The Lower D-sands in the Maui Field: Thin oil column development using an integrated scenario modelling approach

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Abstract

The Maui B Oil development, producing to the FPSO "Whakaaropai", was originally founded around the F-sands reservoirs, currently being drained by two crestal horizontal development wells. The Lower D-sands (D1.6 and D1.10) were initially considered as opportunity for oil only as recovery was considered very limited due to perceived poor reservoir quality and thin oil columns. However, on first (commingled, vertical well) production from these lower coastal plain channel sands, significantly greater than expected oil production rates (3000 bbls/day D1.10 & 7,500 bbls/day D1.6) were encountered. This led to an integrated subsurface review of the Lower D sands, and has resulted in significant upside potential for incremental oil recovery.

Due to wellbore utility constraint, there has been very limited production from the Lower D sand reservoirs to date, with < 3% recovery from only two vertical wells, both localised in the northern area of the field. Consequently there is a high degree of subsurface uncertainty inherent in reservoir modelling of the lower D-sands. In an effort to constrain and manage this uncertainty, a (probabilistic) scenario tree approach has been adopted incorporating multiple subsurface scenario-tree branches; separating out the key uncertain subsurface variables and constraining a discrete range of likely parameter values.

With the oil production facility infrastructure already in place and given a limited FPSO lifetime, a generic development plan was screened as economically attractive. Further detailed modelling was conducted with a single representative base-case scenario to optimise the subsurface targets for the drilling of two (horizontal) wells and one (horizontal) side track in these reservoirs.

This paper describes the contrast in the Maui-B F-sheet sand 'layer cake' reservoir modelling, with the complex and uncertain geological architecture of the channel sand environment of the D-sands. Inherent subsurface uncertainties of the D-sand reservoir were managed through a combination of probabilistic reservoir simulation modelling and a pragmatic approach to development well positioning.

Introduction

The Maui Field is the largest producing field in New Zealand providing over 80% of the county's natural gas, i.e. an equivalent 50% of total New Zealand energy requirements.

The field was discovered in 1969, and is located in the offshore Taranaki Basin on the west coast of the North Island, New Zealand (Bryant, 1996; King & Thrasher, 1996). It is covered by a 1000 km^2 3D seismic survey acquired in 1991 and to date eight exploration/appraisal wells and 24 development wells have been drilled (Soek, 1998; Young, 1998) (Figure 1).

Maui comprises two-low relief structures termed Maui-A and Maui-B with three main Eocene Kapuni reservoir units in each; the C, D & F sands (Figure 2).

Maui produces primarily gas with associated condensate and LPG from the C & Upper D sands. The average gas rate (1998) is ca.10 million m^3/day.

In 1993 a Maui-B development well (MB-3V), targeting upper D-sand gas, was deepened to appraise an F-sand prospect identified from 3D seismic (Young, 1996), resulting in the discovery of the Lower-D & F-sand oil reservoirs at ca. 3000 m TVD. These are fault/dip-closed structures bounded to the west by the Whitiki Fault.

F-sand oil development project

September 1999 represents the third anniversary of F-sand oil production. With ca. 16.5 million bbls of oil recovered

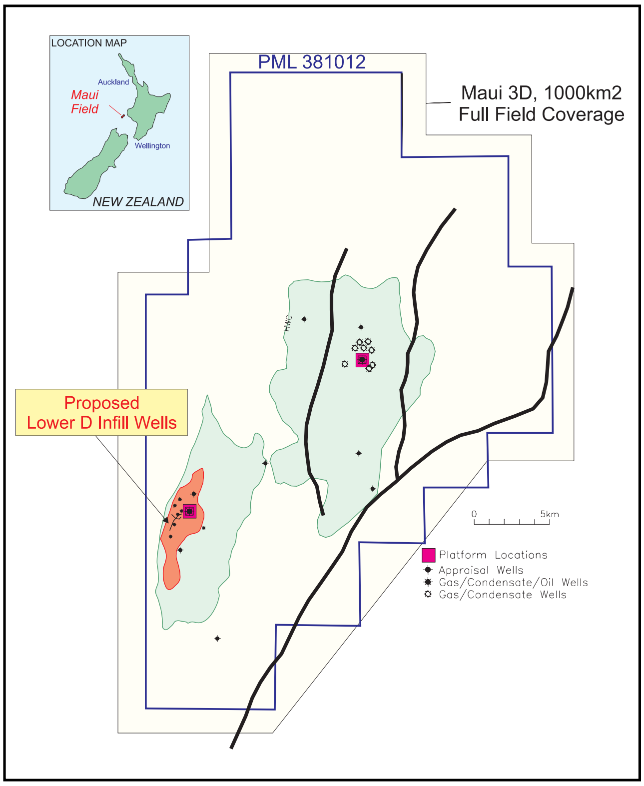

Figure 1: Location of the Maui Field, New Zealand.

(or ca. 80% of expected recovery) the development from Maui-B may be described as relatively mature.

The last Maui-B drilling campaign of 1993-4 included two wells drilled and completed with 3-400 m horizontal sections at orthogonal orientations in the crest of the F-sand structure. Confidence in the F-sand development was sufficiently high to warrant the pre-drilling of these wells prior to any long-term production testing or detailed reservoir modelling.

Subsequent subsurface modelling studies indicated no further development drilling of the F-sand was necessary, and that the two horizontal wells together with existing vertical well MB-8P made up the optimum development.

The F-sand oil reservoir has many favourable qualities resulting in an efficient recovery of oil reserves (Recovery Factor) in excess of 50%:

- homogeneous good quality oil sands;
- 35m (+/-) oil column;
- simple anticline fault/dip-closed structure;
- attic drainage from horizontal wells;
- strong (infinite) aquifer support; and
- favourable oil/water mobility-ratio.

F-sand reservoir modelling is also relatively straightforward, as well penetrations provide log signatures that are easily correlated across the field leaving little uncertainty of the modelled ‘layer-cake’ architecture (Figure 3).

A deterministic reservoir modelling approach was applied to the F-sands in which the marginal variations in reservoir properties were linearly interpolated between wells with a simple distance weighted algorithm.

The uncertainty of ultimate recovery was evaluated by running sensitivities on this base-case deterministic model (initially in ECLIPSE & subsequently migrated to MoReS *).

A further major initial uncertainty was aquifer strength and in the event of minimal aquifer support, a contingent re-completion of MB-8P to water injection was planned.

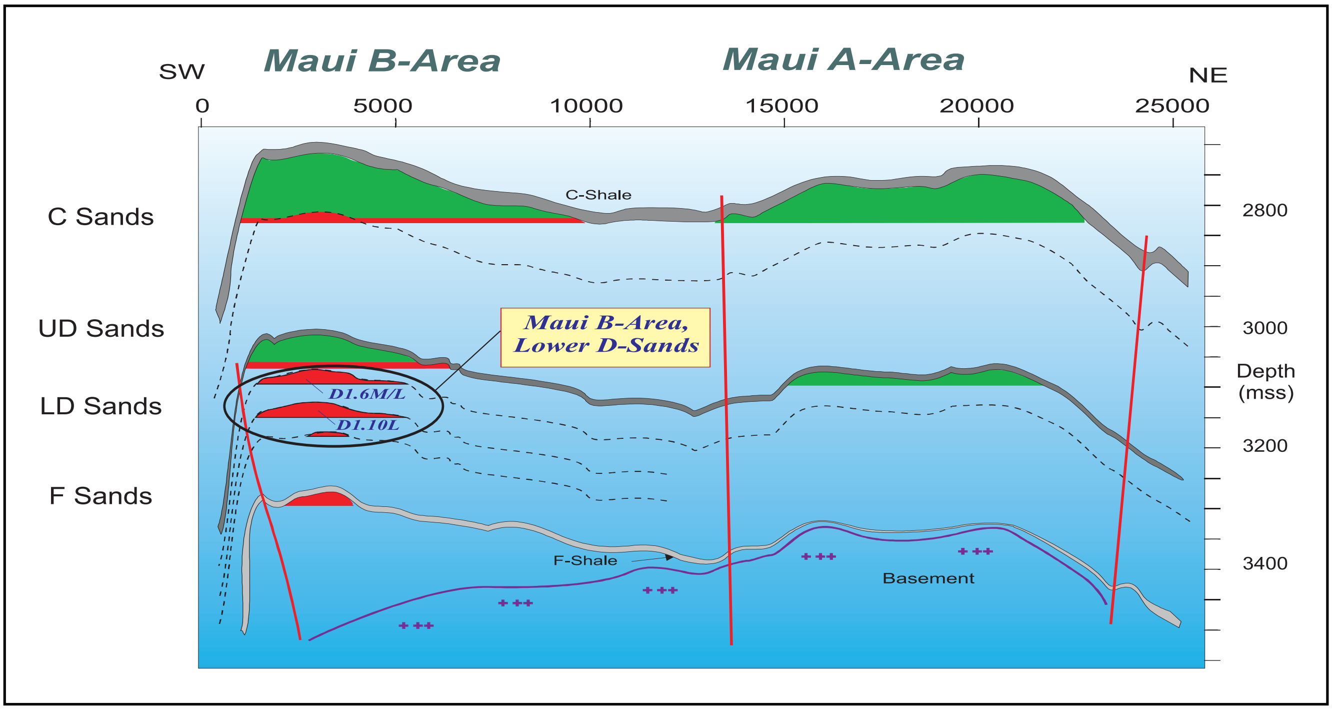

Figure 2: Maui reservoir (SW-NE) cross-section.

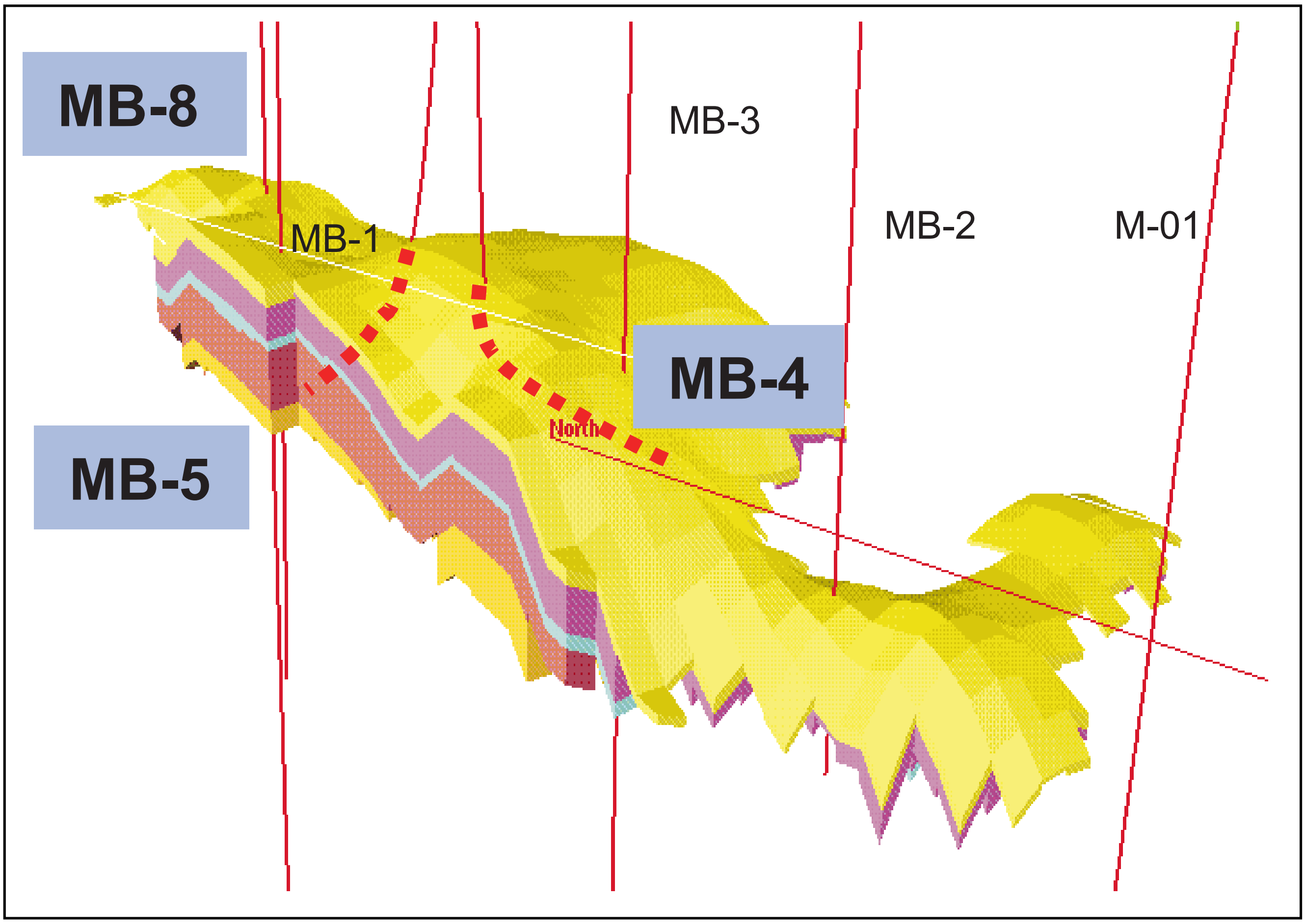

Figure 3: F-sand 'layer-cake' geological model.

The cost of providing oil production, storage and offloading facilities at Maui-B, i.e. the FPSO "Whakaaropai", was fully carried by the F-sand oil development project alone (Figure 4).

Potential in the lower D-sands

The Lower D-sand reservoirs located ca. 150 m (TVD) shallower than the Maui-B F-sands were initially considered to offer 'opportunity oil' only by means of upward perforation/ completion of existing wells.

A number of factors contributed to this cautious approach to the D-sands development potential:

- Early (1994) production testing of vertical well MB-1R completed across the D1.10 produced at a low oil rate of 75m^3/day.

Subsequently, high initial skin was removed and well FTHP significantly reduced.

- FBU analysis of MB-1R identified apparent small-dimension channel sands.

Subsequently, acoustic impedance data identified the channel as non-representative.

- Uncertainty in reservoir quality from logs underestimated permeability.

Subsequently, K/Phi relationship matched to well test-derived (K) increased perceived reservoir quality.

- Reservoir modelling studies conducted prior to production (1996) carried a high level of geological uncertainty, and predicted likely low and non-sustainable oil rates.

However, subsequent modelling studies have been updated with production performance to date, improved reservoir permeability and channel dimensions.

Figure 4: Maui FPSO "Whakaaropai".

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* Shell proprietary software.

A dedicated development of the D-sands could not initially be justified, however this conclusion was questioned once D-sands production started in late 1996.

Well MB-1R was opened to flow across the lower D1.10 sands. The well was sub-optimally located for D-sand development on the northern flank of the structure in a 10m-oil column produced at a surprising 500 m^3/day of dry oil. After sustained production for 5 months a 12 m oil column in the D1.6 sands was additionally perforated and the well produced at a commingled rate in excess of 1800 m^3 oil/day (11,000 bopd).

This high production rate was short lived as water-cut developed to 70% and the oil rate dropped to ca. 300 m^3/day over a 3 month period.

A second D-sand drainage well (MB-8P) commingled production across the F & D1.10 in July 1997. Initial rates were encouraging (500 m^3/oil/day) although an immediate water-cut halved the oil rate within a month and a steady oil decline has been observed to < 50 m^3 oil/day. Recent additional perforation of the D1.6 interval in this well only increased the rate to ca. 200 m^3 oil/day with high watercut.

From the (limited and) varied D-sand production performance it is evident that there is a wide range of potential for any infill wells, and that conditions are likely to suit a horizontal well development.

Challenge

The challenge was to quantify the subsurface uncertainty in the D-sand reservoir, to manage this reservoir uncertainty and to evaluate the risked value of a D-sand development project. Development economics had the advantage of an existing FPSO with oil processing capacity available at Maui-B, however, the facility opportunity was only available over a narrow 5-7 year window. Beyond seven years the FPSO would require costly maintenance servicing to remain fit for purpose.

Lower-D Reservoir modelling

The lower D-sands contain stacked thin oil columns (5-25m thick) in a complex channel-sand reservoir environment. The structure is penetrated by nine wells, however log correlation between wells is complex, confirming the heterogeneous nature of the sands (Figure 5).

Channel sands of reservoir quality (10-100+mD) were modelled as inter-dispersed within a lower quality (0.1-10mD) matrix sand. The sand system is sandwiched between laterally extensive coal zones bounding the reservoir vertically (Figure 6).

The fundamental uncertainties in reservoir geology are de-coupled as follows:

- reservoir top structure (gross rock volume);
- continuity of channel sands (channel size); and
- prediction of reservoir quality from logs (K/Phi relationship).

Lesser impact uncertainties related to the dynamic behaviour of the reservoir:

- aquifer strength/ support;
- sealing faults;
- residual saturation; and
- relative permeability and end-points.

A multiple scenario modelling approach (Cohen et al., 1996) was considered an appropriate reservoir simulation strategy to accommodate the range in uncertain (static) reservoir geology. Each parameter with uncertainty was separated into high, low and median values. Compounded uncertainties were described in a scenario tree. Each element of the tree was attributed a probability of occurrence based upon an engineered judgement from the integrated subsurface team. The tree branches then

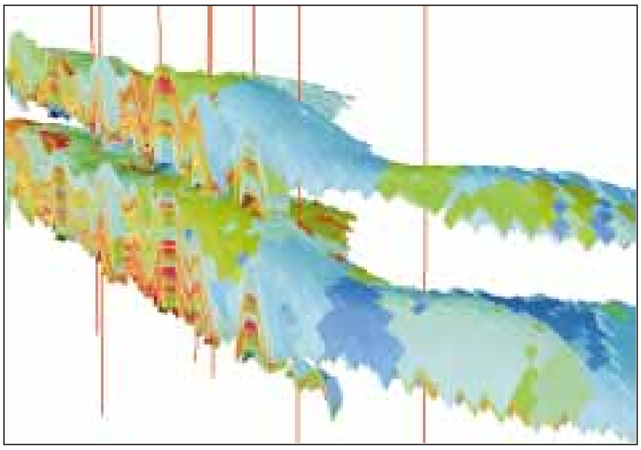

Figure 5: Lower D-sand complex facies model.

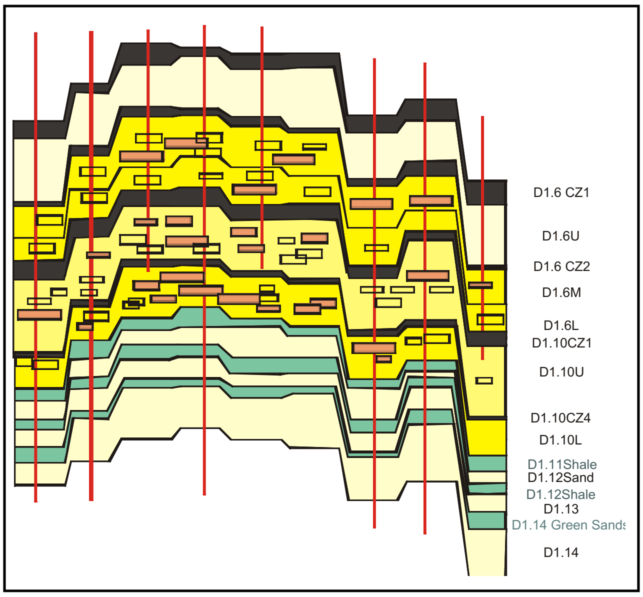

Figure 6: Lower D-sand probabilistic infill.

represent the range of possible reservoir geology, and each outcome has an associated combined probability (Figure 7).

Uncertainty in the top depth map, although constrained by well control, remains predominant in the northern and southern flanks of the field.

Two extremes of geological architecture are envisaged: the reservoir sands may be compiled of discrete non-connected channel sands or, conversely, channel sands that connect up with one another and form a continuous channel sand framework.

Multiple geological models were generated by probabilistically infilling elliptical shaped (channel) sand bodies into a background (matrix) sand within the static geological modelling package GEOCAP[*].

The total volume of channel sand infill was constrained by the ratio of channel-sand : background matrix-sand, as observed in wells. In the correlatable model, this ratio was marginally exceeded and in the uncorrelatable model, the ratio was marginally reduced (Figure 8).

The shape and aspect ratio of each specific infill channel sand is sampled out of a representative (similar environment of deposition) database of observed outcrop data (Figure 9).

The uncertainty in permeability prediction from porosity is based on high, medium and low K/Phi relationships. The medium or 'base-case' K/Phi relationship is based upon a pseudo fit to core porosity data that is forced to fit well-test production derived absolute permeability. The high and low ranges are then +/- 1 porosity unit difference from this base relationship.

From the scenario tree, 18 geological models were probabilistically generated, each with a random realisation of channel sand in-fill. The most likely geological scenario (base-case) is with the P_{50} structure map, the mediun K/Phi relationship and the non-connected channel sands.

The extreme outside scenario branches were discarded due to extremely low probability, and a representative sample (8) of the static models was carried into dynamic simulation studies. History matching was attempted on each of the models, and a match to observed reservoir pressure decline was achieved in all but the low-case reservoir quality scenarios, primarily by adjusting aquifer strength.

A sequence of incrementally complex drilling development scenarios was conceived. These involved drilling two, then

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[*] Shell proprietary software.

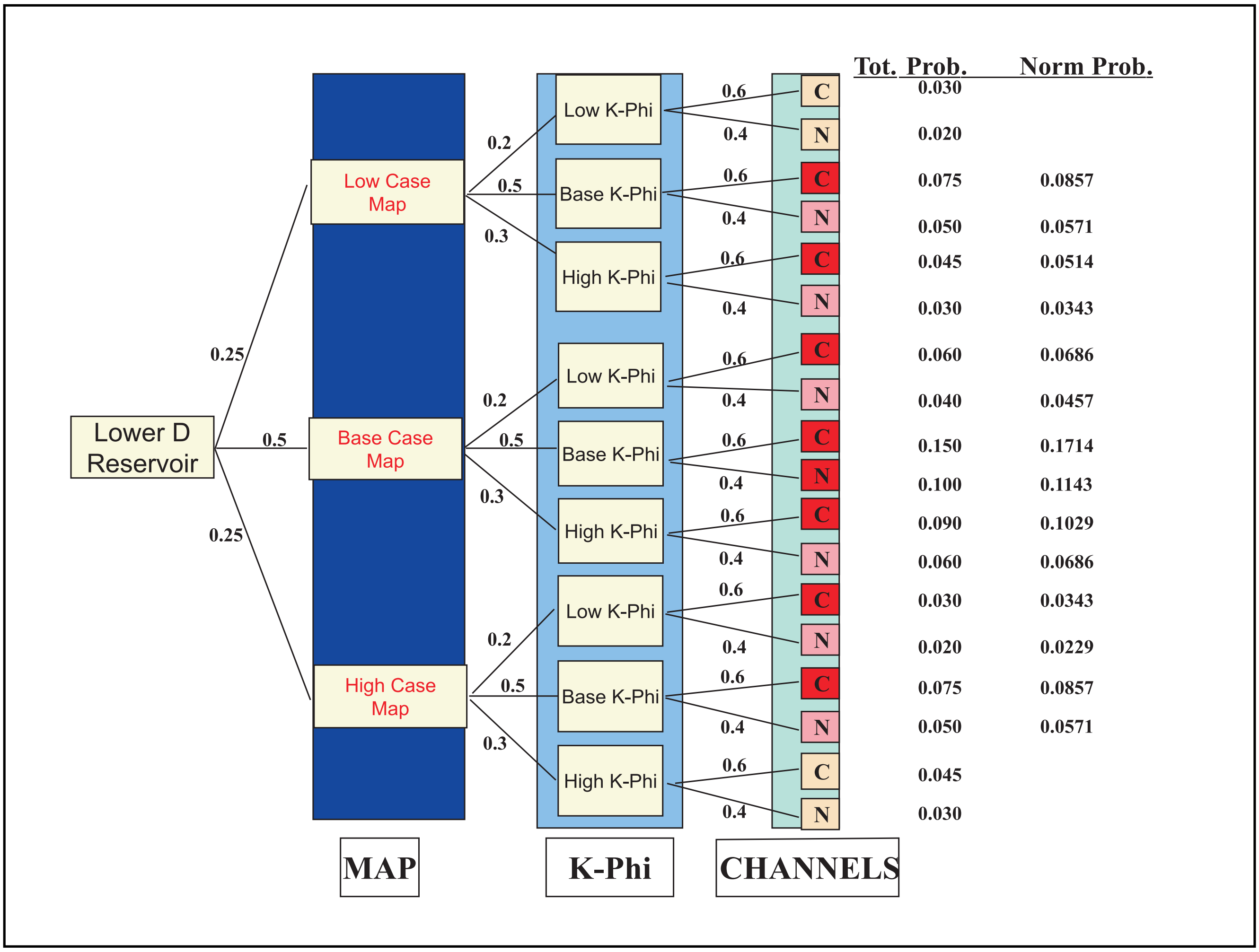

Figure 7: Reservoir model Scenario Tree.

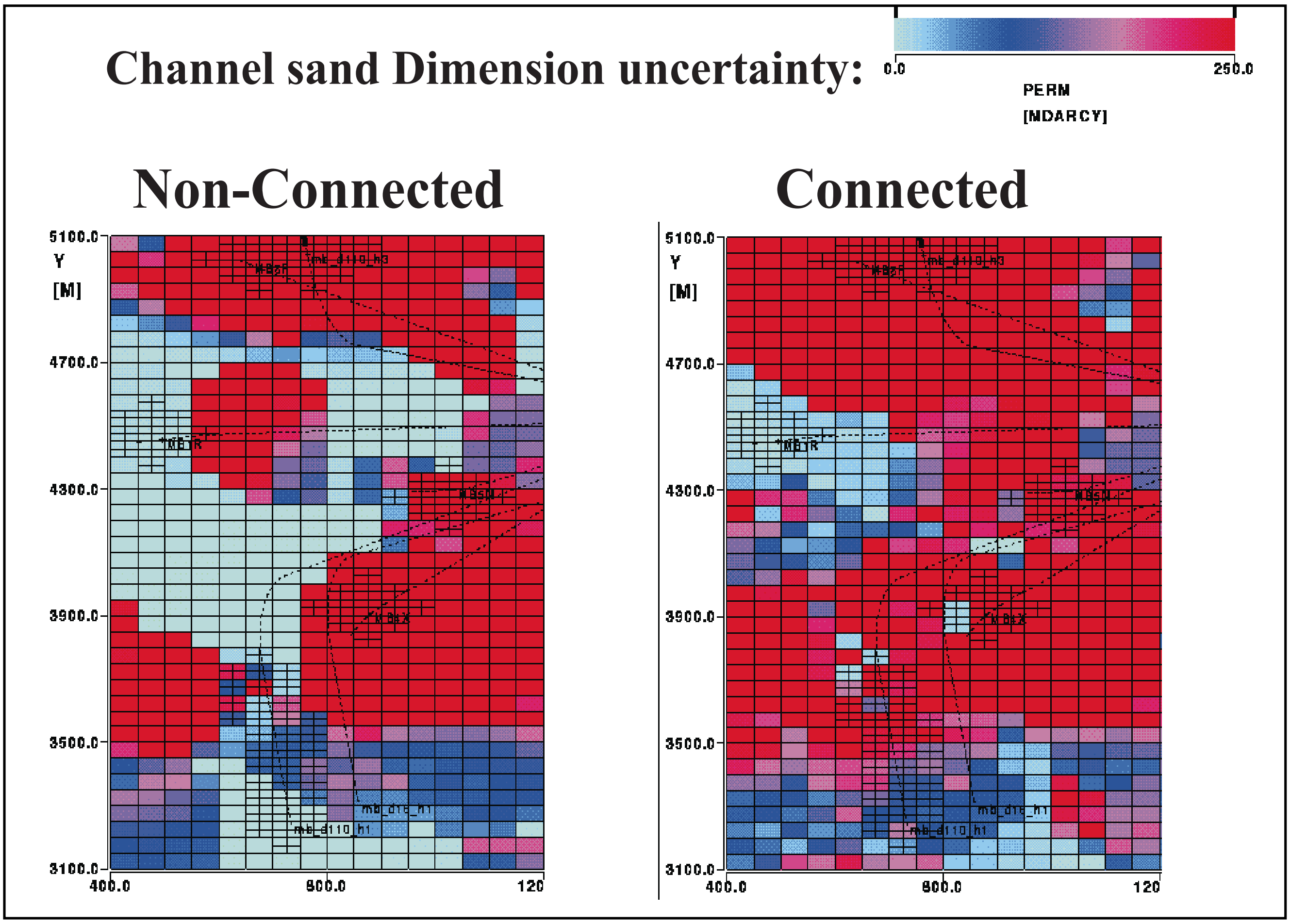

Figure 8: Correlatable and uncorrelatable models.

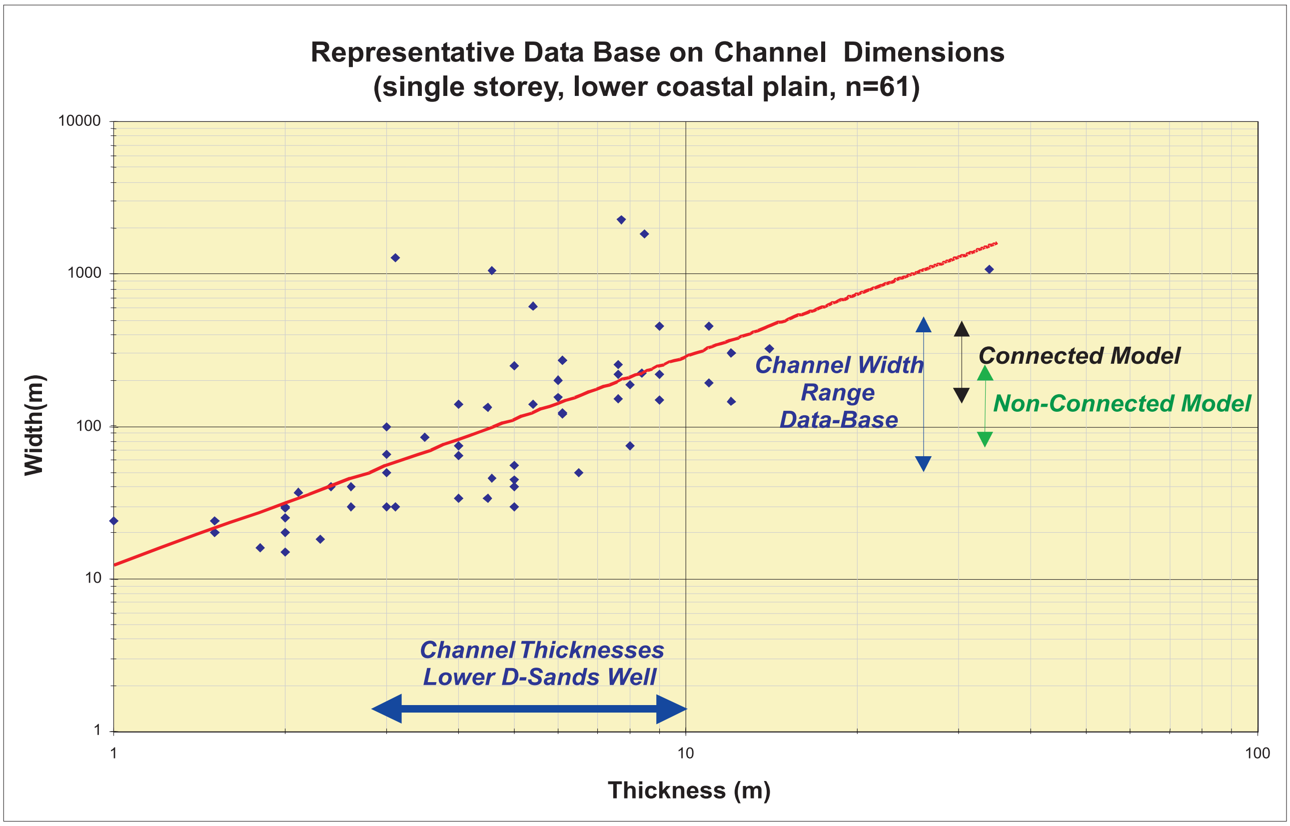

Figure 9: World database of channel sand dimensions.

three crestal horizontal wells (Development Activities: DA1 & DA2), then additional northern & southern flank wells (DA 7 & DA8) (Figure 10).

Dynamic simulations of this sequence of (4) progressively complex development drilling activities were then run on each of the selected (8) static geological models, as described by the scenario tree (32 simulation runs).

This resulted in a ‘creaming curve’ of recovered reserves as a function of number of wells drilled, for each of the static geology scenarios.

As the geological scenarios have an associated probability of occurrence assigned to them, a cumulative probability of recovery can be defined for each development drilling activity (Figure 11).

An acceptable risked oil recovery was identified for an economically attractive three well development; one crestal horizontal well in the D1.6 and two in the D1.10 sands. It was, however, recognised that modelling scenarios were based upon specific random realisations of reservoir quality channel-sand distribution. Consequently none of the models could be used to target well locations.

A second round of modelling was conducted to enable optimisation of the well locations, in which a deterministic reservoir model was selected, based around the P_{50} model parameters.

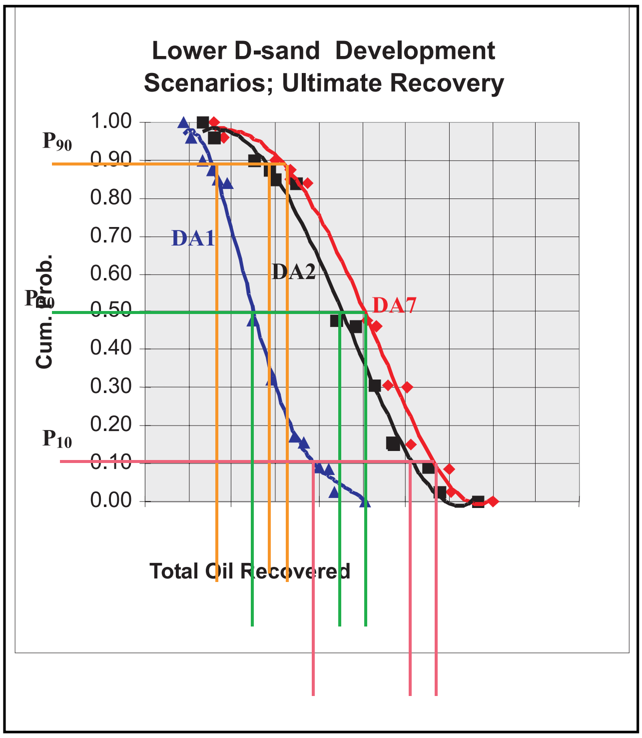

Figure 11: Probable recovery distribution per drilling event.

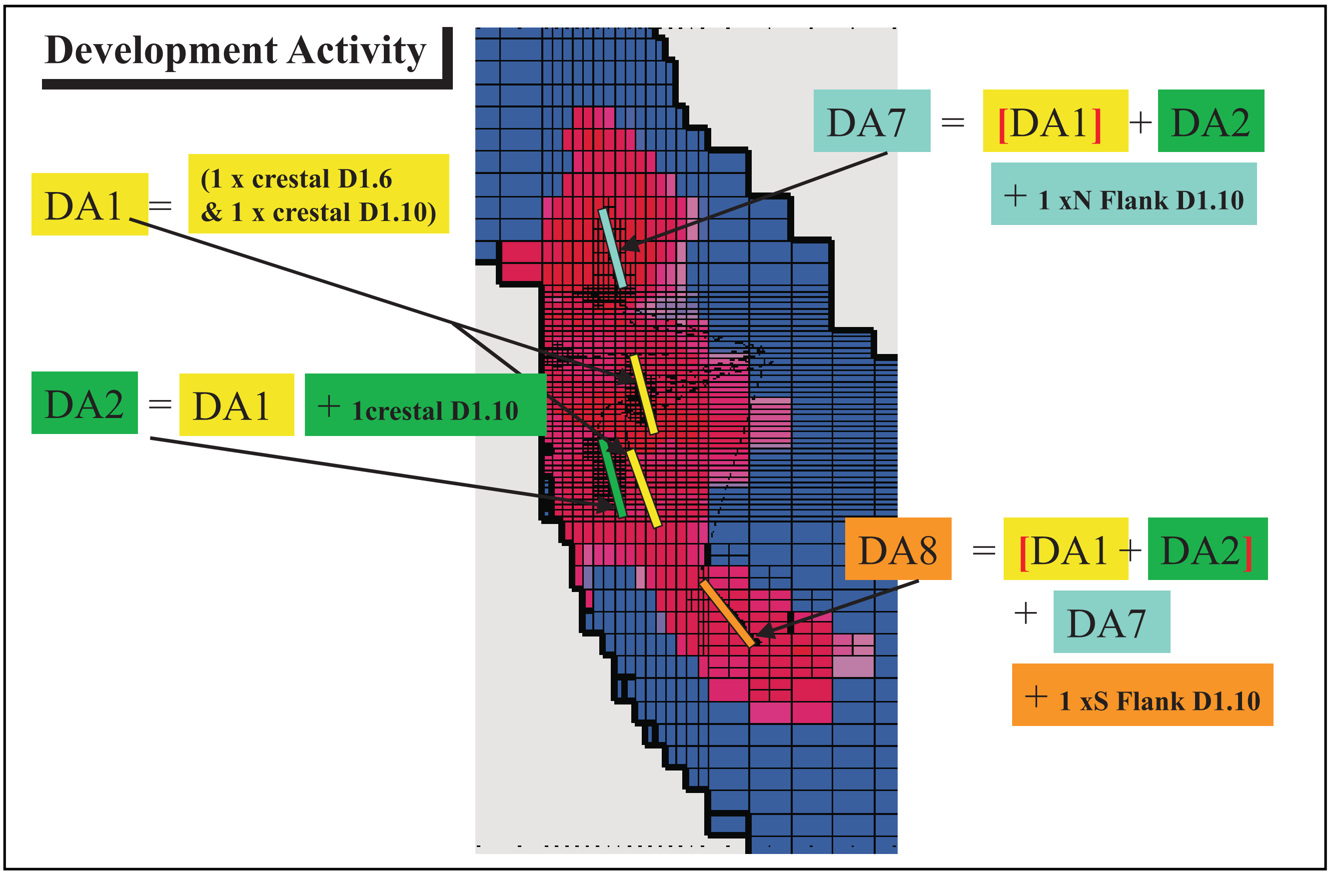

Figure 10: Sequentially complex development drilling scenarios.

Sensitivities to further refine the optimum three horizontal-well development were run to horizontal completion well length, orientation and depth below the top reservoir structure. These studies highlighted the impact on recovery of optimally targeting these development wells in the relatively thin oil columns to within 5 m of the top reservoir structure. Steering the horizontal sections of these wells to the optimum target location will be a challenging but rewarding exercise.

Lower D-sand Oil Development Project

A pragmatic approach to well location (Figure 12) was devised based upon the following:

- placing horizontal wells high in the attic structure;
- locating wells with a known (estimated) drainage radius away from existing wells, and within the HC closure of the reservoir;
- 500 and 700 m horizontal intervals are the maximum length the D1.10 & D1.6 reservoir structures can accommodate respectively;
- orthogonal well trajectories would account for uncertainty in preferential channel sand orientation.

The optimum development is to drill two new 500 m horizontal wells into the D1.10 sands, and to side-track existing well MB-1R with a 700 m horizontal interval into the D1.6. This drilling project, using a small footprint Pool Rig, commenced in November 1999.

The expectation-unconstrained forecast for this development is to produce an incremental ca.10 mmbopd over the following 6-7 years (Figure 13).

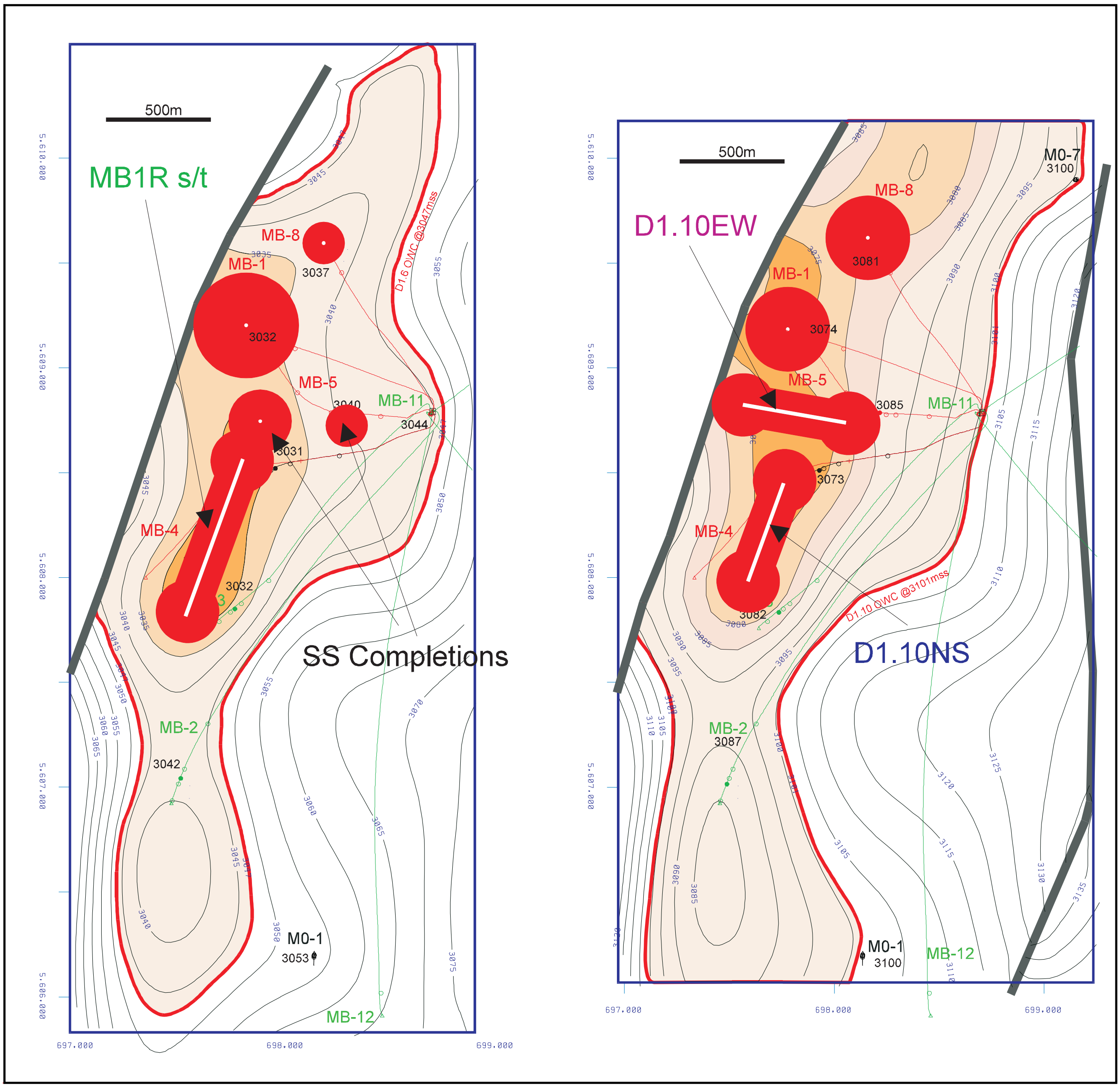

Figure 12: Pragmatic approach to positioning development wells; accommodating both existing and planned development well drainage areas to the structure of the HC reservoir.

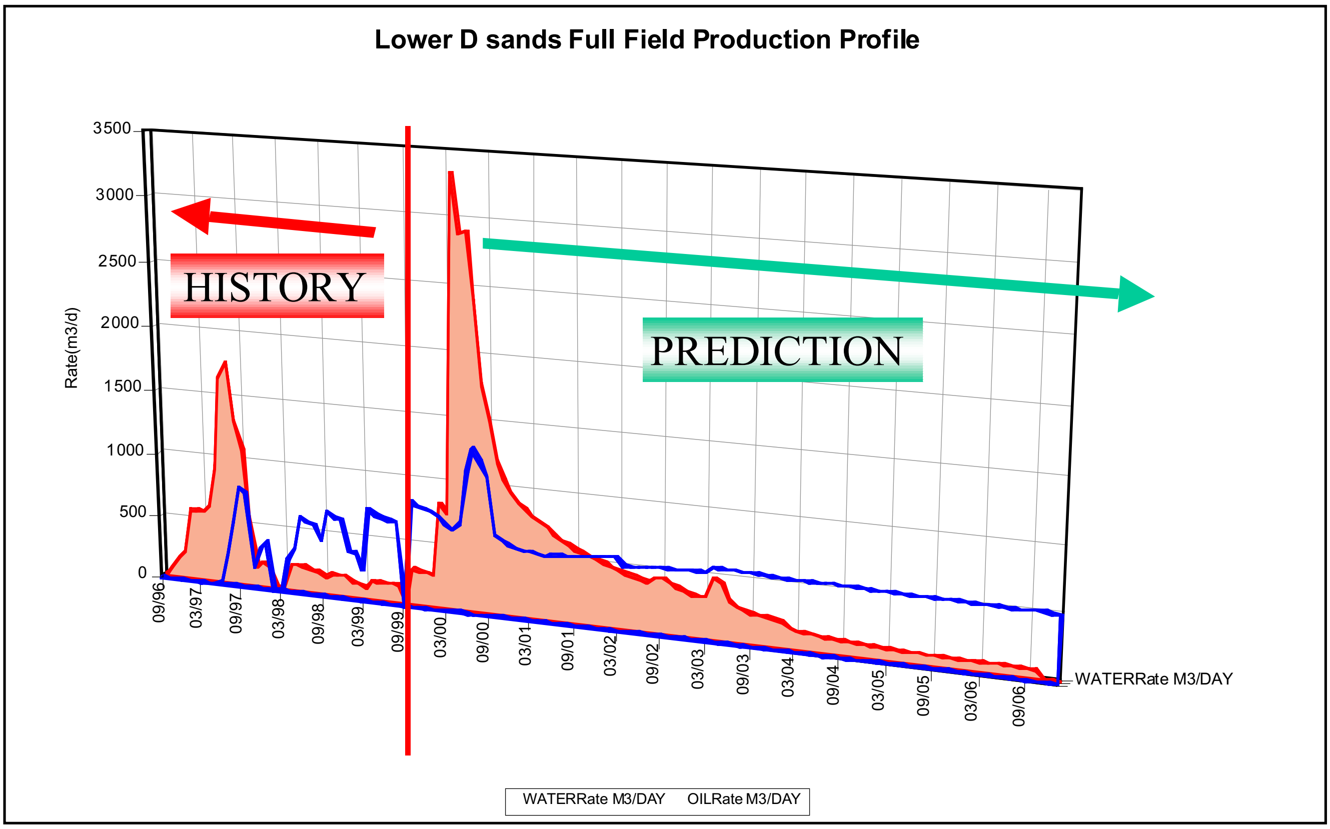

Figure 13: Full field development production profile.

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