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Fluid Saturation Predictions in a "Transition Zone" Carbonate Reservoir, Abu Dhabi

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ABSTRACT

The field is a low amplitude structure with a chalky, Lower Cretaceous, Thamama reservoir characterised by a large hydrocarbon transition zone. Porosity generally decreases with depth within the trap although porosity versus depth trends are skewed by tilting. Porosity and permeability mapping was therefore achieved using templates based on seismic amplitudes. Special core analysis data were used to construct algorithms of Leverett J functions versus saturation for a variety of rock types mapped throughout the 3-D geological model of the field. The templated poroperms were then combined with capillary pressures to predict fluid saturations from these algorithms. The modelling of fluid distributions was therefore dependent upon heterogeneities imposed by the rock fabrics. Calibrating the model-predicted saturations against log-derived saturations at the wells involved regression techniques which were complicated by: notional structural tilting of the free water level, imbibition, hysteresis and permeability averaging procedures. Filtered "stick displays" proved useful in assessing the quality of the calibrations and were invaluable tools for highlighting and investigating data anomalies.

INTRODUCTION

The Lower Cretaceous Thamama Group includes the most important hydrocarbon bearing reservoirs in onshore and offshore Abu Dhabi. All the major fields (Bab, Bu Hasa, Sahil, Asab, Umm Shaif and Zakum) collectively have many tens of billions of barrels of oil reservoired in stacked Thamama limestone reservoir horizons. However, these reservoirs are renowned for their long hydrocarbon transition zones which mainly reflect their diagenetic chalky fabrics (Moshier, 1989; Budd, 1989).

The term "transition zone" is used in reference to that lower part of a hydrocarbon column above the free water level (FWL) which contains water saturations that are higher than the irreducible water saturation with respect to a specific rock type. Transition zones of oil reservoirs typically produce only water or varying proportions of oil and water. However, dry oil is often unexpectedly produced from apparent highly water saturated reservoir units in the Thamama transition zones.

The Thamama transition zones are poorly understood and difficult to manage. Their prominence increases with time as exploration evolves and more subtle, low amplitude structures are explored and developed; and as secondary recovery schemes are implemented in the developed fields. The vertical closures of exploration prospects are often less than, or barely exceed, their hydrocarbon transition zones and so their economic viability requires serious scrutiny. It was against this background that a study was conducted to develop a methodology for modelling the controls and characteristics of transition zones so that exploration / appraisal targets could be ranked and field development plans optimised.

This paper addresses that part of the study which concentrated upon developing a methodology for characterising *static* models of Thamama reservoirs. Particular emphasis was placed upon the main Thamama reservoir within the Kharaib Formation (Thamama B onshore; Thamama II offshore) which is of Barremian age and stratigraphically just beneath the Shu'aiba Formation. The study focused upon an undeveloped field which is located beneath the barrier island and lagoon complex immediately offshore the Abu Dhabi coastline (Figure 1). It measures about 25 by 32 kilometers (km) in the northwest-southeast and northeast-southwest directions respectively. Its Thamama B reservoir has only nine well penetrations to date and well spacing varies between 3 and 10 km.

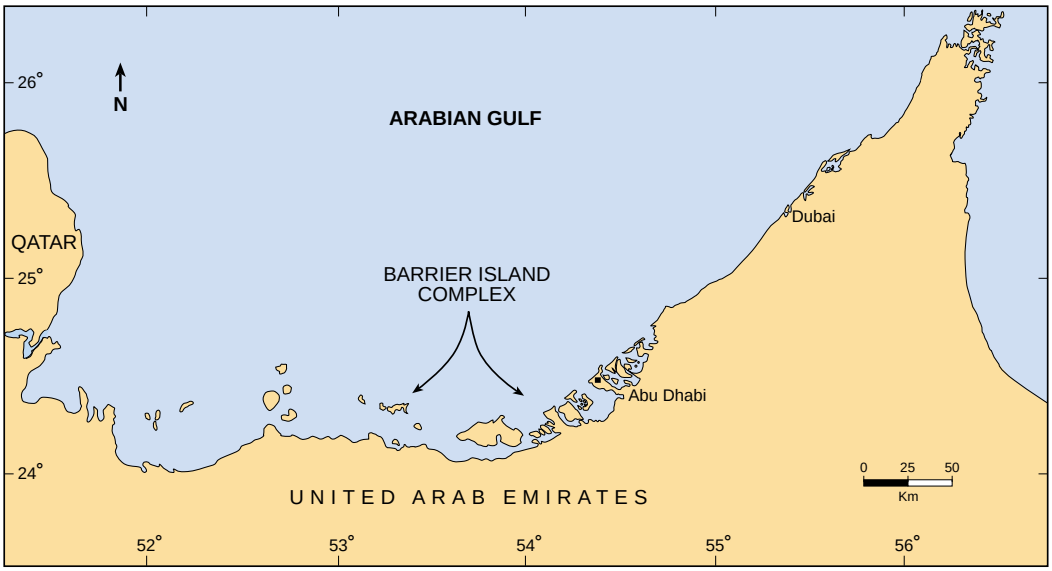

Figure 1: General location map.

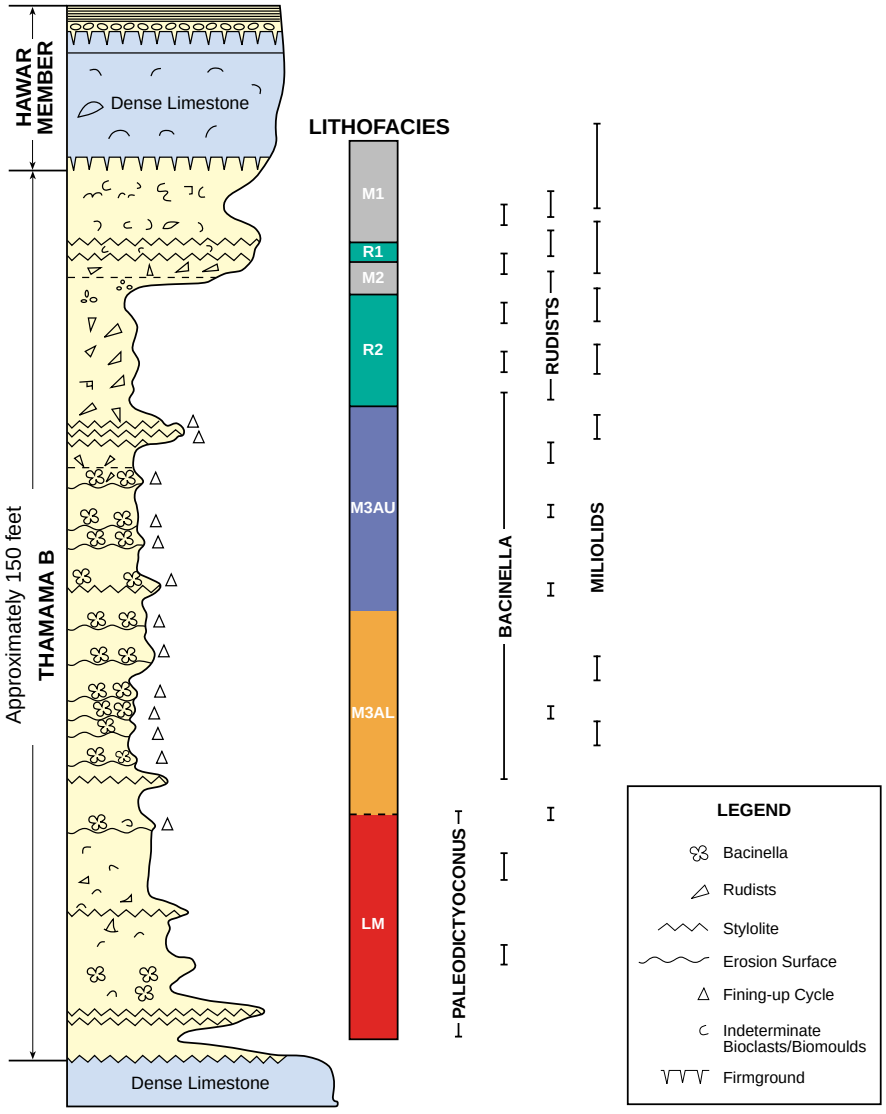

Figure 2: Schematic summary of Thamama B lithofacies.

The Thamama B is about 150 feet (ft) thick at the crest and comprises a series of stacked, shallowing-upwards, depositional cycles. Denser limestones usually associated with prominent stylolites occur at the base of each cycle and historically have formed the basis for fieldwide sub-zonation of the reservoir (Figure 2). Porosities are generally moderate to very high in the "pay" layers but their matrix permeabilities are disappointingly low because of calcite cementation of the grainstone lithologies compounded by diagenetic chalkification of grains and lime mud components which impose often severe capillarity effects leading to thick hydrocarbon transition zones.

3-D STRUCTURAL MODELLING

Despite its size, the field is a low amplitude structure with a maximum vertical closure of 170 ft and flanks generally dipping at less than 3 degrees. The top and base of the Thamama B reservoir were defined by 2-D seismic interpretation but intra-reservoir architecture was beyond seismic resolution. Structural mapping has historically been difficult due to the coarse 2-D seismic grid; compounded by statics problems (velocity anomalies) associated especially with geomorphological features such as Pleistocene-Holocene channeling between islands in the coastal setting. The structure has one major culmination and three minor ones on its southwest flank (Figure 3). Superimposed upon these are subtle undulations which could be partly a function of the above mentioned statics problems, or sub-seismic faulting. No faults have been mapped so far although a recent 3-D seismic survey across the field may well reveal some. The reservoir contains oil with a possible gas cap but it was unclear at the outset of the study whether or not the southwest structural saddles subdivided the field into compartments.

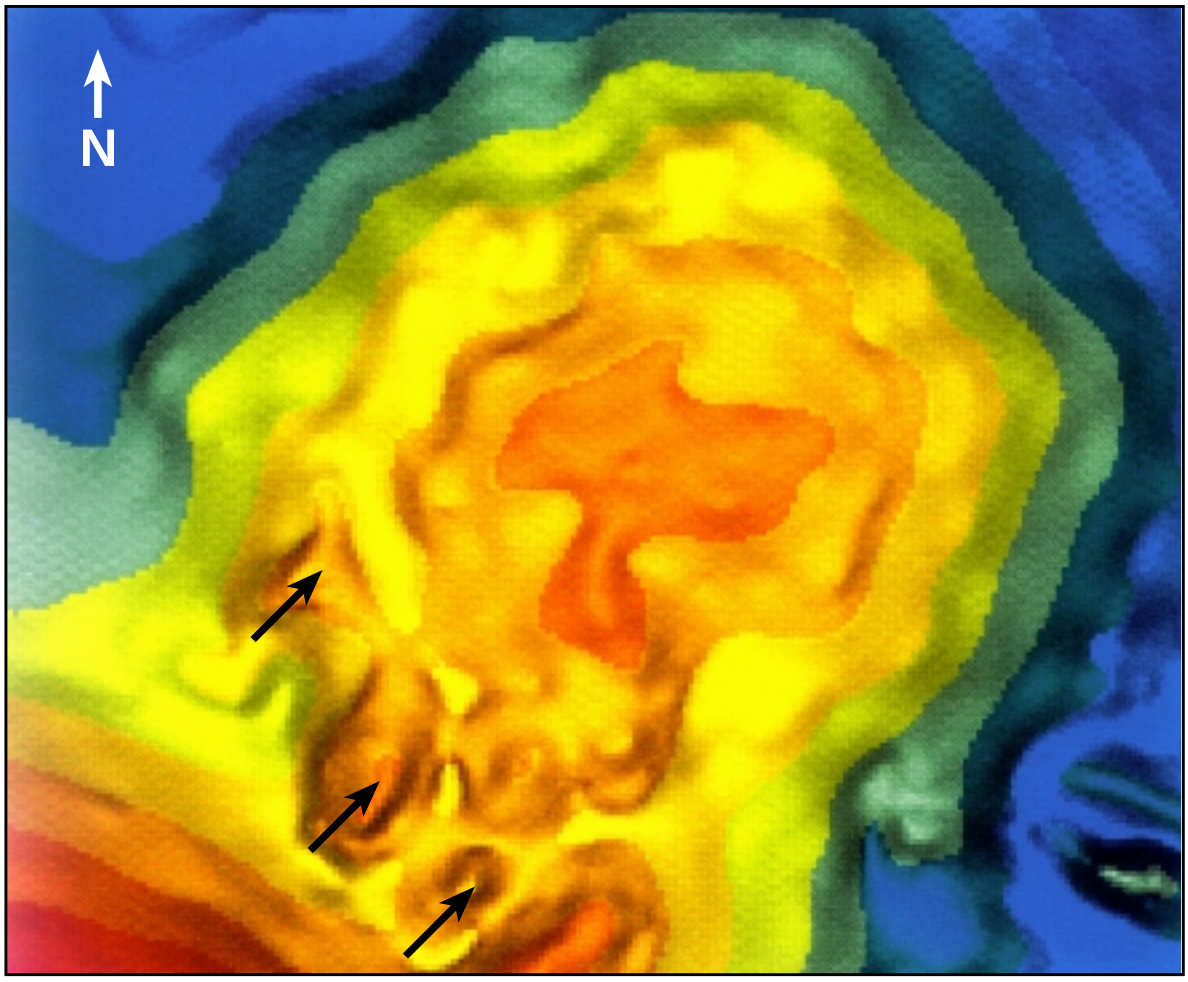

Figure 3: A three-dimensional view of the structure from the south. Note the three minor culminations along its southwest flank (arrowed).

Intra-Thamama B layer boundaries were mapped by upward stacking (from base Thamama B) of layer depth isochores derived from well data alone. The isochore maps were clipped appropriately to avoid spurious convergence or divergence of the layer boundaries between and beyond the widely spaced well control. Finally, a mathematical editing procedure was applied to ensure that the total reservoir isochore derived from the stacking procedure fitted exactly with the seismically defined total reservoir isochore.

All reservoir layer boundaries were then imported to Landmark's 3-D modelling program, Stratigraphic Geocellular Modelling™ (SGM), where the thicker "pay" layers were proportionately sub-layered to a maximum of five feet in thickness.

POROSITY AND PERMEABILITY MODELLING

Severe downflank reductions in porosity and permeability due to matrix cementation and stylolitisation are typical of the vast majority of Abu Dhabi fields (e.g. Oswald et al., 1995). Compaction effects generally dominate over facies or other diagenetic controls on porosity and permeability trends. However, complications are imposed on these trends by structural changes and water-leg diagenesis as discussed below.

Although the structure may have been initiated by salt pillowing as early as the Triassic and Jurassic, it is probable that, as with most of the major structures in Abu Dhabi, it acquired its present day definition during a mainly Campanian compressional phase (Glennie, 1995). There may have been minor tectonic re-adjustment associated with the Early Tertiary uplift of the Oman Mountains, but the structure already existed in more or less its present form prior to receiving its main hydrocarbon charge during the Late Cretaceous-Early Tertiary. Since the charge, the structure has been tilted towards the northeast by the Late Miocene-Recent Zagros Orogeny, causing re-migration of reservoired hydrocarbons. Such tilting is common to many onshore and offshore fields in the region (Kassler, 1973).

Prior to the Zagros tilting, the presence of hydrocarbons had largely protected the reservoir against stylolitisation and therefore helped resist loss of porosity and permeability. Stylolitisation increased with depth through the hydrocarbon transition zone as water saturations increased until it was allowed to proceed relatively unconstrained beneath the oil-water contact. Porosity and permeability trends were therefore symmetrically arranged around the structure in a gross sense although a marked reduction in porosity and permeability occurred at the palaeo (pre-Zagros Orogeny) oil-water contact.

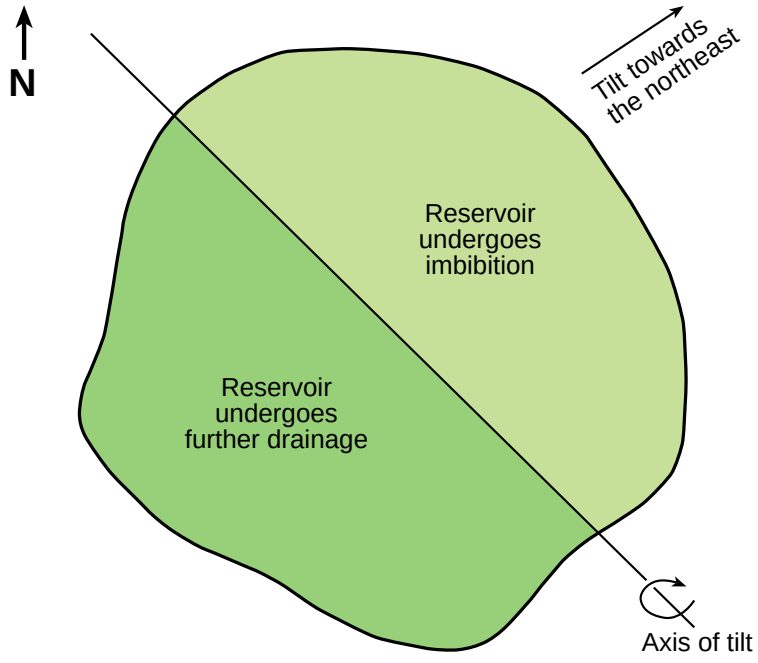

Figure 4: Post-fill, northeasterly tilting of the field.

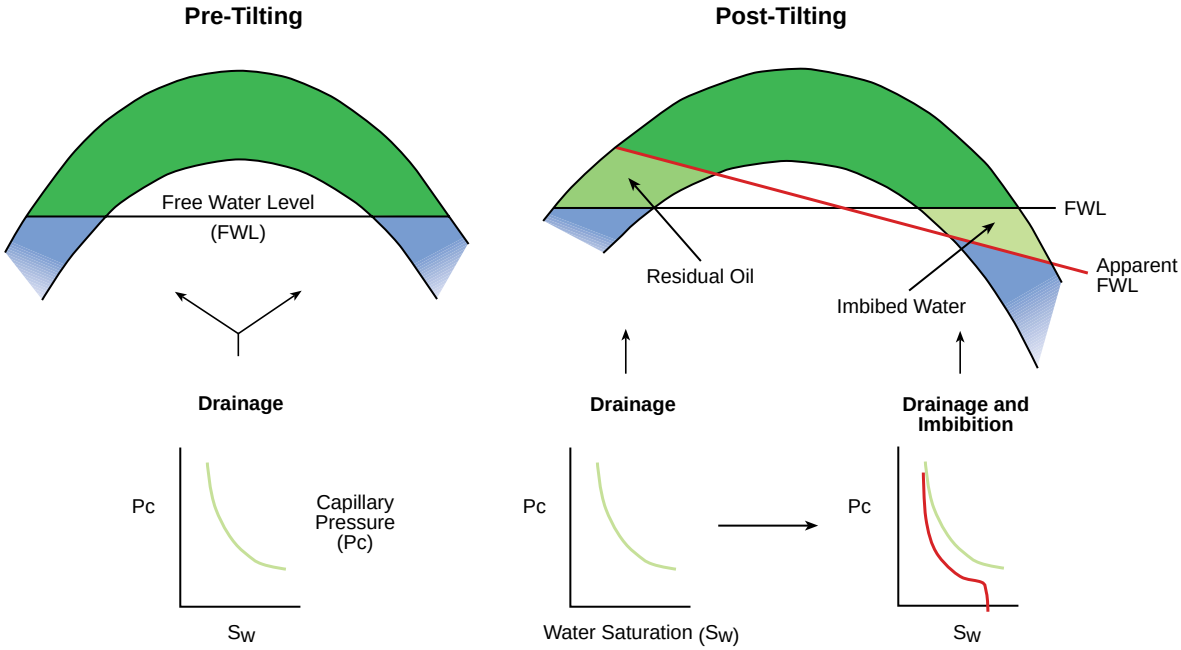

Figure 5: Effect of tilting on the capillary pressure regimes across the reservoir.

The effect of the Zagros tilting towards the northeast was to depress the palaeo fluid contact over the northeastern half of the structure but raise it over the southwestern half (Figures 4 and 5). This resulted in higher porosities and permeabilities being placed beneath the level of the palaeo oil-water contact over the northeastern half; and lower reservoir porosities and permeabilities being raised to the transition zone (hydrocarbon column) over the southwestern half. The porosity and permeability trends within the oil column were therefore skewed to a certain degree and led to difficulties in mapping these attributes using well data alone.

To overcome this difficulty, Mulholland's (1995) research was used to derive a fieldwide aggregate porosity map from seismic amplitudes for the total Thamama B thickness (Figure 6a). It would have been preferable to have used seismically derived porosities for individual reservoir layers, or packets of layers, but the seismic quality precluded such intra-reservoir definition. The resulting porosity map was then normalised and used as a template to bias deterministic porosity and permeability interpolations for every reservoir layer and sub-layer using a combination of Landmark's SGM and Geocellular Template Modelling™ (GTM) programs. Figures 6b-6d show the differences in porosity of one sub-layer, with and without the template. The subject of facies constraints on these interpolations is discussed below.

FLUID SATURATION MODELLING

The approach described by Kirkham and Twombley (1995) was employed for saturation modelling. This technique requires detailed sedimentological evaluation to identify the main reservoir rock types which are then characterised using pore throat analyses and good quality capillary pressure (Pc) data. An average Leverett J Function relating capillary pressure data to saturations is then derived for each rock type. It is also imperative to have a clear understanding of the reservoir's free water level (FWL). Equations (1) to (4) describe the sequential process of calculating the water saturations. The Pc data was calculated with due consideration given to the gas cap using Equation (2). All these equations were implemented within SGM; partly because most of the component attributes were modelled therein and partly because of the excellent visualisation potential of the program (Figure 7).

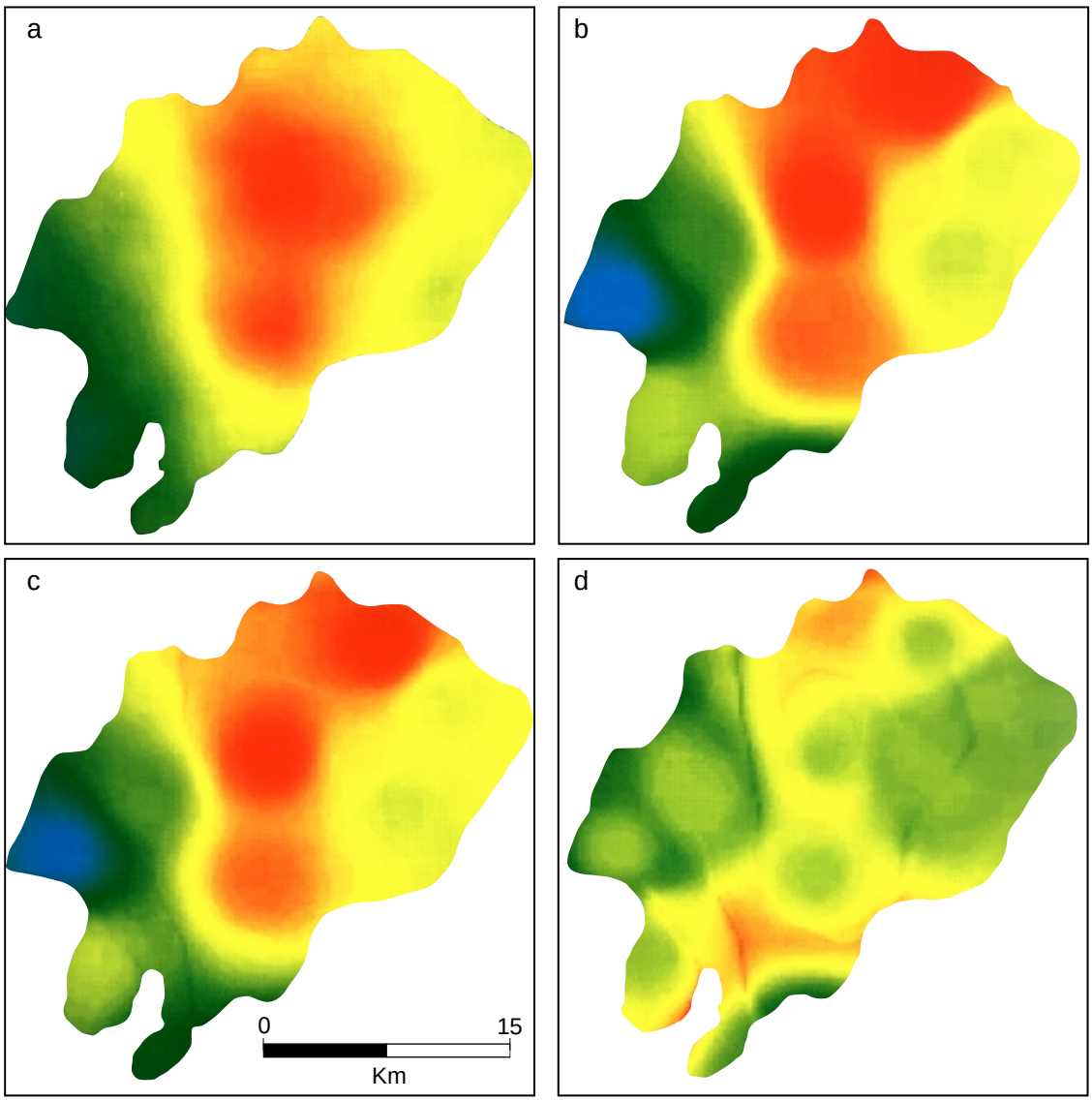

Figure 6: Average porosity distributions for one reservoir layer within the hydrocarbon zones: (a) derived from seismic amplitudes for the entire Thamama B reservoir and used as a template to bias layer porosity and permeability interpolations within reservoir layers; (b) and (c) show porosity distributions with and without the template bias; and (d) shows porosity difference between (b) and (c). Warmer colours represent higher porosities in (a), (b) and (c); or larger differences in (d). Zero differences represented by greens occur at well locations in (d).

$$Pcow = (\rho w - \rho o) \times (h_{FWL} - h) \quad (1)$$

$$Pcgw = (\rho w - \rho o) \times (h_{FWL} - h_{GOC}) + (\rho w - \rho g) \times (h_{GOC} - h) \quad (2)$$

$$J = 0.217 \times (Pc / \sigma \cos\theta) \times (K / \theta)^{-0.5} \quad (3)$$

$$S_w = m_1 + [m_2 \exp(m_3 \times J)] + [m_4 \exp(m_5 \times J)] \quad (4)$$

where

- Pcow = capillary pressure in the oil column
- Pcgw = capillary pressure in the gas column

Pc = capillary pressure of a cell whatever its location within the hydrocarbon column
ρ = fluid density (w = water; o = oil; g = gas; represented as gradients of psi / ft)

h = height above free water level (ft)
h_{FWL} = height of the free water level (ft)
h_{GOC} = height of the gas oil contact (ft)
K = horizontal permeability
Ø = porosity
θ = contact angle (degrees)
σ = interfacial tension (dynes / cm)
# J = Leverett J value
# S_w = water saturation
m = empirical constants
0.217 = a constant to ensure consistency across units of measurement

[# indicates parameters modelled within SGM. Remaining parameters were input to SGM as constants. The equations were activated for each cell using the SGM Operations module].

The details of the actual modelling process are beyond the scope of this paper but the essence of the approach is to characterise every cell in the 3-D model with a rock type prior to applying the above equations on a cell by cell basis. Equation (4) is selectively applied according to the rock type assigned to the individual cell. Assuming that all the parameters are adequately defined and calibrated against actual well data, the ultimate 3-D water saturation distribution reflects the geological heterogeneity within the model.

The quality or accuracy of the water saturation modelling in this study was measured by repeated calibrations against saturations derived from wireline logs. Stick plots constructed within SGM proved invaluable to this calibration process (Figure 8). For instance, they allowed collective visualisation of the differences between model-predicted and log-derived saturations at every cell penetrated by every well in the 3-D model.

Unfortunately, the initial model-predicted water saturations were unacceptably poor when compared against all the wells. Three main sources of error were identified: (1) poor definition of the FWL; (2) incorrect lithotyping; (3) permeability averaging. These items are discussed below.

The Free Water Level

The FWL was poorly constrained by pressure data. Alternative FWL's were used as sensitivities but they failed to improve the match. Unfortunately, the FWL concept was complicated by the recent tilting. As a result, the northeastern part of the field is in an imbibition capillary pressure regime whereas the southwestern part has remained in a drainage regime.

The FWL has remained *theoretically* horizontal throughout the tilting episode although the practicality is that remigration of fluids to adjust to the continuously changing FWL over the last 5 million years has not kept pace. In other words, there has been an hysteresis effect. This conclusion was supported by phase modelling. Another related complication is that residual oil saturations occur beneath the palaeo oil-water contact across the northeast half of the field, which again affected the poor comparison between saturations at the wells because the special core analysis data (SCAL) used to characterise the rock types in the residual oil zone should include imbibition capillary pressure data. None was available and so drainage data was used throughout.

The following method was devised to construct the fieldwide "effective" or "apparent" FWL. Water saturations for each well were modelled using the Leverett J Function approach at 6-inch depth intervals and at various *assumed* FWL depths (Figure 9). These results were then compared by simple regression techniques with the log-derived water saturation profile for the respective wells. The assumed FWL depth which gave the best fit in each well was accepted as the "effective" FWL depth. All these depths were then used as control points for gridding the notionally tilted FWL which not unexpectedly showed a general northeasterly dip (Figure 10) and associated depth variation of about 75 feet across the field.

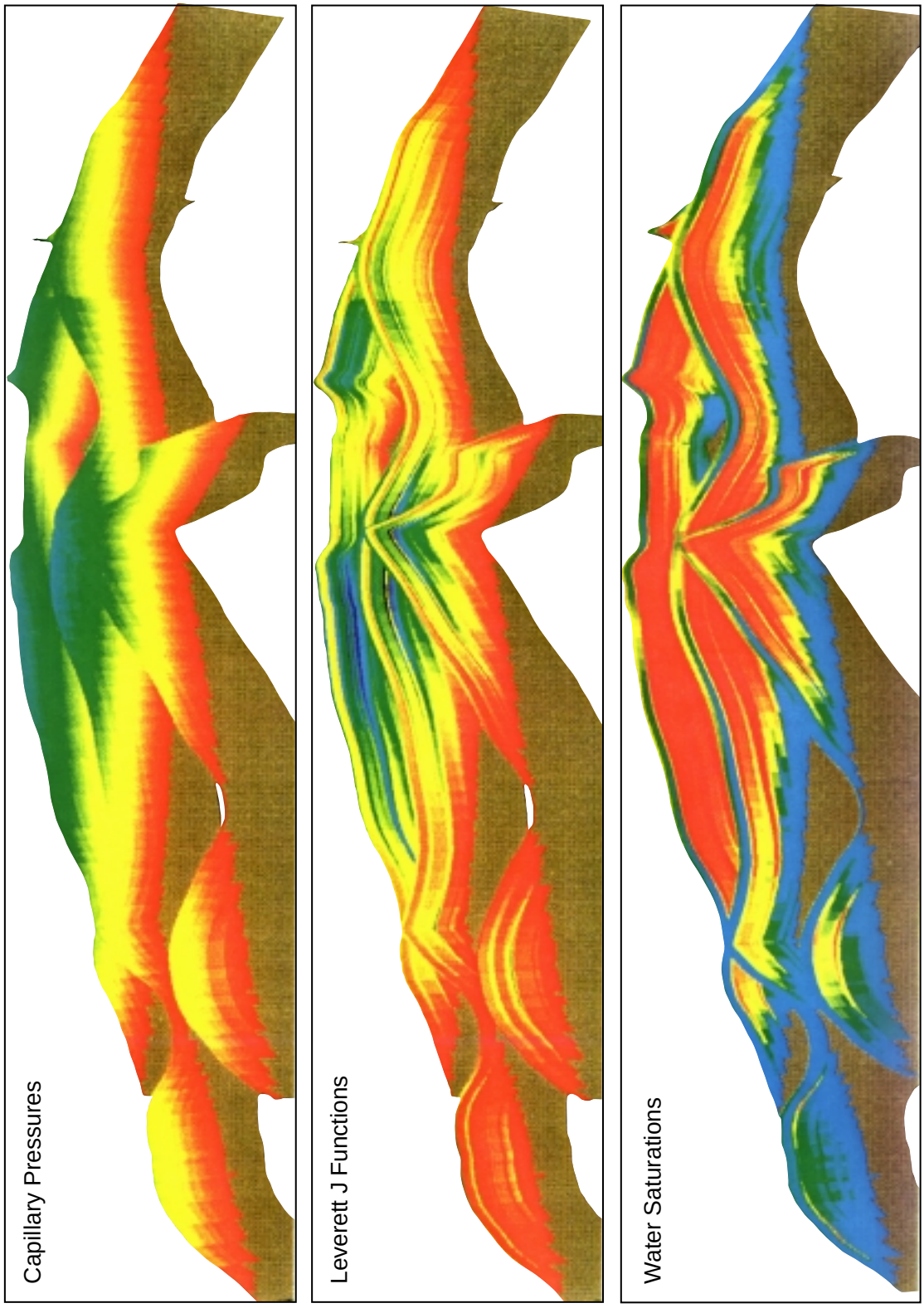

Figure 7: "Three dimensional" cross-section views of capillary pressures, Leverett J values and final water saturations predicted throughout the reservoir. Viewing direction is towards the north. Maximum structural closure is 170 feet.

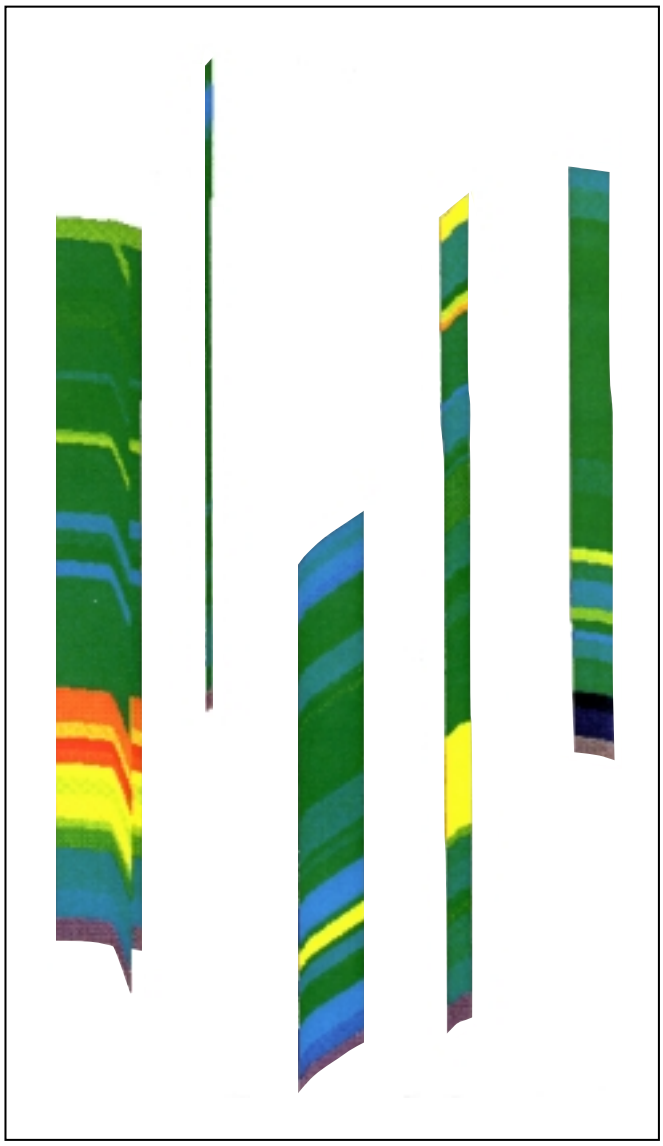

Figure 8: "Three dimensional" view of stick plots showing differences between initial, model-predicted water saturations and log-derived saturations. Greens represent zero or minimal differences. Deep reds and deep blues indicate maximum differences which may represent, for instance, incorrect rock typing.

It is stressed that the above sensitivities were only applied to the oil saturated reservoir intervals. It was assumed that the possible gas-oil contact experienced no significant hysteresis effects.

Rock Type Identification

The Leverett J Function approach to saturation modelling requires that data from rock types with similar pore geometries be grouped in the construction of the dimensionless J value versus water saturation curve. Whilst porosity (and permeability) may vary between samples of a particular rock type, their basic pore structures must be alike. This can be checked by analyses of mercury injection derived pore size distributions. It is also reflected in the variation of the saturation exponent with rock types.

Thamama B limestones were deposited on a very extensive carbonate ramp. In this, and many neighbouring fields, the Thamama B reservoir comprises seven vertically stacked fieldwide lithofacies associations identified by acronyms: LM, M3AL, M3AU, R2, M2, R1 and M1 (Figure 2). These essentially describe a progressively shallowing-upwards sequence from lime mudstone / wackestone through stacked fining-upwards grainstone / packstone beds with algal (Bacinella) fragments and encrusted grains, to an alternating sequence of rudist-rich and fine grained, miliolid-pelloidal grainstone-

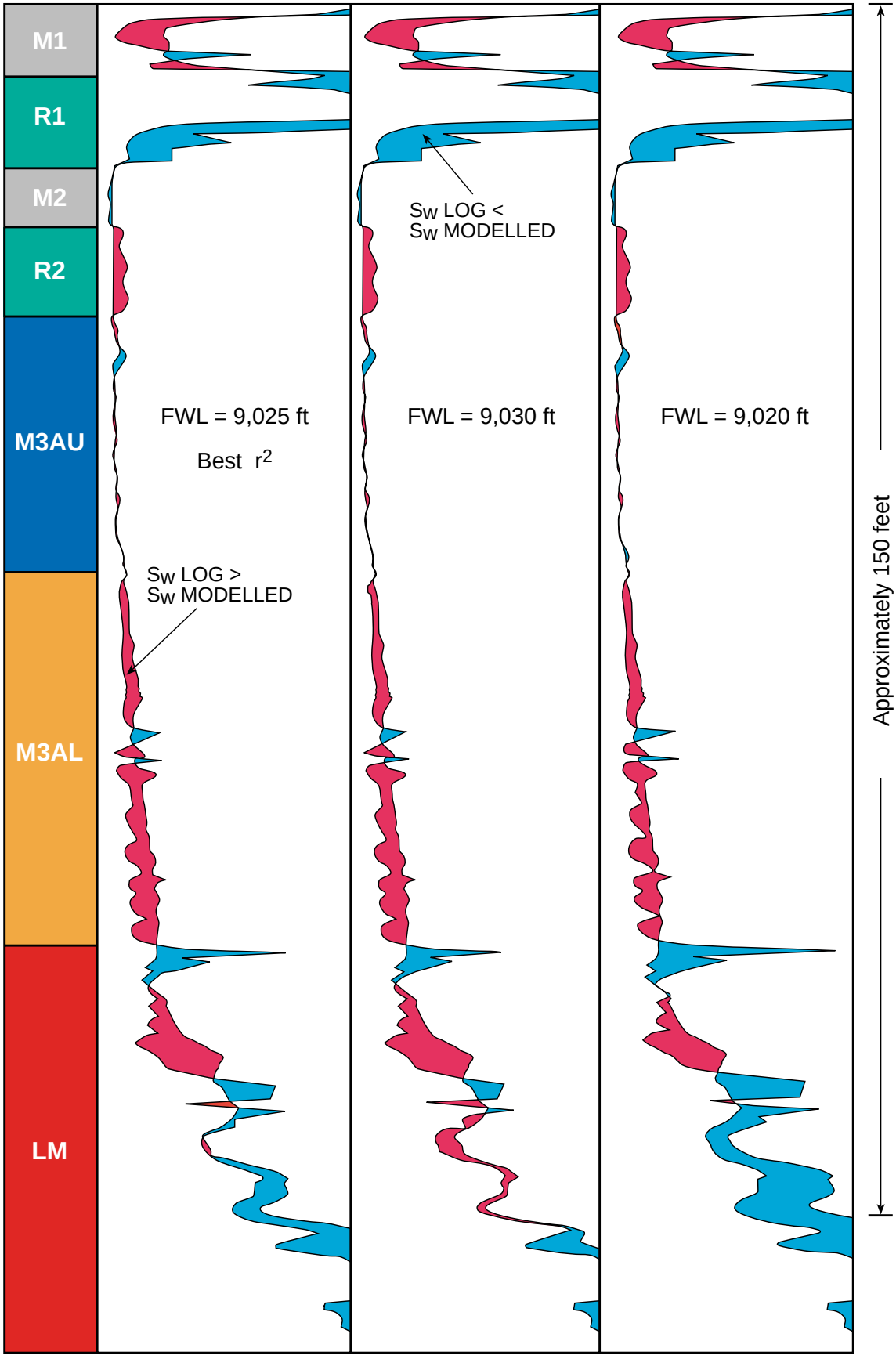

Figure 9: Example of water saturation modelling at different potential Free Water Levels (FWL) for one of the wells. The highest correlation coefficient indicates the best FWL estimate.

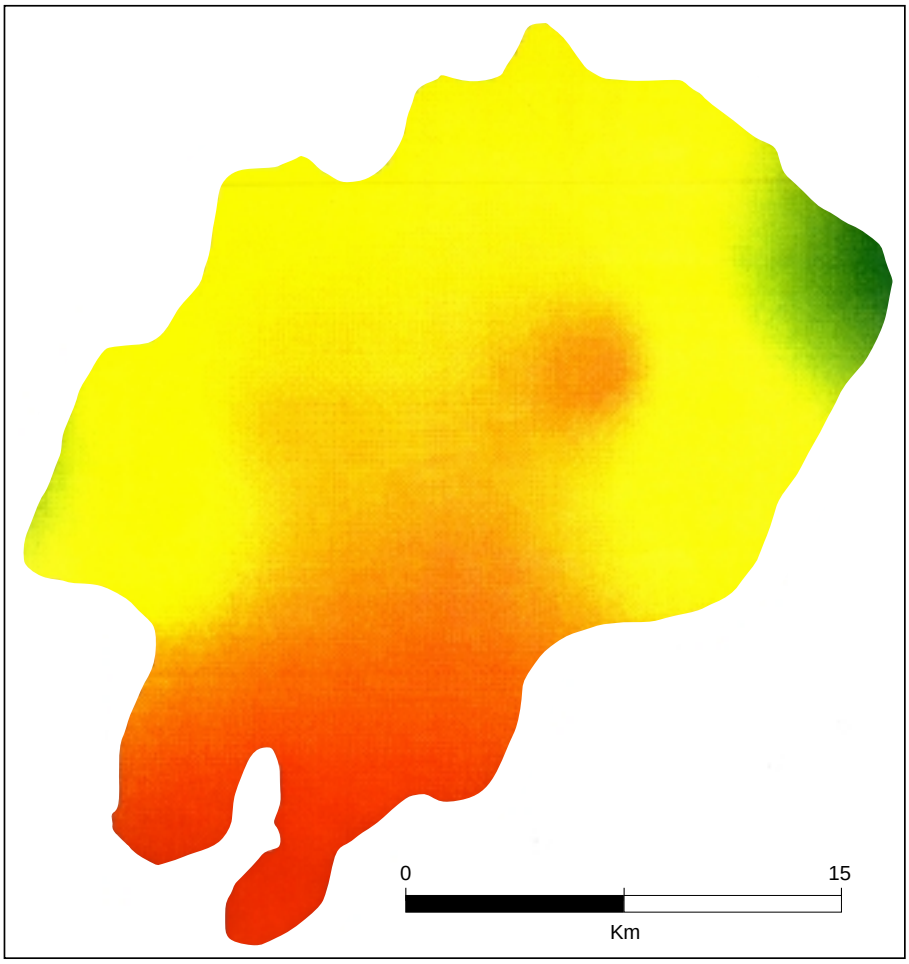

Figure 10: Limit of the northeasterly tilted Free Water Level within structural closure at top reservoir level. Warmer colours represent shallower depths.

packstone. The lithofacies associations may embrace two or more rock types such as lime grainstone, rudist packstone, etc., that are differentiated on the basis of depositional texture (Dunham, 1962). However, severe diagenetic overprints affected the rock types to varying degrees, particularly the cementation of intergranular porosity in the grainstones and the creation of extensive microporosity (chalkification) within the allochems resulting in the blurring of the petrophysical distinction between grainstones and the chalkified, lime mud-rich / mud-packed rock types dominated by matrix microporosity. However, the gross rock type characteristics of the various lithofacies associations were still sufficiently distinct to provide a basis for characterization using SCAL data.

It was initially assumed that each reservoir layer was represented by a single dominant rock type but, as lithofacies associations could contain more than one rock type, selective substitutions were introduced at the wells as the modelling process matured. Unfortunately, the available SCAL data coverage for the rock types was variable. If the coverage for a particular lithofacies was inadequate, the SCAL data for the most similar alternative rock type was used.

It is interesting that the methodology used to identify the most "effective" FWL depths in the individual wells could also be used to assess the applicability of modelled rock types at specific layers in a well. This was done either by changing the rock type or by assuming the same rock type occurs in every layer and re-running the saturation modelling as an aid to identifying the most suitable (dominant) rock type per layer by process of elimination. This, of course, assumed that the "effective" FWL was accurately known at the well and that all rock types had been accurately characterised by SCAL.

Permeability Averaging

The model-predicted water saturations were generally within 5% of the log-derived saturations at 6-inch depth intervals when using the selected FWL depths in the wells. These results were certainly acceptable but the saturation predictions deteriorated significantly when comparisons were made for averaged permeabilities of entire layers or sub-layers. Arithmetic, geometric and harmonic permeability averaging methods were all tried but insufficient overall improvement was attained. The problem lay in the permeability averaging process which had to cope with common occurrences of permeabilities varying by one or more orders of magnitude within a layer or sub-layer, essentially reflecting the distributions of mouldic and remnant intergranular pores. This difficulty was exacerbated by water saturations, as defined by equations 3 and 4, being very non-linear with respect to permeability. Therefore, any averaging must replicate this degree of non-linearity if it is to produce the correct overall layer saturation.

As permeability forms the most critical factor in equation (3) for deriving a Leverett J value, it was paramount that appropriate permeabilities were being used to derive water saturations which calibrated with the control wells. One way of achieving good calibration was to use an extremely fine layering scheme comprising layers of one foot (ft) thickness, for instance. It was ultimately decided to proportionately subdivide thicker layers into sub-layers of maximum 5 ft thickness at well locations, which meant that most layers were less than 5 ft throughout most of the model. This final layering scheme was a pragmatic compromise between computation time, heterogeneity representation, correlation uncertainties and upscaling procedures. Parts of the model still suffered from unacceptable water saturation calibrations at the wells but the following method was devised to solve the problem.

Since log-derived water saturations in the wells were the controls for the saturation modelling, it was decided to derive an "effective" permeability (K_{eff}) which would indeed provide acceptable calibrations with the log saturations for the respective layers or sub-layers. These "effective" permeabilities were obtained by back-interpolation using equation (5). Log-derived layer or sub-layer average water saturations were first used to extract Leverett J values from the Leverett J versus water saturation cross-plot for the relevant lithotype.

$$K_{eff} = \left[\frac{J(S_w) \times (\sigma \cos\theta \times \phi^{0.5})}{(0.217\ Pc)} \right]^2 \qquad (5)$$

These "effective" permeabilities were input to equation (3) and the saturation modelling procedure was repeated. This resulted in a perfect calibration with log-derived saturations for all layers or sublayers at all wells.

An advantage of the method is that it can be used to derive "effective" permeabilities in uncored intervals wherever rock types have been defined (e.g. by neural networks). The derived "effective" permeabilities are synergistic with the measured water saturations at the wells. The respective Leverett J functions would have already been defined using cored intervals in the same or neighbouring wells.

The "effective" permeabilities were then interpolated fieldwide as logarithmic values, which were later "antilogged". Alternative methods of distributing permeabilities throughout the 3-D model could have been used (and were indeed considered) such as, for instance, facies-controlled porosity-permeability transforms and stochastic modelling. The merits and disadvantages of the permeability modelling techniques in 3-D are beyond the scope of this paper which focuses on the need and methodology for ensuring good model calibration with the known well data as a basis for modelling the inter-well volume.

DISCUSSION

Experience has shown that, given geological heterogeneity at all scales, perfect matches between model predictions and actual data are unlikely most of the time. Acceptable error bars for most petrophysical analyses during water saturation calculations are +/- 10% to 15%. If the model predicted water saturations fall within these error ranges they are acceptable. Those predictions falling outside the

range need closer scrutiny. Possible sources of error could include, for example: the wrong rock type being used; an inappropriate permeability averaging process; the Leverett J versus S_w curve has too sharp a slope giving a large water saturation error for a relatively minor error in the J value. The sources of error require specific strategies for total or selective remodelling to achieve acceptable results and the derivation of "effective" permeabilities in the manner described above is offered as an additional tool for helping to address such problems.

Given the large field size and the small number of control wells, the final 3-D water saturation distribution in the reservoir reflected the heterogeneity within the objective of designing a better basic strategy for constructing a static model for such a transition zone reservoir. Variable saturations within the transition zone reflected changes in user defined rock type, porosity and permeability at any point in the 3-D model. Knowing the respective irreducible water saturations, calculations on the capillary pressure data can demonstrate that all rock types create transition zones exceeding 100 ft (Figure 11). Alternatively, composite filtering routines within the SGM model enable one to assess the transition zone heights for each rock type if the structural closure is great enough and if a particular rock type occurs at all depths within the limits of its transition zone height.

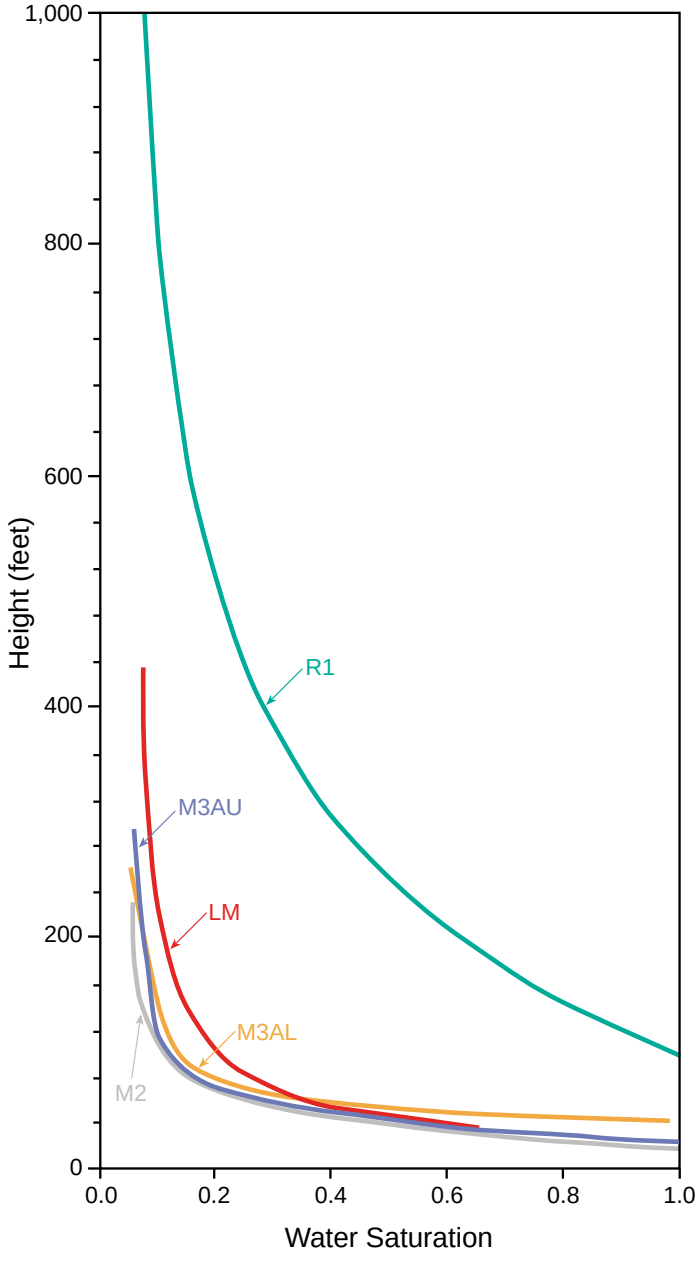

Figure 11: Water saturations versus height above the Free Water Level for various lithofacies associations (R1, M3AU, etc).

Similar filtering routines allow one to interrogate the 3-D model in search of higher reservoir potential rock types within the transition zone. It is the better sorted, coarser grainstones or the bimodal porosity packstones with well connected mouldic porosity which probably provide dry oil production from apparently high water saturated reservoir intervals, but they are often totally undetectable from routine openhole wireline logs if they are thinly bedded. This dry oil production is probably aided by their tendency towards oil wetness due to the thinner films of connate water allowing easier bonding of the hydrocarbons with the rock surfaces.

Furthermore, the tilted "effective" FWL allows only the base of the hydrocarbon transition zone to extend beneath the southwestern structural saddles. A knowledge of the relative permeabilities and saturation distribution therefore suggests a probable lack of mobile hydrocarbon communication across these saddles. The tilted FWL also means that a single depth contour will not define structural closure or volumetrically significant limits of the oil pool. This could also apply to other areally large fields with chalky Thamama reservoirs which have experienced similar structural histories in the region. Closure on this field is estimated to be about 75 ft shallower on its southwest flank due to the tilt of the FWL.

The field is still under appraisal but the above methodology is considered sufficiently robust to be used as part of a general standard procedure for reservoir appraisal. However, there is clearly room for improvement in the method by incorporating imbibition capillary pressure data for saturation modelling over the northeastern part of the field and by refining the rock type characterisation with additional SCAL data.

CONCLUSIONS

Accurate 3-D modelling of water saturations using a Leverett J Function approach with rock types characterised by SCAL data was achieved in the Thamama B reservoir. A pragmatic facies approach to rock type characterisation proved the most practical with the underlying premise that individual reservoir layers were dominated by a single facies due to their deposition in an extensive and uniform ramp setting. The saturation modelling was complicated by: (1) the effects of what is effectively a tilted free water level; (2) difficulties in deriving representative average layer permeabilities which are critical to deriving meaningful Leverett J values and hence water saturations.

The solutions to these two critical problems are easily applicable to other reservoirs in the region. The method of back-calculating "effective" permeabilities at well locations provides a means of deriving permeabilities in uncored intervals if rock types have already been defined and characterised by SCAL data. However, a total solution using the same approach in tilted reservoirs requires imbibition capillary pressure data. The heights of the hydrocarbon transition zones created by all the rock types exceed 100 ft, and must be considered when evaluating prospects or leads and in formulating development schemes.

In practice, several rock types will occur in most reservoirs and so the saturation distributions will vary both laterally and vertically. By implication, it is important for the geologists to understand the reservoir sedimentology and petrophysical attributes in order to accurately predict the reservoir fluids distributions away from well control. 3-D modelling techniques such as the use of stick plots are invaluable to the process of quality controlling the saturation predictions and identifying interpretational anomalies.

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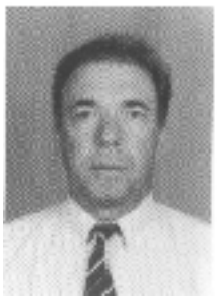

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