How much is in the tank? Estimating the likelihood of reservoir oil volume from 3C-3D seismic data, well logs, and geostatistics

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The volume of hydrocarbon reserves is a primary component of an energy company's value. Estimating that volume is a complicated, but essential and regulated, part of the resource industry's business. Geophysical methods continue to advance and are playing a more fundamental role in reservoir assessment (Hardage, 2009). This paper presents a framework to estimate the likelihood of a reservoir pore (oil) volume using multicomponent (3C-3D) seismic data, well logs, and geostatistics. The multicomponent (3C-3D) seismic data and well log measurements are first interpreted and combined to estimate rock properties using three methodologies: inversion, geostatistics, and multi-attribute analysis (Stewart and Todorov, 2000). The 3C-3D seismic data set and well logs are from the Blackfoot oilfield, Alberta. Conventional model-based inversion is applied to the P-P data to estimate the acoustic impedance. A 3-D converted-wave (P-to-S on reflection) inversion for shear velocity computes a PS weighted-stack followed by a conventional inversion algorithm. Geostatistical methods of kriging, cokriging, and stochastic simulation are used to derive a sand-shale distribution as well as a time-to-depth conversion from the various seismic and well log data. Linear multi-regression and neural networks next derive a relationship between porosity logs and a set of seismic attributes. We find that PS attributes are some of the most important. The sand thickness (gross) around the reservoir, sand percentage (for net thickness), and porosity are then used to generate a pore volume. We estimate an average oil saturation from the well logs, then compute an oil column height (OCH = gross isopach · sand percentage · porosity · oil saturation). Multiplying the OCH by the reservoir area provides a total pore volume. This is the beginning of the volumetric calculation for the reservoir. We need to now try to assess the quality of this volumetric assessment (Uffen, 2011). Our approach is to gather all of the errors (or range of validities) of each part of the total pore volume equation. Blind tests (validations) are used with geostatistics to estimate errors in the predicted thickness and percentage of sand. The error in the neural net values for porosity are also estimated by comparing predicted logs with actual ones. We sum all of these fractional errors to produce a range of validities for the total pore volume. This error or validity range in the pore volume can be attached to a cumulative probability. Various points in the cumulative probability are interpreted as likelihoods of the volumes indicated. We also use these validity ranges in a Monte Carlo approach to predict oil volume likelihoods (Figure 1). The results obtained using these two approaches suggest hydrocarbon volumes for the Blackfoot pool: with a ten-percent probability (P10) of 12 MMbbl (there is 10% of chance that this reservoir has more than 12MMbbl), P50 of 8MMbbl, and a P90 of 5MMbbl. A recent accounting (Ken Mitchell, pers. Comm., 2011), using the actual amount of oil produced from the Blackfoot pool, suggests an original oil in place of 5.5MMbbl.

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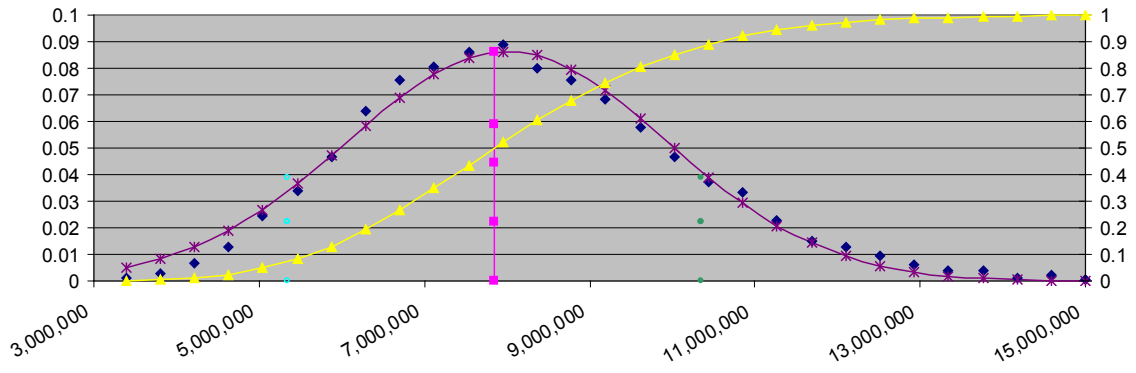[2] Petrobras, Brazil

FIG. 1. The probability curves for oil volumes at the Blackfoot oilfield, Alberta