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October 2005

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High resolution brings new insight into connectivity, reservoir size, sand quality

Marco Polo field comes into sharp focus

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Anadarko-operated Marco Polo TLP.

By using a novel approach that ties pre-stack seismic and well log data, our team has built a uniquely detailed 3D model of Anadarko's Marco Polo field, leading to a better understanding of the vertical and lateral extent as well as the quality of the reservoir.

The new technique yielded a four-fold gain in vertical resolution, and this crispness enabled us to identify additional features associated with the seismic anomalies, such as small faults and lateral changes in sand quality. For Anadarko, the value extends far beyond the Marco Polo field to other holdings where the method can be used to reduce reservoir development risk and improve drilling and production programs.

As part of the analysis, we conducted rigorous testing to understand both sensitivity and uncertainty. In addition, we compared results to findings from earlier reservoir characterization work.

We found that the model was only slightly affected by changes in parameterization, while uncertainty increased monotonically with distance away from wells. Because Anadarko had extensive data from previous analyses and subsequent down-hole measurements, we were able to validate the accuracy of the technique, as well. This inversion technique should yield significant improvements in reservoir detail for many fields throughout the world, enabling a better understanding of net pay, net-to-gross, fluid type, and geologic risk.

Deepwater Gulf of Mexico

Anadarko Petroleum is among the world's largest independent oil and gas exploration and production companies. The deep waters of the GoM are a significant component of the company's growth strategy, and its first discovery there was made in April 2000 in the Marco Polo field. This field is located on Green Canyon block 608,

about 160 mi south of New Orleans, Louisiana. The field is in 4,300 ft of water and is being produced from the deepest tension leg platform in the world. Field production began in July 2004.

The Green Canyon 608 No. 1 well encountered 320 ft of oil sand from five different Miocene targets above salt. Formation tests recovered 30° API gravity oil. Completions were performed on six wells from the platform and 17 separate intervals were completed using overbalance perforating and frac packing over a 164-day completion campaign.

The 3D seismic data for the field was originally acquired and processed in the late 1990s by WesternGeco, and was reprocessed multiple times. This was done to improve the quality, resolution, and signal-to-noise. Each time Anadarko reprocessed the Marco Polo seismic data they were able to improve the understanding of the reservoirs.

Sharpening the focus

As a member of the University of Texas-Austin Research Consortium on Formation Evaluation (UT-Austin), Anadarko became aware of a sophisticated new technique for reservoir characterization and decided to re-evaluate the Marco Polo field using it. A team was formed including representatives from UT-Austin, Anadarko, and Fugro-Jason (developer of the new technique). Anadarko supplied the team with the latest version of the seismic dataset (pre-stack time migration) plus multiple well logs for use as calibration points.

One of the goals of the project was to gain a better understanding of the reservoir geometry, including potential reservoir baffles or barriers that could be caused by changes in sand quality locally or by small faults. These could have significant effects on the connectivity of the reservoir, affecting well production.

A critical aspect of the project was the cohesiveness of the team. There was extensive interaction between all the parties throughout the project.

The team followed a three-step methodology. First, we generated reliable volumes of elastic properties and lithotypes from high-quality pre-stack data using a new pre-stack stochastic inversion technique. We then established precise lithology-dependent multi-dimensional correlations between the elastic and petrophysical properties at the well locations. Third, we used these correlations in conjunction with the lithology realizations to guide the construction of petrophysical models from the inverted volumes of elastic properties.

Initial review and analysis

The team began by analyzing well log data to identify sands. Within these sands we then computed porosity, clay volume, permeability, and water saturation. These computations were performed to correlate well log-based elastic properties (p-wave impedance, s-wave impedance, and density) to the petrophysical properties. The differentiation between sands and shales was very clear. The combination of p-wave impedance and s-wave impedance allowed us to differentiate between types of fluids, particularly between oil and water and between gas and oil.

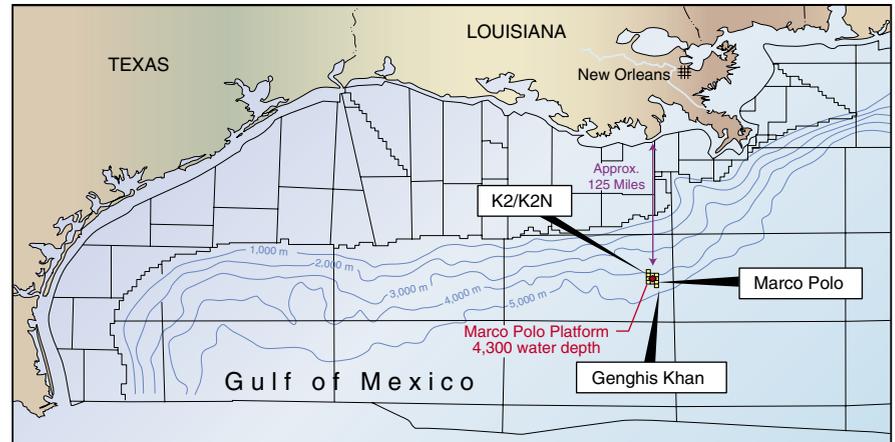
Pre-stack data brings specific advantage

Pre-stack inversion looks at the seismic amplitude variations as a function of angle between source and receiver. Working with 3D pre-stack amplitude data provided more degrees of freedom in the analysis. As a result, our team was able to build a more accurate petrophysical model that had anomalies that actually looked like geologic bodies.

Unlike post-stack seismic amplitude data, which mainly detects acoustic impedance (the p-wave velocity times density), pre-stack data can derive p-wave impedance, s-wave impedance, and density. This enhances the possibilities of differentiation between lithology units, types of lithology, effective porosity, amount of shale, and fluid type.

Pre-stack stochastic inversion produces an estimate of elastic properties in a way that honors the measurements made within boreholes. It is called stochastic because the process estimates these properties by way of statistical realizations. Values for those layer properties are statistically chosen until those that honor the data are identified.

The most important – and unique – aspect of this new approach is that it combines the high vertical resolution of well logs with the relatively dense lateral coverage of seismic amplitude measurements. With seismic amplitude measurement, vertical resolution can



Map illustrates the location of nearby discoveries to the Marco Polo TLP.

vary anywhere from between 10 m to 40 m, whereas well logs can resolve layers as thin as a foot.

In Marco Polo, we found that by parameterizing the technique so that the results honor the well logs, we could increase the vertical resolution of the results. By combining the seismic amplitude data with the well logs, we could increase that resolution from 20 m to about 5 m. This yields a realizable answer that is consistent with the seismic amplitude data.

Modeling the geobodies

After inversion, we correlated the seismic-derived elastic properties (p-wave velocity, s-wave velocity, and density) with log-derived petrophysical properties (porosity, permeability, and water saturation). This enabled us to construct a 3D rendering of the reservoir using multi-dimensional joint distributions of the six properties involved (elastic and petrophysical), yielding a more precise output. The resulting model had significantly more detail than previous models, with many additional features identified.

To build the multivariate distributions we first generated 1D sample histograms for each property using well log data. We then combined this information into both layer- and lithology-dependent probability distribution functions. By doing so, we were able to represent all the relationships and correlations between the six properties.

These multi-dimensional functions were subsequently used to generate the petrophysical models from the inverted elastic volumes. Overall, the process is very efficient. The petrophysical models could easily then be fed into a simulator to predict production as a function of time.

The inversion and subsequent modeling provided insight into reservoir connectivity and confirmed that the Marco Polo reservoirs are not very extensive laterally. They

also shed light on the quality of sand and total net pay estimation. From this analysis, Anadarko gained a better understanding of lateral extents of fluid units containing hydrocarbons.

Validation of results

As a final step, we ran six independent tests of sensitivity and uncertainty. First, we used synthetic seismic data from well logs to test the effect of data quality and our inversion parameters. From this test, it was clear that accuracy in s-wave impedance and density depends on the availability and quality of far angle amplitude information.

Next, we used post-stack data to test various inversion parameters such as variogram type, lithotype fraction, and noise level. From this test, we could see that reasonable variations in the parameters only slightly affected the results. Blind tests showed that when wells were excluded, pre-stack data better estimated lateral extent of sands than did post-stack data. We assessed the effect of including relationships between p-wave velocity, s-wave velocity and density on porosity estimates using 2D and 4D correlations. The most accurate predictions were made using the 4D correlation.

In addition, we were able to show that inversion of pre-stack seismic amplitude data accurately reconstructed elastic properties at the well locations. Finally, uncertainty was assessed using the standard deviation of 30 porosity realizations. The spatial range of uncertainty is consistent with the estimated lateral extent of sand units, and uncertainty increases monotonically away from well locations.

From these and other tests, we were able to conclude that the model is accurate. Pre-stack seismic amplitude data give more degrees of freedom, which generate more detailed and accurate results. By combining pre-stack seismic and well data we were able to extrapolate petrophysical properties in the Marco Polo field with

far greater resolution than previously possible.

Conclusions

Our experience in analyzing the Marco Polo field convinced us that this new technique opens up a whole new window of opportunity in reservoir characterization. It is very effective and can promote a more direct connection between seismic amplitude data and petrophysical properties of a reservoir derived through inversion. It can be applied widely in both clastic depositional systems and in carbonate depositional systems.

Using this technique, Anadarko and other companies will be better able to decide where to drill and how to produce a reservoir. Volumetrics and economic feasibility are more reliably calculated. It can be a real enhancement in achieving more favorable placement of development wells, in terms of thickness of the sand, quality of the sand, fluid type and connectivity. It can even identify previously undetected reservoirs because of its ability to detect thinner layers.

Only two elements must be in place for this technique to yield dramatically improved details. First, there must be a good correlation between the elastic and petrophysical properties, so that they can be used to differentiate between porosity, water saturation, and lithology. A simple feasibility test can determine if this is the case.

Second, the thickness of lithology and flow units needs to be such that seismic amplitude data can detect it. When available data matches these requirements, the technique can provide a significant increase in vertical resolution. Also, because of the nature of the algorithm it is easy to obtain a direct estimate of uncertainty.

Similarly, the correlation of results with petrophysical properties can be performed in a very direct way. These are all unique to this new technique.

Most companies in the industry have found the relatively easy plays and now are looking for deeper and more subtle targets. Many of the new prospective reservoirs are getting smaller and have poorer quality sand or have low porosity. The technique may be useful for reservoir plays such as carbonates and tight sands, where locating a porous zone can make the difference between a dry hole and a producer. Anadarko and other companies in the industry are including these more difficult reservoir targets in their prospect portfolios. We expect that this technique will be used to enhance that effort. ●

About the Authors

Arturo Contreras has been working for the UT-Austin Research Consortium on Formation Evaluation since 2002. The work presented in this article is part of his Ph. D. dissertation research.

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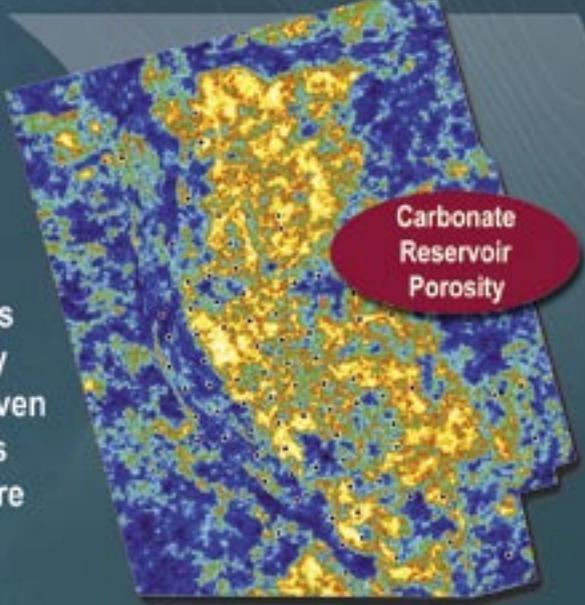
Tim Fasnacht is a Senior Staff Geophysicist and has been part of Anadarko's Geophysical Technology group since 2000.

Acknowledgements

The authors would like to thank Anadarko Petroleum Corp. for providing the data set used for this research

study. We remain grateful to WesternGeco for giving us access to the seismic data. A note of special gratitude goes to Fugro-Jason for its unrestricted technical and software support. This work was supported by UT Austin Research Consortium on Formation Evaluation, jointly sponsored by Anadarko Petroleum Corp., Baker Atlas, BP, ConocoPhillips, ExxonMobil, Halliburton Energy Services, the Mexican Institute for Petroleum, Occidental Petroleum, Petrobras, Precision Energy Services, Schlumberger, Shell International E&P, Statoil, and Total.

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