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CO_2 Sequestration Monitoring in a Low Salinity Formation Water Environment

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Summary

CO_2 sequestration involves the injection of CO_2 into permeable reservoirs with saline water (brine). It has been shown that when water salinity is sufficiently high, in-situ monitoring of the CO_2 front can be accurately described via traditional cased hole time-lapsed sigma logging (Sakurai et al, 2005). However when the targeted reservoir's water salinity is not sufficiently saline uncertainty in the sigma (Σ) approach increases and it becomes more qualitative than quantitative.

In this paper we review a CO_2 monitoring project in Japan where formation water salinities were low for the sigma based approach. To enhance the interpretation alternative measurements like inelastic ratios, oxygen inelastic relative yield and neutron porosity were acquired with sigma and combined with the open-hole resistivity, neutron-density and magnetic resonance logs to derive a robust answer.

Introduction

The Research Institute of Innovative Technology for the Earth (RITE) is responsible for a five-year project, Research and Development of Geological Sequestration Technology for Carbon Dioxide (www.rite.or.jp/index_e.html). The project aims to establish a technology that provides stable, safe and long-term geological sequestration of carbon dioxide emitted from large-scale sources in Japan.

In this project a CO_2 injection test was carried out at Nagaoka in the Niigata prefecture (Fig. 1). An injection well and three monitoring wells were drilled at a test site and super-critical CO_2 was injected into a saline sandstone aquifer at a depth of approximately 1100 meters. The injection test started in July 2003 and continued until November 2004. Monitoring started before injection using the monitor wells and is still continuing.

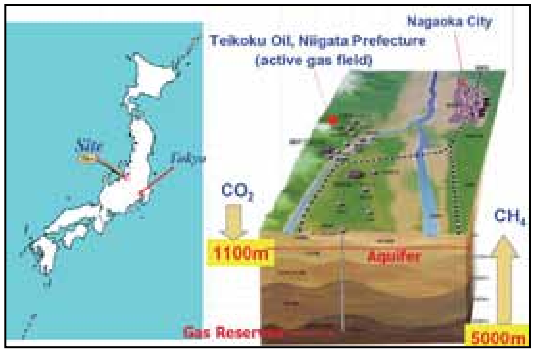

Fig. 1 – Site of Research Institute of Innovative Technology for the Earth (RITE) Carbon Dioxide Sequestration Technology project.

As a part of this project, pulsed neutron capture and pulsed neutron spectroscopy log measurements were acquired in both an injection well and a monitoring well in the same geological formation in March 2008. The injection well has steel casing and the monitoring well has fiber glass casing. In the injection well pulsed neutron data were acquired across the perforated intervals before and after water injection. The fluid in the wellbore before logging was CO_2 and the formation was saturated with supercritical CO_2. After this acquisition, water with a salinity of 35,700ppm NaCl equivalent was injected into the formation and a second pulsed neutron acquisition was made. The formation water salinity before water injection was 7,150ppm NaCl equivalent. For the monitoring well acquisition the well was filled with water.

Pulsed neutron measurements can have many applications including lithology identification in open- or cased-hole, accurate time-lapse reservoir monitoring, and evaluation in difficult logging environments such as variable formation water resistivity. In conventional reservoirs oil saturation can be derived from carbon-oxygen ratios (COR) or inferred from sigma measurements. Inelastic gamma ray spectra are used to determine the relative concentration of carbon and oxygen in the formation. A high carbon-oxygen ratio indicates hydrocarbon-bearing formation; a low ratio indicates water or gas bearing formation. Sigma measurements essentially measure the abundance of chlorine in the formation from the rate of decay of thermal neutron capture gamma rays. High sigma indicates saline water and low sigma fresh water or hydrocarbon. As long as formation water salinity is high, constant and known, formation water saturation (S_w) may be calculated from sigma.

Sigma Measurements

Sigma is a material's ability to absorb thermal neutrons and is defined as the material's capture cross section. Sigma is measured in capture units (cu). In oilfield geology, formation fluids containing chlorine atoms are the most effective at capturing thermal neutrons. Salt water sigma values may range from 30 cu (25,000 ppm) to 130 cu (275,000 ppm). Estimating CO_2 saturation when formation water salinities are sufficiently high is relatively straight forward as per equation (1) below.

$$Sw = \frac{(\Sigma \log - \Sigma matrix) - \theta(\Sigma CO2 - \Sigma matrix) - Vshale(\Sigma shale - \Sigma matrix)}{\theta(\Sigma water - \Sigma CO2)} \qquad (1)$$

where;
Σ_{log} is the measured formation sigma, Σ_{matrix} is the sigma value of the formation matrix, Σ_{CO2} is the sigma value of CO_2, Vshale is the volume of shale, Σ_{matrix} is the sigma value of shale, Σ_w is the sigma water and θ is formation porosity

Some common formation fluid sigma values are i.) 90 cu (water salinity 200,000 ppm); ii.) 35 cu (water salinity 37,500 ppm); iii.) 25 cu (water salinity 7,150 ppm); iv.) 20 cu (oil); v.) 8 cu (gas) and vi.) 3.2 cu (CO_2).

Carbon-Oxygen Ratio (C/O Ratio)
Although the hydrocarbon volume in the formation relates directly to the carbon yield, C/O ratio's are commonly used as they are less dependent on borehole environmental effects. Water saturation is then computed via a transform from C/O ratio to oil saturation from an extensive database that depends on lithology, porosity, hole-size, casing size and weight, and the carbon density of the hydrocarbon phase.

Unfortunately the Carbon Density Value (CDV) of CO_2 is very low, hence the resolution of C/O ratio based CO_2 saturation determinations is poor, the CDV of water and CO_2 are both small. For the purposes of this interpretation only qualitative estimates of CO_2 saturation were made from C/O ratio's. Some common fluid values of CDV are i.) water = 0 g/cc; ii.) 25 API oil (density 0.90 g/cc) = 0.7664 g/cc and, iii.) carbon dioxide CO_2 (density 0.60 g/cc) = 0.1637 g/cc

Geophysical Log Interpretation
Fig. 2 shows the pulsed neutron and open-hole interpretation results for the injector well. Track 1 has the gamma ray, bit size and open-hole caliper logs; the depth track shows the perforation interval (vertical red line). Track 2 has the open-hole induction resistivities and Track 3 the open-hole porosities derived from the neutron (blue), density (red) and magnetic resonance (black) measurements, and the core porosity (black circles). Track 4 contains the petrophysical volumetric analysis; this includes the rock volumes for clay (grey), quartz (yellow) and carbonate (dark blue) and the fluid volumes before water injection for free water (white), irreducible water (light blue) computed from magnetic resonance and CO_2 (red). Track 5 has the sigma before (blue and green) and after injection water (black and red) passes. Track 6 has the pulsed neutron thermal neutron porosity (TPHI) before (blue and green) and after (black and red) injection water. Track 7 has the far detector carbon-oxygen ratio (FCOR) before (blue) and after (black) water injection.

Due to the borehole fluid being changed from CO_2 to water there is an obvious separation in the C/O ratio, TPHI and sigma measurements between the before and after passes. Further to this there is an additional separation between the before and after passes across the perforation interval (1093m-1105m) due to changes in formation CO_2 saturation. Interestingly, across the interval 1094.5m to 1097m the sigma measurement after saline water injection is higher than the one before, and is not consistent with the C/O ratio and TPHI. As the sigma of CO_2 is low, it was expected that sigma before saline water injection would be lower. It is difficult to explain this inconsistency, a high sigma value could be associated with a high sigma material like squeezed cement. Nevertheless, the C/O ratios and TPHI measurements confirm that CO_2 was injected into this zone.

For the interval (1083.5m-1087.5m), TPHI before and after injection is low, due to CO_2 being trapped in the annulus between the packer and bottom of tubing. For the interval (1103.5-1107m) water in the sump did not move before or after water injection, hence for this interval, the before and after C/O ratio, TPHI and sigma measurements are very similar.

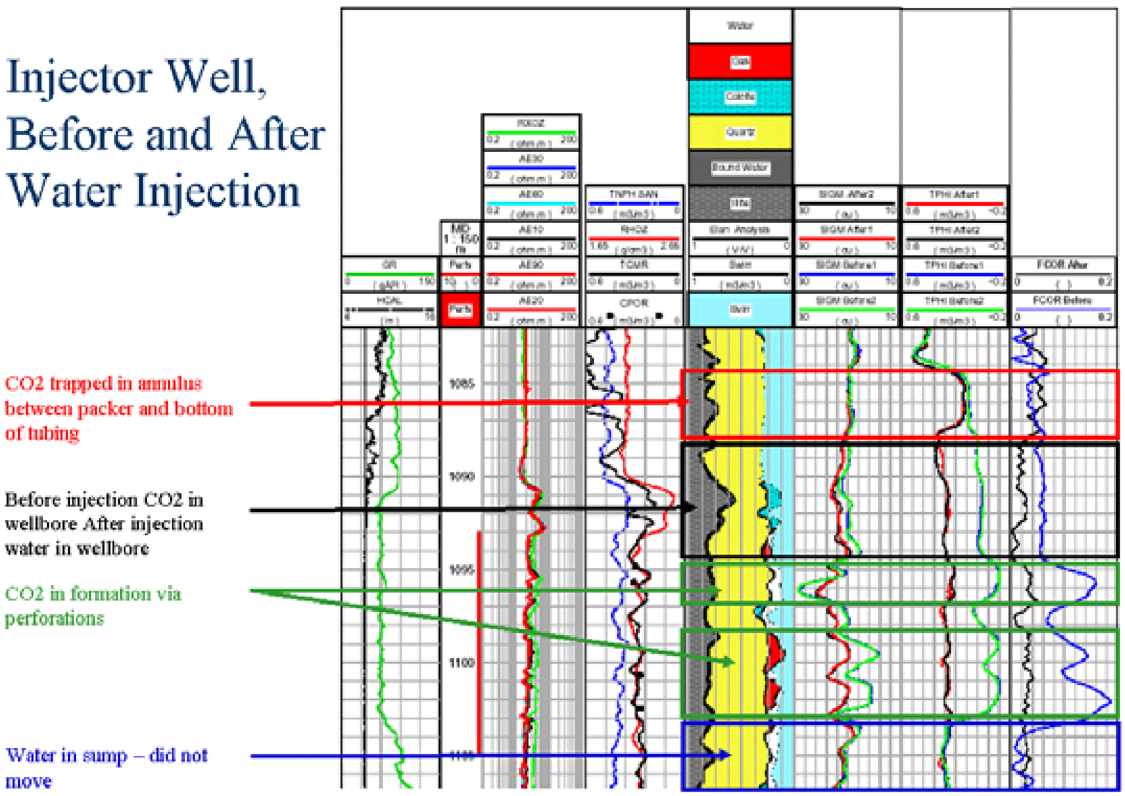

Fig. 2 – Injector well log interpretation results - Before and after water injection.

Conclusions

For the injector well large changes in CO_2 saturation before the before and after water injection passes were observed on the sigma, C/O ratio, and TPHI measurements. CO_2 saturation before injection water varied from 30% to 60%. Due to the relatively saline injection water, CO_2 saturation estimates were derived from pulsed neutron sigma. An odd sigma response across the interval 1095-1097m is not explained – an element with high sigma appears to be present. But C/O ratios confirm CO_2 was injected into this zone. The low Carbon Density Value (CDV) of CO_2 allows for only qualitative saturation estimates with C/O ratios.

References

Sakurai, S., Ramakrishnan, T., Boyd, A., Mueller, N. and Hovorka, S., 2005, Monitoring Saturation Changes for CO_2 Sequestration; Petrophysical Support of the Frio Brine Pilot Experiment, 46th Annual SPWLA Logging Symposium, New Orleans, USA, June 26-29, 2005.