Time-lapse Seismic Modeling in Leming Lake, Alberta

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Introduction

Heavy oil has been produced since 1986 from the Clearwater formation in Leming Lake area. Imperial Oil has shot time-lapse 3D seismic surveys over this production pad in an attempt to monitor fluid flow and reservoir conditions around five horizontal wells. Seismic interpretation for changes in saturation, pressure and temperature in the reservoir adds another constraint on reservoir simulation in addition to production history matching. In this paper the authors focus on time-lapse seismic modeling based on reservoir simulation and rock physics models. The output of synthetic seismograms is used to evaluate time-lapse seismic feasibility and to extract seismic attributes for identification of changes in the reservoir.

Reservoir Characterization

A primary task of reservoir characterization is to identify the distribution of porosity and permeability. The accuracy of the distributions affects the reliability of reservoir simulations. This section presents a method of estimating porosity and permeability distributions for input to a reservoir simulator.

Core measurements and well logs in the reservoir showed a bimodal distribution of porosity at zero and 35% (Zhang and Bentley, 2004). The majority of the samples were at 35% porosity and represent unconsolidated oil sands. The samples at zero porosity were calcite cemented sands or limestones (Zhang and Bentley, 2004). Consequently the reservoir can be viewed as a body of high-porosity oil sands with randomely distributed zones of zero-porosity tight rocks. To the first-order approximation, the reservoir characterization problem reduces to finding the distribution of tight rocks. Tight rocks are identified in well logs by spikes of high electrical resistivity, low sonic travel times and high density. A statistical model of the distribution of tight rocks was developed from the well logs (Zhang and Bentley, 2004). Seismic modeling indicates that tight rocks should cause reflections within the reservoir zone. High amplitude reflections from a 3-D survey were interpreted as tight rock zones. After deconvolution to remove the embedded wavelet from seismic traces, the positions of strong reflection peaks within the 410-460 ms reservoir zone were regarded as those for tight rocks. The minimum amplitude for a pick was adjusted until the statistical model was approximately matched and statistics such as the average, maximum and minimum number of tight rock zones per areal location were similar to the statistics developed from the well logs. The zones were then upscaled by averaging to the larger elements of the simulator grid. Figure 1 is the upscaled porosity model based on seismic picks. The permeability model has similar characteristics.

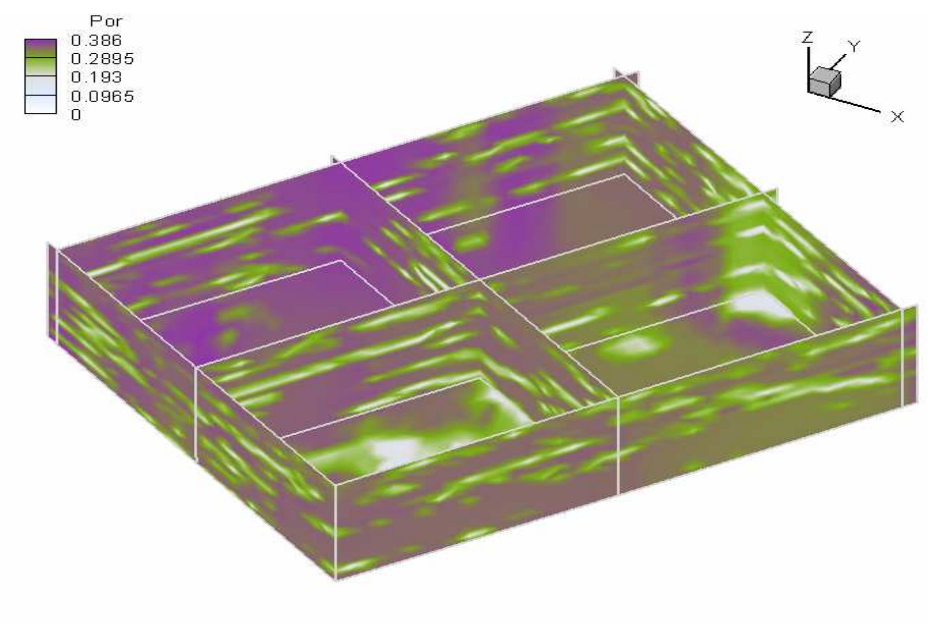

Figure 1 3-D visualization of the porosity model

Reservoir Simulation

Imperial Oil drilled five horizontal wells for cyclic steam stimulation (Table 1). Steam injection started in September,1997 for the first three wells and then in October of the same year for the other two. Oil production from the first well started in October, 1997 and continued until February, 1998. The second well terminated steam injection in October, 1997 and produced oil from November until February, 1998. The remaining three wells were shut in December 1997 after two months of steam injection, and then were put on production from January to February 1998. The first minotor survey was shot in February 1998 in an attempt to map the fluid flow and steam comformance. The goal of the reservoir simulation is to generate a time-lapse picture of reservoir conditions, which will be converted to a time-lapse picture of velocity and density changes through a set of rock physics models. The velocity and density estimates will be used for time-lapse seismic modeling.

Table 1 Summary of the timing of steam injection and oil production

	Sept., 1997	Oct., 1997	Nov., 1997	Dec., 1997	Jan., 1998	Feb., 1998
Well 1	INJ	INJ & PROD	PROD	PROD	PROD	PROD
Well 2	INJ	INJ	PROD	PROD	PROD	PROD
Well 3	INJ	INJ	INJ	SHUT-IN	PROD	PROD
Well 4		INJ	INJ	SHUT-IN	PROD	PROD
Well 5		INJ	INJ	SHUT-IN	PROD	PROD

GeoSim was the coupled flow and geomechanical modeling program used in this study. The reservoir simulation coupled with geomechanical modeling assumed a 3-component 3-phase fluid system for a thermal flow modeling. Water, heavy oil and light oil constitute three components and occur in three separate phases of water, oil and gas. Water and light oil were allowed to evaporate into gas, but heavy oil existed only in the oil phase. The molar fractional ratio of one component between two separate phases was calculated by a thermal dynamic equation and is a function of pressure and temperature. The geomechanical model is a 3D finite element stress-strain simulator, which iterates with the reservoir simulation and finds the stress and strain distribution. As shown in Figure 2, the distribution of saturations, pressure and temperature are ocated around the wells, with pressure changes extending the furthest from the wells. Note that gas exsolves from oil and accumulates along the entire length of the first well that has been on production the longest.

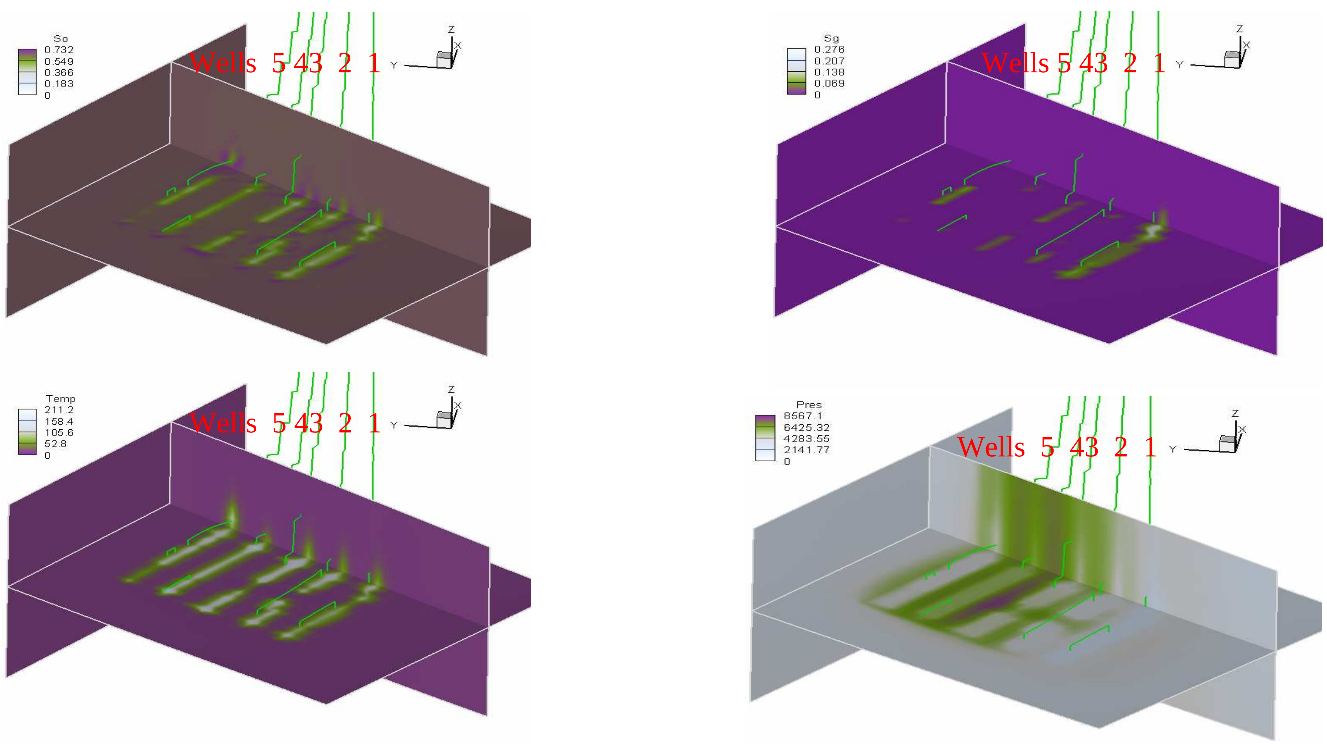

Figure 2 Distribution of oil saturation (upper left), gas saturation (upper right), temperature (lower left) and pressure (lower right) at the end of February, when the first monitor seismic survey was shot in an attempt to monitor the fluid flow.

BACK

Rock Physics Models

Rock physics models link the reservoir parameters to the elastic moduli and the density. In this study we employed the key models as follows:

1) Given the molecular weight or specific gravity of gas, the bulk modulus and density at any pressure and temperature can be calculated using empirical formulae (Batzle and Wang, 1992). Two gases of steam and methane may occur with molecular weight 18 and 16, respectively, during the process of heavy oil recovery. Given API or density at standard conditions, the bulk modulus and density of oil can be calculated at any pressure and temperature using empirical formulae (Batzle and Wang, 1992). Heavy oil and light oil are the two components in the oil phase and their densities are assumed to be 1.0 and 0.7, respectively. Given the salinity of water, the bulk modulus and density of brine can be calculated at any pressure and temperature using empirical formulae (Batzle and Wang, 1992). The salinity of brine in the area is assumed to be 0.36%.

2) The mixture of fluids has the bulk modulus averaged harmonically over three phases due to the assumption that low seismic frequencies provide enough time for fluids to equlibrate pressures among different phases.

3) The dry bulk and shear moduli will change with effective pressure. Lewis (1990) measured the bulk and shear moduli of sands at a variety of pressures and proposed a set of equations to relate them. The following equations are a modified version (after Lewis, 1990):

$$\text{Bulk Modulus:} \quad dK_d/d\sigma = a\sigma^{b-1}Pa^{1-b}/F(e)$$
$$\text{Shear Modulus:} \quad d\mu_d/d\sigma = c\sigma^{d-1}Pa^{1-d}/F(e)$$

where, σ is mean effective stress; Pa is atmospheric pressure; a, b, c and d are constants; $F(e)=0.3+0.7\,e^2$; e is void ratio.

4) For fluid-saturated sands, the effect of fluid on the bulk modulus is estimated using Gassmann's equation. Fluid effects are assumed to exert no influence on the shear modulus.

The dry bulk and shear moduli of oil sands before recovery were extracted from the velocity model (see the next section) using Gassmann's equation. The velocity distribution at the time of the first monitor seismic survey, was then calculated using the results of reservoir simulation (the previous section) and the above rock physics models.

Time-lapse Seismic Modeling

The formations from the surface to the reservoir were divided into six layers and each layer was assumed to have a constant velocity and density, blocked from well logs. As stated in the section on Reservoir Characterization, the reservoir is a body of oil sands with tight rock inclusions. The velocity of the reservoir layer was therefore determined from two rock types, oil sands and tight rocks. It is assumed that the significant contrast of acoustic impedance between these two types of rocks generates strong reflections within the reservoir. The reservoir does not have a strong acoustic impedance contrast with the overlying and underlying formations and consequently is not delineated with strong reflections.

The velocities above the reservoir were assumed to be unaltered during recovery. The velocity of the tight rocks within the reservoir may undergo some changes, but, considering no fluid substititution, it was also assumed to be constant. The velocity of the oil sands was changed using the procedure described in the previous section.

NORSAR3D generated normal-incidence synthetic seismograms based on the velocity models before and after recovery are shown in Figure 3.

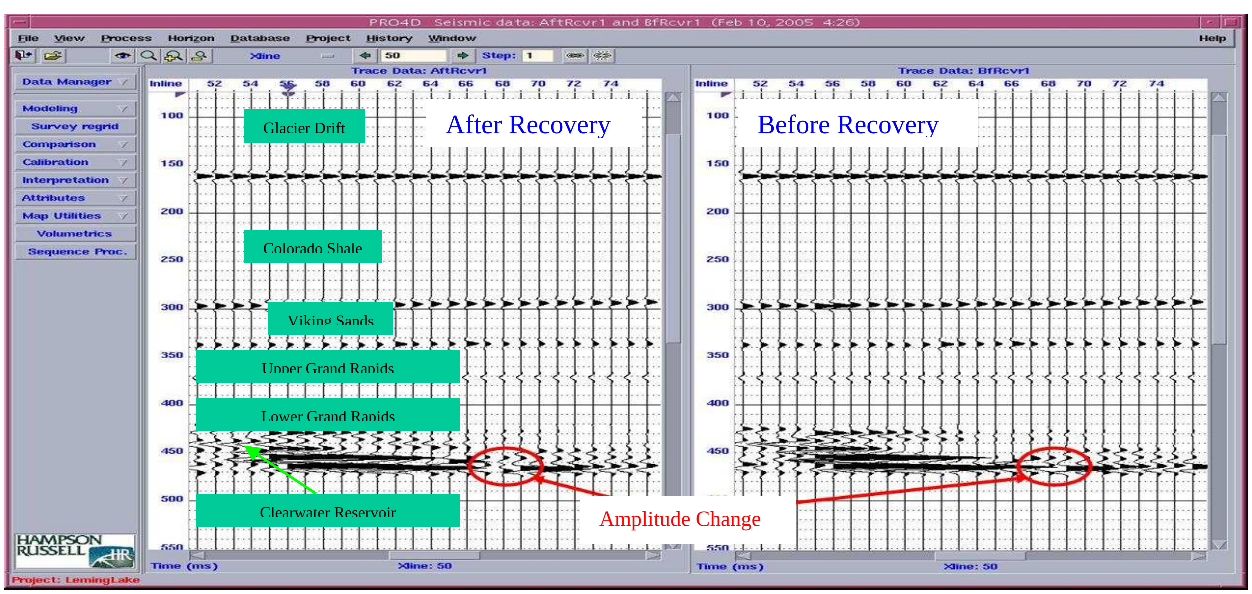

Figure 3 Synthetic seismograms generated from NORSAR3D seismic modeling

Amplitude changes from reflections from tight zones are observable in Figure 3. In order to map the areal distribution, we computed the rms amplitudes for the time window of the reservoir and subtracted the synthetic baseline survey from the synthetic first monitor survey. Figure 4 indicates that rms amplitude changes lie along the location of the five wells. This seismic attribute may be capable of differentiating changes in real time-lapse seismic data.

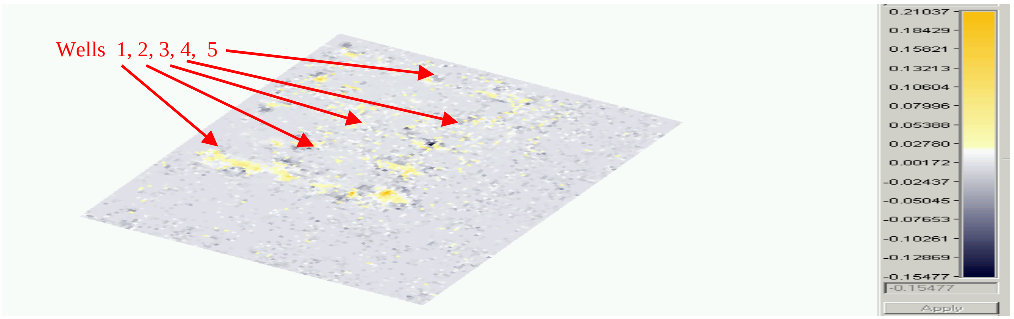

Figure 4 RMS amplitude changes

The cross correlation coefficient of the seismic traces between the baseline survey and the monitor survey provides another seismic attribute to extract the changes. It is believed that the seismic traces correlate better in areas without changes than along the wells and adjacent regions. Figure 5 (left) is the contour of cross correlation coefficients. The low values along the wells are more clearly defined than RMS amplitude changes in Figure 4. The time shift refers to the time difference between the peak amplitude and zero time point on the cross correlation coefficient trace. It is small or zero in the absence of changes, and bigger if changes occurred. Figure 5 (right) shows larger relatively large time shifts along the wells, especially surrounding well 1. These two attributes appear to have great potential to delineate changes in real time-lapse seismic data.

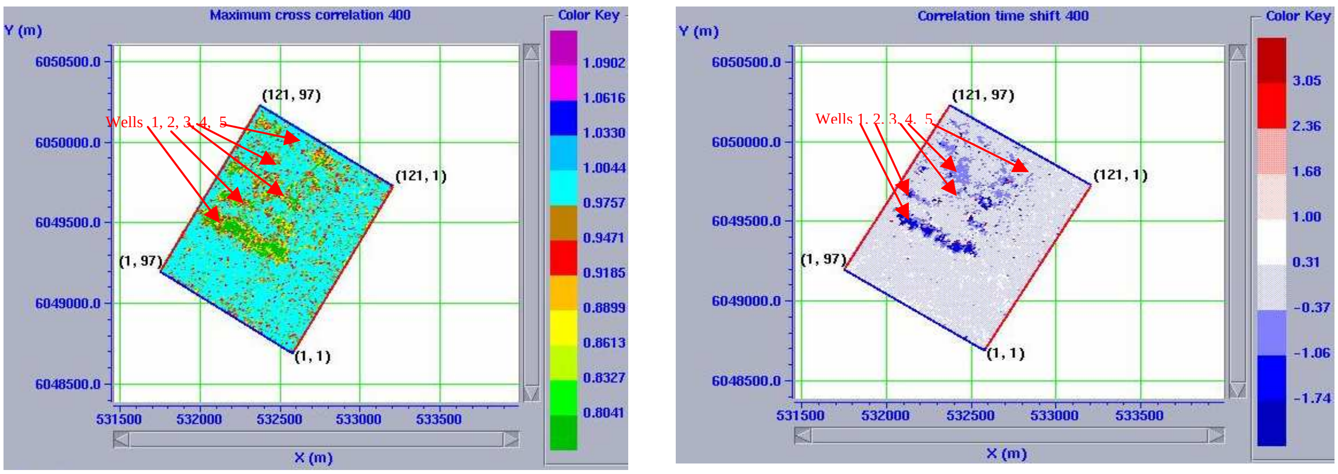

Figure 5 Cross correlation coefficient (left) and time shift (right) of seismic traces between the baseline survey and the monitor survey

Conclusions

Gas exsolved from oil seems to act as the major contributor to lowering the velocity of oil sands, as evidenced by the similarity of continuous distribution in gas and changes of seismic attributes along well 1. Therefore, the time-lapse seismic feasibility to monitor the five horizontal wells depends largely on the existence of gas. Reflections from tight rocks within the resevoir have undergone changes during recovery, and the changes can be detected by the rms amplitude differences, the cross correlation coefficients and time shifts. The latter two appear to serve as better seismic attributes.

Acknowledgements

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