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Quantitative Estimation of Directional Permeability Barriers as a Reservoir Heterogeneity – A New Approach Using Synthetic Core

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Summary

One of the major challenges in reservoir characterization is to estimate the effective porosity and the permeability of the reservoir due to reservoir heterogeneity. Often the vertical and the horizontal permeabilities are not considered separately in 3D geo-cellular models and in the reservoir simulations. Conventional reservoir modeling extrapolates all of the small-scale data to full-field scale data without considering the impact of the small-scale geological details, and therefore carries forward inherent errors into the reservoir predictions as a consequence of ignoring the reservoir heterogeneity. Most reservoirs are geologically complex and heterogeneous and that greatly influences reservoir performance.

A case study is taken from a Cold Heavy Oil Production with Sands (CHOPS) field. An innovative method of reservoir heterogeneity estimation has been introduced to illustrate the complex reservoir heterogeneity honouring all of the small-scale geological details in the 3D geological model. This detailed near-wellbore modeling through a synthetic core can provide the realistic quantitative volumetric assumption of the production prediction and improve the Enhanced Oil Recovery (EOR) processes.

Introduction

The objective of this study is to quantitatively estimate the small-scale sub-seismic reservoir heterogeneity and its influence in the reservoir simulation process and reservoir characterization, as the conventional up-scaling mechanism cannot preserve the integrity of the original reservoir properties in the simulator. In this study, the approach administers the deterministic geological processes in a stochastic framework, combining advantages of both the deterministic and stochastic modeling methods. This innovative up-scaling method resulted in the model being more geologically realistic than by only using conventional geostatistical approaches, which are either object-based or cell-based (Jonoud et. al., 2008). Reservoir heterogeneity was found to be a major challenge in the reservoir evaluation and production history matching processes. Flow simulation and reservoir performance estimations are directly dependant on the geological model of the reservoir. Building a realistic 3D geo-cellular model to improve estimation of reservoir heterogeneity was the key factor in the evaluation of the reservoir performances and in planning for the EOR strategy, especially of a CHOPS pool.

In this study, sedimentary bedforms were categorized by the shale volume factors, which were derived from conventional wireline log interpretation and rule-based relationships established among log-facies representing the different sedimentary bedforms structures observed from cores. The study was taken from the Primate CHOPS pool that belongs to the Upper Mannville Group (Albian) whose rocks were deposited in a prograding deltaic estuarine-fluvial environment within a foreland basin (Christopher, 2002).

Methods of Study

In this study, a 3D geo-cellular property model was built from synthetic cores and high resolution 3D near wellbore models that estimated the reservoir directional permeabilities (kx, ky and kz). Emphasis was put on facies distribution, sedimentary bedform structures of the known depositional environment and high-resolution up-scaling in the 3D geological model. In this study, 4D seismic data was used in determining the lateral extent of the reservoir and in finding the production footprints of the CHOPS pool (Figure 1). The vertical high resolution (cm-scale) facies distribution of the reservoir has been analyzed from wireline logs and offset core data. These integrated results, along with the detailed near wellbore heterogeneity imaging, allowed for an exhaustive evaluation of the reservoir performance. Subsequently, additional drilling opportunities were identified, which enhanced the EOR processes by avoiding this CHOPS pool's wormhole network.

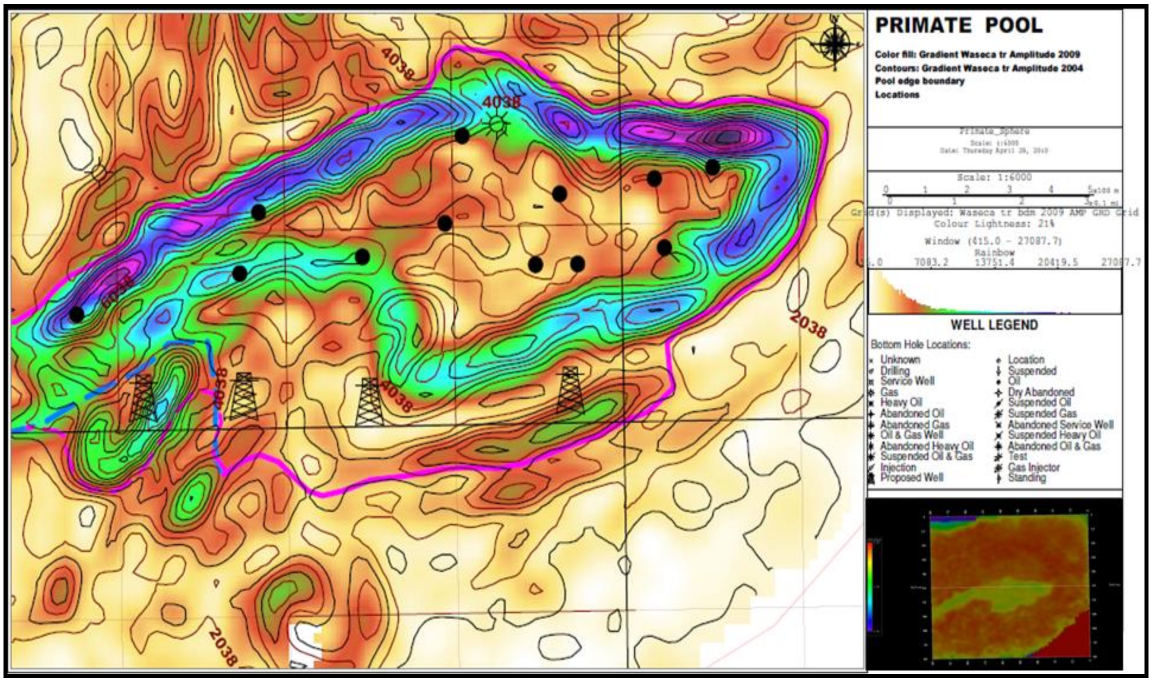

Figure 1: Map showing the trough amplitude gradient of the 2004 base survey as the contours and the 2009 monitor survey as the color fill.

Gamma Ray (GR) and Neutron-Density (Porosity) logs were used in electro-facies analysis and compared with the electric log (i.e., Resistivity). For reservoir rock type characterization, quantification of the shale abundance was needed to reveal the lithological variation and identifying the depositional energy condition for a known depositional environment. The shale volume (V_{SH}) was determined using GR and Neutron-Density logs separately and each averaged for use in facies classification.

<u>Shale Volume Calculation</u>

Shale volume (V_{SH1}) was calculated by using the following formula from GR logs:

$$I_{sh} = \frac{\gamma_{\log} - \gamma_{Min}}{\gamma_{Max} - \gamma_{Min}} \qquad V_{sh1} = 0.083(2^{3.7(I_{sh})} - 1)$$

For Tertiary and younger rocks, the above formula by Rider (2002) was used and cross referenced from Larionov (1969), where I_{sh} is the estimated shale volume, V_{sh1} is the estimated shale volume after compaction correction, $\gamma_{\log}$ is the GR log reading, γ_{Min} is the clean sand section reading and γ_{Max} is the 100% shale section reading.

Another method by Thomas-Steiber (1975) was also used to calculate shale volume (V_{SH2}) using the Neutron-Density data:

$$V_{sh2} = \frac{\phi_D - \phi_N}{(\phi_D)_{SH} - (\phi_N)_{SH}}$$

where, ϕ_D is the Log Density-porosity and ϕ_N is the Log Neutron-porosity. $(\phi_D)_{SH}$ and $(\phi_N)_{SH}$ are the '*Wet Shale Point*'s for density-porosity and neutron-porosity values, respectively.

Averaging the shale volume obtained from the above GR log and the Porosity log, the final shale volume factor was derived and used in the facies classification.

$$V_{SH} = (V_{sh1} + V_{sh2}) / 2$$

Rule - Based Facies Classification

A rule-based or own-interpreted log classification scheme was established to categorize the log facies based on the average shale volume (V_{SH}) factors obtained from the individual wells. The log-derived facies were plotted for individual wells and correlated geo-statistically over the pool.

Core Analysis

In absence of core data from the Primate pool, three offset cores from neighbouring wells adjacent the Primate pool were validated with similar sedimentary facies to that of the Primate pool. Petrophysical properties from the well logs and the cores were correlated to evaluate the reservoir properties being used in the 3D geo-cellular model for the flow simulations. Individual core descriptions and wireline log responses including shale volume factors related to the detail sedimentary facies have been categorized. The results have been compared and transferred to the wells that had no cores.

A total of seven sedimentary facies were identified in three facies associations from the three offset cores: (A) tabular or massive sand (lowermost facies), (B) trough cross-bedded sand, (C) planar bedded sand, (D) lenticular bedding with minor shaley silt, (E) low angle ripple with major shaley silt and/or with planar bedded shale, (F) bioturbated shale, and (G) laminated shale (upper most facies). The facies associations are: 1) cross-bedded very fine sand and silt with laminated (planar and low-angle) shale, 2) tabular bedded sand (trough cross-bedded sand interbedded with low-angle, small-scale cross-beds, and 3) alternating ripple cross bedding (low energy) and flat planar bedded shale and silt. The depositional sequences were classified as facies associations based on detail observations and genetic classification. Subsequently, seven SBED facies models were constructed as templates for property analyses and correlation.

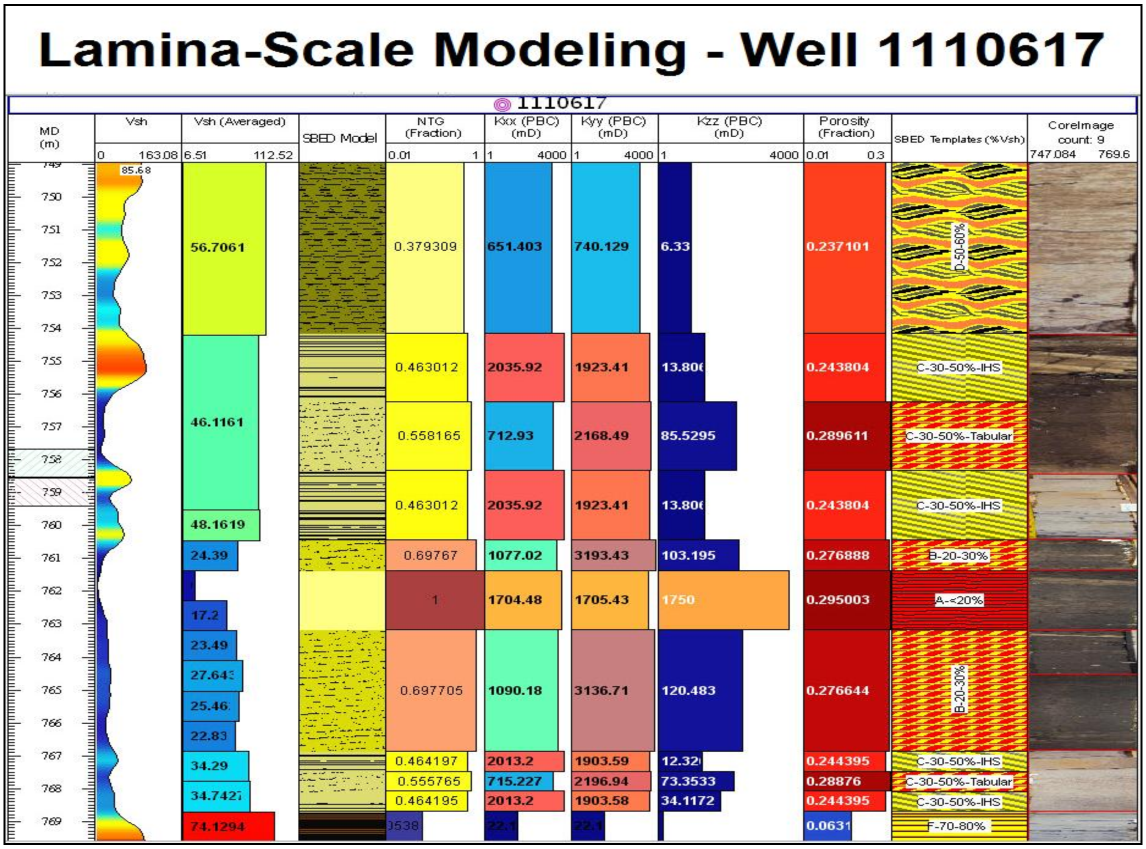

Figure 2: SBED up-scaled reservoir properties based on the detailed facies classification.

<u>3D Geo-cellular Model</u>

In this integrated approach, time-lapse 3D seismic interpretation was used, along with wireline log interpretation, core analysis and petrophysical interpretation for geological facies estimation and reservoir property evaluation using a 3D geo-cellular model. Numerous aspects were examined, correlated and extrapolated in a 3D geo-cellular model, which was used both for visualization purposes and to determine infill or prospective additional drilling locations for enhanced oil recovery. Reservoir heterogeneity was estimated quantitatively to evaluate the reservoir performance and production history matching in a realistic cutting edge manner, while maintaining the vertical high resolution of lamina scale sedimentary features. A detailed log-facies classification and its vertical distribution were modeled at centimetre scale (Figure 2 and 3) to preserve all the reservoir attributes and honour all the impermeable baffles in an apparently homogenous reservoir. This integrated approach resulted in a 3D geo-cellular model (Figure 4) that better predicts the influence of directional permeability barriers in reservoir simulation processes evaluating reservoir performance.

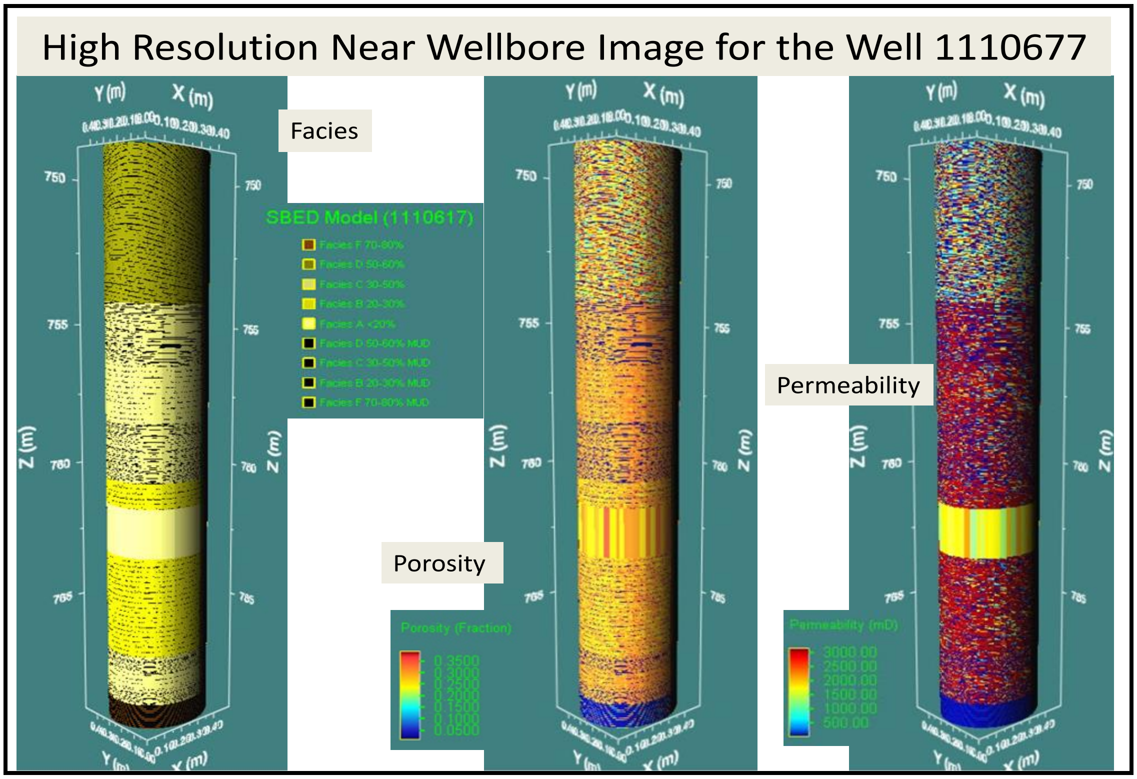

Figure 3: Reservoir properties i.e., porosity and permeability distribution are shown in the high resolution near wellbore image.

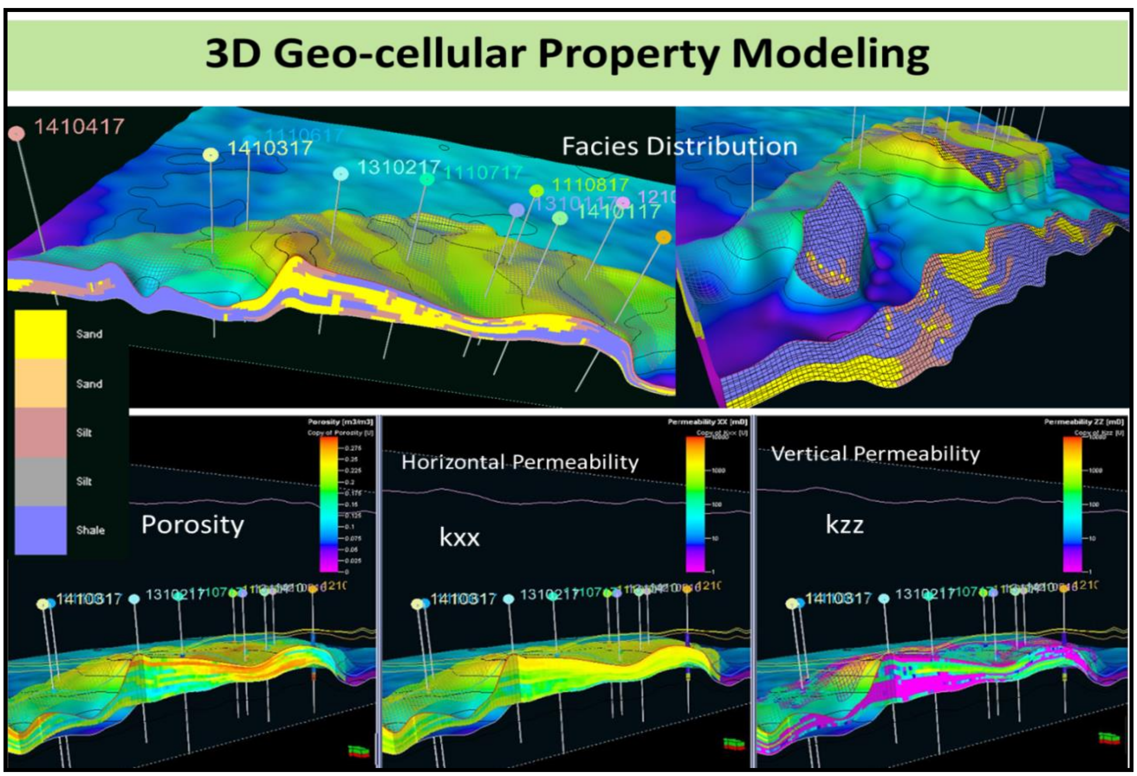

Figure 4: Directional permeability (horizontal and vertical) distribution is displayed in the Primate 3D geo-cellular model created using Petrel.

Conclusions

Directional permeability distribution in the 3D geo-cellular model enables the prediction in the future drainage area along the horizontal permeable direction (the area between kx and ky distribution), and aids in predicting the very important wormhole network for cold heavy oil production. It enables the identification of directional permeability (kx, ky, kz) barriers and enables a better understanding of the reservoir to minimize uncertainties and maximize the recovery factor. A better high resolution 3D geological model aids in decision-making for infill or additional development drilling locations, and introduces an alternative and new technology for EOR. This advanced 3D geo-cellular modeling helps to develop and improve the reservoir characterization process. When reservoir models are history matched and honour the detail geologic description, the production prediction from the models can be very realistic and accurate.

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