Evaluation of Moki sands prospectivity in Maui PML

P. Engbers

Shell Todd Oil Services Limited, New Plymouth, New Zealand

Abstract

This paper describes the rise and fall of a Miocene exploration prospect in the Maui PML offshore New Zealand. Strong positive indications of moveable hydrocarbons in Whaarangi were finally shown by a RCI program not to relate to mobile hydrocarbons. Petrophysical evaluation indicated moderate quality sands with medium hydrocarbon saturations (around 50%) in the Moki B3 sand in the Maui B area. Positive oil indications were observed while drilling. The B3 sand showed a rather clear oil pressure gradient. Moreover, a sample containing 1.5 litres of oil (40^{o} API) had been recovered in an earlier MDT program. In addition, the inferred contact from logs and pressures fitted a DHI on 3D seismic that also coincided with a structural 4-way dip closure. However, given the history of other Moki sands (low productivity) and the small potential oil column (transitional), commercial produceability was considered the main risk. With the development infra-structure already in place for the deeper Eocene reservoirs, and given the potential size of the accumulation, only relatively low oil rates from the Moki sands would be required for commercial development. Consequently a recent infill well targeting the deeper reservoirs provided the opportunity to sample and potentially test the Moki sands. With facilities lifetime reducing, a definitive result on Moki development potential was essential. Several RCI samples at a single reservoir point were recovered at increasing pump-out. The proportion of mud filtrate versus formation water was analysed by using a tracer added to the mud system. At the end of the pump-out, mainly formation water was recovered with only traces of oil. This conclusively demonstrated that the oil was immobile. Consequently, by low cost means, a definite result on the production potential was obtained, thereby avoiding expensive production testing. In addition, it downgraded further Moki prospectivity in the wider Maui PML.

Introduction

The Moki formation sands lie above the giant Maui gas and oil field. Various early Kapuni Group exploration and development wells penetrated the Moki formation with abundant hydrocarbon shows. However, data acquisition was relatively sparse over the Moki Formation. Evaluations before 1994 concluded that the Maui Moki play was uneconomic, due principally to the perceived low production rates from these low hydrocarbon saturated sands with relatively low permeability. Petrophysical re-evaluation (1998), using new information from recent exploration wells (e.g. formation water resistivity) and using the Waxman-Smits shaly sand evaluation approach, concluded the existence of considerably higher hydrocarbon saturations than previously evaluated. In addition, the recent Maari-1A (30 km south of the Maui PML) well, which tested comparable Moki fan lobes at 4400 bbls/d, was very encouraging.

Geology quickly seen through volume interpretation

The Moki Formation in the Maui PML, offshore New Zealand, comprises Middle Miocene fine-grained deep marine turbidite sequences. The lower part of the Moki Formation (the Moki B sands) was deposited on a basin floor well in front of the approaching slope front located to the South East. The frequent occurrence of turbidity currents resulted in an interval of many stacked sands with up to 275 m gross thickness. This was followed by a period of quieter sedimentation of dominantly bathyal claystones, represented in the Moki B shale unit. In the late stage, the depositional setting had shallowed to upper bathyal, and base of slope turbidites were deposited as the Moki A sands (Fig. 1). The Moki A sands have a lower Net to Gross ratio than the Moki B sands.

Sand development is spectacularly imaged by volume interpretation on acoustic impedance data. Various features

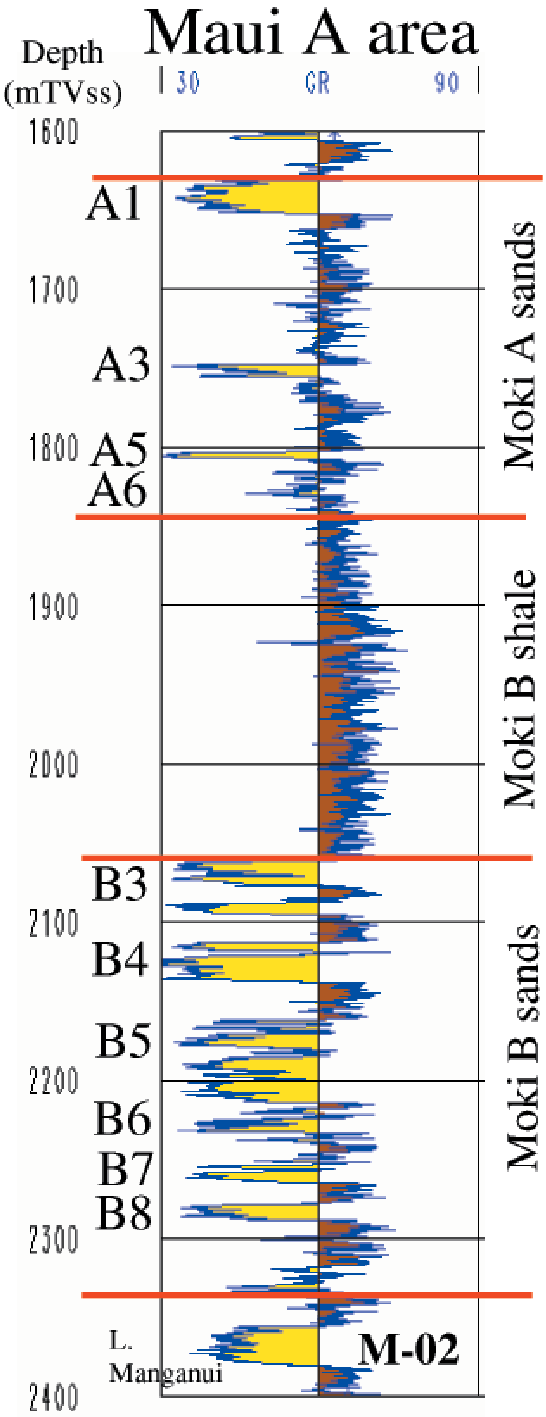

Figure 1: Simplified Moki stratigraphic column.

in the Moki A sequence are observed which characterise the turbidite deposition (Fig. 2-4). Sands were deposited as crevasse-splay and channel levee sediments associated with major valley systems. Clear narrow submarine fan channels are visualised that meander in a morphology similar to a large river on a low-lying floodplain. Deeper in the Moki sequence, the Moki B sands are interpreted to contain more laterally extensive turbidite sheet sands that were subsequently dissected by mud-filled submarine channels (Fig. 5). These Moki B sands are the main reservoir targets.

The Whaarangi prospect

Already in the early days of the Maui 3D survey, the Whaarangi prospect was identified as a structurally conformable amplitude anomaly, with a flat base, in a dip closure (Fig. 6) truncated by a clay-filled channel to the South and Southwest. The culmination of Whaarangi lies up-dip from hydrocarbon shows and low hydrocarbon saturations evaluated in appraisal well Maui-7. Evaluation of the prospect was undertaken by using a standard suite of logs from six deviated Maui B development wells that all penetrated the prospect. Evaluation of these wells indicated low to medium hydrocarbon saturation levels (20-40%) leaving many questions to its prospectivity. However, it was realised that uncertainties in the water salinity and the saturation model used (Archie) in these fine grained sands could implicate considerable upside potential. To resolve remaining uncertainty, core, pressure and fluid data were acquired in addition to a complete set of logs in a vertical Maui development well MB-11.

The Whaarangi "oil accumulation"

MB-11 recorded oil shows in the Whaarangi B3 sand whilst drilling and oil shows in the core. Limited pressure data suggested an oil gradient (Fig. 7). A twelve-gallon MDT fluid chamber recovered 1.5 litres of oil (40° API) with the remainder being mud filtrate. The oil was geochemically finger-printed as similar to regional Moki oils.

Since the results of MB-11, various review studies referred to the Whaarangi oil accumulation but failed to mature any follow-up proposals. In 1998, all the data were re-evaluated using newly acquired formation water salinity data from a nearby exploration well and using a shaly sand saturation evaluation approach. MB-11 showed raised B1-B3 HC saturations (around 45%) relative to the deeper B4-B7 sands (Fig. 8). The evaluation concluded hydrocarbon saturations ranging from 25% for the off-structure wells to 55% for the structurally highest well (about 30 m above the interpreted OWC at 2120 mTVss, Fig. 9a). The consistent gradual increase of saturation above the OWC was interpreted as mainly transitional saturations. The edge of the seismic amplitude anomaly coincided with the OWC (Fig. 9b). Seismic modelling showed that the amplitude increase on-structure fits with a 40 API oil fill model with reservoir parameters as logged in MB-11 (Fig. 9c). In addition, the OWC was consistent with the flat base of the low impedance, fitting exactly with the structural spillpoint (Fig. 10). All this led to the strong belief that Whaarangi was an oil accumulation with a STOIIP of about 50 million bbls.

The Whaarangi B3 sand has good porosity (23%) but moderate permeability (75 mD). Considerable work was carried out on the MB-11 core, including relative permeability measurements on core plugs. It concluded that oil was likely to flow at the evaluated saturations though only at low rates

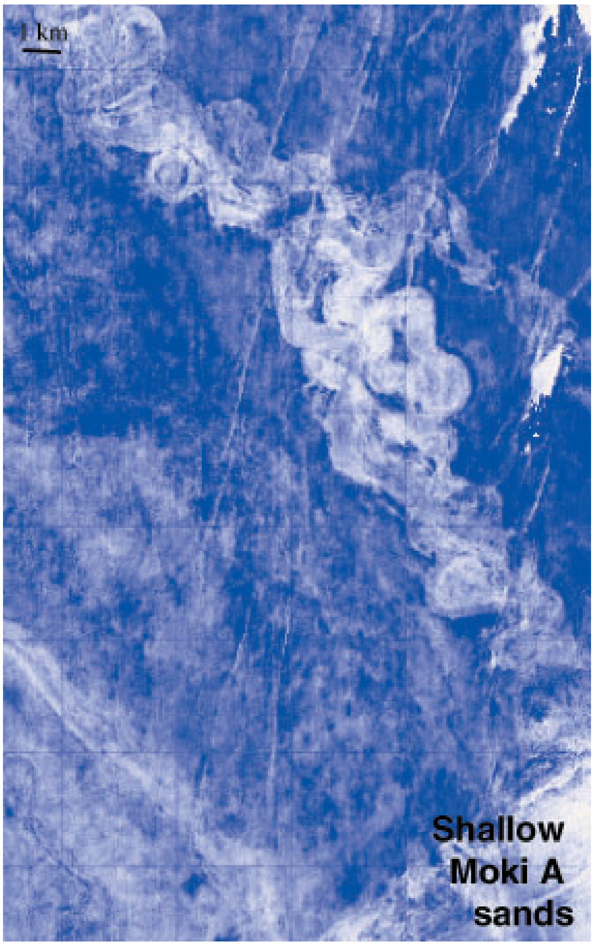

Figure 2: Channel levee sediments associated with major canyon systems.

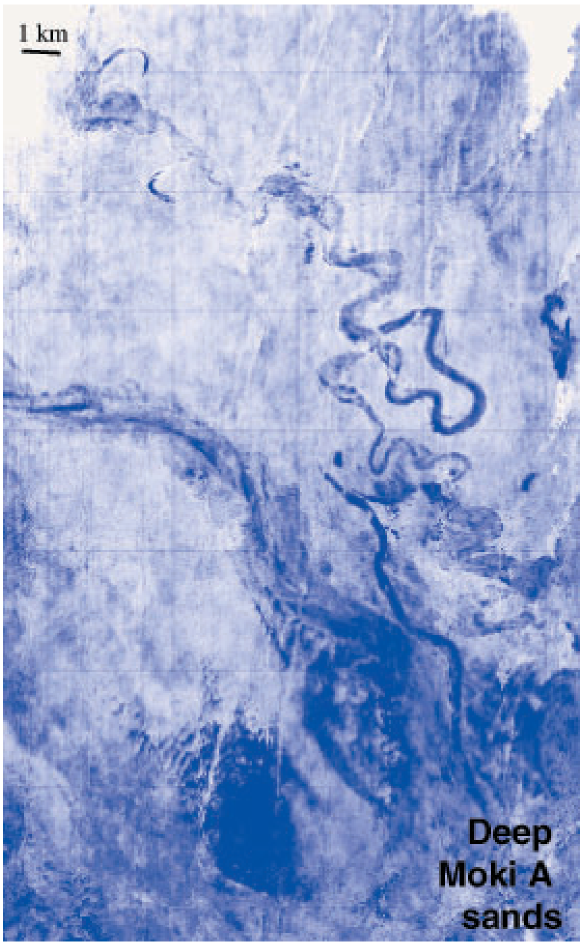

Figure 3: Meandering narrow submarine fan channels.

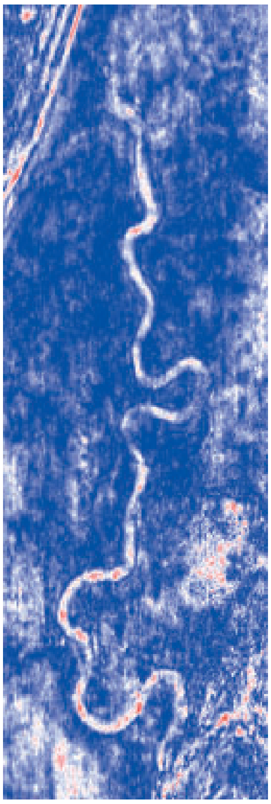

Figure 4: Meandering narrow submarine fan channels.

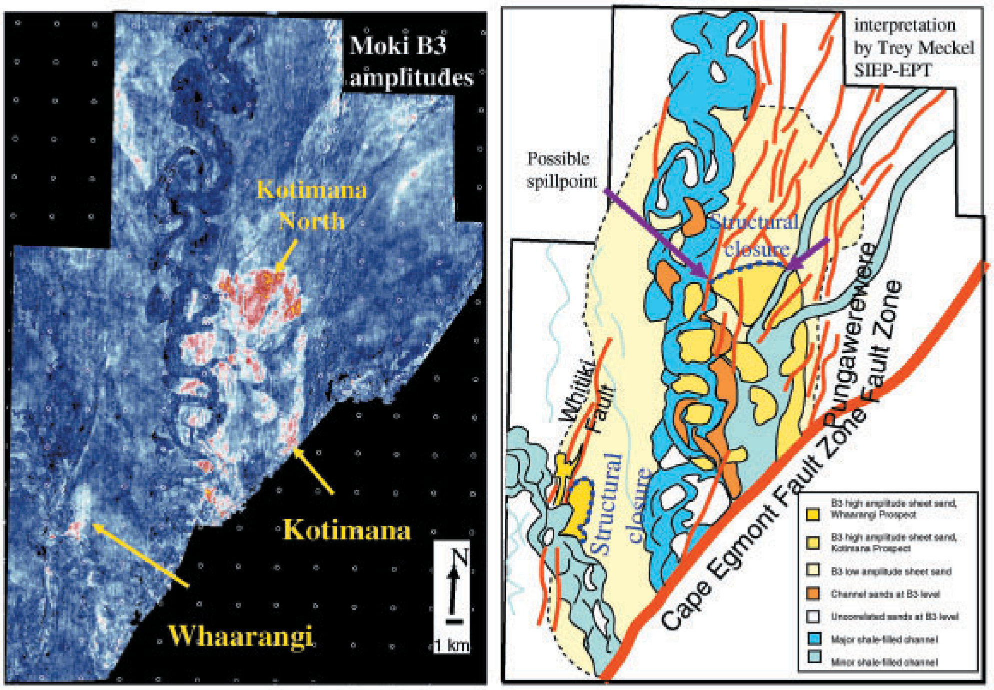

Figure 5: The Moki B3 laterally extensive turbidite sheet sands were subsequently dissected by mud-filled submarine channels.

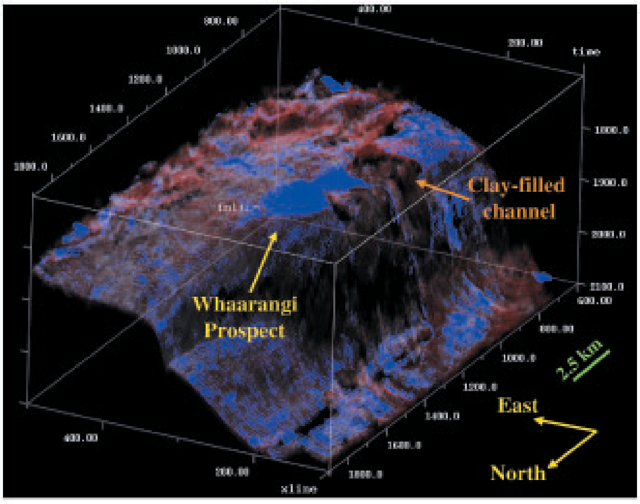

Figure 6: Moki B3 Impedance optical stack transparency showing the Whaarangi prospect in a structural high position

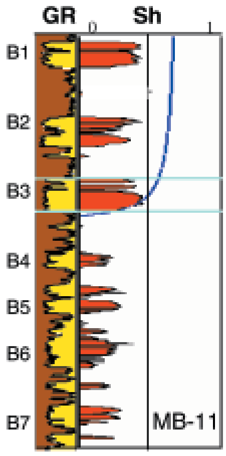

Figure 8: MB-111 showing raised B1-B3 HC saturation relative to B4-B7.

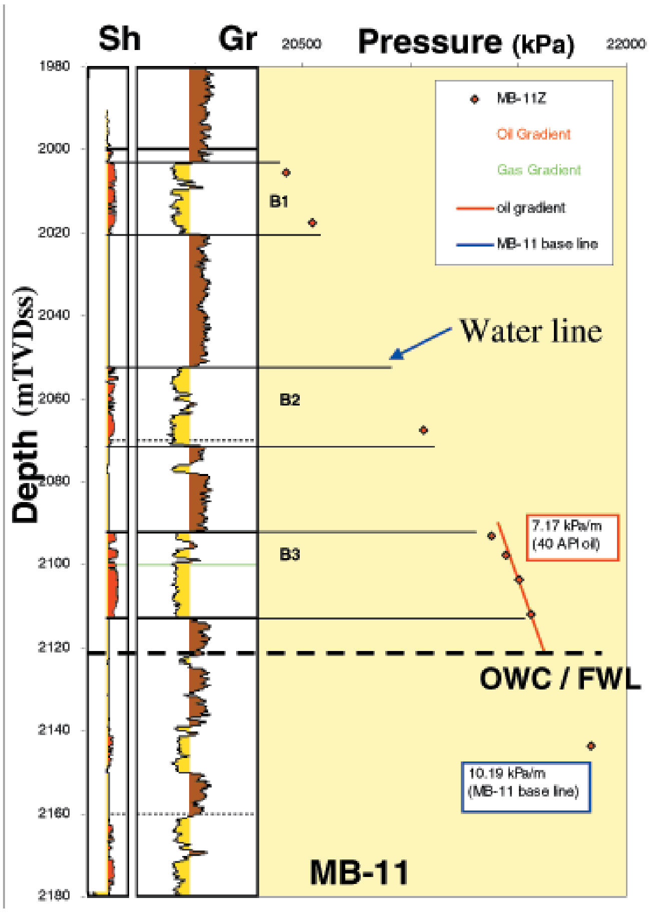

Figure 7: MB-11 pressure data indicating oil gradient in Moki B3 above 2120 m.

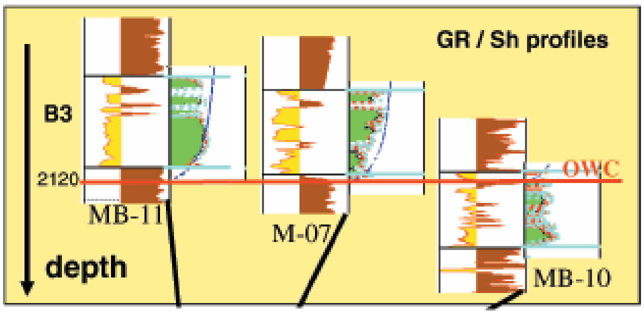

Figure 9a: Higher HC saturations on-structure (above 2120 m).

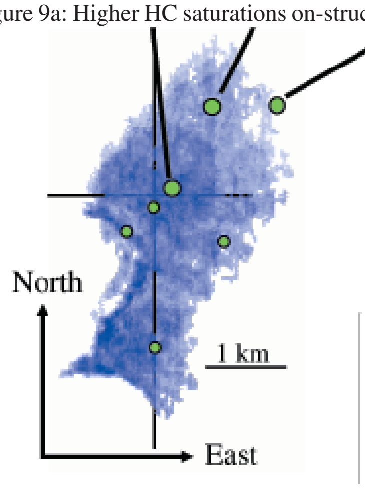

Figure 9b: Whaarangi B3 seismic impedance (structurally conformable anomaly).

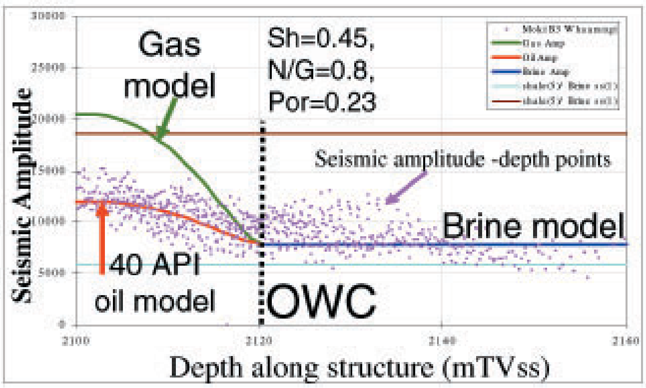

Figure 9c: Seismic (amplitude versus structure) fits oil model on - structure (above 2120 m).

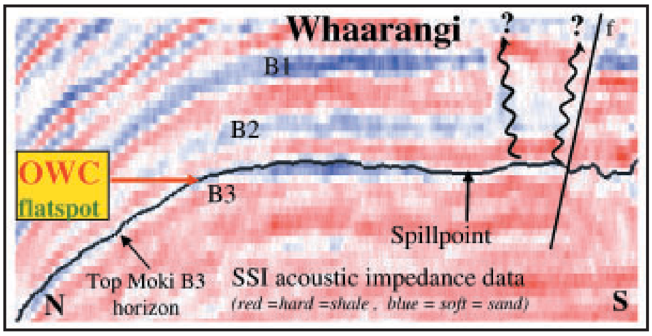

Figure 10: Seismic line through Whaarangi showing dip-closure with flat-spot indication of OWC.

and at a potentially high water-cut. At the mid hydrocarbon saturation level of 47%, water-cut could be around 50%, while at the highest evaluated hydrocarbon saturations of 55%, water-cut could be less than 10% (Fig. 11). However, this is very sensitive to the evaluated saturation and only a 10% lower evaluated hydrocarbon saturation level would conclude water more mobile than oil. Given the history of other Moki sands in the Taranaki basin (low productivity) and the relatively small oil column (transitional), commercial produceability was considered the main risk. Economic scenarios and production rate models resulted in a low commercial POS of just over 10%. It was clear that a production test was required to prove commerciality.

With the development infra-structure already in place for the deeper reservoirs, and given the potential volume of the prospect, only relatively low oil rates from the Moki sands would be required for commercial development. With a limited facilities lifetime, an early definitive result on the Moki development potential was essential. Consequently a recent infill development well, MB-07, targeting the deeper Eocene D sand reservoirs provided an excellent opportunity to test the Moki sands.

Testing or sampling an “oil accumulation”?

With the stated confidence in having an oil accumulation, as verified by the oil sample, and with production rate information considered to be the key to solving the commerciality issue, a production test would seem the obvious next step. However, it was appreciated that the previous Whaarangi fluid sampling in MB-11 was not conclusive due to the high volume of mud filtrate contamination. Some debate was still ongoing on whether all information to date really excluded residual oil saturations. Therefore, the possibility of more conclusive results from a new well designed fluid sampling program was considered. Even at low probability of impacting the test decision, a fluid sampling program was easily justified, given the low cost of fluid sampling relative to production testing.

Design of the fluid sampling program as input to the test decision scenario

The objective of the fluid sampling program was mainly to distinguish between oil as a continuous mobile phase and as immobile or residual oil. In the former case, it could also provide an indication of the possible water cut in a stable flowing production test (to indicate whether we could reject

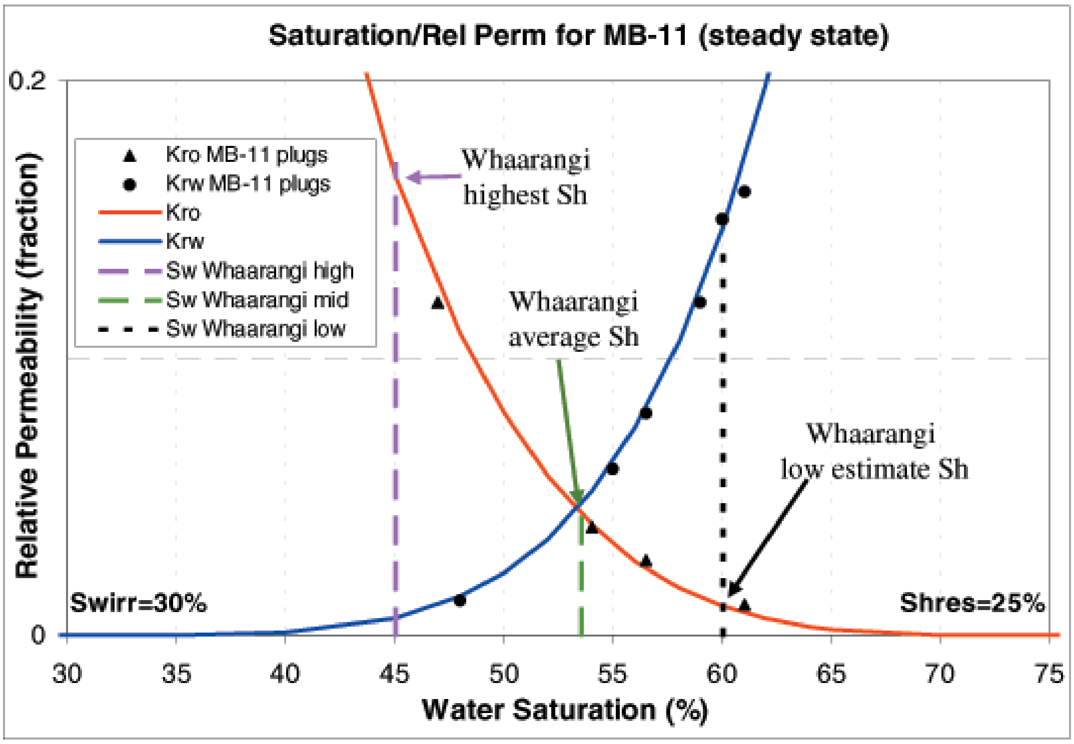

Figure 11: MB-11 rrelative permeability measurements and models suggesting that oil in the higher Sh range could flow with less than 50% water-cut.

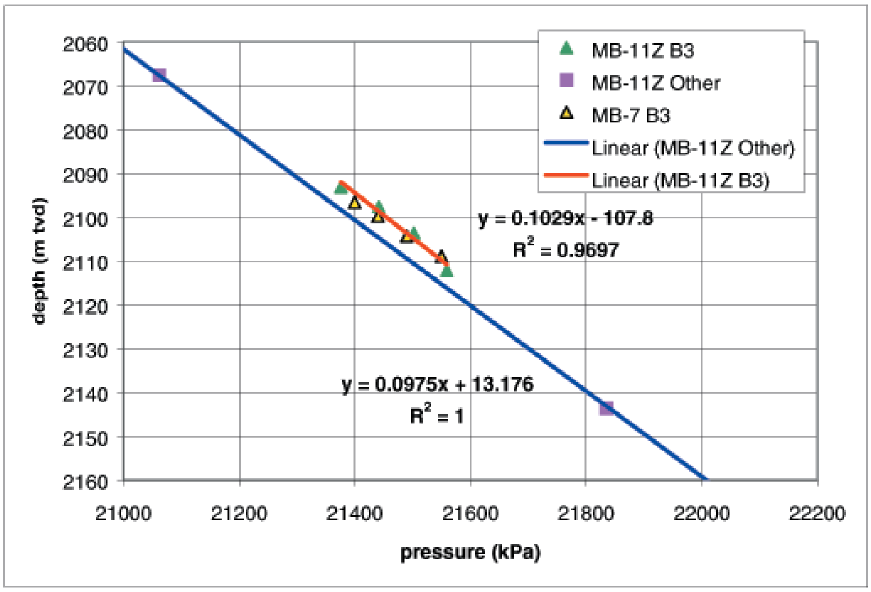

Figure 12: Formation of pressure data from MB-11Z and MB7 through the Moki Formation showing a consistant water gradient, but slightly overpressured.

Pressure data from the B3 sand showed an apparent water gradient (Fig. 12) and six of the samples, which were immediately analysed in a portable on-shore lab, showed a clear trend from an initial 6% formation water and 94% filtrate to a final 13% filtrate / 87% formation water (Fig. 13). Only a trace/ film of oil was observed in each of the samples taken, showing that formation water was much more mobile than oil.

Within 24 hrs of logging and sampling the Moki sands all derived data conclusively proved the oil to be residual with remnants of immobile oil only. The DST was abandoned prior to mobilising equipment and personnel. Despite the disappointing outcome, savings of several million dollars were achieved. These savings can be attributed directly to the down hole sampling program and to the value of information gained.

the probability of economical oil flow), and enable a decision to be made on whether to proceed with a production test.

The fluid sampling program, using Baker Atlas RCI tool, was designed such that minimal contamination (drilling fluid filtrate invasion in the near well bore formations during and after the drilling process) was obtained in the final RCI sample (after considerable pump-out). To help distinguish the amount of formation fluid from mud filtrate, a tracer was added to the drilling mud. Seven samples were taken at various stages of pump-out. Using the trend of fluid fractions in these samples, an asymptotic "virgin fraction of flowing oil" could be derived. The trend should also help differentiate between producing oil (increasing oil fraction) and residual oil potentially released by a large draw-down (decreasing oil fraction).

Results of the formation fluid sampling in well MB-07

The recent Maui D-sand development well MB-07 penetrated the Whaarangi B3 sand slightly shallower than any of the other wells with porosities and hydrocarbon saturation equal to or slightly better than the other on-structure wells. Because of tool sticking problems, the program was shortened to acquiring four pressures in the B3 sand only. After completing the 4 pressure tests, a series of seven samples were collected at a depth where the quality of the B3 sand was evaluated the best to minimise pump-out volumes. The seven samples were acquired after pumping out 1.5, 30, 80, 120, 160, 186 and 190 litres. After sampling was completed the tool could not be freed (no tension seen on cable head). A cut and strip operation was then conducted and the tool with the seven samples was successfully retrieved.

Review of the petrophysical evaluation

In the 1998 Moki petrophysical evaluation, extensive use had been made of porosity vs. hydrocarbon saturation plots to classify hydrocarbon potential (Fig. 14**).** Three levels had been identified. Data for most of the Moki sands plotted on the low trend, interpreted as residual. The Whaarangi B3 sand data plot on the intermediate trend, which were believed to be mobile as was "proven" by the oil sample (intermediate level explained by either transition zone or by poor rock facies). The upper "best" line related to zones that flow-tested oil in the Moki elsewhere in Taranaki. For example, Moki-1 and the nearby horizontal Maari-1A well tested oil at rates of resp. 660 and 4400 barrels per day.

The intermediate saturation level has now been proven by MB-07 to be mobile water, even when oil is present in the formation.

An obvious suggestion would be to interpret the intermediate level as residual hydrocarbons and the low trend as water bearing. This would imply that the petrophysical evaluation may have over-estimated the hydrocarbon saturations. Although this scenario is possible, the widespread hydrocarbon shows in sands while drilling suggest that the Moki sands of the Maui PML have at least residual hydrocarbons. The fact that there would be residual hydrocarbons in sands that are at present not structurally closed implies that they must be either related to migration paths or to paleo structures. Indeed, the long residual hydrocarbon column that is petrophysically interpreted in the Eocene indicates that a significant oil volume has leaked away which moved upward into the Moki sands. Migrating oil would have passed through the available conduit sands,

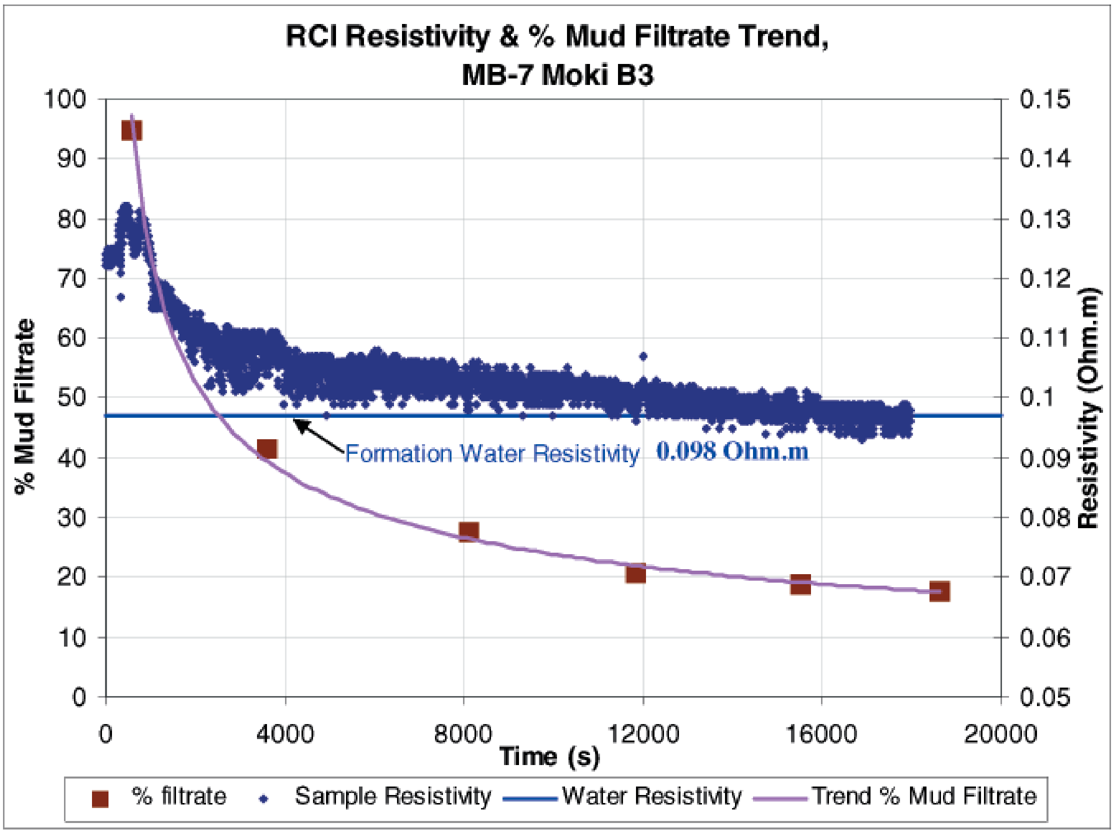

Figure 13: MB-07 RCI result showing decreasing mud filtrate (increasing formation water) with time.

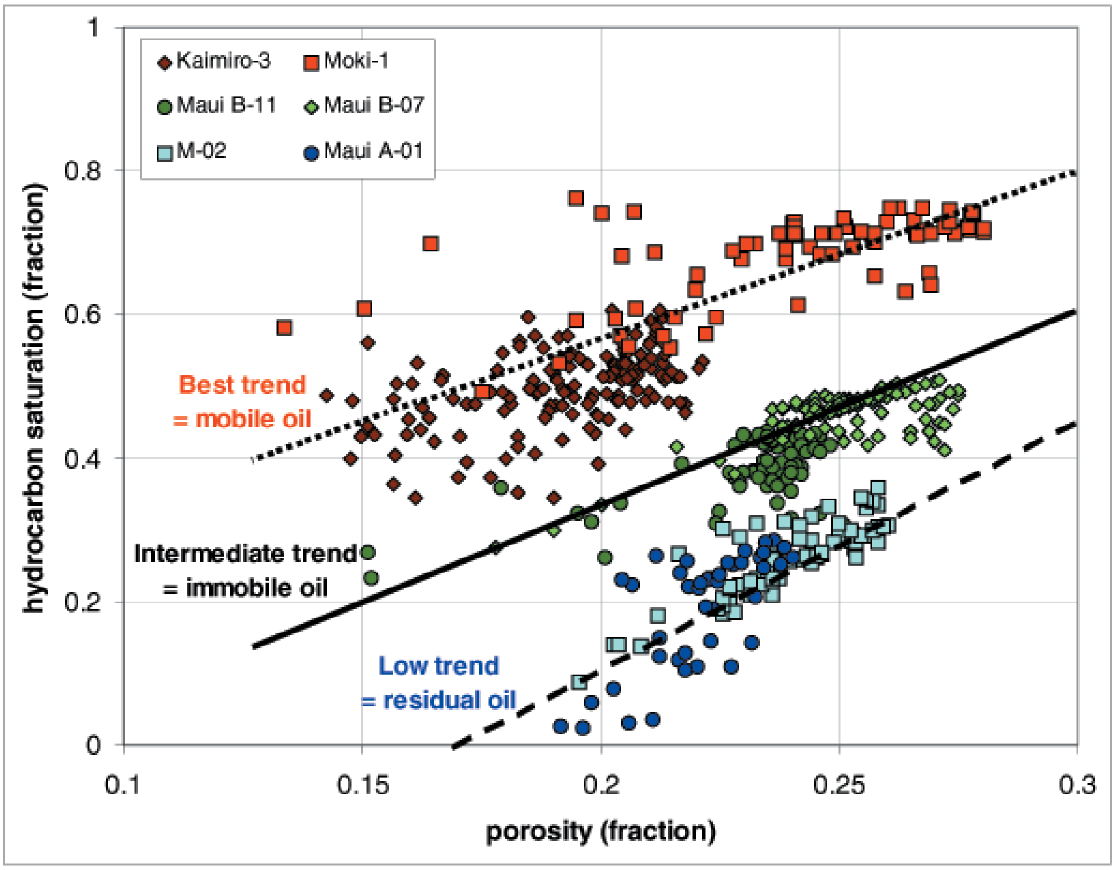

Figure 14: Porosity against hydrocarbon saturation for various wells in the Moki Formation.

and/or was trapped in a large paleo structure that may have existed before tilting of the main Maui structure or before breaching of the currently active bounding Cape Egmont Fault, leaving a residual column behind.

Also, the fluid sampling results could still be explained by very low permeability relative to oil related to a transition zone.

Discussion

This case study shows that caution should be exercised, even when a series of very strong positive indications for an oil accumulation exist. The step-wise approach to data acquisition, with clear decision points, paid off in favour of an at first sight cheaper direct approach of immediate testing.

It should be noted that we assigned only a small chance (20%) to such a conclusive negative result of no mobile hydrocarbons at all. The fact that the saturations were only intermediate, i.e. not as high as could possibly be expected for a 30 m oil column, was used to heavily risk commerciality (Probability of Commercial Success was estimated at just over 10% only) but not used to risk mobile hydrocarbons (Probability of Geological Success, i.e. mobile oil, was estimated at 80%). That may well have been an over-estimation. In hindsight, perhaps we should have given more weight to the negative indications. Maybe we were blinded by all the positive signs that contradicting information was not appropriately included. Obviously, the evidence of 1.5 litres of oil was seen as close to the ultimate proof.

A few negative indications were present. And a few questions were asked. Why don't we see higher hydrocarbon saturations closer to irreducible water saturation at the culmination of the structure? The hydrocarbon saturation in the upper part of the B3 unit is lower than expected from either the drainage or imbibition capillary pressure curves (this was explained by lower reservoir quality/different facies). Why did the two shallowest B3 pressure points not lay on the oil gradient? This was attributed to the tight streaks in between. In the B1 and B2 sands, similar hydrocarbon saturations as the B3 did not suggest an oil pressure gradient (though only very few points were recorded). With the results of MB-07, we now see a consistent picture with both MB-11 and MB-07 pressures (Fig. 12) almost on a perfect local water gradient through the B3. However, the B3 pressures sit above the general Moki water line. It was these raised pressures together with the oil recovered from the 12 gallon chamber in MB-11 that enforced the belief that mobile oil could be found in Whaarangi.

The explanation for the 1.5 litre of oil in the MB-11 sample is still under discussion. It is our current belief that a small amount of "immobile" oil in the invaded zone was "mobilised" by the very high drawdown (194 bar) applied during sample acquisition. This high drawdown must have changed the equilibrium conditions, locally mobilising the residual hydrocarbon saturations.

The additional confidence that was built through the seismic indications being consistent with the OWC interpretation from logs is not in disagreement with residual oil. Modelling shows that residual oil can also explain the seismic response. As such, this is another, rather obvious message; always give enough weight to the possibility of good seismic indicators (DHI's) being related to a reservoir with only residual / non-mobile hydrocarbons.

As a final point, the results for Whaarangi downgrades the larger Maui Moki prospectivity. Further appraisal (fluid sampling) is still planned as part of any upcoming MA development wells.

Conclusions

- A step-wise approach to acquisition and evaluation of data was taken which proved cost efficient and conclusive.
- The RCI formation sampling exercise in MB-7 has been very successful, giving definitive proof that Whaarangi does not contain oil volumes that can be produced.
- The Whaarangi structure has been filled with oil, probably to spillpoint, but has leaked over time, leaving residual / non-mobile oil behind.

Learning points

- This case study shows that caution should be exercised, even when a series of very strong positive indications exist. It is easy to filter out negative indications in abundance of positive indications.
- 1.5 litres of recovered oil do not necessarily prove an oil-accumulation.
- A fluid sampling program with multiple samples at various stages of pump-out can conclusively distinguish between mobile hydrocarbons and mobile formation water. Addition of a tracer to the drilling mud is instrumental in distinguishing the amount of formation fluid from mud filtrate.
- Always give enough weight to the possibility of good seismic indicators (DHI's) being related to a reservoir with only residual / non-mobile hydrocarbons.

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Author

PETER ENGBERS is the senior seismic interpreter and quantitative interpretation geophysiscist with Shell Todd Oil Services. He has 16 years experience in the Shell Group working in petrophysics, seismic processing, prospect evaluation research (Netherlands), special studies (Nigeria), geophysics (Brunei) and seismic interpretation (New Zealand). Peter has a MSc in Physics from Eindhoven University, the Netherlands.