A comparison of porosity estimates obtained using post-, partial-, and prestack seismic inversion methods: Marco Polo Field, Gulf of Mexico.

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Summary

We compare porosity estimates obtained using post-, partial-, and prestack (i.e., full waveform) seismic inversion methods in Miocene sandstones. We invert a single 3D seismic data set using commercially available poststack and partialstack inversion algorithms and a prestack inversion algorithm that optimizes a quasi-linear objective function via local optimization methods. We compare the inversion results with a priori structural and stratigraphic information and draw the following inferences:

- Density is the most valuable elastic parameter for estimating porosity in the unconsolidated sandstones. P-impedance-to-porosity transformations are unstable and magnify errors in the estimated elastic parameters.
- Partialstack seismic inversion only resolves P-impedance and S-impedance within the study area. It cannot resolve density because the linearized forward model is insensitive to density over the seismic aperture and the NMO correction removes the low frequency velocity information that is necessary to decouple density and velocity within the P-impedance.
- Poststack and partialstack seismic inversion methods rely upon P-impedance to estimate porosity and produce nonphysical porosity estimates.
- Prestack seismic inversion resolves P-velocity, S-velocity, and density within the study area.
- Only the prestack seismic inversion yields accurate porosity estimates within the study area.

Introduction

Seismic inversion is a geophysical tool for estimating elastic interval properties from seismic data recorded at the Earth’s surface. Elastic layer properties are more intuitive to interpret and may be transformed into reservoir characteristics (e.g., porosity or hydrocarbon saturation) via well-calibrated transformations for enhanced reservoir modeling. The seismic inverse problem, in its most general form, is strongly non-linear and inherently ill-posed (Sen, 2006). To overcome these difficulties and to make seismic inversions more tractable and commercially viable, simplified seismic inversion methods—poststack (e.g., Lindseth (1979)) and partialstack seismic inversion methods (e.g., Pendrel et al. (2000) and Hampson et al., 2006)—have been developed that rely upon reduced forms of the seismic data (e.g., NMO corrected and stacked data) and linearized forward models to estimate elastic parameters. Unfortunately, each reduction in the quantity of data decreases the degrees of freedom and restricts which elastic parameters can be resolved with the particular inversion method. In particular, deterministic linear seismic inversion methods have historically failed to resolve density (Debski and Tarantola, 1995). In this study, we invert a single seismic data set with deterministic post-, partial-, and prestack seismic inversion algorithms and transform the estimated elastic parameters into porosity to characterize Miocene reservoirs in Anadarko’s deepwater Marco Polo Field.

Marco Polo Field is located 160 miles south of New Orleans in Green Canyon Block 608, Gulf of Mexico. The deepwater (4300 ft water depth) field consists of a Miocene-aged succession of poorly consolidated (>30% core porosity) sandstones and shales at 11,500-12,500 burial depths. The southward prograding high porosity reservoir sandstones—designated the M-series—average 50-100ft in thickness and consist of two upward coarsening parasequences whose capping sandstones (i.e., the gas-productive M-10 and oil-productive M-40 sandstones) make the primary reservoirs. Seismic data consist of one near-angle stacked seismic volume; four partially stacked seismic volumes (6-16°, 16-26°, 26-36°, and 36-46°) with angles computed via ray tracing through the smoothed migration velocity model, and 3D Kirchhoff time migrated gathers. Figure 1 shows a seismic transect through the Marco Polo Field. The hydrocarbon-saturated M-series sandstones produce bright amplitudes in the stacked section and are characterized by elastic Class III AVO (Rutherford and Williams, 1989) anomalies. The black box in Figure 1 shows the location of the detailed sections that are displayed in the subsequent figures. In the following section we describe our techniques and compare the results.

Methodology

None of the seismic inversion methods included in this study explicitly estimates porosity as a model parameter. Instead, each method parameterizes the model space with and estimates some combination of elastic parameters that map into porosity via fluid-dependent transformations obtained from well logs. We derive fluid-dependent transformations that are calibrated to the Marco Polo Field by cross-plotting the measured elastic parameters (i.e., P-impedance and density) against shale-corrected porosity for gas-, oil-, and brine-saturated intervals from three Marco Polo Field wells (Figure 2). Cross-plot analysis indicates that density is best-suited for estimating porosity because the steep gradient of the density-to-porosity transformation implies minimal error magnification during mapping from the elastic parameter domain to the reservoir characteristic.
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domain. Conversely, the shallow gradient of the P-impedance-to-porosity transformation results in substantial error magnification. We identified cutoff values that separate hydrocarbon-saturated sandstones from shales and water-saturated sandstones. These cutoffs, which serve as thresholds for the fluid-dependent transformations (i.e., the red and blue trends in Figure 2), should reduce the dependence of the elastic parameters to porosity. (We neglect the effects of pore geometry, pressure, fractures, etc.) The choice transformation input parameter depends on the parameterization of the model space and the resolvability of the model parameters. Clearly, the most robust and most sensitive parameter (i.e., density) should be transformed whenever possible.

Poststack seismic data refers to near-angle stacked data in which every poststack CMP approximates the response of a single normal incident plane wave. The goal of poststack seismic inversion is to estimate a P-impedance (Zp) pseudolog at each seismic trace location (Lindseth, 1979). We use Fugro-Jason's Zero-offset Constrained Sparse-Spike Inversion (ZO-CSSI) algorithm to invert the near-angle poststack data. The algorithm assumes the data consist solely of primary PP reflected energy, and it calculates synthetic seismograms by convolving a reflectivity series with an a priori wavelet. An a priori low frequency P-impedance model (6 Hz) serves as the initial model for the model-based inversion and constrains the solution in a soft and hard sense. Additionally, we merge the low frequency model into the estimated P-impedance to correct for drift from the background trend that results from the low signal-to-noise ratio in the roll-off region of the seismic frequency band.

Partialstack seismic data refers to CMP gathers that have been partitioned according to angles of incidence and stacked into near, mid, far, and ultra-far angle substacks. Partialstack seismic inversion methods utilize angle-dependent amplitude variations (Ostrander, 1984) to simultaneously estimate P-impedance (Zp), S-impedance (Zs), and density (\( \rho \)) pseudologs at each CMP location. We parameterize the model space with impedances because the velocity uncertainty errors are highly correlated for NMO corrected AVA data (Debski and Tarantola, 1995). Fugro-Jason's AVA Constrained Sparse Spike Inversion (AVA-CSSI) algorithm extends the ZO-CSSI algorithm by incorporating angle-dependent reflectivity into the forward model. The four angle-dependent reflectivity series (one for each angle range) are calculated from the model parameters via Fatti (1994)'s re-parameterized form of the Aki-Richards (Aki and Richards, 2002) linearized Knott-Zoeppritz equation for PP reflectivity. The AVA-CSSI algorithm assumes the data consist solely of primary PP reflected energy, and it calculates angle-dependent synthetic seismograms by convolving each angle-dependent reflectivity series with its respective a priori angle-dependent wavelet. Extending the ZO-CSSI base case, three a priori low frequency (6 Hz) trends, corresponding to the three model parameters, serve as the initial model for the model based inversion and constrain the solution in a soft and hard sense. Again, the a priori low frequency trends are merged into the final estimates to correct for low frequency drift.

Prestack seismic data refers to full-fold CMP gathers that have not been corrected for normal moveout. Prestack seismic inversion methods—also known as full-waveform seismic inversion methods—exploit angle-dependent amplitude and phase (i.e., moveout) variations to simultaneously estimate P-velocity, S-velocity, and density pseudologs from each CMP gather. Historically, pre-stack seismic inversion methods have only been applied to a few CMP's or over small time windows due to high computation costs (e.g., Sen and Stoffa (1991), Xia et al (1998), and Mallick (1999)). However, we implement a computationally efficient prestack inversion algorithm that uses local optimization and is suitable for 3D applications. The forward model rapidly computes plane wave synthetic seismograms for each individual pre-stack CMP by calculating the composite response—including reflections, transmissions, mode conversions, and internal multiples—of a series of homogeneous, horizontal layers via the reflectivity method (Kennett, 1983). We apply an adaptive smoothing operator to the model space that weakens the non-linearity and reduces the objective function to a quasi-linear functional that we minimize with the method of conjugate gradients (Sen and Roy, 2003). Frechét derivatives are quickly calculated as finite differences by taking advantage of the top-down fashion of the reflectivity modeling (Sen and Roy, 2003). We smooth the well logs 1000 times and interpolate to obtain the initial model. This is equivalent to a 1-2 Hz low frequency model.

Results and Discussion

The poststack and partialstack inversions both resolve P-impedance with full dynamic range, accurately tie with the well log, and correctly model the major stratigraphic and structural features in the Marco Polo Field (Figure 3). For example, the southward prograding M-series sandstones, which have a lower P-impedance than the shale background, thin to the south and are offset by north-dipping normal faults. The hydrocarbon saturated M-series sandstones are characterized by anomalously low P-impedances in the north where they trap against the fault. In principle, the partialstack inversion should provide a better P-impedance estimate than the poststack inversion because the former fits more data. However, in the Marco Polo Field, the two estimates are nearly identical.
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Figure 4 compares the partialstack and prestack density estimates. (We omit the other partialstack and prestack model parameters because we are only interested in porosity estimation.) The partialstack estimated density (Figure 4a) has considerably lower dynamic range than its P-impedance counterpart and the well log density. Partialstack inversion cannot resolve density because, when the model space is parameterized with impedances, the Knott-Zoeppritz equation is only sensitive to density at extremely far offsets—beyond the normal seismic aperture—where the signal-to-noise ratio is low, anisotropic effects may be significant, and NMO-related wavelet stretch is substantial. In addition, a linearized Zoepritz equation is not valid at angle ranges where the Zoepritz equation is sensitive to density. Furthermore, because the partialstack forward model is insensitive to density over the data aperture and the conjugate gradient optimization scheme calculates model updates from the derivatives of the forward model with respect to the model parameters (i.e., density), the model updates do not improve the prior model and the prior model—not the data—determines the optimal model. Instead, P-impedance and S-impedance contrasts alone sufficiently describe linear amplitude characteristics over the normal seismic aperture.

In contrast, despite the smoother starting model, the prestack estimated density (Figure 4b) is well resolved, accurately ties with the well log, and correctly models the a priori structural and stratigraphic features. The prestack seismic inversion algorithm yields an unprecedented well-resolved density for several reasons. First, the incorporation of moveout adds an additional degree of freedom to the ill-posed inverse problem that allows for the resolution of velocities from two independent information sources: the long spatial wavelength (i.e., moveout) and short spatial wavelength (i.e., amplitudes). Second, because velocities are decoupled and well resolved, they can be separated from the near-offset reflectivity to isolate density. Third, the amplitude data is uncontaminated by NMO stretch and residual moveout. Fourth, the forward model calculates precise amplitudes by incorporating reflections, transmissions, mode-conversions, and internal multiples. Fifth, the forward model computes synthetic seismograms via the wave equation, which is valid over all angles of incidence. Finally, the Frechét are semi-analytically evaluated from the full wave equation and are valid over all angles of incidence.

As described above, density is the most valuable elastic parameter for estimating porosity in Marco Polo Field. Unfortunately, because partialstack seismic inversion cannot resolve density, we must estimate porosity from P-impedance. For the prestack case, however, we transform the estimated density to obtain porosity. As expected, the poststack (Figure 5a) and partialstack (Figure 5b) porosities are nearly identical and suffer the same drawbacks. In particular, the poststack and partialstack porosities both contain large discontinuities because the fluid-dependent transformation uses divergent ‘wet’ and ‘hydrocarbon’ trends. In addition, both predict unrealistically high porosities (<35%) in the ‘wet’ zones because of instability in the ‘wet’ trend. Lastly, both predict average porosity values (15%) in intermediate zones. The prestack porosity (Figure 5c), on the other hand, accurately predicts porosity for most lithologies and ranges of water saturation. Note that the two coarsening upward parasequences (blue arrows) are accurately modeled. Note the high quality prestack porosity pseudolog was obtained via a very crude transformation. This is further evidence that the prestack inversion algorithm resolves density.

Conclusions

Density is the most valuable parameter for estimating porosity in Marco Polo Field. Even when P-impedance is well resolved, instability in the P-impedance-to-porosity transformation produces unrealistic porosity estimates. Poststack and partialstack inversion methods both rely upon P-impedance to estimate porosity, and they cannot accurately estimate porosity in Marco Polo Field. Only prestack inversion resolves density in Marco Polo Field and provides a means to accurately model porosity variations.

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Figure 2: Cross-plots of P-impedance (a) and density (b) against porosity show that density is best-suited for estimating porosity because the steep density-to-porosity transformation gradient implies minimal error magnification. The water-saturated (blue) and hydrocarbon-saturated (red) trends are applied according to the respective elastic parameter thresholds (dashed red).

Figure 3: P-impedance estimated from poststack (a) and partialstack (b) seismic inversion methods are nearly identical.

Figure 4: (a) Partialstack inversion cannot resolve density from NMO corrected gathers because the forward model is insensitive to density variations over the seismic aperture. (b) Prestack inversion resolves density from amplitude and phase variations at near-offsets because the moveout provides an additional degree of freedom and decouples density from velocity in the traditional P-impedance parametrization.

Figure 5: Poststack (a) and partialstack (b) inversion methods estimate porosity from P-impedance. The 'wet' P-impedance trend is highly unstable and produces unrealistically high porosities (>>35%) in 'wet' zones. The prestack inversion estimates porosity from density and closely matches the measured porosity in most zones. Note the two upward coarsening cycles (blue arrows).
EDITED REFERENCES
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