Crosswell Seismic and Electromagnetic Monitoring of CO₂ Sequestration

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ABSTRACT

The quantitative estimation of changes in water saturation ($S_w$) and effective pressure ($P$), in terms of changes in compressional and shear impedance, is becoming routine in the interpretations of time-lapse surface seismic data. However, when the number of reservoir constituents increases to include in situ gas and injected CO₂, there are too many parameters to be determined from seismic velocities or impedances alone. In such situations, the incorporation of electromagnetic (EM) images showing the change in electrical conductivity ($\sigma$) provides essential independent information. The purpose of this study was to demonstrate a methodology for jointly interpreting crosswell seismic and EM data, in conjunction with detailed constitutive relations between geophysical and reservoir parameters, to quantitatively predict changes in $P$, $S_w$, CO₂ gas saturation ($S_{CO₂}$), CO₂ gas/oil ratio ($R_{CO₂}$), hydrocarbon gas saturation ($S_g$), and hydrocarbon gas/oil ratio ($R_g$) in a reservoir undergoing CO₂ flood.

INTRODUCTION

Crosswell seismic and EM technology has been developed over the past two decades to provide high spatial resolution images of the compressional velocity ($V_p$), shear velocity ($V_s$) and the $\sigma$ of the inter-well region. Much of the effort, as measured by the topics of published and presented work, has concentrated on developing and improving algorithms for estimating the geophysical parameters themselves. In most reported applications, the output from a survey is a cross section of $V_p$, $V_s$, or $\sigma$, or the time-lapse change ($\Delta$) of these parameters, which is discussed in terms of its implications for the distribution and/or $\Delta$ of the reservoir parameter of interest. These interpretations are qualitative and can be in error when more than one reservoir parameter affects the geophysical parameter.

In many settings, the geophysical parameters depend on a number of reservoir parameters that are variable in both space and time. In particular $\phi$, $P$, $S_w$, and $S_g$ strongly influence $V_p$. $\sigma$ can generally be described as a function of $\phi$, $S_w$ and fluid $\sigma$ [1]. As we will show in a multicomponent fluid reservoir, the spatial distribution of the time-lapse change in geophysical parameters, such as $V_p$, can differ significantly from the spatial distribution of the time-lapse change in a desired reservoir parameter such as $R_{CO₂}$. This difference results from the geophysical parameters dependence on other parameters such as $P$ and $S_w$, which must be sorted out before a picture of any single reservoir parameter can be obtained.
The objective of the work described in this paper is to demonstrate a methodology for combining time-lapse changes in $\sigma$, $V_p$, and $V_s$ with a detailed rock-properties model to produce quantitative estimates of the change in $R_{CO_2}$ and $S_{CO_2}$.

**EXPERIMENT DESCRIPTION**

Crosswell seismic and EM measurements were conducted in the Lost Hills oil field in southern California during a CO$_2$ injection pilot study conducted by Chevron Petroleum Co. The P and temperature (T) of the reservoir make this an immiscible flood; CO$_2$ is in the gas phase within the reservoir. The experiment took place in a portion of the field that had been undergoing water flood since 1995. Two observation wells, OB-C1 and OB-C2, were drilled for the pilot and fiberglass cased to allow the use of crosswell EM. The nearby CO$_2$ injector (11-8WR) is located just 6 m (20 feet) out of the crosswell-imaging plane. The injection wells are hydraulically fractured to increase injectivity into the low permeability diatomite reservoir. In some cases, downhole pressures were increased above the lithostatic pressure, which may have induced fracturing above the desired injection interval. If the fracture did indeed extend above the desired interval there is a high probability that much of the injected CO$_2$ will not sweep its intended target, but will move in the higher section.

The baseline crosswell seismic and EM surveys were conducted in September 2000, just prior to the beginning of CO$_2$ injection. Two seismic sources were used; a piezoelectric $V_p$ source and an orbital vibrator $V_s$ source with maximum frequency contents of 2000 and 350 Hz respectively. A repeat seismic survey was conducted in late May 2001, with the repeat EM survey conducted in early July 2001.

**ROCK PROPERTIES MODEL**

The reservoir parameters that have a dominant affect on the geophysical parameters are $\phi$, $P$, $S_w$, $S_g$, $R_g$ and $R_{CO_2}$. Effective pressure, $P$, is equal to lithostatic minus pore pressure ($P_{pore}$). So as $P_{pore}$ increases, $P$ will decrease. Pressure has a significant effect in Lost Hills since this is a shallow reservoir in soft rock. We sought constitutive relations between geophysical and reservoir parameters (rock-properties model) that would be able to predict observed $V_p$, density and $\sigma$ from observed $P$, $\phi$, $S_w$, and $S_g$. Laboratory measurements of the dry frame moduli and grain density of the diatomite reservoir rock were unavailable, so Hertz-Mindlin theory with the modified Hashin-Strikman [2] lower bound was used to model the dry-frame moduli of the reservoir rock. Fluid substitution in the dry frame is modeled by Gassmann's equation. The bulk moduli and densities of gas, live oil and brine, as well as $R_g$, are modeled using relations published by Betzel and Wang [3]. The bulk $\sigma$ of the reservoir rock is modeled using Archie’s [1] relationship.

A simplex algorithm was used to solve for the model parameters that would minimize the combined miss-fit between observed $V_p$ and density logs and the model predictions given the $\phi$, $S_w$ and $S_g$ logs. The results of this minimization, along with the Archie’s law fit to the OBC1 $\sigma$ log, are shown in Figure 1(a) - (d).

The pressure-prediction capability of the model was validated by comparison to laboratory measurements on core samples of diatomite from the Lost Hills field. Figure 1(e) presents the measured data recast as $\Delta V_p$ as a function of $\Delta P$ at a reference $P$ of 4.7 MPa, the effective pressure in the reservoir at the start of CO$_2$ injection. The model predictions are within a few percent of the lab measurements for vertical $V_p$ over the expected range of pressure decrease, from 0 to 2.5 MPa from the initial pressure.

The rock-properties model is used to calculate changes in $V_p$, $V_s$, and $\sigma$ as functions of changes in $P$, $S_w$, $S_g$, and $S_{CO_2}$ when certain reference values of $P$, $\phi$, $S_w$, and $S_g$ are assumed. Figure 2 shows $\Delta V_p$ and $\Delta V_s$ as functions of $\Delta P$ and $\Delta S_w$ about a reference point (reservoir just prior to CO$_2$ injection) where $S_w$, $\phi$, and $P$ are equal to 0.5, 0.5, and 4.7 (MPa) respectively. Relations between $\Delta V_p$ and $\Delta V_s$ and $\Delta P$ and $\Delta S_w$, such as...
illustrated in Figure 2(a) and (c), form the basis of 4D seismic $\Delta P$ and $\Delta S_w$ prediction. However, when $S_g$ is non-zero, as shown in Figure 2(b), the orientation and magnitude of contours of constant $\Delta V_p$ change dramatically. The change in $V_s$ is only slightly effected (through density) by the presence of gas. Without additional information, $\Delta V_p$ and $\Delta V_s$ are insufficient to predict $\Delta P$, $\Delta S_w$ and $\Delta S_g$. EM data provides an independent estimate of $\Delta S_w$. Electrical conductivity ($\sigma$) is a much simpler function of reservoir parameters than is the velocity and can be described by Archie’s law [1]. Assuming $\phi$ is constant, $\Delta \sigma$ is only a function of $\Delta S_w$ and $\Delta$ pore $\sigma$. Since water flood has been in effect for over 6 years, we assume that the pore-fluid water has reached equilibrium between injected and native water, and fluid $\sigma$ does not change. Therefore, conductivity changes are interpreted solely in terms of water saturation changes.

**Figure 1:** Rock-properties model uses logged porosity (+), water saturation (box) and gas saturation (dots) shown in (c) as inputs in a multi-parameter simplex regression to predict the $V_p$ (a), density (b) and electrical resistivity (d). Measured $V_p$, density and resistivity are shown as dots, model predicted values are shown as lines. Panel (e) is $\Delta V_p$ as a function of $\Delta P$ (solid curve) compared to measured vertical (triangles) and horizontal (circle) $\Delta V_p$ from laboratory measurements.

**Figure 2:** Changes in P and S wave velocity (m/s) as functions of changes in effective pressure and water saturation. Panel (a) $\Delta V_p$ with $S_g = 0.0$, panel (b) $\Delta V_p$ with $S_g = 0.02$, panel (c) $\Delta V_s$ with $S_g = 0.0$. $\Delta V_s$ is essentially independent of $S_g$. All calculations are done at a reference $S_w$, $\phi$ and P of 0.5, 0.5 and 4.7 MPa.
INTEGRATED TIME-LAPSE GEOPHYSICAL IMAGES

The strategy we adopted to maximize the spatial correlation between $V_p$, $V_s$, and $\sigma$ images was to begin with the EM where the most *a priori* information existed, then use the $\sigma$ images to produce starting $V_p$ models, and then follow that by producing starting $V_s$ models from the final $V_p$ models. We chose to use a conjugate gradient algorithm [5] because the final model is sensitive to the initial model and is perturbed from the starting values only as much as needed to fit the observed data.

The EM inversion [4] for the data at initial conditions was started from a model built by laterally interpolating the $\sigma$ logs between the OB-C1 and OB-C2 wells. The EM inverse $\sigma$ model at initial conditions was then used as the starting model for the inversion of the July 2001 EM data. Differencing these inversions provides the $\Delta\sigma$ shown in Figure 3©. There is a high degree of correlation between the 11-8WR permeability log and the areas where the largest decrease in $\sigma$ occur. The correlation between high permeability and large changes in $S_w$, and thus $\sigma$, is expected. Also, the largest $\sigma$ changes occur more in alignment with the estimated location of the old water injection fracture than with the much newer CO₂ fracture. This is not surprising when we consider that the water injection was ongoing for more than 6 years and thus likely produced a high permeability damage zone that is a better conduit for flow than the very new CO₂ fracture.

![Figure 3: Time-lapse changes in (a) $V_s$, (b) $V_p$ and (c) $\sigma$. Major unit boundaries are shown as black horizontal lines, estimated location of previous water injection fracture is vertical line (x=45 ft), estimated location of the CO₂ injection fracture is shown as a vertical white line (x=60 ft), perforation intervals for CO₂ injection are shown as black dots, location of a fault zone is shown as the black diagonal line. The permeability log from the CO₂ injection well 11-8WR is shown in black on panel (c).](image)

Next, the pre- and post-CO₂ $\sigma$ models were converted to $V_p$. These were then used as initial models in the inversion of the $V_p$ travel time data to produce the change in $V_p$ shown in Figure 3(b). In addition to $V_p$ changes occurring in the vicinity of the estimated water-injection fracture, there are decreases in $V_p$ that align with the mapped fault. Since there is no $\sigma$ changes obviously correlated with the fault, we interpret this to mean that pressure changes are occurring along the fault zone advanced in time relative to significant changes in water saturation.

The $V_p$ sections were converted to $V_s$ using a $V_p/V_s$ ratio derived from the rock properties model and used as starting models for the $V_s$ travel time inversions resulting in the $\Delta V_s$ section shown in Figure 3(a). The $\Delta V_s$ section is smoother than either the $\Delta \sigma$ or $\Delta V_p$ sections, due in part to the lower frequency content in the shear wave data. The $\Delta V_s$ section is also smoother because $V_s$ is relatively insensitive to $\Delta S_w$, which has high spatial variability, but very sensitive to $\Delta P$, that has much lower spatial variability. Even with the
smoother spatial changes in the $V_s$ data, we see correlation with the $V_p$ and $\sigma$ changes. In particular, the zone along the fault shows a decrease in $V_s$, lending support to our interpretation that pressure is changing along the fault zone.

**PREDICTING CHANGES IN RESERVOIR PARAMETERS**

First the $\Delta \sigma$ image was used to predict $\Delta S_w$, assuming that $\phi$ and fluid $\sigma$ did not change. The predicted $\Delta S_w$ was used with the observed $\Delta V_s$ and the relation illustrated in Figure 2(c) to predict $\Delta P$. The predicted $\Delta S_w$ and $\Delta P$ were then used to calculate the $\Delta V_p$ that would be caused by $\Delta S_w$ and $\Delta P$ alone, assuming $S_g=0$. Over the majority of the image plane, $\Delta S_w$ and $\Delta P$ are negative thus producing a negative $\Delta V_p$. The difference between the observed and calculated $\Delta V_p (\Delta V_R)$ was generated. We expect the CO$_2$ to decrease $V_p$ in excess of the effects of $\Delta S_w$ and $\Delta P$ alone. There are two mechanisms for CO$_2$ to decrease $V_p$: 1) through decreasing the bulk modulus of the oil by increasing $R_{CO2}$ and 2) by increasing $S_{CO2}$ through introduction of free CO$_2$. Either of these mechanisms would produce a negative $\Delta V_R$. On the other hand, a $+\Delta V_R$ can result if the assumption $S_g=0$, is incorrect. The presence of initial gas will produce this effect, as seen by comparing Figure 2(a) and 2(b) where the presence of gas reduces the decrease in $V_p$ associated with a given $\Delta S_w$ and $\Delta P$. If *in situ* hydrocarbon gas is present and has been accounted for in the calculation of $\Delta V_R$, $+\Delta V_R$ can result when $S_g$ is reduced, as the pore pressure increase dissolves gas into the oil.

The OB-C1 log showed the presence of hydrocarbon gas over certain intervals within the reservoir. Therefore a two-step process was used to calculate $\Delta V_R$. The first pass used $S_g=0$ as described. Next, sections of the image with $+\Delta V_R$ were recalculated assuming $S_g = 0.02$ (the average non-zero $S_g$ in the reservoir interval). After the second pass calculation of $\Delta V_R$, much of the areas that had $+\Delta V_R$ after the first pass became negative. The final $\Delta V_R$ was converted to $\Delta R_{CO2}$ by a linear interpolation, since $\Delta V_R$ is a linear function of $\Delta R_{CO2}$.

![Figure 4: Predicted $\Delta R_{CO2}$. See Figure 3 caption for figure overlays.](image)

This final step requires assumptions about the partitioning of negative $\Delta V_R (-\Delta V_R)$. First we assumed that the $+\Delta P_{pore}$ caused by injection would drive as much of the initial hydrocarbon $S_g$ into the oil as possible. Next, we assume a partitioning between the $+\Delta R_{CO2}$ and $+\Delta S_{CO2}$ effects on $\Delta V_R$. We chose to allow the maximum increase in $R_{CO2}$ for the given $+\Delta P_{pore}$ and $\Delta S_w$. Areas of $-\Delta V_R$ were converted to $+\Delta R_{CO2}$ up to the maximum $R_{CO2}$ for the final $P_{pore}$ and $T$. The observed $-\Delta V_R$ could be completely accounted for by $+\Delta R_{CO2}$ without requiring $+\Delta S_{CO2}$. Figure 4 shows the calculated $\Delta R_{CO2}$ generated from the geophysical parameter.
changes shown in Figure 3. As has been stated, these calculations are based on differences calculated at reference values of \( P, \phi, S_w \) and \( S_g \). The sensitivity of the \( \Delta R_g \) and \( \Delta S_g \) predictions to the reference parameters has been studied. These studies show that the calculations are relatively insensitive to the reference \( \phi \) and \( S_w \) values. The calculations are most sensitive to the assumed hydrocarbon gas saturation, with incorrect assignment of \( S_g \) producing errors in predicted \( \Delta R_{CO2} \) of 10 - 15 \%. The next largest source of error is the choice of the reference \( P \), with a 15\% error in the reference \( P \) producing errors in \( \Delta R_{CO2} \) of approximately 10\%.

The predicted \( \Delta R_{CO2} \) (Figure 4) shows a strong correlation with the location of perforation intervals that account for the majority of the injected CO2. The percentage of injected CO2 going into each perforation is plotted to the right of Figure 4 and shows that the upper four perforations account for 95\% of all the CO2. Almost 50\% of the CO2 goes into the upper most perforation. The location of this perforation corresponds with the large \( +\Delta R_{CO2} \) associated with the fault zone and region above, indicating loss of substantial CO2 into the upper portions of the reservoir. The next three perforations down account for roughly another 45\% of CO2 injected with each perforation aligning with a laminar zone of \( +\Delta R_{CO2} \). The only poor correlation between injected CO2 and predicted \( +\Delta R_{CO2} \) occurs at the perforation at a depth of 564 m (1850 ft). At this depth a laminar \( +\Delta R_{CO2} \) zone aligns with a perforation, but the injectivity log indicates little injected CO2.

**CONCLUSION**

We have demonstrated that by combining seismically derived \( \Delta V_p \) and \( \Delta V_s \) with EM derived \( \Delta \sigma \), estimates of \( \Delta P, \Delta S_w \) and \( \Delta R_{CO2} \) can be made in a complex reservoir containing oil, water, hydrocarbon gas, and introduced CO2. The resulting predicted \( \Delta R_g \) is better correlated with measured CO2 injectivity than any of the time-lapse geophysical parameter images. The predicted \( \Delta R_g \) images indicate that a significant portion of the injected CO2 is filling the upper portions of the section above the intended injection interval. These conclusions are validated by CO2 injectivity measurements made in the 11-8WR well.

The methodology outlined in this paper relies on many assumptions that were required because the project was not designed to use this methodology. However, in future applications these assumptions could be substantially reduced by design. In particular, considerable benefit could be drawn from repeat logging of the wells with a full suite of logs. This would provide control points for the \( \Delta P, \Delta S_w, \Delta S_g, \Delta V_p, \Delta V_s, \) and \( \Delta \sigma \), all of which would serve to greatly constrain the problem. In addition, having full log suites would enable much better control of the geophysical inverse solutions through superior starting models.

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**References**