Definition of a 3D Integrated Geological Model in a Complex and Extensive Heavy Oil Field, Oficina Formation, Faja de Orinoco, Venezuela*

By
Jean-Paul Bellorini, Johnny Casas, Patrick Gilly, Philippe Jannes, Paul Matthews, David Soubeyrand, and Juan-Carlos Ustariz
Sincor OPCO, Caracas, Venezuela

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Introduction

SINCOR is a giant and fully integrated project combining upstream and downstream. The overall project is being implemented by an Operating Company (OPCO) with Totalfinaelf (47%), Venezuela's national oil company PDVSA (38%) and Statoil (15%) as shareholders. These companies have brought together teams from both the Exploration & Production and Refining & Marketing segments to extract ''by cold production'' 200,000 b/d of extra-heavy crude (8-8.5^{o}API) from Venezuela's Orinoco Belt. The SINCOR lease is located in the Zuata block, one of the most prolific areas of the Maturin Sub-Basin (Figure 1). Heavy oil is produced from thick sequences of lower Miocene sands (Oficina Formation) ranging from fluvial to upper delta plain in environment. The fluvial succession is basically divided in four stratigraphic units composed of stacked sand bodies where 80% of the more than 300 horizontal drains have been drilled during the last three years.

Integrated Geological Model

To build a coherent 3D model of a reservoir dominated by fluvial deposits is a tremendous task that requires a multi-disciplinary approach and the effective management of a large amount of data (i.e., outcrops, cores, logs, 3D seismic, well tests and production data). To ease this process, the 500 sq km of the SINCOR lease have been divided in three geographical assets regrouping all the E & P disciplines: geophysics, geology and reservoir engineering (Figure 2). These integrated teams share a common project database where all the relevant static inputs required for the 3D geomodel are officially stored. To get the best picture of the reservoir and its associated uncertainties, stochastic modeling conditioned to well data is performed in order to generate several realizations of the geological parameters on which to base reservoir production simulations. Principal steps and direct inputs (static and dynamic) required to build the 3D reservoir model are given here below.

Figure 1. Location map of Northern Venezuela, showing the Orinoco Oil Belt (in red) and its four main areas: Machete, Zuata, Hamaca and Cerro Negro. The SINCOR lease, covering 500 sq. km, is located inside the Zuata area.

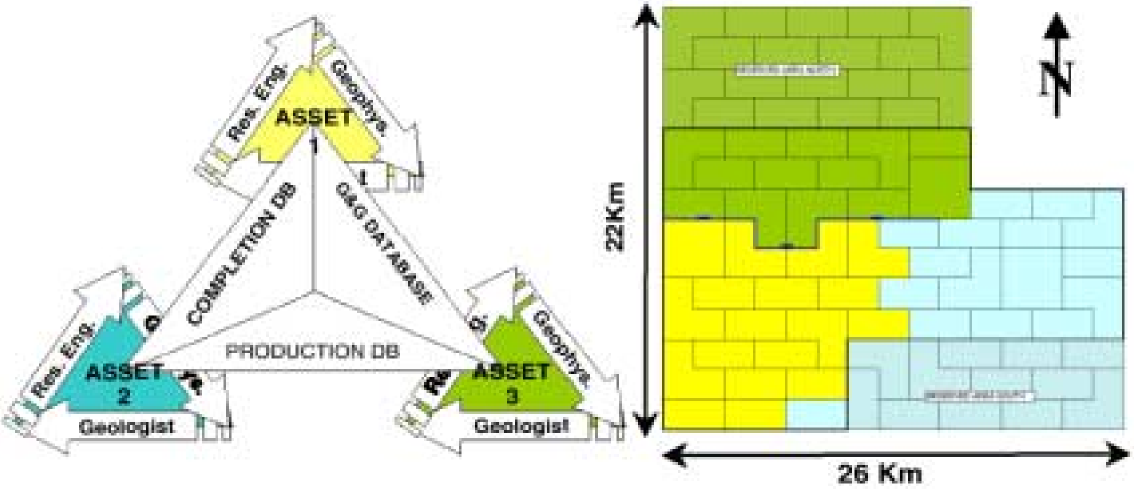

Figure 2. Organization and location of the three geographical assets.

Structural and Stratigraphic Model

Geologists and geophysicists of each asset provide top and bottom structure maps of the fluvial interval based on 3D seismic and well data (vertical, deviated, and horizontal wells included). Because of the low acoustic impedance contrast between sand and shale, it is not possible to image the internal structure of the fluvial reservoir directly on the existing 3D seismic. Therefore, a most-likely framework of the fluvial interval is inferred from detailed well correlation scheme based on sequence stratigraphy. The application of this concept provides a detailed framework that may reduce the risk of miscorrelations between different genetic units. Sequence boundaries were defined in the vertical and the slant wells at the base of the main channel belts (i.e., at the top of the underlying shale where it has not been fully eroded) and correlated at the full field scale. So far, four stratigraphic units, that form the main reservoir architecture, have been identified in the fluvial succession. The thin shale layers at the top of the units may act locally as pressure barriers between overlying and underlying sandstones and may impact the vertical communication within the reservoir. Pressure data from wireline tester tools (SFTT) help in validating the chronostratigraphic correlation scheme and detecting the major shale baffles that are so far the major heterogeneity identified in the fluvial reservoir of SINCOR. This important issue has conditioned the choice of the different modeling techniques applied for building of the 3D reservoir grid.

Modeling of Facies

Once the geometric framework of the reservoir section has been validated, it is populated with the lithological characteristics of the reservoir rock according to their spatial distribution. The facies model is built integrating a fluvial depositional model that has been clearly identified in core material. The present interpretation of the sedimentological setting varies from meandering to braided according to base sea level changes (changes in accommodation/supply ratio).

Only two facies (i.e. shale and sand) have been defined from the logs and distributed throughout the field. This simple facies classification was the only way to incorporate into the modeling process the huge amount of Logging While Drilling (LWD) data provided by more than 300 horizontal wells. The pay and the non-pay facies are identified on all the wells (vertical, slant and horizontal wells) by applying log cut-offs on the Shaliness (Vsh) and the Porosity (PHIE) curves. Normalized Gamma Ray logs have been used to ensure the consistency of the facies identification for all the wells. This normalization is highly recommended when such a classification is based on a non-homogenous set of wireline and LWD logs.

Once all the wells have been interpreted with a lithofacies log, a 3D distribution of facies can be performed for the whole reservoir. This distribution of sands and shale is obtained through stochastic modeling including not only the well data but also a set of 2D Net to Gross maps as major constraints. These Net to Gross maps are generated for each stratigraphic unit (4) by using the well data, the information brought by an analog outcrop study (Salt Wash Member, Morrison Formation of Utah) and the geological knowledge of the area (mainly source and direction of the sand supply). These maps provide also an average Net to Gross value (facies percentages) for each stratigraphic unit that is used as a stop criterion during the shale modeling process. Shale objects fill a stratigraphic unit until the Net to Gross ratio reached the value given by the stop criterion. A shale object-based (shale are objects and sands are background) stochastic approach is applied to SINCOR clastic reservoir to insure a better modeling of shale extensions (potential vertical barriers) and a better conditioning of well data including horizontal wells (Figure 3). At this stage, a huge 3D stochastic facies model (7,300,000 cells) that honors the wells but does not fully describe the reservoir heterogeneity is available. To enhance the static reservoir description prior to perform any production history match a large effort has been made to integrate all available dynamic information from well tests, fiber optic and production data. In practice, cells of shale (within the model) and 2D Net to Gross maps are manually edited to match the fiber optic interpretations, the well test interpretations, and the well producing behaviors. These adjustments, when giving satisfactory results, are considered as a deterministic input that conditioned the modeling (as well data) whatever the simulation is.

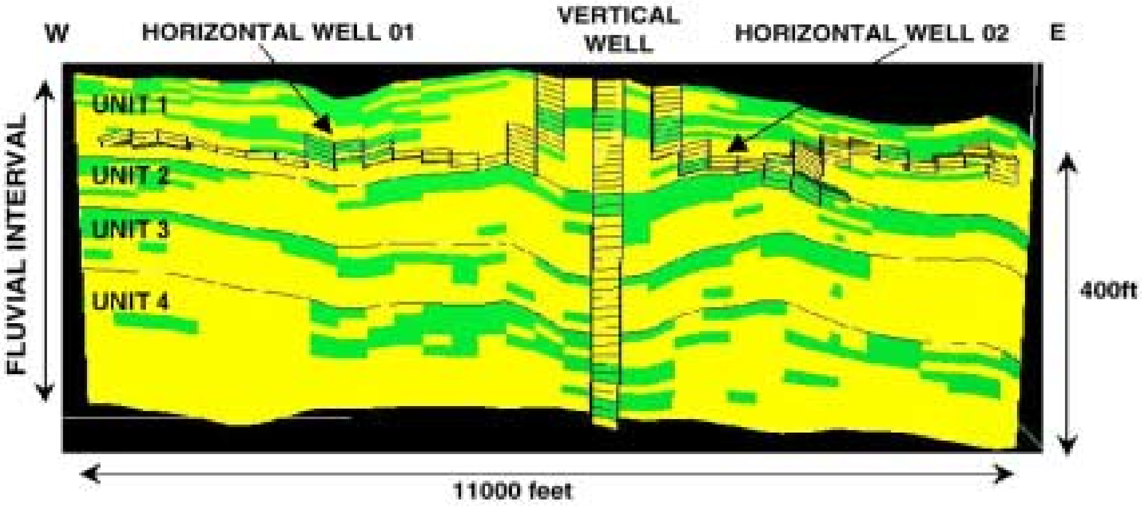

Figure 3. E-W Cross-section of a shale object-based simulation constrained by vertical and horizontal well data; green cells represent shales and yellow cells are sands.

Petrophysical Modeling

The aim of a geological reservoir model is to provide a complete set of continuous reservoir parameters (i.e. porosity, permeability and water saturation) for each cell of the 3D grid. Many different techniques can be used to generate these parameters. After several attempts and several loops between reservoir geology and reservoir engineering, some modeling techniques have been selected and implemented.

The porosity is determined stochastically within each lithological facies (backbone for calculating petrophysical parameters). As porosity modeling is concerned, no seismic attributes that may be used as a predictor have been identified. Therefore, the 3D distribution of the porosity is based on the vertical well profiles (Figure 4). The well data are transformed (normal score) so they are approximately Gaussian distributed. The

Gaussian model is characterized by various statistical parameters, which reflect the spatial variability of the porosity. A standard deviation, to specify the local scale spatial variability and a variogram, to specify the local scale variability, are defined. The variogram parameters indicate to what degree the measured porosity values in a position can impact the unobserved porosity values in a position nearby. First, a sequential screening algorithm simulates one realization of an unconditional Gaussian field. The grid cells that correspond to well trajectories are each assigned to a value corresponding to the measured upscaled well logs. The cells with the values for the well trajectories are ‘‘merged’’ with the unconditional Gaussian field. This is done by standard kriging techniques and results in a conditional Gaussian field that honors the well logs, standard deviations, and variograms specified.

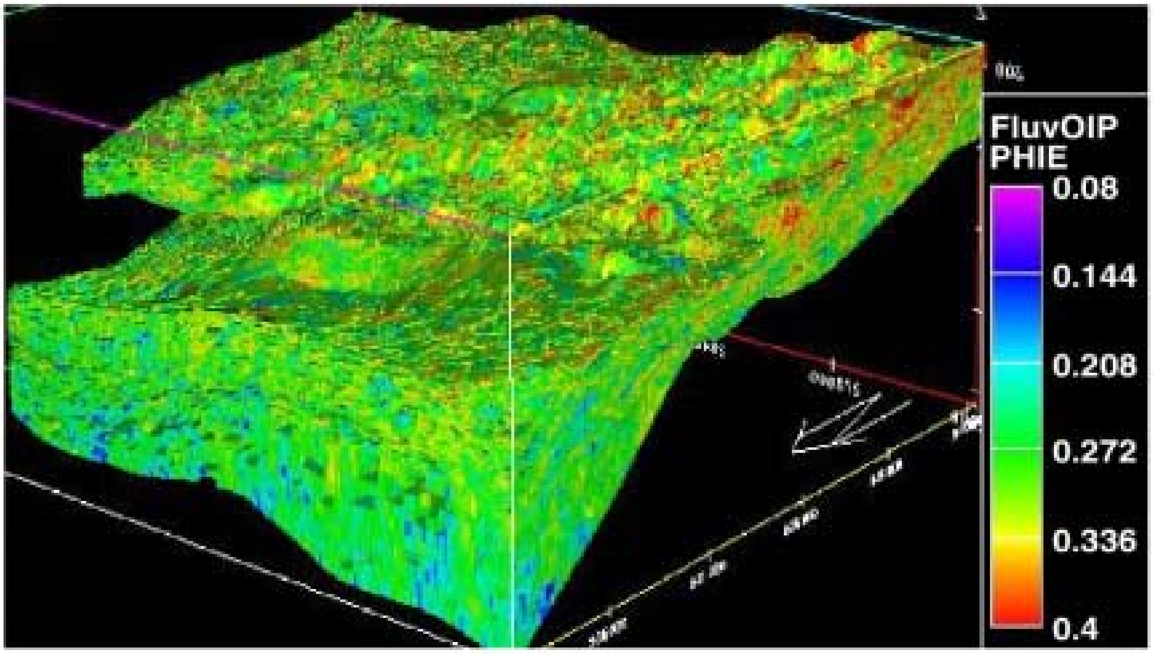

Figure 4. Porosity is calculated stochastically based on most likely porosity log values in vertical wells

Permeability is considered to be a function of porosity. A set of equations was derived from well tests and porosity logs and used to populate the 3D grid. This method for deriving permeability distribution gives satisfactory results compared to the simple kriging of the well test data.

Water Saturation is calculated based on distributions related to porosity ranges. The full range of porosity has been divided in five arbitrary classes (e.g., between 20% and 25%) in which associated Water Saturation values from logs were statistically analyzed. It turned out that within each porosity class, related Water Saturation data fit a log normal distribution. These distributions condition perfectly the modeling of the Water Saturation for each porosity class. This fast and simple method allows the generation of a consistent water saturation distribution that respects a realistic degree of correlation between porosity and saturation. Besides, the method is perfectly suited for the unconsolidated sands of SINCOR where there is no transition zone (nil capillary pressures). With this simple technique, the distribution of the saturation is performed in one step for all the reservoir cells that are located above the Oil-Water Contact (OWC). The definition of this hydrocarbon contact is complicated due to the small density contrast between the oil (0.965) and the water, the occurrence of a flushed zone, the heterogeneous character of the reservoir, and poor well borehole conditions that negatively impact on the acquisition of reliable geological data. The definition of the OWC is therefore possible by a complete and simultaneous analysis of different types of data: conventional logs, resonance magnetic logs, wireline tester pretests, drill stem tests, and cores.

Conclusion

Building a coherent 3D geological model of a complex heavy oil field, with 2 years of production is a tremendous task that requires a multi-disciplinary organization and approach, by an integrated team, at each stage of the process. To improve the description of the reservoir heterogeneity, all the available static and dynamic inputs must be introduced in both detailed lithological grid and petrophysical grids that are intimately related. Any modifications to match the dynamic constraints are discussed by the concerned team and introduced into the fine 3D geological grid as deterministic inputs. The integration of such inputs enhances considerably not only the static reservoir description but also the consistency of the future reservoir model which will better reproduce the observed field performance and facilitate at a latter stage the production history matching process.