SEISMIC METHODS FOR IMAGING PHYSICAL PROPERTIES OF THE EARTH

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ABSTRACT

We present an integrated study in which we develop a range of techniques for deriving images of rock properties, such as porosity and shaliness, from cross-well seismic tomograms. One of the keys is to incorporate rock physics knowledge of the relations between velocity, porosity, and clay content which were developed in the laboratory and calibrated in the field. Geostatistical techniques, such as kriging and cokriging, are used as a means to combine the heterogeneous data set, consisting of well logs, the tomogram, and laboratory results.

1. INTRODUCTION

Most of what is known about the internal structure of the Earth has come from seismic imaging. Earthquakes have been used for decades as natural compressional and shear elastic wave sources to study the very large scale structure; the travel times, amplitudes, and spectra of directly transmitted, reflected, refracted, and surface modes can be inverted to yield the three-dimensional distribution of velocity, impedance, and Q of the Earth, from which we try to infer the composition, as well as temperature and stress state.

By far, the greatest effort and investment in seismic imaging have been directed toward the exploration and production of oil and gas. In this case the common energy sources include dynamite, electrical discharges, and air blasts, all of which are impulsive, and large vibrators, with controlled frequency, phase and polarization, which allow frequency sweeps (chirps). Typically, each source is recorded by an array of several hundred single or multicomponent receivers. Then the source is moved and repeated at hundreds or thousands of locations on the surface of the Earth It is not unusual for a reflection seismic survey to record several million traces, with a thousand samples each.

The vast majority of seismic imaging with active sources is "reflection imaging". In this case, all of the source points and receiver points are at or near the Earth's surface. The waves propagate downward and scatter (or reflect) from contrasts in acoustic impedance back to the receivers. Many of the problems in reflection seismic imaging are similar to those in medical acoustic, X-ray, sonar, and radar imaging -- rejection of coherent and random noise -- and many of the same 1-D, 2-D, and 3-D filtering and image enhancement methods are applied. However, two problems make the seismic imaging problem unique, and much more challenging: One is simply the tremendous volume of data that must be processed. The oil industry is the largest consumer of magnetic tapes (after the Federal government), and it is not unusual for a single survey to take many months of main-frame CPU time to process. The second, and perhaps biggest problem is the tremendous heterogeneity of the medium to be imaged. The wave speed (or index of refraction) can vary up to an order of magnitude throughout the imaging volume. This creates "shadow" zones where it is difficult to achieve good ray coverage for imaging, and more importantly, the energy is refracted so much that seldom can straight-ray imaging be used. We are faced with the highly nonlinear problem of imaging unknown features in a medium with unknown wave velocity.

The final step in the imaging process is mapping the acoustic image to an image of the rock and fluid properties that are of interest. This is the field known as Rock Physics. It turns out, fortunately, that for rocks in the upper 10 km of the Earth, the wave speed, impedance, and Q are determined primarily by the pore space and pore fluids (e.g., oil, water, steam, or natural gas). Generally, the wave speed in a fluid-saturated rock is faster than in a rock with some gaseous phase. Furthermore, the compressibility and viscosity of complex fluids, like oil, are

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themselves highly sensitive to variations in temperature and pressure. Therefore, in principle, seismic images can reveal distributions of fluid types, their saturations, and the physical conditions of temperature and stress.

One particularly interesting technique that has evolved during the last decade is well-to-well imaging. In this case, seismic sources are placed in one deep well, and receivers are placed in another. Images are formed from a variety of methods, for example, transmission travel time tomography, reflection imaging, and Born inversion. Seismic well-to-well tomography allows us to constrain the seismic wave velocities much better than with classical reflection seismology methods, because with precisely located downhole sources and receivers we essentially avoid the velocity/depth ambiguity that is common with surface methods. The spatial resolution, on the order of a wavelength (~4-5 m) for transmission tomography, is generally much better, since temporal frequencies are often in the kilohertz range, while surface seismic methods are usually limited to less than 100 Hz. Finally, the signal to noise ratio and the bandwidth are generally better with down-hole methods, since they avoid the highly attenuative weathered rocks and soils at the Earth's surface.

At the same time, laboratory experiments and modeling have increased our understanding of the relations between seismic observables and the *rock properties* of interest, such as pore volume (porosity), the type of fluids that saturate the pore space, and rock type. We present here a brief exercise in which we use the seismic-to-rock properties transforms, obtained from both the laboratory and well logs, to derive images of porosity and shaliness from an actual cross-well velocity image. Three different approaches are presented and compared: (1) the conventional approach of using a deterministic velocity-porosity relationship to map the velocity tomogram to porosity, (2) purely geostatistical techniques to extrapolate measured values of porosity at the wells into the interwell region using correlations derived from the well logs, and (3) an integrated approach involving well logs, seismic data, and laboratory and field-derived rock properties relations, using geostatistical tools to combine the heterogeneous data.

2. DATA

The data set consists of a tomogram of seismic compressional ("P-wave") velocities [1] and well logs in the two adjacent boreholes, in Miocene sediments in the Gulf of Mexico area (Figure 1). The rocks are a sequence of poorly consolidated sands, shaly sands, and shales, offset by steeply dipping faults. The cross-section of interest is 250 ft (76 m) wide (distance between the two boreholes) and 1700 ft (518 m) high, between depths of 2400 ft (732 m) and 4100 ft (1250 m). A set of nuclear, electrical, and acoustic logs is available in the two boreholes, which allow us to estimate depth profiles of rock type, shale content, and pore volume in the rocks at the well-bore locations.

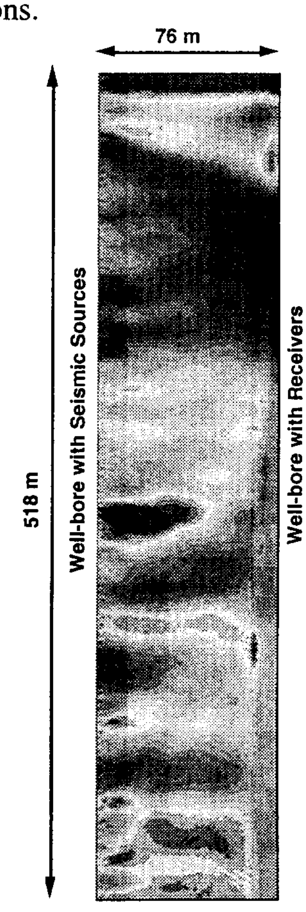

Figure 1. Tomographic image of seismic compressional wave velocity between two wells.

3. ROCK PHYSICS

The next step is to interpret this image in terms of rock properties of interest. One approach is to map the velocity tomogram to porosity using velocity-porosity relations derived from laboratory and well-log data. One traditional approach is to use the semi-empirical time-average relation:

$$\frac{1}{V} = \frac{\phi}{V_w} + \frac{1-\phi}{V_0}$$

where V is the velocity of saturated rock, V_W is the velocity of P-waves in water, V_O is the velocity of P-waves in the minerals making up the rock, and ϕ is the porosity. The porosity image is obtained by solving this equation for ϕ, and substituting in the tomogram velocities pixel by pixel. Although this equation has an intuitive appeal, it is often at the expense of a good fit to the data, since it does not incorporate other parameters such as consolidation, pressure, and clay content. Furthermore, it ignores information from the well logs, and in fact, the image derived using this relation disagrees with direct measurements made with the porosity well logs. Images derived in this way are simply rescaled versions of the tomogram, since they use a one-to-one mapping from V to ϕ.

A more complete relation is suggested by the laboratory work of Han [2] on a large set of Gulf Coast sandstones. Han found that much of the scatter in velocity-porosity relations was not random, but closely correlated with clay. At a given pressure he found an excellent empirical fit using an equation of the form:

$$Vp=5.59-6.93\ \phi-2.18\ C$$

where C is the volume fraction of clay or shale. We find similar relations involving velocity, porosity, and clay using values derived from the well logs. In order to use these relations we need an estimate of clay at various points between the wells.

4. GEOSTATISTICS

In this approach, we use purely statistical techniques: the porosity ϕ and velocity V are treated as two random fields in space, and we make no *a priori* assumptions about their relation. Instead, we estimate their auto- and cross-correlations (equivalently the variograms and crossvariogram) statistically from the data. The velocity variogram is estimated from the tomogram in both the vertical and horizontal directions; the porosity variogram is estimated only in the vertical direction (from the porosity logs), and an anisotropy coefficient deduced from velocity tomograms is applied to estimate the porosity variogram in the horizontal direction. The crossvariogram between ϕ and V is estimated in the vertical axis and the same anisotropy coefficient is applied. The porosity ϕ is estimated on a regularly spaced grid, from either (1) "hard" ϕ data at the wells only (kriging) or (2) a combination of "hard" ϕ data and "soft" velocities V from the tomogram (cokriging) (Figure 2). At each point of the grid, the estimate is a linear combination of the hard data and soft data, in which the weights depend not only on the distance from the data points, but also on the spatial continuity of the variables, described by the variogram (or the crossvariogram in the case of more than one variable like in cokriging).

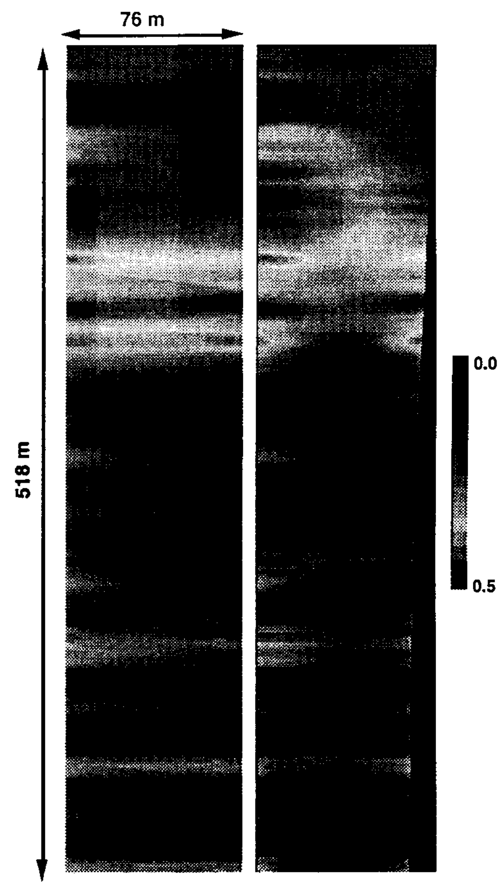

Figure 2. Porosity estimated using ordinary kriging (left) and cokriging (right).

5. INTEGRATED APPROACH USING LOGS, TOMOGRAM, ROCK PHYSICS, AND GEOSTATISTICS

In this approach we combine the laboratory rock physics relations with geostatistical tools. The cokriging technique, combining the velocity tomogram and log-derived estimates of clay at the wells, is used to generate an estimated clay content image. This image agrees perfectly with the clay at the wells and reflects some of the heterogeneous features between, which are derived from the tomogram. The final porosity image is then derived by applying the empirical V-ϕ-C relation to the clay image and tomogram velocity image (Figure 3).

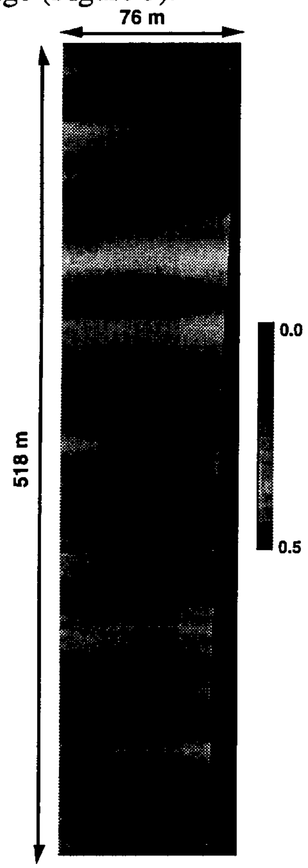

Figure 3. Porosity image derived from kriged clay image, tomogram velocity, and the velocity-porosity-clay relation.

6. CONCLUSIONS

As expected, ordinary kriging using only the porosity logs gives a fairly detailed image of porosity very near to the wells, but a low resolution, low accuracy image in the interwell region beyond the correlation range. Adding velocity information via cokriging gives slightly more detail in the interwell region; however the apparently poor crosscorrelation between velocity and porosity derived from the logs indicates less accuracy and resolution than desired. The use of the pure rock physics techniques gives porosity images with interwell features that mimic the velocity image; however, they do not reflect the uncertainty of velocity-porosity relations, and they do not match the measured porosities at the wells. The images that combine rock physics and geostatistics have the best features from both methods: (1) they match the measured porosities at the wells, (2) they reflect many of the features in the velocity image, which we expect from laboratory experience, and (3) they incorporate the relatively tight relation between velocity, porosity, and clay content. One focus of our current work is to reconcile the very good apparent correlation between velocity and porosity measured in the lab with the relatively poor one that is derived from the logs. The magnitude of the correlation impacts the relative influences of the porosity and velocity data on the estimated porosity image.

7. REFERENCES

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