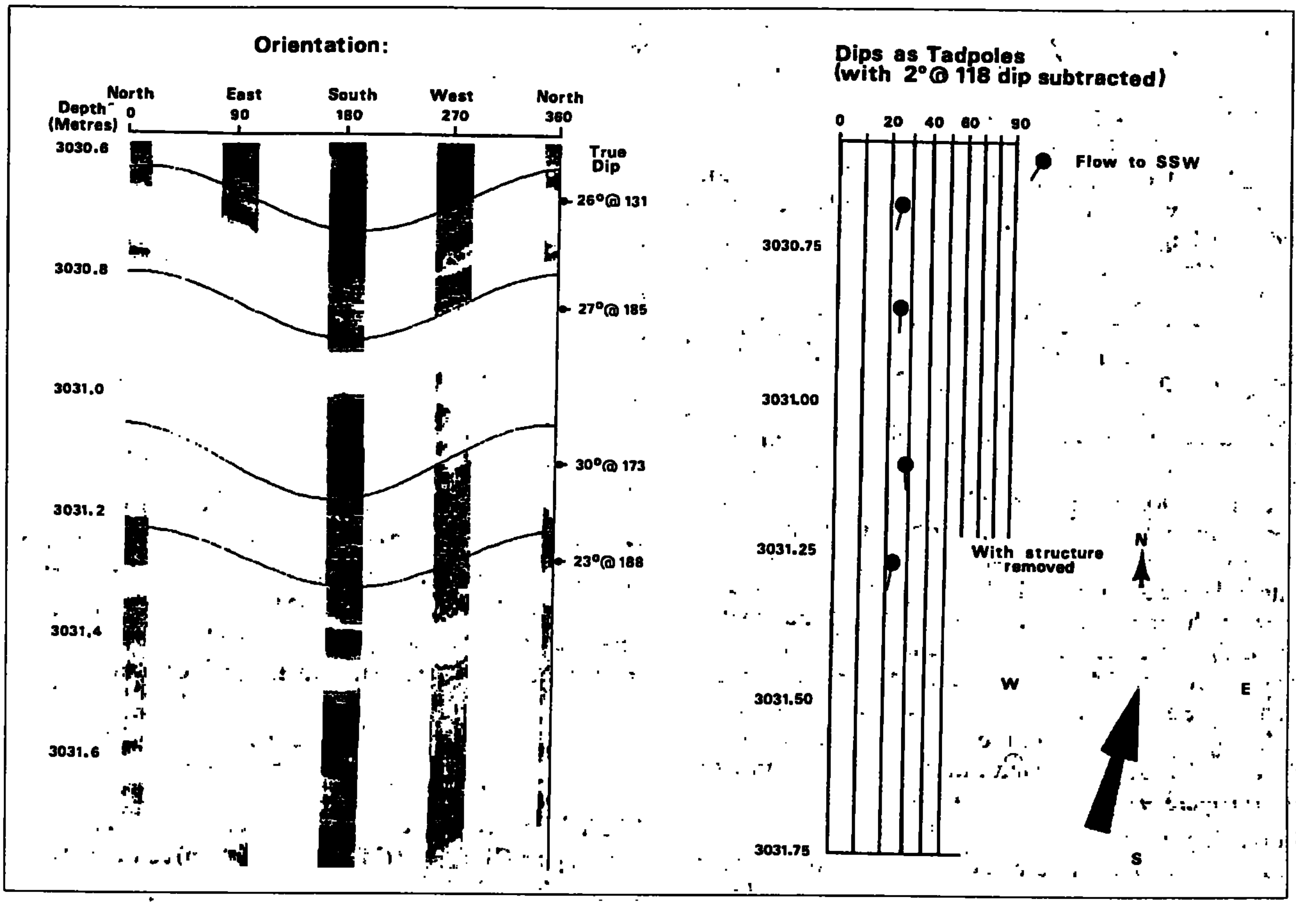

Fig. 7. Dynamically normalised FMS images that show southerly directed crossbeds from the upper part of the D Sands in well MB-(Z)11.

enable crestal drainage of both the lower and upper C1 intervals since "attic gas" would otherwise remain trapped at the crest of the structure.

The identification of a thin carbonate-cemented horizon associated with the minor pressure step within the thin oil leg (figure 11) suggests that the upper oil zone might be perforated. Dry oil could be produced here, being afforded protection from bottom water coning by this cemented unit. This contention remains to be tested.

Reservoir architecture

The well and seismic data have been combined, within a sequence stratigraphic framework, to construct a 3D geological model of the field that is consistent with the dynamic performance of the reservoir (Bryant et al, 1993). The recognition of the pressure breaks associated with the thin shales and tight conglomerates (flooding surfaces) within the C Sands has re-emphasised the importance of fine-scale log correlation in order to provide a description of the effective vertical layering of the field to guide future reservoir management. FMS images have extended the core database of the vertical and lateral distribution of facies.

Borehole stability

The Turi Formation, an under-compacted shale that immediately overlies the C Sand reservoir, can cause significant drilling problems if not properly controlled. Although increasing the mud weight helps stabilise the Turi, higher mud weights cause problems such as lost circulation and formation damage once the partially pressure depleted C Sands reservoir is penetrated. Therefore, the choice of an optimum mud weight is critical. The principal horizontal stress information derived from the FMS, together with mud weight versus borehole condition from existing deviated Maui wells, was used to create an empirical model that related optimum mud weight with deviated well azimuth. This model, although simplistic, provided mud weight guidelines that were used to reduce the mud weight as much as possible for subsequent deviated wells.

Identification of oil from gas

Both the C and D Sand gas accumulations are underlain by thin oil rims. Discrimination of oil from gas can be very difficult using standard open-hole logs (density - neutron crossover) because of lithology effects (shaliness or bound water) and free gas within the oil leg. Given the different densities of oil and gas, a change in slope of the MDT derived pressure gradients occurs when going from gas to oil to water. Fluid pressure gradients derived from the MDT measurements have proven to be an effective tool for discriminating oil from gas bearing sands (figure 11).

Faulting/natural fractures

Sealing faults within the Maui reservoirs would have significant reservoir management implications. Although the Taranaki Basin has undergone a complicated tectonic history, very little faulting within the C Sands reservoir has been recognised. Careful analysis of the 3D seismic data indicates the Western Boundary Fault, the Whitiki Fault, as the only major fault affecting the closure area of the Maui B area. Lineament mapping from seismic attribute maps indicates features exist which might indicate sub-seismic faults (< 20 m throw). However, the complete lack of fractures within the C Sand cores suggests that these features are unlikely to correspond to faults. The FMS images

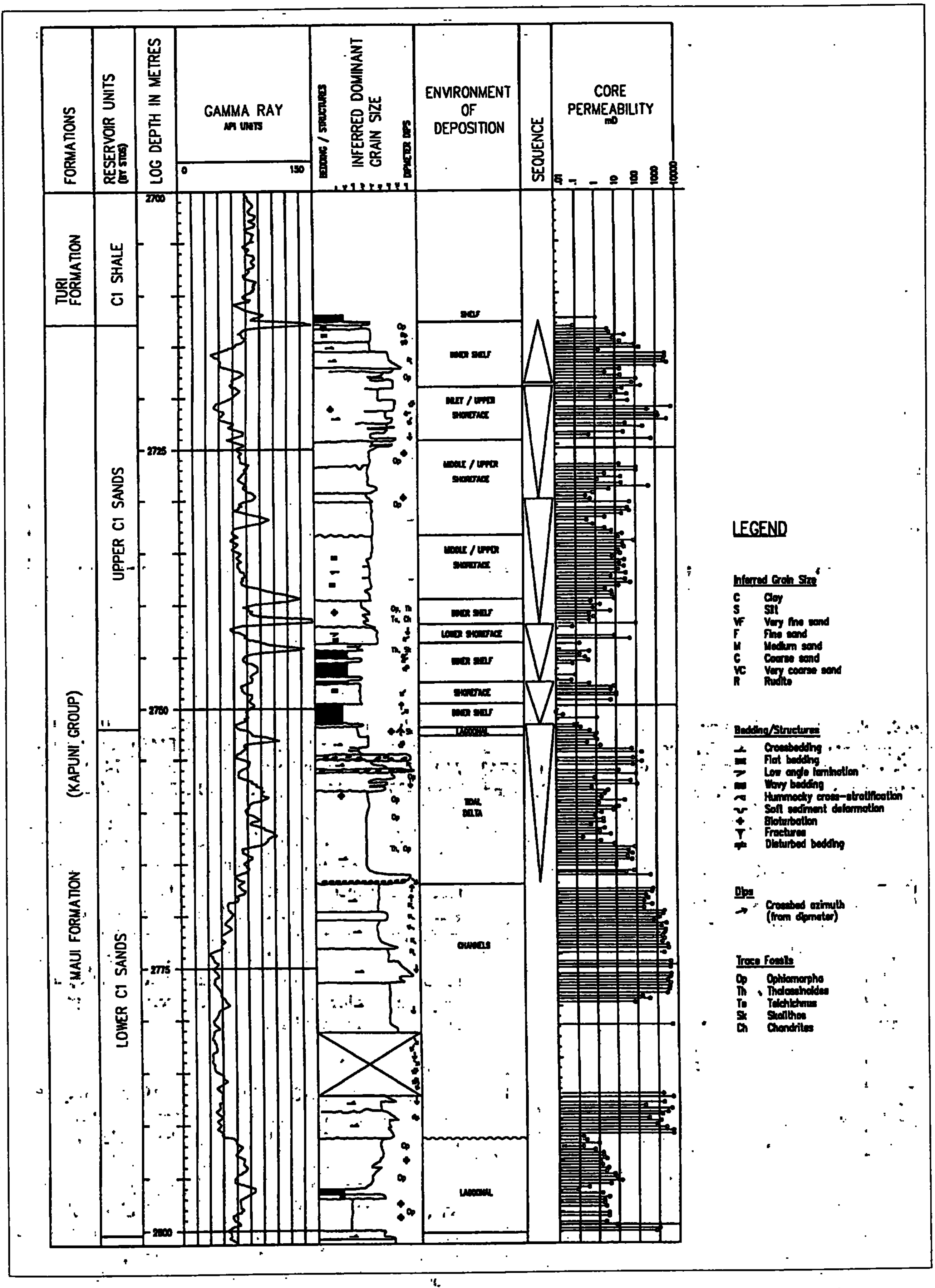

Fig. 8. Description of the C Sands cores from appraisal well M-07. Note the high permeability sands are for the most part crossbedded and have high angle dips that were detectable from the carefully processed SHDT dipmeter data. Low to moderate permeability sands are predominantly flat-bedded or bioturbated.

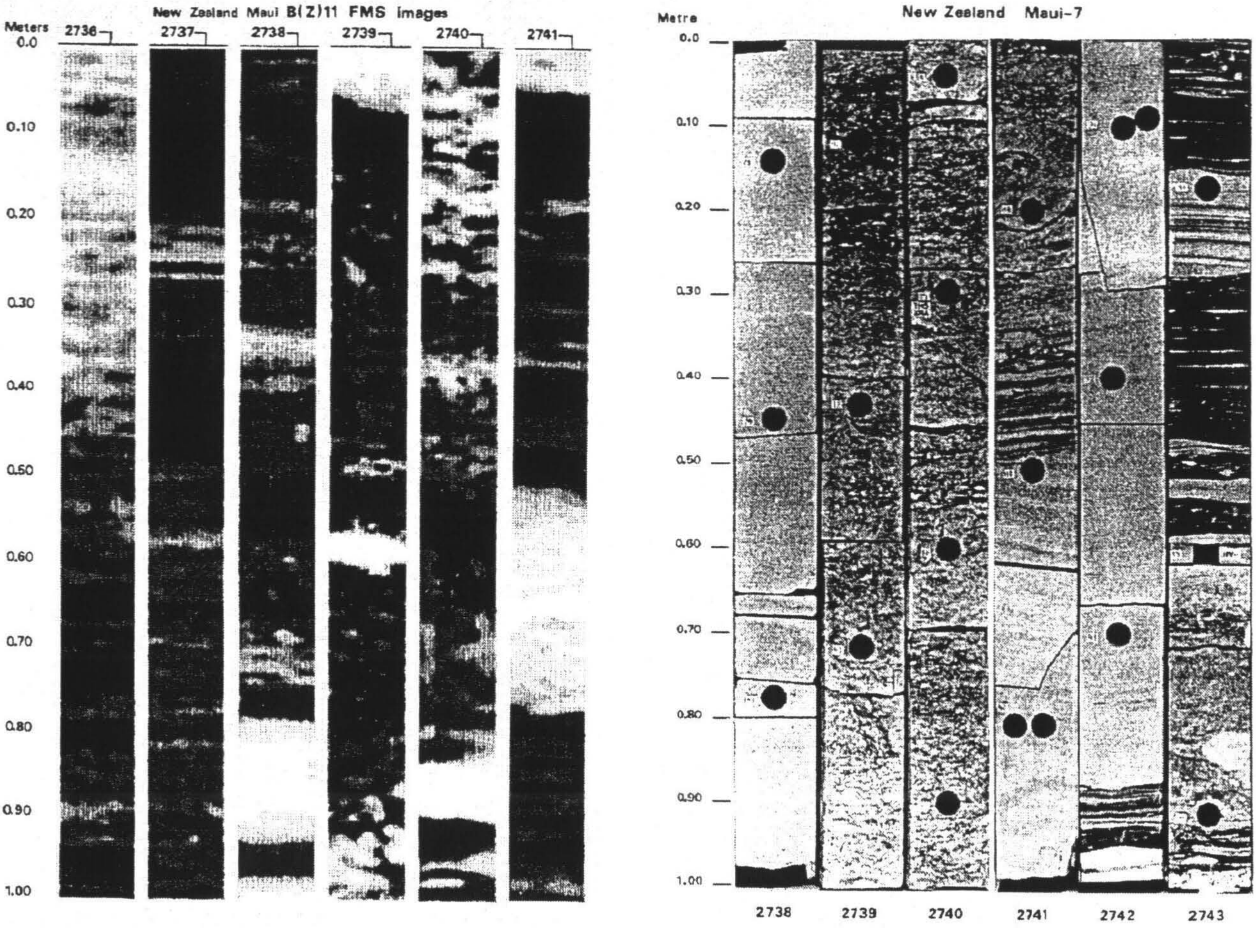

Fig. 9. Normalised FMS images (left) from a C Sands interval of MB-(Z)11 compared to core photographs (right) from an equivalent interval in M-07. Lithofacies recognised in the cored well are interpreted on the basis of FMS image textures: laminated sands & shales (2742-2740.9 in MB-11 (Z) & 2743-2740.3 in M-07); bioturbated sands & shales (2740.9-2739.1 in MB-11 (Z) & 2740.3-2748 in M-07); & flat bedded sands (2739.1-2736 in MB-11 (Z) & 2740.3-2748 in M-07).

provide an inexpensive way (when compared to coring) to extend this data set over large sections of borehole. No small scale features (faults or non-drilling induced fractures) were recognised which support small-scale faulting within the C Sands reservoir. Additionally, MDT pressure measurements made in subsequent B area development wells do not indicate the presence of sealing faults. Pressure measurements made in correlatable units from wells many kilometres apart are very similar which suggests that the reservoir is in pressure communication over large distances.

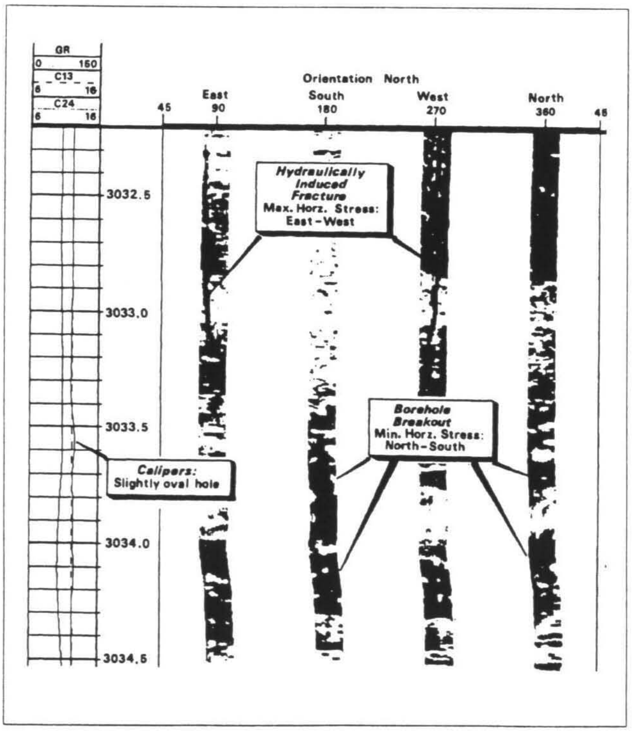

Fig. 10. Normalised FMS images from MB-11 (Z) showing drilling-induced hydraulic fractures on east–west pads and borehole breakouts on orthogonal north–south pads.

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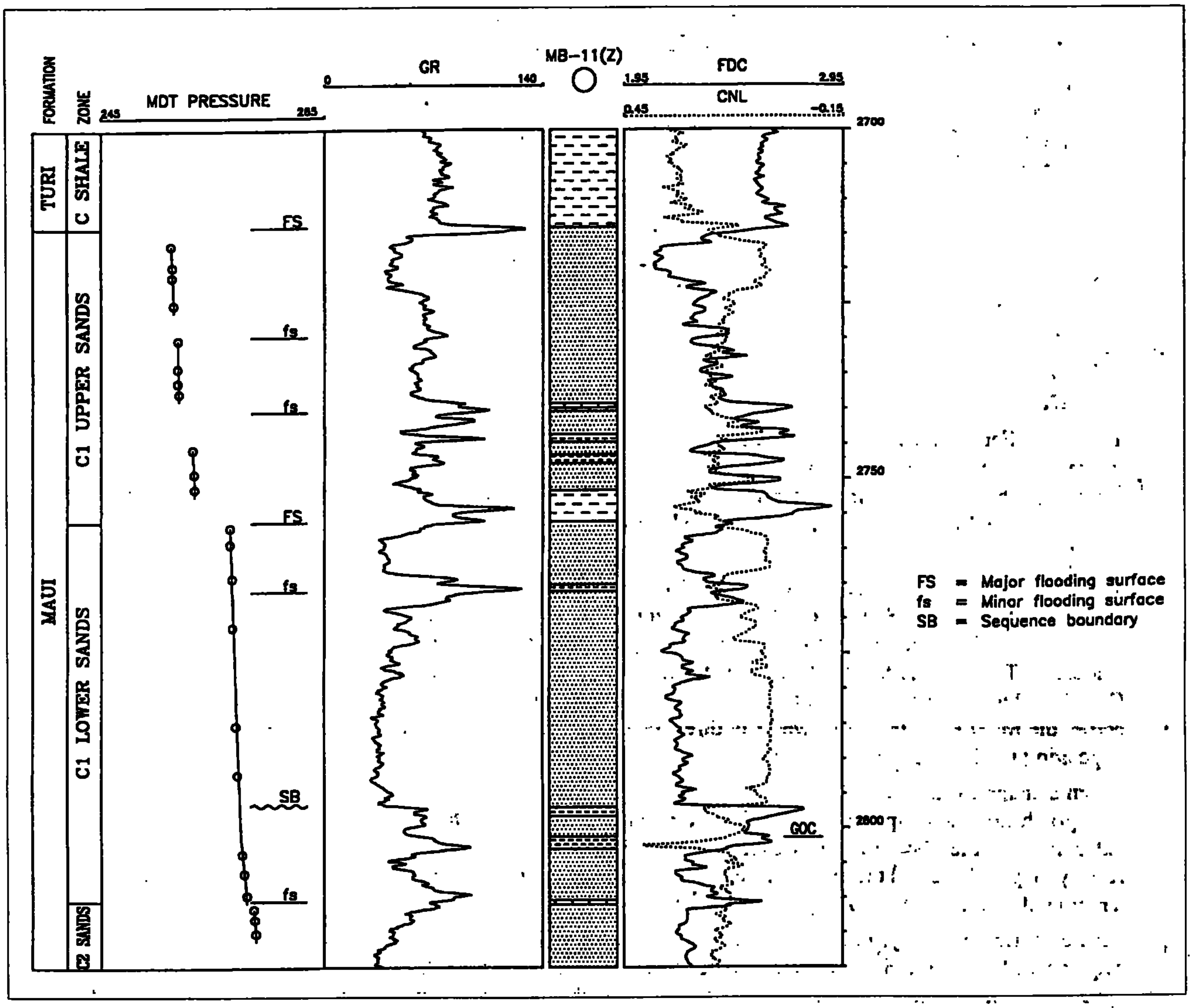

Fig. 11. Wireline logs and MDT formation pressure measurements from the C Sands interval of MB-(Z)11. Note that the major pressure steps coincide with major flooding surfaces identified in the geological model. Also note the small pressure step at 2810 m that corresponds to a carbonate-cemented "tight streak" that may afford protection from bottom-water influx to a completion in the overlying oilrim. (GOC — interpreted gas-oil contact; GR — gamma ray; FDC — density; CNL — neutron porosity).

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Acknowledgments

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