Use of time-lapse analysis to predict fluid changes in a carbonate pool: a case study of the Rainbow B pool

Hannah Tran, Laurence R. Bentley and Edward S. Krebes, University of Calgary, Calgary

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Introduction

The Rainbow B pool is a carbonate pool that is in the process of tertiary production. Miscible gas and solvent were injected into the top of the reservoir in an attempt to extract the remaining oil. The oil in the pore space is being replaced with the gas and the solvent. Two 3D seismic surveys were recorded for the Rainbow B pool. One was acquired in 1987, shortly after the start of tertiary production and the other survey was acquired in 2002. A comparison of the two surveys will reveal seismic differences that can be attributed to the production related changes within the reservoir. This will help determine any inefficiencies of the production process. Before the two surveys can be compared to one another, they must be made to match each other in terms of geometry, time, phase, and frequency. This process is referred to as crossequalization. Then the differences between the two 3D surveys should only reveal production changes. Three different seismic changes were examined: time delays, amplitude changes, and impedance changes. The replacing of oil with gas and solvent will cause a time delay below the reservoir, an amplitude increase at the top of the reservoir, and an impedance decrease within the reservoir. These changes observed in the seismic data will be discussed.

Geological Setting

The Rainbow B pool is an atoll reef located in northwest Alberta, township 108-109, range 8 W6M. An isochron map, representing the thickness of the Keg River reservoir, shows that there is a north lobe and a south lobe (refer to Figure 1). An area referred to as the "saddle point" connects the lobes. The reef is 5.6 km long and 2.1 km wide at its widest point. The average thickness of the reef is 200 m and it is located at a depth of approximately 1800 m. The pool is producing oil from the Middle Devonian Keg River formation. The Keg River formation is overlain by the Muskeg member, which is made of impermeable evaporites, and is underlain by calcareous shales and argillaceous limestones (Hirsche et al., 1998). The average porosity within the B pool is 8% while the average permeability is 460 mD. The majority of the reef is dolomitized. There are nine porosity types identified in the reef but the vuggy porosity type dominates (Laflamme, 1993). The vuggy type porosity is mainly located at the reef margins. The lower porosity and the intergranular type porosity are located mainly within the interior of the reef. This is because the depositional environment in the interior of the reef is in a quieter lagoonal setting. This reef is fairly heterogeneous because the facies and the porosity type vary both vertically and laterally within the reef. Figure 2 shows a map of the porosity, which is determined by taking the weighted average through all the layers from the CMG simulation results.

Reservoir Background

Husky Energy is the operator of the pool and this pool has been producing oil since 1965. The original oil in place is $43.7 * 10^6$ m^3. During primary production, 1.6% of the oil was recovered while 36.5% was recovered during secondary production (Nagel et al, 1990). The pressure in the reservoir during production never reached bubble point, which is at 10 845 KPa, so the dissolved gases in the oil did not come out of the solution. Also, the pressure in the reservoir remained relatively the same, about 17.2 Mpa, from 1987 to 2002.

To further enhance oil recovery, miscible gas and solvent are injected into the top of the reservoir. The solvent helps remove the excess oil from the reservoir. The solvent is injected first and then a lean gas is injected into the top of the reservoir to push the solvent bank down. It is imperative the solvent bank remains horizontal, especially when the solvent bank reaches the saddle point (Nagel et al, 1990). Time-lapse analysis will help determine the injected fluid locations in the reservoir. There are currently 12 injection wells in the reservoir.

The Gassmann equation underpredicts velocity changes

The Gassmann equation (1951)(Equation 1) is used for calculating the effects of fluid substitution on bulk modulus, K, which is then related to the velocity. In this case, the oil is being substituted for gas and solvent.

$$K_{sat} = K_{dry} + \frac{(1 - \frac{K_{dry}}{K_s})^2}{\frac{\varphi}{K_{fl}} + \frac{1-\varphi}{K_s} - \frac{K_{dry}}{K_s^{\ 2}}}, \tag{1}$$

where K_{sat} is the bulk modulus of a rock saturated with fluids, K_{dry} is the bulk modulus of a dry rock, K_{fl} is the bulk modulus of the fluids, and K_s is the bulk modulus of the solid mineral making up the rock. Also, φ is the porosity. After substitution with a new fluid, a new bulk modulus (K_{sat}) is obtained and a new velocity can be determined. The Gassmann equation, unfortunately, does not account for pore geometry.

Time-lapse analysis is not commonly done for carbonate pools because the bulk modulus of carbonate is very high. The high bulk modulus of the carbonate will greatly exceed the low bulk modulus of the fluids within the pore space. Thus, the fluid effects seen in seismic data after gas injection are small and difficult to detect. Hirsche et al. (1998) applied time-lapse analysis on two seismic lines in the Rainbow B pool and discovered that the velocity changes, from pre- to post-tertiary production, are bigger than Gassmann predicted. This is because the Gassmann equation does not take into account the shape of the pores. A lower pore aspect ratio rock would cause a higher velocity change than a higher pore aspect ratio rock (Kuster & Toksoz, 1974).

Calculations using the Gassmann equation and the Batzle and Wang equations (1992) were done for the Rainbow B pool using saturation values and porosity values found in the CMG simulation results. The time delays calculated (Figure 3) using the Gassmann equation are an order of magnitude smaller than the real seismic data results show. This is because the pore geometry of the Rainbow B pool leads to higher velocity changes than what the Gassmann equation predicts. The pore aspect ratio of the Rainbow B pool is fairly small and thus the velocity changes are greater.

Time shift, Amplitude change and Impedance change results

Prior to comparing the 1987 survey to the 2002 survey, crossequalization data processing must be performed. These are time-lapse processing steps that include regridding the seismic data, applying a phase & time shift, applying a shaping filter or a matched filter, crosscorrelation shallow statics or otherwise known as warping the data, and applying time variant shifts. These steps attempt to alter the monitor survey (2002) to have the same geometry, phase, time, frequency and amplitude as the base survey (1987). The crossequalization details will not be discussed in this paper. Please refer to Rickett and Lumley (2001) for more information on crossequalization.

Three different seismic changes were observed: time delays, amplitude changes, and impedance changes. The injection of gas and solvent would cause a velocity decrease in the reservoir resulting in a time delay below the reservoir. Time delays can be easily detected at the Cold Lake horizon, located at 1230 ms, because it is a strong amplitude event below the reservoir (Figure 4). A crosscorrelation is done between the 1987 and the 2002 survey at a window of 1200 – 1250 ms. The time shift required to match the Cold Lake horizons in the Base and the crossequalized Monitor survey is represented in map view (Figure 5). The purple/pink areas can be interpreted as locations where the reservoir changes are occurring, such as in the injection of gas and solvent. These purple/pink areas correspond very well to the location of the injection wells. The problem with the interpretation of this map is that the porosity type and the facies vary both horizontally and vertically within the reservoir. The porosity and the porosity type will affect the time delay results. For example, the time delay through a vuggy porosity type area is different than the time delay through an intergranular porosity type area even though there are the same amount of gas and solvent present. This means that the value of the time delay does not determine the amount of gas and solvent injected. Similarly, a lack of time delay does not determine that there is no gas and solvent injected. For example, well 12-10 is believed to contain a high amount of injected gas and solvent but the time delay map does not indicate this situation (L. Carr, personal communication). The reason for this could be that the time delays are only detected in areas of certain porosity types. The porosity type at well 12-10 is intergranular. Thus we can conclude that a lack of time delay does not indicate bypassed oil within intergranular porosity type areas of the reservoir. At each location of the reservoir, from 1987 to 2002, the porosity remained the same from 1987 to 2002 and also the pressure remained the same. Therefore, the only changes from 1987 to 2002 are due to the injection of gas and solvent or possibility due to the opening of new fractures as gas and solvent were injected. Then we can conclude that the areas where there are time delays can be interpreted as areas where gas and solvent are injected regardless of the porosity and regardless of the amount injected.

Amplitude differences at the top of the reservoir can also be detected. The injection of gas and solvent replacing oil should cause an amplitude increase at the Keg River horizon. A difference map is made between the 1987 and the 2002 survey. Figure 6 shows a map of the normalized RMS amplitude differences with a window of 5 ms centered at the Keg River horizon. The purple/pink areas can be interpreted as areas where there has been an injection of gas and solvent. Unfortunately, this map does not correlate to the time delay map nor does it correlate to the injection wells. Also, the amplitude changes seem too small to be significant.

To visualize the seismic stacked data in terms of impedance, modelbased inversion has been applied. Impedance is the product of the density and the velocity of the reservoir. The injection of gas and solvent would cause the velocity and the density to decrease resulting in an impedance decrease. Figure 7 is a map showing the arithmetic mean of the impedance change from a window of 20 ms below the Keg River horizon. The purple/pink areas representing impedance decrease can be interpreted as areas where there is gas and solvent. These areas appear to correlate to some of the injection wells in the south lobe. The north lobe does not show any impedance decrease. Unfortunately, this map also does not correlate well to the time sag map. It appears that the time sag map is more robust than both the amplitude change map and the impedance change map.

Conclusions

Three different seismic change results were analyzed: time delay, amplitude change, and impedance change. The time delay results appear to be more robust than the amplitude change and the impedance change maps. Also the locations of the time delays match the locations of the injection wells fairly well. The porosity type and the facies vary within the reservoir, which make it difficult to determine how much the reservoir is changing at the time delay locations. This is because the velocity change in this pool is very much dependent on the porosity type. There is a higher velocity change (or higher time delays), from 1987 to 2002, in areas of the reservoir where the pore aspect ratio is low, where the pore type is vuggy, and where the permeability is high. In areas of intergranular type porosity, there is not much velocity change as the Gassmann equation also proves. This does not mean there is bypassed oil within these zones.

It appears that the time delays are visible at locations where the porosity type is vugular but not visible at locations where the porosity type is intergranular. Thus, at the vuggy locations, we can be more confident of our interpretation because if there is a reservoir change, it will show up on the time delay map. In a heterogeneous carbonate reservoir, as in the Rainbow B pool, it is very important to interpret the time-lapse results with regards to the pore geometry and the facies type.

Future Work

A more careful and detailed interpretation will be conducted with respect to the dominant facies type.

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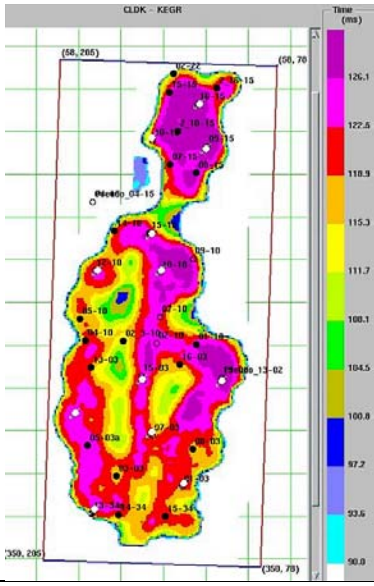


Figure 1. Isochron map from Keg River to Cold Lake; injection well s in white

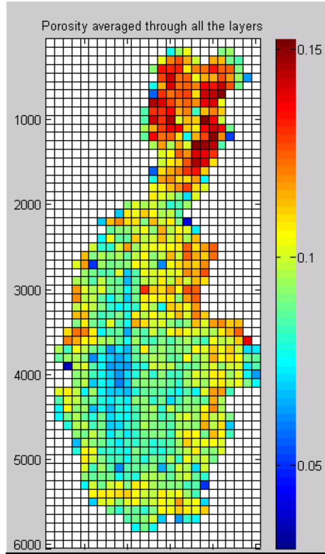


Figure 2. Porosity map: weighted average of all layers

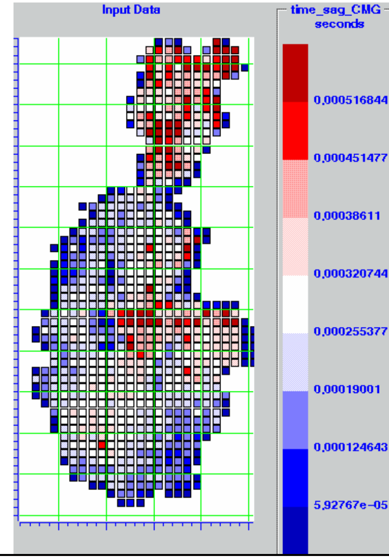


Figure 3. Time delay map calculated from the Gassmann equation

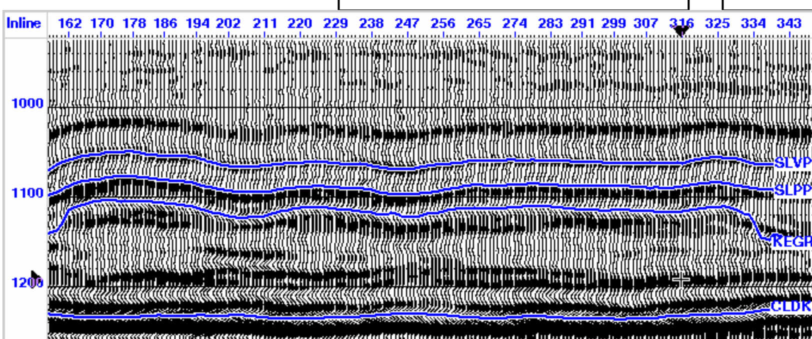
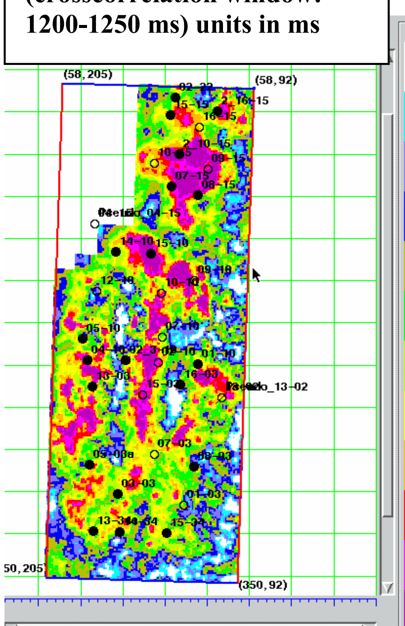


Figure 4. 2002 seismic data: N-S cross-section (crossline 130)

Figure 5. Time delay map (crosscorrelation window: 1200-1250 ms) units in ms



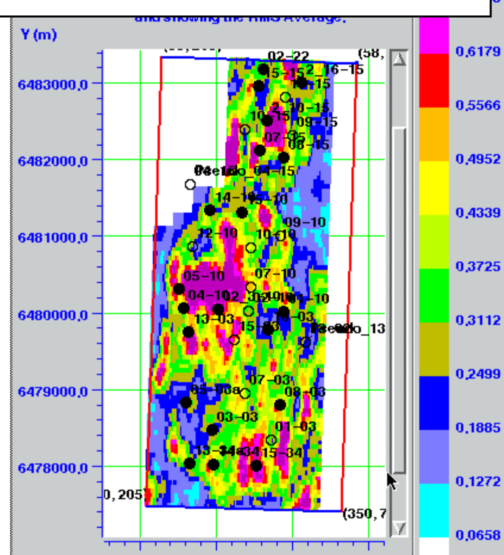


Figure 7. Impedance difference map (arithmetic mean, window 20 ms below Keg River)