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Direct probabilistic inversion of seismic AVO data for reservoir characterization in the presence of thin beds and elastically ambiguous facies

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Summary

Within the discipline of seismic reservoir characterization, there is an ever-present ambition to improve the accuracy and detail in the analysis of the seismic data. At the same time, reservoir related decision-making and risk analysis also requires an increasingly degree of assessment of the uncertainties associated with any interpretations and statements based on the seismic data. Bayesian inference solutions provide a framework where these issues can be addressed. However, in its standard formulation and given the size of typical seismic volumes it might result computationally expensive. In this study we show how, under reasonable assumptions, a high dimensional Bayesian inference problem can be reduced to a number of local low dimensional inference problems, reducing the computational cost of this solution. This enables the application of a general and flexible probabilistic framework for rigorous propagation of uncertainties where prior knowledge from multiple domains can be easily integrated. We tested this approach on the local scale inference problem of estimating surfaces with uncertainties, here defined as transitions between subsets of facies. Our results illustrate the method's ability to provide robust surface estimates at and below seismic tuning due to the utilization of statistical prior information.

Introduction

Different facies and fluid configurations might result in similar elastic responses. This is an intrinsic characteristic of the non-uniqueness of the inversion problem. This can be mitigated by integrating relevant and non-redundant information into the inversion process. Standard inversion techniques for example, are vertically "unaware" of the geological ordering, bed thickness distributions and fluid ordering (gas/oil/water) within the interval of interest. However, this information can be readily available from geological studies that might provide insights about specific ranges of elastic properties for certain facies, average thicknesses and their variation, existence within an specific regional formation, stratigraphic position respect to other facies, and presence of oil saturated or brine saturated facies bellow it. Defining a set of rules based on this information will reduce the solution space dramatically. However, in conventional deterministic seismic inversion algorithms all this information is difficult to integrate. Moreover, the correct propagation of uncertainties through the inversion is not possible.

The following will present an integration example, where information from standard processed seismic amplitude versus offset (AVO) data are integrated with information from a range of other domains. We show how this approach can help with the interpretation of surfaces and reservoir interfaces even below the seismic resolution limits. The location of these interfaces will be estimated as a result of the integration of data and information from different domains such as well logs, seismic data and geology.

Direct Probabilistic Inversion

Our direct probabilistic inversion (DPI) is a one-step inversion process, based on the Bayesian probabilistic formulation introduced by Jullum and Kolbjørnsen (2016). This approach honours multi domain inputs and assumptions, respecting the confidence in these inputs. A key attribute of DPI is that the geological framework of prior information can be encoded and combined with seismic AVO modelling to provide reliable results. This geological framework might include geological rules, facies thickness, disallowed facies transitions, elastic property ranges and intra property correlations and distance correlations for each facies. The prior information can be broad and plausible but also very strict/narrow depending on the level of available knowledge. Handling the spatial information enables an optimal propagation of uncertainty and handles the non-uniqueness of the problem by providing probabilities. Under some conditions the reduction of the solution space allows DPI to resolve features below seismic resolution.

The direct result of the DPI is a probability volume for each of the defined facies. Many other properties can be derived from having the probability for each facies. For example, all the facies probabilities can be combined into the most likely facies and corresponding probability. It is also possible to integrate all the probabilities to define surfaces. Thus, one can find surfaces with uncertainty using the full AVO signal and the geological information which can prove useful for picking difficult seismic horizons.

Example

The following real data example illustrates the applicability of the outlined method and demonstrates the power of combining information from different geophysical and geological domains. We use seismic AVO data obtained from a 3D land seismic survey covering a producing oil field in Australia’s Eromanga Basin. Very often in this area, the reservoir thickness is below seismic tuning and difficult to map. In addition, the presence of overlying, laterally varying amounts of calcite, distorts the seismic response increasing the difficulty of the interpretation. Furthermore, the oil sands have very low oil saturations making the fluid response weak.

From a large number of regional wells, shale, brine sand, oil sand and calcite were identified as the primary facies belonging to the relevant formations (Figure 1) resulting in 33 different defined facies. A priori probabilities for the surfaces of interest were defined from regional major interpreted surfaces and converted into prior facies probabilities with the simple assumption of equal proportions of facies inside each formation. The a priori local spatial structure of the facies (Figure 2) is assumed to be 1D and can be approximated by a vertical Markov process (Larsen et al. 2006). The estimated transition probability matrix form the basis for the rules from which samples of the prior distribution of facies are generated.

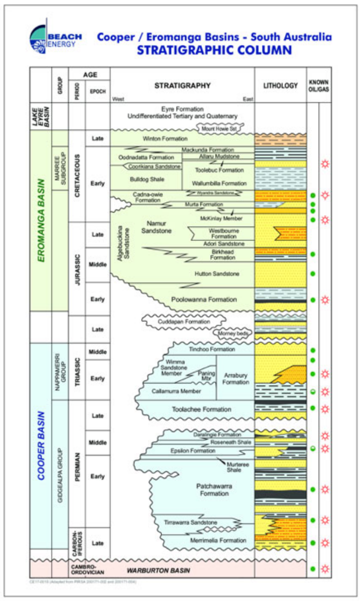

Figure 1: Stratigraphic column for the study area in the example. The interval of interest is Early Cretaceous to Middle Jurassic.

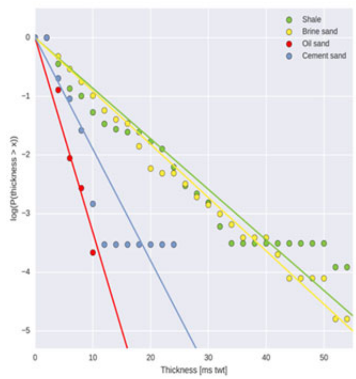

Figure 2: Logarithm of the probability of thicknesses larger than a given thickness measured in ms twt for the real data example. The linear trend for each facies indicates that thicknesses are exponentially distributed in line with a first order Markov spatial model.

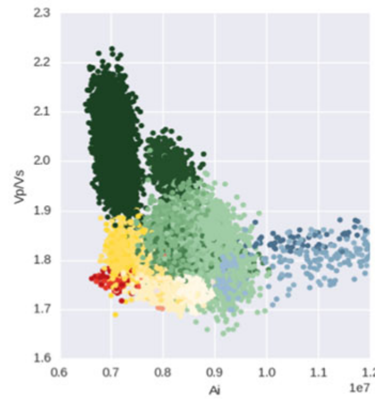

Figure 3: . Realizations of the statistical RP model based on the well log data. Seismic scale acoustic impedance versus Vp/Vs with defined facies, shale (green), brine sand (yellow), oil sand (red), calcite cemented sand (blue). Color saturation decreases with depth of formation. Separation of the different facies indicates that the facies may be resolved by seismic AVO data.

Well log elastic data are used as input to a statistical rock physics model (Figure 3). Wavelets specific for each of the nine input seismic angle stacks are estimated. Then, a Gaussian seismic likelihood model is defined by combining the wavelets with an Aki & Richards AVO model and a seismic noise model.

Following the application of the method to the nine seismic angle stacks, the prior and posterior marginal facies probabilities are shown for a trace at a bin location near a well (Figure 4). The added information from the seismic AVO data is clear, as the transitions between facies are sharper. A similar comparison for the defined surface interfaces in a small section is also shown. Note the consistency with the well formation tops, as well as the width of the surface distributions due to the limited seismic resolution.

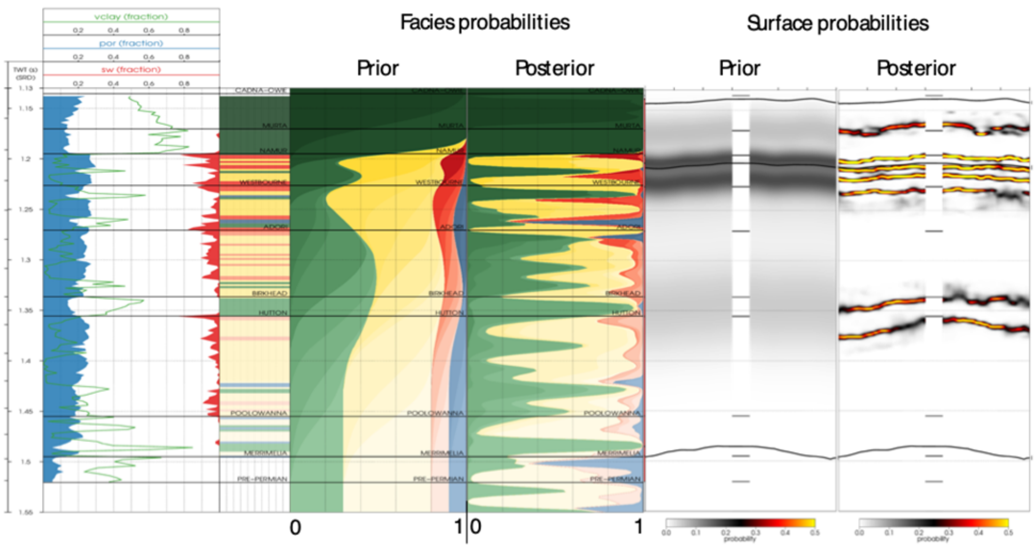

Figure 4 Evaluation at a well location. From left to right: Petro-physical logs, facies log, prior and posterior marginal facies proportions at the well location, mini-sections of posterior and surface marginal probabilities along a mini section around a well location. The probabilities are summed for 4 selected surfaces for display. Facies color-code is the same as in Figure 3. Note the resolution of the Top Namur, Top intra Namur shale and the Top Westbourne surfaces. The Top Birkhead surface is only resolved to a limited degree and exhibits multiple likely solutions for a given trace location.

Conclusions

Under reasonable assumptions, a high dimensional Bayesian inference problem can be reduced to a number of local low dimensional inference problems. This enables an application of a general and flexible probabilistic framework for rigorous propagation of uncertainties and for integrating prior knowledge from multiple domains. Moreover, this approach renders the Bayesian inversion a computationally affordable solution for industry sized AVO seismic volumes. The results of this study illustrate the ability of this method to provide robust surface estimates at and below seismic tuning due to the utilization of statistical prior information.

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