[GC]Relative Rock Properties – An Alternative to Estimate Reservoir Properties from Seismic Data*

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General Statement

Estimates of reservoir properties (porosity, lithology and fluids) using seismic data are customarily obtained through seismic inversion in two stages: in the first stage rock properties (P- and S-impedances and density, for example) are computed through elastic inversion, and in the second stage the estimated rock properties are inverted to the reservoir properties of interest.

Elastic inversion computes rock properties by minimizing the difference between observed data and data modeled through relationships that incorporate AVO, the offset-varying wavelet and a low frequency model (LFM). Under this scheme inversion software searches for the rock properties that result in the synthetic data that best matches the real data. It is a mathematically complex process. The parameters in available software usually are not intuitive and the sensitivity of inverted properties to changes in input parameters is typically poorly understood by the regular user. Parameterization is done, many times, by iteratively modifying parameters and comparing the inverted properties to their equivalent from well-logs.

The LFM, required when inverting to absolute rock properties, provides the low frequency component (including DC) on which the relative changes from seismic are superimposed. Its frequency bandwidth falls outside that of the seismic and it remains mostly unchanged during the inversion process. The LFM is created from non-reflectivity data, usually well-logs and seismic velocities, and its magnitude is several times larger than that of the relative rock properties' changes measured by seismic. A small percent inaccuracy in the LFM can result in errors as large as the range of variation of the relative changes.

Many approaches exist to estimate reservoir properties from the inverted rock properties. Some are qualitative and based on defining in cross-plots (or multi-variate space) the clusters of seismic attributes associated to a reservoir property as determined from equivalent properties from well-logs. Model based approaches are deterministic and relate a reservoir property (i.e. porosity) to a rock property (i.e. impedance) using effective media relationships. Sometimes empirical relationships are obtained by fitting the inverted properties to well-log or core measurements of the sought for reservoir property at well locations. The obtained relationship is then applied to the rock properties in the 3D volume to obtain estimates of the desired reservoir property.

The previous methodology is analyst intensive and the reliability of results is strongly dependent upon analysts' experience. The analyses to compute rock properties and the estimation of reservoir properties are often done by different geoscientists, thus adding uncertainty to the estimated reservoir properties.

Reducing User Input

A methodology is proposed in which relative rock properties are used to compute reservoir (or resource) properties. It reduces user input and simplifies parameterization. In the proposed methodology, each of the components of elastic inversion is done separately and their order of execution is modified. Under this scheme the seismic wavelet is offset-equalized and phase corrected in the data conditioning stage, prior to computing relative properties. The LFM is incorporated, if necessary, when computing the reservoir properties from relative rock properties. The methodology relaxes the need of a rigorous LFM and bypasses the estimation of absolute rock properties. Figure 1 compares the customary and proposed inversion flowcharts.

Reservoir properties are computed as a linear combination of relative rock properties. The parameters of the linear equation are obtained from well-log data by least-squares fitting the reservoir property of interest through two or more relative rock properties (regression analysis). The LFM, when required, is input into the regression analysis as one of the properties through which the reservoir property is fitted. The LFM can be the low frequency expression of any property that mimics that of the reservoir property of interest. In many cases, for example, p-wave velocity from seismic is used as the LFM when computing total porosity. Figure 2a shows a quality control display for the estimation of the linear relationship. In this case, relative Lambda*Rho and relative Mu*Rho, computed at seismic resolution, are linearly combined to obtain a band-limited estimate of porosity.

The last step in the proposed methodology is to compute reservoir properties in the seismic volume using the linear relationship estimated from well-log data. Relative properties from seismic are obtained by integrating (running sum) the reflectivities of the corresponding rock properties obtained through analytical transforms of AVO attributes. In the example shown (Figure 2b), porosity is computed from seismic through the linear combination of relative Lambda*Rho and relative Mu*Rho obtained in the well-log analysis shown in Figure 2a.

Conclusion

The proposed methodology computes, from seismic data, quantitative estimates of any reservoir (or resource) property that can be represented as a linear combination of relative rock properties. Effective porosity, brittleness and minerology (including volume fraction of kerogen) are examples of properties to which seismic data can be inverted.

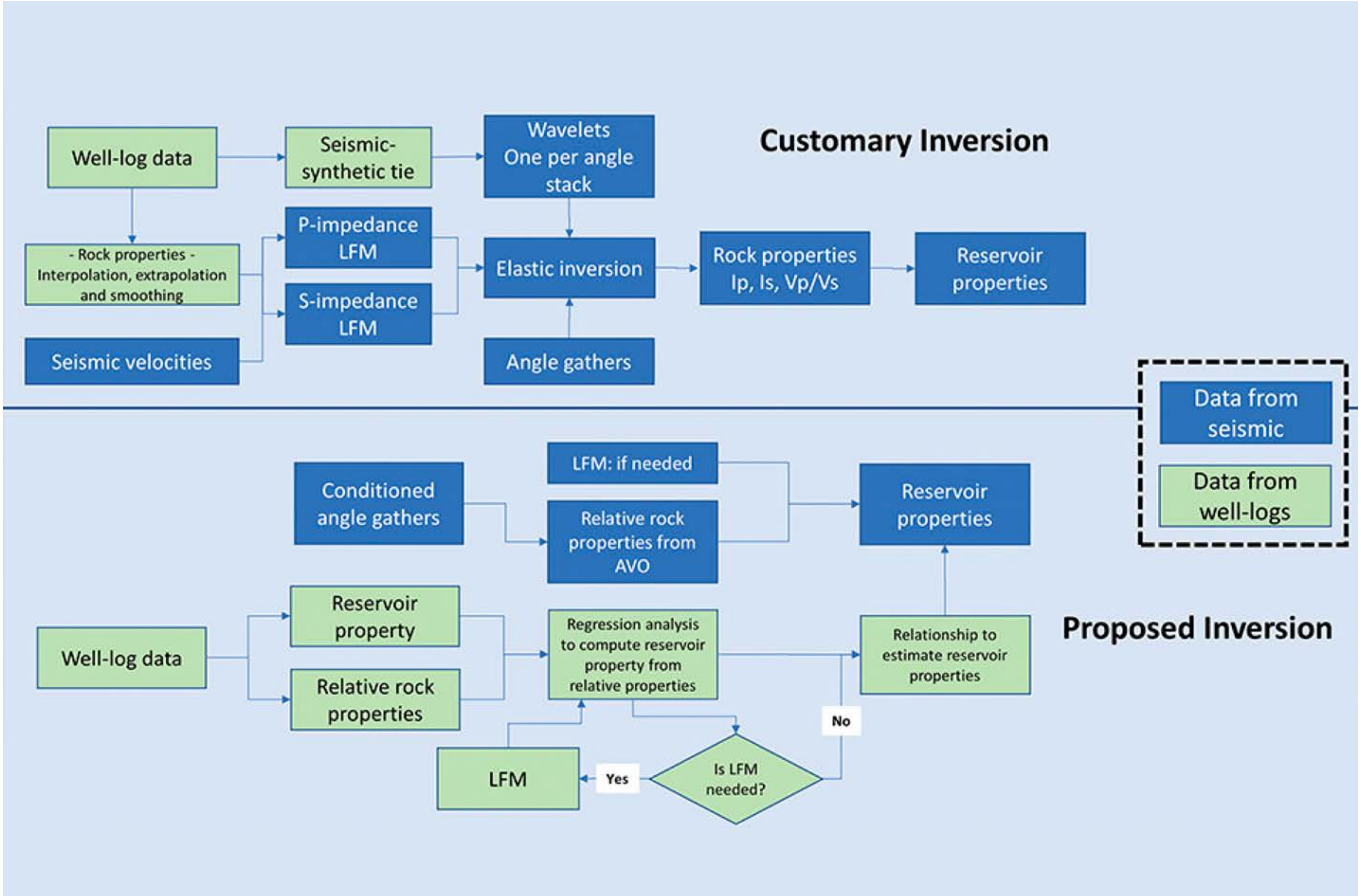

Figure 1. Comparison of the customary and proposed inversion flowcharts

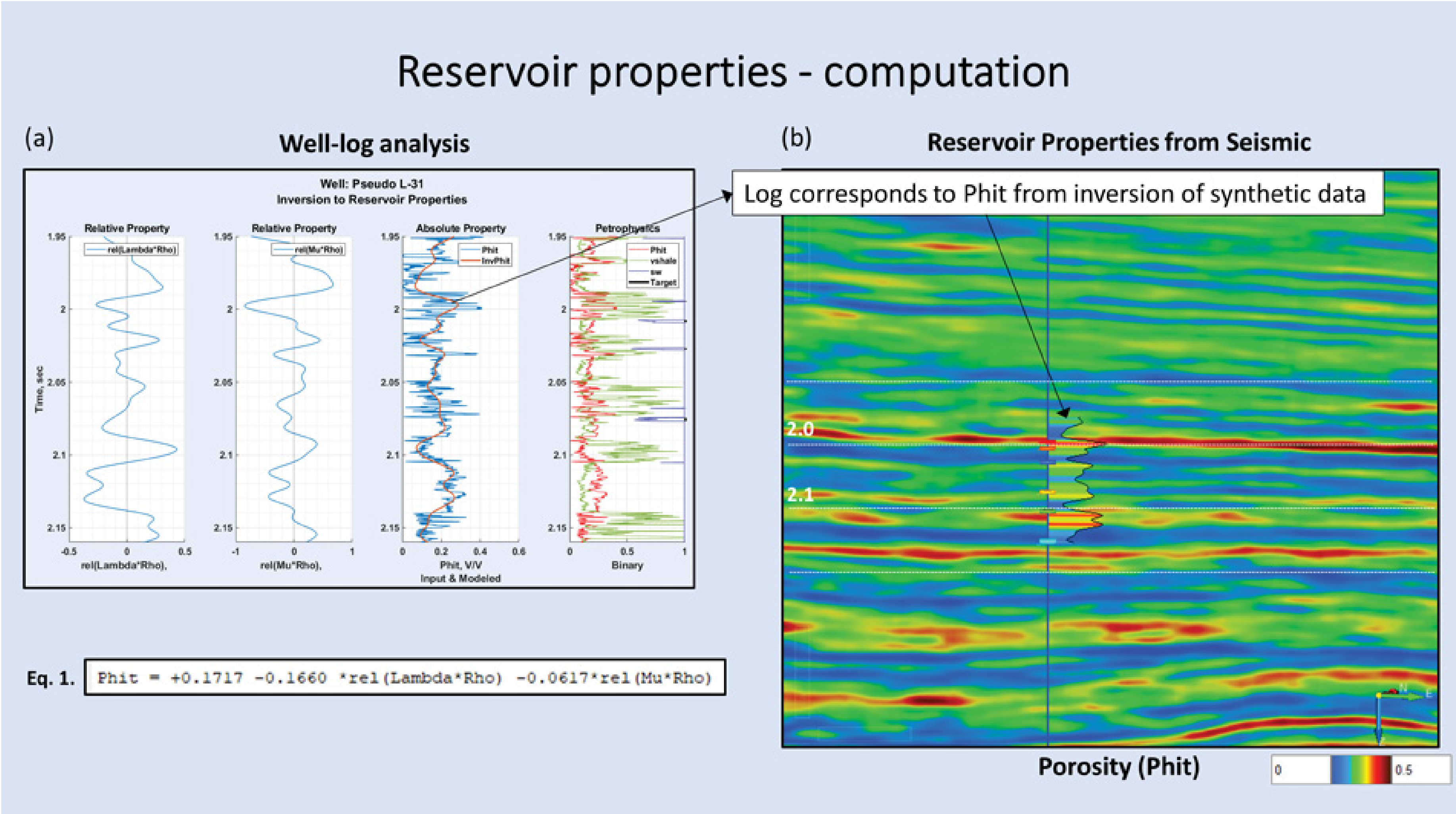

Figure 2. (a) Well-log analysis. Quality control display for the estimation of reservoir properties. The first two tracks are Lambda*Rho and Mu*Rho at seismic resolution. Track 3 shows the total porosity log (blue) and the band-limited porosity (red line) computed using equation 1. Track 4 shows the petrophysical evaluation. (b) Reservoir properties from seismic. In this figure total porosity is computed using the equation obtained from well-log analysis (equation 1). Relative Lambda*Rho and relative Mu*Rho are obtained from seismic by integrating (running sum) Lambda*Rho reflectivity and Mu*Rho reflectivity which are obtained by analytical transformations of AVO attributes.