

# Prestack seismic data reduces uncertainty in the appraisal of dynamic reservoir behavior

Omar J. Varela and Carlos Torres-Verdín\* *The U. of Texas at Austin*

## Summary

Integrated reservoir characterization makes use of various types of data to construct detailed spatial distributions of petrophysical and fluid parameters. The benefit of data integration is the generation of reliable reservoir models that can be used for accurate asset management and optimal sweep efficiency. This paper appraises the dynamic behavior of reservoir models constructed with a novel inversion strategy based on the use of 3D pre-stack seismic data, wireline logs, and geological information. Such strategy extrapolates petrophysical variables laterally away from wells subject to honoring the existing 3D pre-stack seismic data. A numerical study in three dimensions is performed to evaluate the estimation algorithm as well as to assess the dynamic behavior of the estimated petrophysical properties. Depending on the number of wells and on the distance between them, the inversion algorithm can produce estimates of inter-well petrophysical properties with a vertical resolution intermediate between that of seismic data and well logs. Models generated with this inversion algorithm yield accurate and unbiased predictions of dynamic behavior after the onset of production when compared to predictions performed with either post-stack seismic data or standard geostatistical techniques.

## Introduction

Accurate and efficient reservoir management requires geological models amenable to numerical simulation of multiphase fluid-flow. These models are used to match production history data and to design production strategies in light of time-dependent value of assets.

Seismic data are sensitive to the entire reservoir and hence provide a means to fill the spatial gap between sparse well locations. The quantitative use of seismic amplitude variations in space and time (or depth) offers a powerful tool to guide the simulation of inter-well reservoir properties. This approach is referred to as geostatistical seismic inversion (Bortoli et al., 1993 and Haas and Dubrule, 1994). It makes use of post-stack seismic data to constrain the stochastic simulation of inter-well reservoir properties. Improvements and applications of this approach can be found in the technical literature (Grijalba-Cuenca et al., 2000). Recently, Varela (2003) developed a novel procedure to generate spatial distributions of reservoir properties between existing wells by joint stochastic

inversion of 3D pre-stack seismic data and well logs. This procedure makes optimal use of the high vertical resolution of well logs and of the dense lateral sampling of 3D pre-stack seismic data to construct spatial distributions of petrophysical properties.

The thrust of this paper is to assess the dynamic behavior of spatially complex reservoir models constructed with Varela's (2003) joint inversion algorithm. A synthetic reservoir model is used as reference. Static and dynamic comparisons are performed between the reference model and reservoir models constructed via (a) standard geostatistical techniques and (b) joint inversion of well logs and 3D pre-stack seismic data.

## Description of the 3D Complex Synthetic Model

Figure 1 is a 3D view of the synthetic subsurface model constructed to perform the numerical experiments described in this paper. This model represents a fluvial depositional environment that was designed to include the effect of variable seismic resolution due to wavelet tuning. It consists of an oil-saturated sand embedded in a shale background. The total number of cells is approximately 1.3 million. Petrophysical properties such as porosity were populated into the reservoir using stochastic algorithms with a prescribed degree of spatial correlation. Permeability and initial fluid distributions in the oil-saturated sand were calculated by means of correlations. Subsequently, elastic properties were calculated using a rock physics model that included the effect of mechanical compaction. Seismic data simulated for this 3D subsurface model consist of 80 by 80 CMP gathers spaced at approximately 25 m intervals, and spanning from 1.1 to 1.5 seconds of two-way seismic travel time. Numerical simulation of pre-stack seismic data was performed using the reflectivity method (Fuchs and Muller, 1971). A Ricker wavelet (central frequency of 35 Hz) was used in both simulation and inversion of pre-stack seismic data. The time sampling interval was 2 ms and CMP gathers were corrected for normal moveout. A total of five pre-stack seismic offsets per CMP gather were considered in this study and the spacing between receivers was assumed uniform and equal to 600 m. Finally, ten percent, zero-mean, random Gaussian noise was added to the pre-stack seismic data in an effort to replicate acquisition and processing errors.

## Pre-stack seismic data reduces uncertainty in the appraisal of dynamic reservoir behavior

### Description of the Joint Inversion Algorithm

The estimation of inter-well petrophysical parameters (and of elastic parameters as by-products) jointly from pre-stack seismic data, well logs, and geological description and interpretation, is cast as a global inversion problem. This inverse problem is solved using very fast simulated annealing while enforcing (a) a harmonic objective function, (b) initial models constrained by well information and sampled from local PDFs (probability density functions), and (c) a global target property histogram. Perturbations of properties are performed directly in the petrophysical domain through a random walk in space and seismic time. A joint PDF is used to impose a statistical link between the petrophysical and elastic properties. Due to the stochastic nature of the inversion algorithm, different random seeds are used to generate multiple realizations that allow one to quantify the uncertainty of the inverted parameters. Additional details on the inversion algorithm can be found in Varela (2003).

### Numerical Experiments

Ten realizations for porosity were performed using the 3D volume described in Figure 1 to assess the dynamic behavior of reservoir models constructed using both the joint stochastic inversion algorithm (Case I) and standard geostatistical techniques (Case G). When using the joint inversion algorithm, the inverted result is porosity and elastic parameters are obtained as by-products (i.e., P-wave impedance, Swave impedance, and bulk density). Static model realizations and their associated dynamic predictions are compared against those of the reference model. The dynamic evaluation corresponds to a waterflood process (one injector and 4 producer wells). All production constraints remain the same for all realizations.

Figure 2 is a map of average similarity for one realization between the actual and estimated distributions of porosity computed at the first (Panel a) and final (Panel b) iterations of the inversion algorithm, respectively. The average similarity of porosity was calculated trace by trace. Maps in Figure 2 indicate that initial porosity (Case G) distributions exhibit an average correlation of 0.50 whereas the inverted porosity distributions (Case I) exhibit an average correlation of 0.90.

An assessment of prediction error over time (or global uncertainty,  $U$ ) of some dynamic measurements was performed as the L2-norm of the difference between the time records of fluid production associated with the reference case (case T) and those associated with each realization for a given case (case G and case I). This metric of data misfit provided a quantitative assessment of the effect of the spatial distributions of porosity on the time records of fluid production. Individual errors were

normalized against the overall maximum error and Box plots were constructed to appraise the results. Figures 3 and 4 show Box plots of the global uncertainty for cumulative oil recovery and average reservoir pressure, respectively. These figures indicate that the magnitude of the prediction error for case G (no use of seismic data) is larger than the magnitude of the prediction error for case I (use of the full gather of pre-stack seismic data) for all of the time records considered in this study. The same plots suggest a larger variability for case G than for case I. Results shown in Figures 3 and 4 represent global reservoir responses and indicate that more accurate and less biased forecasts of dynamic reservoir behavior are performed from reservoir models constructed with the use of pre-stack seismic data.

### Conclusions

Pre-stack seismic data can be used to fill the spatial gap between sparse well locations and to reduce the uncertainty in the construction of petrophysical property models. The stochastic nature of the inversion algorithm described in this paper enables the appraisal of dynamic reservoir behavior after the onset of production. Depending on (a) the average value of porosity, (b) the vertical resolution of the seismic data, and (c) the degree of statistical correlation between elastic and petrophysical parameters, we have found that the use of 3D pre-stack seismic data in the construction of reservoir models does reduce uncertainty in the prediction of dynamic behavior. This conclusion holds when the dynamic behavior of the reservoir is primarily controlled by the spatial distribution of porosity. However, because seismic data are seldom sensitive to permeability or rock-fluid properties, the absence of good porosity-permeability relationships will increase uncertainty in dynamic behavior. In those situations, reduction of uncertainty can only be achieved by incorporating time records of fluid production measurements in the inversion algorithm.

### References

- Bortoli, L.J.F., Alabert, F., Haas, A., and Journel, A.G., 1993, Constraining stochastic images to seismic data: In *Geostatistics Tróia 1992*, A. Soares, ed. Kluwer, Dordrecht, 1, 325-337.
- Fuchs, K., and Muller, G., 1971, Computation of synthetic seismograms with the reflectivity method and comparison with observations: *Geophys. J. R. Astr. Soc.*, 23, 417-433.
- Grijalba-Cuenca, A., Torres-Verdín, C., and Debeye, H.W., 2000, Geostatistical inversion of 3D seismic data to extrapolate wireline petrophysical variables laterally away

## Pre-stack seismic data reduces uncertainty in the appraisal of dynamic reservoir behavior

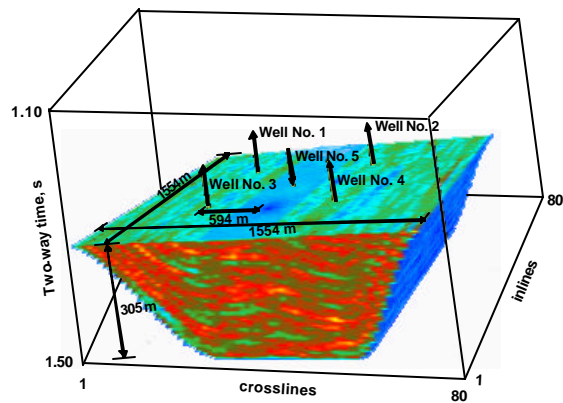
from the well: SPE 63283 presented at the Annual Technical Conference and Exhibition, Dallas, TX.

Haas, A., and Dubrule, O., 1994, Geostatistical inversion: a sequential method for stochastic reservoir modeling constrained by seismic data: *First Break*, 12, 561-569.

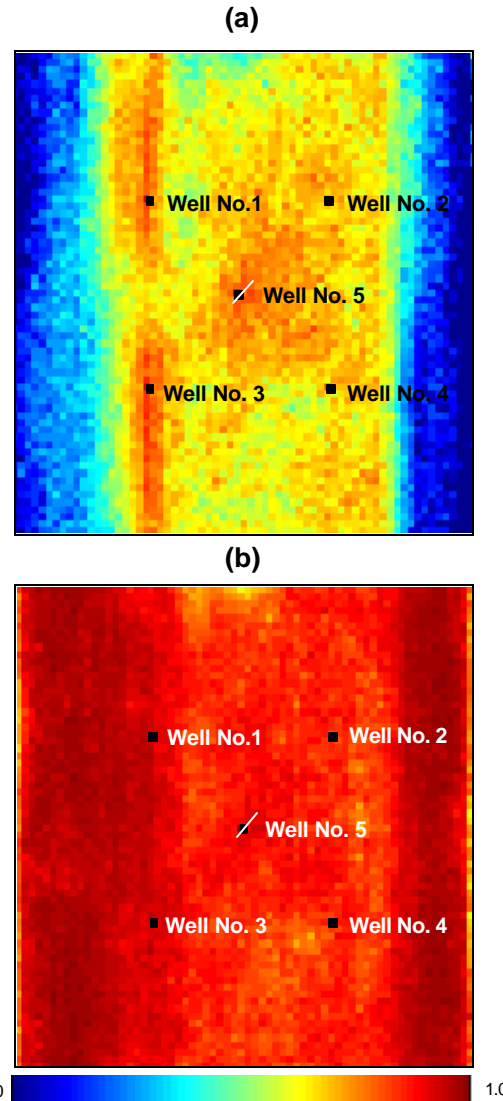
Varela, O.J., 2003, Stochastic inversion of pre-stack seismic data to improve forecasts of reservoir production: PhD Dissertation, The University of Texas at Austin.

### Acknowledgements

This work was supported by the US Department of Energy under contract No. DE-FC26-00BC15305.

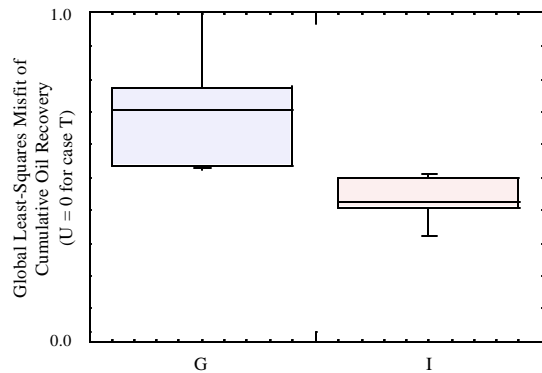


**Fig. 1.** Three-dimensional description of the reference model used for the numerical experiments described in this paper.

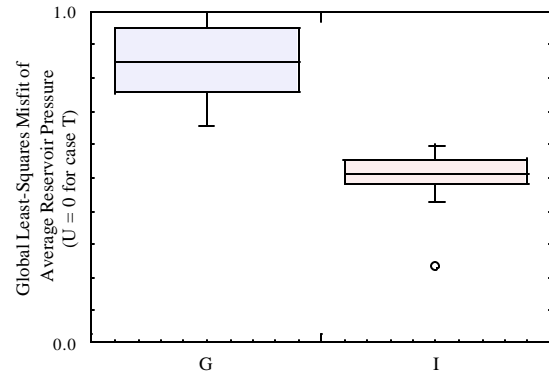


**Fig. 2.** Similarity between the reference model and (a) initial model (geostatistical realization) and (b) final model estimated with the joint inversion algorithm. The rainbow-color scale describes perfect similarities in red and null similarities in blue.

## Pre-stack seismic data reduces uncertainty in the appraisal of dynamic reservoir behavior



**Fig. 3.** Box plot representation of the global least-squares misfit (U) for cumulative oil recovery calculated for the porosity distributions rendered by standard geostatistics (case G) and the joint inversion algorithm (case I).



**Fig. 4.** Box plot representation of the global least-squares misfit (U) for average reservoir pressure calculated for the porosity distributions rendered by standard geostatistics (case G) and the joint inversion algorithm (case I).