Lithology and Fluid Prediction Project Phase 3 (LFP3)

Background

Rock Solid Images, starting in 2004, has organized two phases of a very successful industry consortium (LFP and LFP2) to improve the technology for the determination of reservoir lithology and fluid properties from surface and downhole measurements. The second phase of this consortium is drawing to a close at the end of 2009, and we are proposing a third phase (LFP3) to start in January 2010 and last three years.

Introduction

In the past years we have conducted several studies in support of the growing interest in unconventional resources, both domestic and international. These resources include shales (primarily in North America), tight gas sands, carbonates, and abnormal pore pressure formations. These studies all point to the same thing: that a conventional approach to rock physics modeling and seismic inversion may not be adequate to address these issues. We need better rock physics models and inversion methodologies to help us fully tackle these problems. The upside is a much better understanding of these reservoirs, which allows us to recover and manage our resources in an optimal manner.

In addition, the increasing acceptance of time-lapse reservoir monitoring also requires a better rock physics model: one that allows us to better understand the distinction between the stress and fluid effects in our data and allows us to monitor the flow through reservoirs at the seismic scale, not just at discrete well locations. The increased complexity in our data requires an increased complexity in our rock models, the chief requirement being the parameterization of the pore space by more than the single porosity value.

Based on these studies, we have identified several areas that are worthy of further research. These are divided into rock physics and seismic modeling/inversion categories, but they share the common theme of “unconventional resources”. Rock Solid Images proposes a three-year industry consortium, LFP3, to address the following areas:

Rock Physics Modeling

Carbonates

In LFP2 we initiated studies of carbonates, specifically using the DEM and Self-Consistent models to better understand the elastic behavior and fluid substitution methodology for carbonates and chalks. We will continue these studies, test other models and methodologies, and use other measurements (such as resistivity and permeability) to help constrain the data.

Shales

Shales have been long neglected as possible reservoir rocks, and thus their properties are not very well understood. We need improved rock physics models and transforms for shales. We also need the development of better geophysical attributes to quantify sweet spots within thick shale sections. In addition, shales can be very anisotropic. We need to understand how this anisotropy affects our normal workflows and how we can quantify it from core, log, and VSP measurements.

Tight Gas Sands

In low porosity sands, porosity does not appear to be simply correlated with velocity. Velocity-porosity relationships in these rocks cannot be explained without either the addition of cracks to the rock matrix or changing pore geometry with decreasing porosity. The effect of pore geometry may be more important than the effect of porosity (Figure 1), and amplitude variations may be more indicative of lithology. We need to develop rock physics models and workflows specifically for tight sands.

Common Rock Physics Models for Elastic and Electrical Measurements

The development of CSEM methods for offshore hydrocarbon detection and renewed interest in using electrical methods onshore have underlined the need for a more unified understanding of rock physics relationships to permit an integrated model based interpretation of seismic and electromagnetic data, both downhole and for surface measurements. This is of particular importance in shales since current models for resistivity and elastic properties are not consistent with each other. In addition, resistivity and elastic measurements measure different aspects of the pore space. The integration of these measurements will allow us to describe the pore space better and in more detail, and thus provide a more accurate picture of the reservoir properties when there are fluid and stress changes.

Time Lapse Reservoir Monitoring and Stress Changes

Time lapse reservoir monitoring includes an additional parameter that is often missing from rock physics models, namely, stress changes. Changes in *in situ* stresses due to drawdown or injection may result in significant changes in elastic and electrical properties, and these changes can easily be misinterpreted as changes in pore fluids (Figure 2). Furthermore, these stress changes are often non-hydrostatic, leading to anisotropic variations in the resulting velocity fields. In addition, stress-induced anisotropy is common in many reservoirs. These changes can usually be related to the “micro-cracks” in the pore space; however, existing models of such pore space descriptions are complex and untested.

A better understanding of how the underlying rock properties vary with changing stress conditions is needed.

In summary, we need to develop new rock physics models and transforms that can address the challenges from issues related to unconventional reservoirs and time lapse monitoring. Existing models tend to be too complex. We need to simplify these models in ways that allow us to address these more complex situations, but not have too many unknown (and unmeasurable) parameters to be useful for quantitative interpretation and reservoir characterization.

Seismic Modeling and Inversion

Inversion with Multiples

During LFP2, we have shown with 1D examples that for seismic full waveform inversion (FWI), the elimination of multiples destroys useful signal energy, and is therefore counterproductive. This is because multiple elimination also distorts the primary signal, thus reducing our ability to extract rock physical information from the data. The next (and crucial) step is to extend these ideas to the 2D case. This effort will include the search for accurate, high-speed forward modeling code, and for an appropriate computational platform.

Global Minimization

Most FWI work at RSI has thus far concerned itself with local, rather than global, algorithms. However, local algorithms require a good starting model, and we should recognize that such prior information is often not available. This means that the generally more time-consuming global algorithms (e.g., Simulated Annealing, Genetic Algorithms, and others) should be investigated to resolve such situations that often occur in practice. We will begin by examining these approaches, and investigate circumstances when they are likely to give us superior inversion results compared to more standard industry approaches (Figure 3).

Uncertainty Estimates

Another area of seismic inversion we will actively pursue is the issue of inversion uncertainty estimates. All inversions incorporate errors, both in the recorded data and in the assumed model leading to an inherent non-uniqueness in the result. Although deterministic inversion approaches are extremely efficient, it is often hard to quantify the uncertainty in the derived model parameters, and hence, difficult to establish the robustness of an interpretation based on these. One way to characterize this uncertainty is by the use of Bayesian methods: here one starts out with an *a priori* estimate of the model and then, instead of coming up with a particular set of inverted model parameters, one gets the so-called MAP (Maximum *A Posteriori*) estimate. The peaks of this probability distribution correspond to the most likely values of the individual parameter estimates, whereas their spreads (standard deviations) provide a quantitative uncertainty estimate. The MAP estimate is, of course, multidimensional, with its dimensionality given by the number of parameters in the forward model.

Anisotropic Inversion

A third area of interest is seismic anisotropy. Shales can be very anisotropic, and a proper inversion for shale properties needs to take this into account. We will be developing anisotropic pre-stack inversion for shales, initially for VTI (Vertical Transverse Isotropy) anisotropy, and will be integrating these developments into our shale workflow once new algorithms have been tested.

Upscaling

A major unsolved problem that we simply must come to grips with is upscaling from the rock physics scale to the well log scale, and from there to the surface seismic scale. Rock Solid Images has a number of innovative ideas in this area, and we will be testing them on synthetic as well as real data in the near future. One such promising technique involves the use of self-organizing neural networks to achieve this objective.

Anticipated Deliverables, 2010

During year one of LFP3, we propose to focus on new rock physics models for seismic properties, well-tie, and seismic inversion tools. The following are goals and deliverables that we plan to achieve during 2010. These goals may be refined depending on feedback from sponsors.

Goals

Rock Physics

Develop new methodology for modeling seismic properties in carbonates, shales and tight gas sands, with the goal of better predicting these properties under difference stress and fluid conditions. We will increase our emphasis on additional characterization of pore geometry in addition to porosity.

Seismic Modeling/Inversion

Investigate and implement a high speed forward modeling code in 2D, including multiples. Investigate and implement a fast global inversion algorithm for full waveform seismic, allowing quantification of uncertainties.

Deliverables

Science: Research Reports, Data Analysis, and Practical Workflows

- Reprints and bibliographies of literature on carbonates, shales, and laminated sands
- iMOSS projects with example well log data representing typical carbonate, shale, and laminated sand lithologies

Tools: Software Implementation in iMOSS

- Carbonate, shale, and tight gas sand, and stress-dependent rock physics diagnostic technology delivered as LFP-only iMOSS tools, workflows, and example data sets
- One seat of iMOSS
- Support, maintenance, and upgrades at no cost to LFP3 sponsors
- Technology transfer: robust recipes, best practices, and workflows

Training and Consulting

New consortium benefit will include two man-days of on-site training and consulting with each sponsor to demonstrate software, best practices, and workflows developed by LFP. These sessions will be scheduled individually with each sponsor beginning in the first quarter of 2010. (Travel costs not included in sponsor fee.)

Personnel

OHM Rock Solid Images: Arthur Cheng, Scott Singleton, Franklin Ruiz, Paola Newton, Rone Shu, Jeffrey Chen. Consultants: Gary Mavko (Stanford), Sven Treitel (Tridekon), Subhashis Mallick (U. of Wyoming), Steve Brown (NER/MIT)

Timing and Cost

Start date	January 1, 2010
End date	December 31, 2012
Duration	36 months
Exclusivity period	12 months from delivery
Annual fee	$52,000

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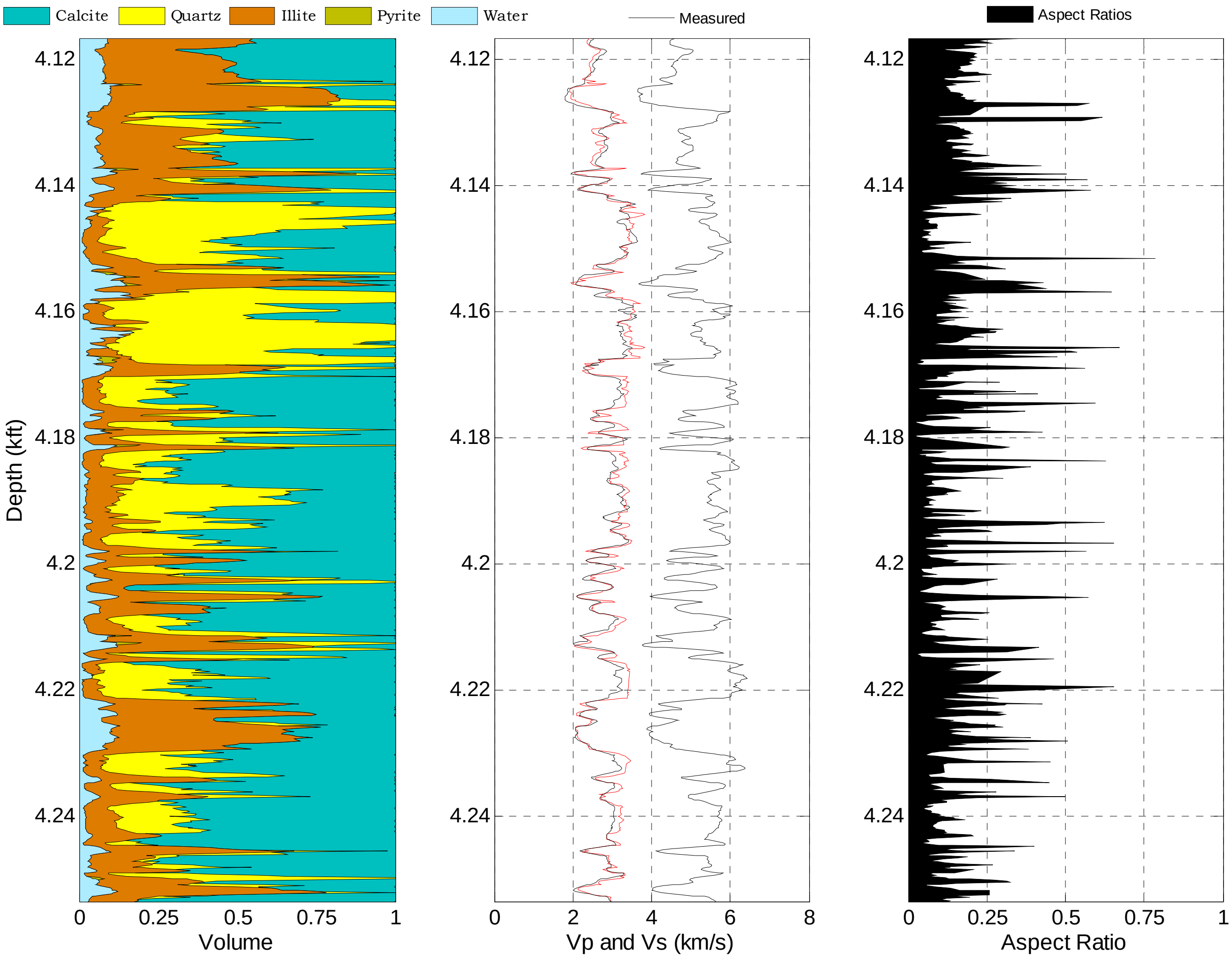

***Figure 1**: Fit to measured P wave velocity and prediction of S wave velocity in low porosity rock using variable aspect ratios (after Ruiz, 2009). We intend to extend this approach to tight gas and carbonate environments where micro-cracks may play a significant role.*

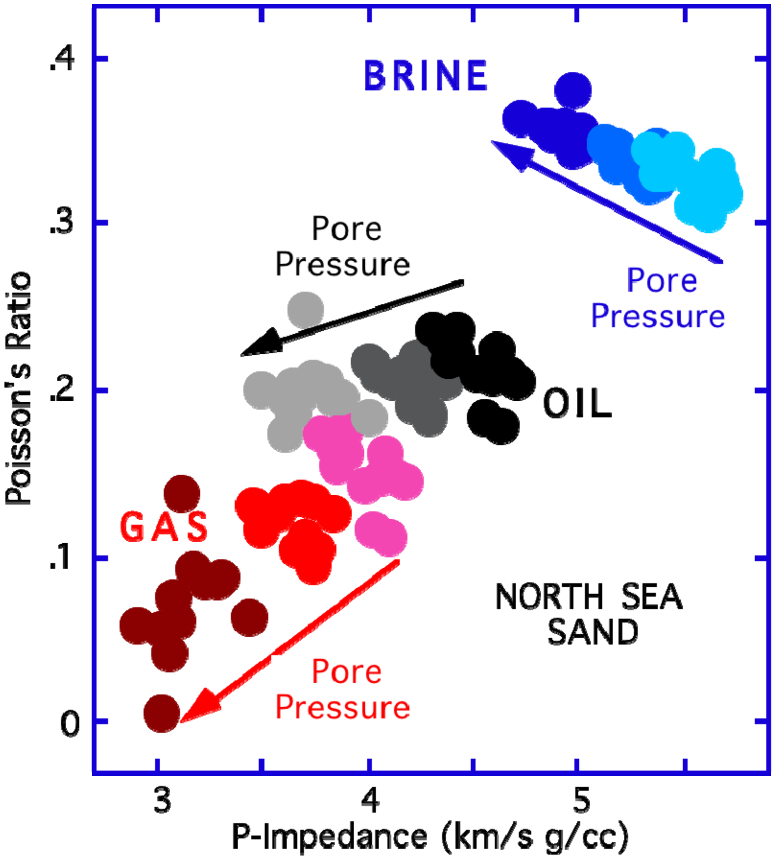

***Figure 2**: Pressure and saturation effects on Poisson's Ratio and P-Impedance cross-plot (after Blangy, 1991, courtesy of Jack Dvorkin). We intend to continue our studies on the stress effects on fluid saturation and seismic attributes on unconventional reservoirs.*

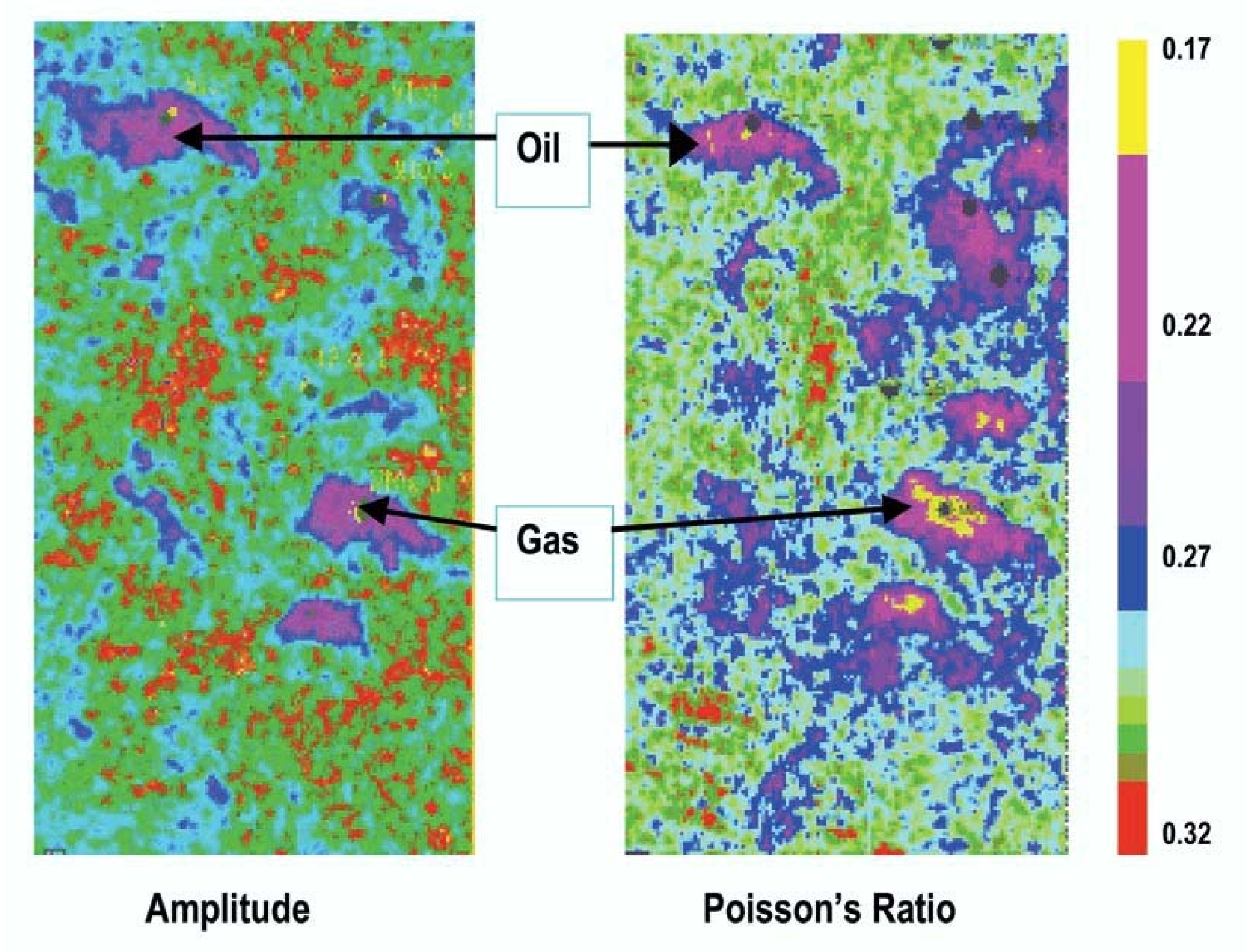

Figure 3: *Amplitude from the stacked data and the Poisson's Ratio from a hybrid inversion over a portion of data with oil and gas discoveries. Notice that the amplitude map could not show a difference between oil and gas, but the Poisson's Ratio map did (from Benabentos et al., TLE, 2002, courtesy of Subhashis Mallick). We intend to develop fast and efficient inversion algorithms in LFP3.*