Viscosity Estimation Using Seismic Inversion

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ABSTRACT

In the analysis of enhanced heavy oil production, it is crucial to have some knowledge of fluid viscosity in order the flow of oil in reservoir simulation. While viscosity can be measured using fluid samples taken from the borehole, it would be advantageous to have some measure of viscosity between wells. We develop a methodology for doing this by using seismic traveltime tomography to estimate velocity, followed by attenuation tomography to estimate seismic-Q. Tomographic inversion methods have been applied to crosswell seismic data from a heavy oil field in Northern Alberta. The Q values are transformed to viscosity values using the Biot Squirt theory (BISQ). While this transformation can be ambiguous, the ambiguity problem can be obviated if we have some borehole information about viscosity to within an order of magnitude.

The estimates of Q could presumably be further improved by the use of full waveform inversion. One of the concerns with full waveform inversion is its sensitivity to noise. We have tested full waveform inversion on noisy model data and have found it to be robust for signal-to-noise ratios of 5, with convergence to a model fit within three iterations.

The next steps in this research should involve the application of the inversion methods and rock physics to time-lapse crosswell seismic data to monitor the changes in viscosity with time. This greatly enhance our ability to characterize dynamic changes is a heavy oil reservoir.

INTRODUCTION

The flow of heavy oil fluids can be described by Darcy's Law. In its single-phase form,

$$q = -\frac{kA}{\eta}\nabla P \tag{1}$$

Here q is the volume of flow, k is the permeability of the medium, A is the cross-sectional area, η is the fluid viscosity, and ∇P is the pressure gradient. While the permeability of heavy oil sands is high (often in the Darcy range), the mobility, $\frac{k}{\eta}$, is low in the reservoir at initial reservoir temperatures prior to heating due to the high viscosity of oil in the reservoir. For shallow reservoirs in the Athabasca oil sands, the viscosity is sometimes as high as 1 million centipoise. In order to model the flow of heavy oil using hot production methods, it is important to reliably estimate viscosity as a function of time and space.

Time-lapse 3-D (4-D) seismology is a tool for monitoring reservoir changes and has been widely used in the industry for the past 30 years. In heavy oil reservoirs, the 4-D seismic method has been used to track steam zones by detecting zones in the subsurface where we see zones of lowered seismic velocity or zones of lowered seismic-Q. While logging and core analysis have been widely used to examine reservoir properties in the vicinity of the borehole, 4-D seismic monitoring have been used to track changes throughout the entire reservoir volume.

METHODOLOGY AND RESULTS

A methodology for estimating fluid viscosity by the use of crosswell seismic data has been presented by Vasheghani and Lines (2012). This method used seismic traveltime tomography and Q-tomography, a method developed by Quan and Harris (1997), in order to produce velocity tomograms and Q-tomograms. The Q-tomograms were converted to viscosity tomograms by using the Biot-Squirt theory (BISQ) (Dvorkin and Nur, 1993). While there is an ambiguity in converting Q values to viscosity values (Vasheghani and Lines, 2009), the ambiguity is reduced by borehole viscosity measurements.

As a further refinement of Q estimations, one can apply full waveform inversion following traveltime tomography and Q-tomography. All three methods represent model-based inversion methods in which we attempt to solve **Ax=b,** where **A** is the Jacobian matrix, **x** is the parameter change vector and **b** is the discrepancy vector between data and model response values. For further description of model-based least squares methods, the reader is referred to Lines and Treitel (1984). The three-stage inversion approach would be the following:

1. Estimation of seismic velocity using traveltime tomography, solving $\mathbf{D}\Delta\mathbf{s} = \Delta\mathbf{t}$. Here **D** is the matrix of ray path distances in cells, **s** is the slowness vector, and $\Delta\mathbf{t}$ is the difference between data traveltimes and modeled traveltimes.

2. Estimation of seismic absorption coefficients using $\mathbf{D}\alpha = \Delta f_c$, where α is the absorption coefficient divided by frequency, and Δf_c is the difference in the centroid frequency between source and receiver. (See Quan and Harris, 1997, for details.) The Q values for the tomogram can be computed by using the velocity values from step 1 and the absorption coefficients from step 2 to compute $Q = \frac{\pi f}{\alpha v}$ in the creation of a Q tomogram.

3. We could refine (improve) our estimates by using full waveform inversion with the Q values from step 2 being used as the initial values of Q in step 3. In this inversion, A is the Jacobian for amplitude variation with Q, Q is the parameter x, and **b** is the difference between data amplitudes and model amplitudes.

The Q tomogram would be converted to a viscosity tomogram using the BISQ rock physics model. While the viscosity tomogram has been computed using tomography and BISQ, we have yet to apply the three-stage inversion for viscosity estimation. One of the concerns was the application of full waveform inversion to noisy data. We have completed preliminary model tests that have shown full waveform inversion to be robust when the data noise is random and these results were presented by Lines, Vasheghani and Bording (2013) at the PIMS Summer Workshop at the University of Calgary. The converged inversion results were accurate with full waveform inversion for signal-to-noise ratios of 5:1. Further noise tests will need to be carried out.

CONCLUSIONS

Seismic inversion methods have been successful used to estimate Q through tomography and full waveform inversion. While the tomography methods have been tested on crosswell tomography data, full waveform inversion methods require more testing on noisy model data and real data. The Q estimates can be converted to viscosity estimates using the BISQ rock physics algorithms.

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