Journal of Applied Geophysics 146 (2017) 54–66

Contents lists available at ScienceDirect

Journal of Applied Geophysics

journal homepage: www.elsevier.com/locate/jappgeo

Integrated petrophysics and rock physics modeling for well log interpretation of elastic, electrical, and petrophysical properties

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ARTICLE INFO

Article history:
Received 11 December 2016
Received in revised form 23 August 2017
Accepted 2 September 2017
Available online 8 September 2017

Keywords:
Petrophysics
Rock physics
Multiphysics model
Formation evaluation
Reservoir characterization

ABSTRACT

Rock and fluid volumetric properties, such as porosity, saturation, and mineral volumes, are generally estimated from petrophysical measurements such as density, resistivity, neutron porosity and gamma ray, through petrophysical equations. The computed petrophysical properties and sonic log measurements are generally used to estimate the petro-elastic relationship between elastic and rock and fluid volumetric properties used in reservoir characterization. In this paper, we present a unified workflow that includes petrophysical relations and rock physics models for the estimation of rock and fluid properties from elastic, electrical, and petrophysical (porosity, density, and lithology) measurements. The multi-physics model we propose has the advantage of accounting for the coupled effect of rock and fluid properties in the joint petro-elastic and electrical domains, and potentially reduce the uncertainty in the well log interpretation. Furthermore, the presented workflow can be eventually extended to three-dimensional reservoir characterization problems, where seismic and electromagnetic data are available. To demonstrate the validity of the methodology, we show the application of this multi-physics model to both laboratory measurements and well log data.

1. Introduction

The estimation of hydrocarbon reservoir parameters from geophysical data is generally affected by a large number of uncertainties. The integration of different geophysical data and methods allows estimating physical properties in the subsurface and reducing the ambiguities of the interpretation. Both petrophysics and rock physics play critical roles in the evaluation of reservoir properties. Petrophysical models applied in well log interpretation allow transforming downhole measurements into rock and fluid properties such as saturation, clay content, and porosity (Ellis and Singer 2007); on the other hand, one of the goals of rock physics models is to determine physical relationships between rock and fluid properties and the observed seismic response (Mavko et al. 2009). One of the goals of petrophysical interpretation of well logs is to determine the volumetric fractions of the formation components (solid and fluid phases) by combining the measurements provided by several tools, such as well-log resistivity, acoustic, density, neutron porosity, nuclear magnetic resonance, fluid sampling, coring, and imaging (Theys 1991; Darling 2005; and Ellis and Singer 2007). Because this problem includes multiple physics models, parameters, and measurements, several optimization and uncertainty quantification methods have been proposed (Heidari et al. 2010; Fylling 2002; Verga et al. 2002; Kennedy et al. 2010; Viberti 2010). Similarly, one of the goals of rock physics models is to predict elastic attributes from rock and fluid properties, according to the geological environment. A number of models is available in literature; for more details, we refer the reader to Bourbie et al. (1987), Nur and Wang (1989), Wang and Nur (1992, 2000), Avseth et al. (2005), Mavko et al. (2009), and Dvorkin et al. (2014). The application of these petroelastic models to well log data requires the knowledge of rock and fluid properties previously estimated from petrophysical logs.

In quantitative log interpretation, rock physics and petrophysical models are applied independently, with the exception of a limited number of applications in which empirical velocity-porosity relations are applied in the well log analysis. Petrophysical models focus on volumetric relations for the estimation of rock and fluid volumes, based on petrophysical logs and core measurements, but generally do not account for the sonic measurements. Empirical relations between P-wave velocity and porosity, such as Wyllie's equation or linear regression models, have been included in the quantitative log interpretation workflow (Darling 2005; and Ellis and Singer 2007), but these relations are generally limited to P-wave velocity and are generally first order approximations of more complex rock physics models. On the other hand, rock physics models are usually applied in reservoir characterization to estimate rock properties from elastic attributes such as borehole sonic or seismic velocities. The relationship between elastic and rock properties is calibrated using well log measurements of elastic properties and petrophysical attributes estimated from measured logs, but

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http://dx.doi.org/10.1016/j.jappgeo.2017.09.007
0926-9851/

the rock physics model is not generally integrated in the quantitative log interpretation workflow.

The goal of this work is to integrate petrophysics and rock physics models in a unique framework for formation evaluation analysis and define a multi-physics model to link rock and fluid properties to well measurements of petrophysical, elastic, and electrical properties. The model is applied in an inverse problem setting to estimate the properties of interest, i.e. rock and fluid volumetric properties, from well log measurements. The main advantage of the proposed multi-physics approach is to provide a more accurate description of the reservoir rocks at the well location by accounting for the coupled model of petrophysical, elastic, and electrical properties. The rock physics model could then be used in reservoir characterization problems to infer rock and fluid properties from seismically derived velocities and electromagnetically derived resistivities, as a solution of a mathematical inverse problem (Tarantola 2005). For illustrative purposes, we choose a set of equations in the rock physics and petrophysics literature and demonstrate the proposed joint workflow. The selected models include Raymer and the stiff sand model (Mavko et al. 2009), Simandoux model, and linear volumetric balance equations (Ellis and Singer 2007). However, other models could be used in the analysis. Several physical equations have been proposed to describe the physical processes related to velocity, density and resistivity in porous rocks. Elastic models establish physical relationships between petrophysical properties (porosity, mineralogy, and fluid content) and seismic velocities, whereas electrical models link petrophysical properties to resistivity (Mavko et al. 2009). For example, electrical resistivity can be computed in clean sand and shaley sand using Archie's law (Archie 1942), Simandoux model (Simandoux 1963), or Poupon Leveaux equation (Poupon and Leveaux 1971). P-wave and S-wave velocity can be estimated using empirical relations, such as Wyllie, Raymer, or Nur's models (Wyllie et al. 1956; Raymer et al. 1980; Nur et al. 1995), granular media models, such as soft sand, stiff sand, or cemented sand models (Dvorkin et al. 1994; Dvorkin and Nur 1996; Gal et al. 1998), and inclusion models, such as Kuster-Toksoz, Berryman, or Xu-White models (Kuster and Toksoz 1974; Berryman 1995; Xu and White 1995). Many of these models account for texture, diagenesis, and anisotropic parameters. Rock physics models relating electrical conductivity to seismic velocities are also available for both isotropic and anisotropic rocks (Carcione et al. 2007, 2012; Kachanov et al. 2001). Werthmüller et al. (2013) proposed a method to estimate resistivity from seismic velocities by combining Gassmann's equations with self-similar models (Werthmüller et al. 2013). The relationship between seismic wave velocity and electrical resistivity has also been studied based on laboratory measurements (Wang and Gelius 2010; Han 2010, Han et al. 2012; Jones et al. 2009). Han et al. (2011) studied the relationships between petrophysical properties (porosity, permeability and clay content) and the joint elastic-electrical properties of reservoir sandstones.

In this paper, we present a method to integrate rock physics and petrophysical models to compute rock properties including porosity, saturation, and clay content by joint inversion of sonic, resistivity, and petrophsyical (porosity, density, lithology) logs. In the elastic domain, we use constitutive equations to link porosity, matrix and fluid bulk moduli, and density to P-wave and S-wave velocities. In the density domain, densities of individual fluids and minerals are linearly combined to compute the bulk rock density. In the electromagnetic domain, porosity, clay content and fluid saturation are related to electrical resistivity through exponential relations. By combining information from the elastic, electrical, and density domains, it is possible to reduce the ambiguities of reservoir interpretation. For example, water and oil have similar densities and elastic properties, but the electrical conductivity of reservoir rocks is highly sensitive to changes in water and oil saturation. In our approach, the inversion is performed using a gradient-based method, the Levenberg-Marquardt algorithm, but statistical methods, such as Monte Carlo techniques (Grana et al. 2012) could be used as well. Our methodology has been validated using core measurements and applied to two sets of well-log data. In the second example, we also compare the proposed gradient-based inversion with a stochastic optimization method.

2. Methodology

Constitutive equations link rock properties with well-log measurements. Various rock physics models have been presented in the literature based on the lithology and fluid type in the porous rocks (Mavko et al. 2009). For example, lithology and porosity can be empirically related to elastic velocities. In the Raymer model (Raymer et al. 1980), the P-wave velocity of the equivalent medium V_p can be calculated combining the velocities of the solid and fluid phases

$$V_p = (1-\phi)^2 V_0 + \phi V_{fl} \tag{1}$$

where ϕ is the porosity of the rock, V_{fl} and V_0 are the compressional wave velocity of the pore fluid and the solid matrix, respectively. The model can fit several datasets of sandstones or shaley sandstones with low- to medium-porosity (Mavko et al. 2009). In a reservoir scenario of shaley sandstone saturated with oil, gas and water, the effect of clay content is expressed in the compressional wave velocity of the solid matrix, i.e. the matrix bulk and shear moduli:

$$V_0 = \sqrt{\frac{K_0 + \frac{4}{3}\mu_0}{\rho_0}} \tag{2}$$

Voigt-Reuss-Hill average provides a good approximation to estimate the bulk and shear modulus of the solid matrix.

$$K_0 = \frac{1}{2}\left(v_c K_c + v_q K_q + \frac{1}{\frac{v_c}{K_c} + \frac{v_q}{K_q}}\right) \tag{3}$$

$$\mu_0 = \frac{1}{2}\left(v_c \mu_c + v_q \mu_q + \frac{1}{\frac{v_c}{\mu_c} + \frac{v_q}{\mu_q}}\right) \tag{4}$$

where v_c and v_q are the volumetric fractions of clay and quartz, and K_c, K_q, μ_c, and μ_q are the corresponding bulk and shear moduli. Similarly, the P-wave velocity of the fluid is a function of the saturations and bulk moduli of the fluid components (water, oil, and gas). The mixing law for the computation of the bulk moduli of the fluid mixture depends on the spatial distribution of the fluid components: for homogenous distributions Reuss average can be used to estimate the bulk modulus of the effective fluid and the P-wave velocity of the fluid can be written as

$$V_{fl} = \sqrt{\frac{K_{fl}}{\rho_{fl}}} \tag{5}$$

where

$$K_{fl} = \frac{1}{\frac{S_w}{K_w} + \frac{S_o}{K_o} + \frac{S_g}{K_g}} \tag{6}$$

where S_w, S_o and S_g are the saturations of water, oil, and gas, respectively and K_w, K_o and K_g are the corresponding bulk moduli. For patchy saturations, the Voigt linear average should be used (Mavko et al. 2009).

The volumetric average of the rock and fluid density, ρ_0 and ρ_{fl}, can be calculated using linear averages to preserve the mass balance:

$$\rho_0 = v_c \rho_c + v_q \rho_q \tag{7}$$