Using Geostatistical Inversion of Seismic and Borehole Data to Generate Reservoir Models for Flow Simulations of Magnolia Field, Deepwater Gulf of Mexico

Peter McCarthy[1], John Brand[1], Bob Paradiso[1], John Ezekwe[1], Nick Wiltgen[1], Alex Bridge[1], Richard Willingham[2], Mark Bogaards*[3],

[1]Devon Energy Corp., [2]CR Willingham & Assoc., [3]Fugro-Jason

Summary

Study of key parameters of reservoir viz, porosity, water saturation, permeability and pore size distribution from well logging data is more complicated in carbonate reservoir due to geological heterogeneities than Clastic reservoir.

The Magnolia field is located in GOM blocks GB 783 and 784 and produces from Plio-Pleistocene turbiditic sands that form a complex channel/levee sequence penetrated by 16 boreholes. The primary pays consist of two sands, each about 200 feet thick, separated by a 15 foot shale layer. The pays are divided into an eastern gas prone province and a western oil prone province. A reservoir flow simulation model is planned to optimize production from existing wells and to facilitate future field development. Construction of an accurate model is complicated by MDT pressure measurements which indicated compartmentalization below the resolution of conventional seismic analysis, and by overlap of the seismic attributes derived from producing reservoirs, wet sands, and shales.

To mitigate these factors, geostatistical inversion was chosen to produce the rock property inputs for the flow simulation models. This approach allowed development of a rock properties model consistent with core data, log data, and geologic constraints as well as seismic information. It also allowed assessment of uncertainty through the generation of a statistically significant number of internally consistent alternate solutions (realizations). A Markov Chain Monte Carlo method was employed to integrate borehole and geologic information to produce acoustic impedance and lithology volumes which were then used to co-simulate porosity, permeability, p-wave velocity, and water saturation volumes. Multiple realizations of these products were reviewed, uncertainty was assessed, and a rock properties model was selected for conversion to a flow simulation modeling format. The entire process can be rerun relatively quickly to accommodate additional wells and improved seismic data or to match production history.

Introduction

The Magnolia Field is located in the deepwater Gulf of Mexico, in Garden Banks blocks 783 and 784, 180 miles south of Cameron, Louisiana. Discovered in 1999 in 4700 feet of water, Magnolia has 16 penetrations of reservoir rocks, 8 of which are either producing or planned to be put into production from the ConocoPhillips operated tension leg platform.

The field produces from the Lower Pleistocene B20 and B25 turbidite sands located on the north flank of a salt structure. Reservoirs consist of silt sized sediments that that form a complex series of generally fining-upward channel/ levee deposits.

A north-south trending permeability barrier divides the B20 and B25 horizons into eastern and western reservoir provinces with separate oil/water contacts. The west side is exclusively oil and volumetrically contains the majority of the oil in the field, whereas the east side is predominantly gas with a small oil rim. On the west side, the main pays are about 200 feet thick and are separated by a 15 foot thick shale layer, with the B20 reservoir having lower porosity (~20%) than the B25 reservoir (25-30%). On the east side, pay thickness in the B20 varies from 20 to 120 feet, and the B25 thickness averages 50 feet. The eastern wells in the B20 and B25 horizons display porosities that range from 25-30%.

Reservoir development issues

MDT pressure analysis indicates compartmentalization in the western province. Well data suggest vertical connectivity in each well, but a lack of lateral connectivity between the wells. A reservoir simulation model, derived from geostatistical inversion, can be used to predict the expected recoveries and abandonment timing for each well. The model also may assist in determining the timing and locations of future wells.

Previous work

A proprietary 3D seismic survey was acquired over the prospect in 2001. The data was processed by the acquisition contractor as a prestack time migrated volume, and subsequently reprocessed as a prestack depth migrated volume by ConocoPhillips. The time volume used in this study has a bin size of 12.5 meters by 20 meters and is nominally 60 fold.

During the initial drilling program, the seismic data was assessed using seismic facies analysis, voxel body analysis, P and S wave seismic attribute comparison, acoustic impedance inversion, lambda-rho/mu-rho analysis and geostatistical inversion. These evaluations did not provide the necessary detail to delineate the reservoir architecture in a manner consistent with data from existing wells and MDT measurements. However, they did indicate that, with additional well control, geostatistical inversion offered the most viable means of integrating all the available data.

Geostatistical inversion methodology

The geostatistical inversion is based on statistically integrating core data, well logs, and geological constraints with the seismic data. The outputs from the geostatistical inversion are a lithology volume and a corresponding acoustic impedance volume. These volumes are statistically associated (co-simulated) to produce additional rock properties: porosity, permeability, water saturation, and p-velocity. A net sand volume is generated from a cross-plot (transform) of the geostatistical inversion outputs. Multiple realizations are generated to allow the assessment of uncertainties.

A Markov Chain Monte Carlo (MCMC) approach was used for the geostatistical inversion. MCMC is a technique for obtaining a statistically correct random sample from a complex probability distribution. It is better suited for inversion problems than the more commonly used sequential simulation-type algorithms. MCMC incorporates seismic and borehole information as well as geological constraints in a quantitatively and statistically rigorous manner throughout the inversion process. Therefore, it is possible to exploit synergies that exist between different data types to retrieve details which deterministic inversion techniques blur or omit. Also, the process allows control over the degree of match between the seismic and borehole/geologic data in order to accommodate variation in the reliability of the input data sets.

As a consequence of the high lateral resolution of seismic data and the detailed vertical resolution of borehole and geologic information, these data, when treated simultaneously, are more than the sum of their parts. Details beyond the seismic bandwidth cannot, by definition, be resolved precisely and unambiguously; nevertheless, it is possible to statistically estimate the existence, multiplicity, thickness and connectivity of sub-seismic formations. Further, by producing multiple statistically consistent realizations of the integrated data volumes, it is possible to develop an intuitive and tangible picture of the uncertainty in the inversion results.

Results

The overlap of the ranges of impedance signatures among high quality hydrocarbon reservoirs, wet sands, and shales was a primary issue in constructing a data-consistent model of the Magnolia reservoirs. To help quantify this issue and to facilitate the construction of a geologic framework for geostatistical inversion, the Magnolia field was assigned five lithofacies. These facies were determined from assessments of core descriptions, log calculated v-shale cutoffs, and engineering estimates of hydrocarbon fluid saturations required for commercial production. The lithofacies are defined as:

1. Oil sands – reservoir rocks occurring in the western province, where oil is the major hydrocarbon phase.

2. Western wet sands – wet sands occurring in the western province; these are thicker and have lower porosity than the wet sand occurring in the eastern province.

3. Shale – non-reservoir rocks occurring in both provinces.

4. Gas sand – reservoir rocks occurring in the eastern province, where gas is the major hydrocarbon phase.

5. Eastern wet sands – wet sands occurring in the eastern province.

Figures 1 and 2 show stacked histograms of these lithofacies and illustrate the overlapping impedance characteristics of the rock lithofacies within the Magnolia field.

Additional geostatistical inversion inputs were histograms and variograms constructed to match the thickness and connectivity characteristics of each of the stratigraphic layers defined by the impedance volume, and

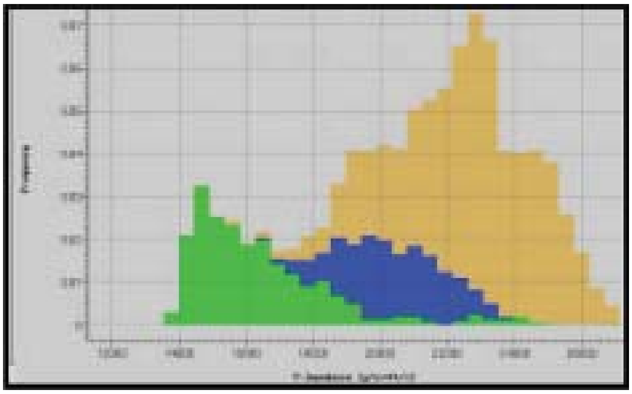

Fig 1: Western Province Lithofacies Stacked Histogram: frequency of occurrence of impedance values of the three western province lithofacies

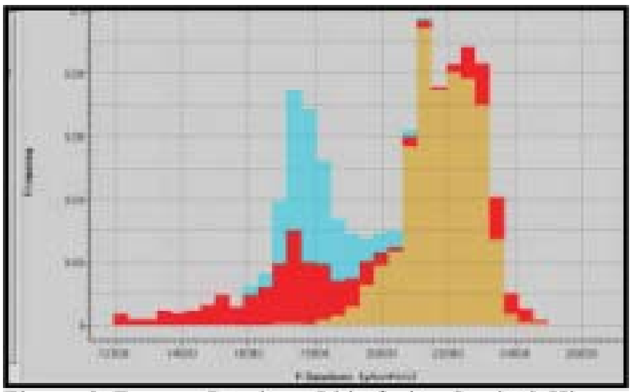

Fig 2 : Eastern Province Lithofacies Stacked Histogram: frequency of occurrence of impedance values of the three eastern province lithofacies.

1. Oil sands – reservoir rocks occurring in the western province, where oil is the major hydrocarbon phase.
2. Western wet sands – wet sands occurring in the western province; these are thicker and have lower porosity than the wet sand occurring in the eastern province.
3. Shale – non-reservoir rocks occurring in both provinces.
4. Gas sand – reservoir rocks occurring in the eastern province, where gas is the major hydrocarbon phase.
5. Eastern wet sands – wet sands occurring in the eastern province.

the 16 lithology and acoustic impedance logs penetrating pay horizons. These data provided constraints on the inversion process and ensured that the quantitative integration of the seismic and borehole/geologic data conformed to known characteristics of spatial rock property distributions.

The outputs of the geostatistical inversion were 33 reservoir realizations each containing a set of volumes of lithology and acoustic impedance and their associated co-simulation rock properties. Each model was a possible solution that satisfied the statistical and spatial relationships of all the input data.

The final reservoir model analysis and selection was accomplished by focusing on two factors: hydrocarbon volume and reservoir connectivity. For each reservoir model, conservative and optimistic cutoff values were used in a 3D visualization tool to body capture the connected, hydrocarbon filled sands. A net pay map was generated for each cutoff value for the combined B20 and B25 reservoir horizons. Next, the reservoir models were ranked in order from the smallest to the largest reserve volumes. The project team reviewed the net pay maps for the oil and the gas prone provinces and for both cutoff values. Based on conformity of realizations to known constraints, and on a qualitative assessment of uncertainty, one realization was selected as the best representation of the Magnolia field.

Time sections, flattened on the B20 horizon, are displayed in Figure 3. The western oil province is displayed on the left. In this province sands are thicker and less interconnected than the gas province sands displayed on the right side of the diagram. The geostatistical inversion improves the resolution from a blocky massive texture (seen in the top two panels of Figure 3) to a thinner lateral texture, closer to the expected geometry of the reservoir as defined by the borehole data.

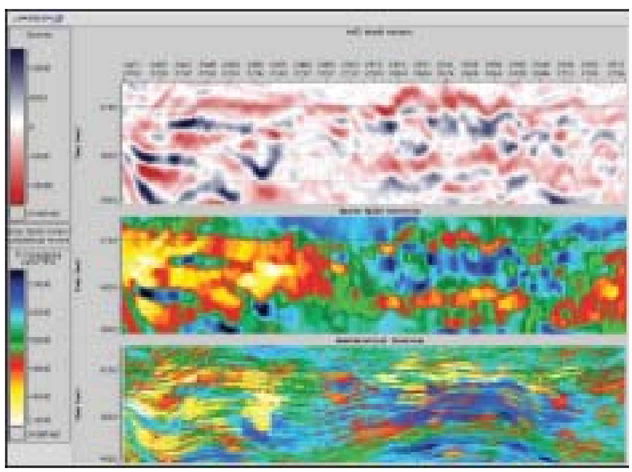

Fig. 3 : Time sections flattened on the B20 horizon. The top panel is the full seismic. The center panel is the constrained sparse spike inversion of the full seismic. The lower panel is the acoustic impedance from the selected geostatistical inversion realization .

Path forward and conclusions

The selected reservoir model is at the appropriate scale for flow simulation and is a statistically valid solution consistent with the seismic data and the well log properties in the Magnolia field. The ultimate goal of the reservoir modeling is to construct a flow simulation model that accurately represents the distribution of rock properties in the main producing reservoirs. This flow simulation model will be used to history match well production, predict future production rates and EURs for the individual wells, and suggest locations for future development wells. The current geostatistical inversion provides the flexibility to create alternative reservoir models based on different realizations in the event that production data dictate the need for modification of the model to better match the observed well performance.

Acknowledgements

The authors would like to thank Devon Energy Corporation and ConocoPhillips for publication release and Fugro-Jason for the geostatistical inversion work. The authors would also like to acknowledge Kevin Chesser and Steve Bahret for their contribution to the project.

References

Debey H. W.J., and Van Riel, P., 1990, Lp-norm deconvolution: Geophysical Prospecting, v. 38, p381-403.

Hastings, W.K. "Monte Carlo sampling methods using Markov chains and their applications," Biometrika, Vol. 57, Issue 1 (1970), pp. 97-109

W.R. Gilks, S. Richardson, D.J. Spiegelhalter. Markov chain Monte Carlo in Practice. Interdisciplinary Statistics Series. Chapman & Hall/CRC (1996).