O221-008 **Room: 301B** **Time: May 20 13:55-14:10**

Quantitative evaluation of fluid displacement using time-lapse seismic: an approach based on rock-physics theories

Futoshi Tsuneyama[1]

[1] Idemitsu Oil & Gas

The reflection coefficient of seismic data is a function of the impedance contrast at a subsurface interface. Hence, seismic-inversion process derives rock impedance from the seismic data. Impedance inversion becomes a common analysis for reservoir characterization, since impedance is much useful property than interface responses such as seismic amplitude. However, if one can decompose impedance into two fundamental properties, namely velocities and density, currently available rock-physics applications enable us to recognize a rock trend in the Vp-density plane for the determination of shale volume. Then, the proper and careful construction of a sequence of rock-physics analyses provides us a way to derive the properties of in-situ formation fluid.

In this paper, first, I present a method of impedance decomposition using three elastic impedance data derived from the seismic inversion of angle stacks. I discuss the effect of noise on the analysis as the most important reason that decomposition is difficult. Then, I show a method incorporating rock-physics bounds as the constraints for the analysis. The method is applied to an actual dataset from an offshore oil field; I demonstrate the result of the analysis for sand-body detection.

Next, I introduce a newly developed workflow to determine the saturations of formation water, oil, and gas from seismic data through a sequence of rock-physics analyses and computations, based on the resultant properties of the elastic-impedance analysis discussed above. In this workflow, I pre-condition the seismically derived impedance data to the time-lapse differences of the pressure effect and the saturation scale of fluids. Then, I demonstrate a deterministic approach to computing the fluids saturation to evaluate the time-lapse seismic data. This approach derives the physical properties of the 100% water-saturated sandstone reservoir, based on the several inputs: Vp, Vs, density and the shale volume from the elastic-impedance analysis; in addition, the average properties of sand grains and the formation fluids properties from laboratory measurements. For this step, the integration of geophysical, geologic, and engineering data is a key to control the quality of output. Afterwards, by comparing the in-situ-fluid-saturated reservoir properties to the 100% formation-water-saturated reservoir properties, I determine the bulk modulus and density of a fluid phase in the reservoir. Solving three equations simultaneously, which are relating the saturations of water, oil, and gas in terms of the bulk modulus, density, and the total saturation; I compute the saturation of each fluid.

The application result of the workflow to a real time-lapse seismic dataset from an offshore oil field in the Norwegian North Sea demonstrates the clear distribution of fluid displacement in a quantitative manner as shown in the attached figure.