CHAPTER 5

HOW DO WE KNOW WHERE THE CO_2 IS? – DEVELOPMENTS IN GEOPHYSICAL MONITORING

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5.1 INTRODUCTION

In order to reduce the risks associated with CO_2 stored in geological subsurface formations, monitoring of the CO_2 is fundamental to the operation and management of the storage site. Generally, monitoring is the continuous or repeated observation of a situation to detect changes that may occur over time. To be able to monitor a given CO_2 store, we must be able to observe and track changes in the 3D distribution of CO_2 during injection, post-injection site management and post-closure stewardship.

Objectives of monitoring are therefore, (1) to enable optimal reservoir engineering by repeated or continuous assessment that informs on the evolving physical conditions in the store, and (2) to allow operation of the storage site within regulatory monitoring requirements and agreed industry practices. With the scarcity of established regulation and active CCS storage during the life cycle of CASSEM and of other pioneering CCS-demonstration R&D, the second objective includes providing assurance to (would be) regulators and stakeholders that unexpected or undesired migration in the storage can be tracked and mitigated, informing well in advance of any 'leakage', 'escape' or 'emission', in the public parlance. Correspondingly, the monitoring strategy is 'proactive' (DET NORSKE VERITAS, 2010).

5.2 MONITORING METHODS

Several methods have been proposed for monitoring stored CO_2, including geochemical, geomechanical and geophysical methods. Geochemical methods use direct sampling of subsurface fluids or escaping gases and have limited spatial resolution. Geomechanical methods such as comparing satellite measurements repeated over time to monitor earth surface movements (e.g. uplift) as a mechanical response to a large amount of injected CO_2 are only viable (1) for onshore reservoirs and (2) where the target geological layers are sufficiently shallow to impact the earth's surface. Geophysical monitoring methods have a much broader scope; they remotely measure subsurface changes by sending signals like seismic (i.e. acoustic) waves into the ground, measuring them either at the surface or in boreholes after propagation through the subsurface, and analysing the data for subsurface information. The application of geophysical monitoring methods to subsurface exploration and monitoring is well developed in the hydrocarbon industry and other resource storage and waste disposal sectors. They are, therefore, the most likely methods to be used to monitor stored CO_2. The remainder of this chapter considers only geophysical monitoring methods.

A range of geophysical methods have been used to monitor major CO_2 storage sites around the world, such as Sleipner in the Norwegian North Sea, Weyburn in Canada and In Salah in Algeria. Repeated seismic monitoring is currently the key method providing most information about the subsurface. However, gravity and electromagnetic methods at Sleipner (e.g. Alnes, 2008) and microseismic monitoring at Weyburn (Verdon et al., 2010) have also been deployed. In the case of In Salah, time-lapse (repeated) satellite imagery (monitoring ground surface displacement) has proven to be informative (Mathieson et al., 2009). This site in particular is well-suited to satellite imagery because it is situated in the desert (this technique is more efficient when the earth surface is covered with bare rock). The most applicable and informative suite of monitoring methods is therefore site-dependent.

5.3 MONITORABILITY

The suite of geophysical monitoring techniques employed should be able to detect where some minimum threshold volume or saturation of CO_2 has been exceeded within a subsurface reservoir or after migration into the overburden. Moreover, the saturation (and hence volume) of CO_2 must be estimable within some predefined or characteristic spatial volume, with some minimum degree

of accuracy. Defining these minimum thresholds is equivalent to defining the term 'monitorable'. To date, no standard definition of what is required for a site to be monitorable has been agreed.

This chapter contributes new insight and information towards this definition. Particular attention is paid to offshore geophysical methods, but many of the conclusions are also valid for onshore monitoring. Whether or not monitorability requirements can be met depends essentially on the geology and geography of the storage site. Site geology dictates the magnitude of the change in CO_2 saturation that is measurable in any given injection scenario. Pertinent geological information is obtained from the geological model, rock properties and lab petrophysical data (see Chapters 3 and 4). Site geography limits the range of applicable geophysical monitoring methods (dictated by whether the site is offshore, mountainous, remote wilderness, etc).

To assess the detectability of petrophysical changes in storage reservoir rocks, the expected magnitudes of corresponding changes in geophysical signals are calculated by petrophysical and geophysical modelling. Petrophysical modelling comprises constructing mathematical relations that predict geophysically monitorable parameters such as the velocity of primary (P) waves and shear (S) waves propagating through the rocks, from estimated rock properties such as permeability, porosity, clay content and saturations of different fluids. Geophysical modelling involves predicting the magnitude of the measurable signal based on those modelled values of geophysical parameter changes and on the site geology. When a monitoring survey is carried out, the real geophysical signals are measured in the field, from which critical rock properties (e.g., fluid saturations) are estimated by applying the reverse form of the above mathematical relations. This technique is called 'inversion'.

For the purposes of the CASSEM project we propose that 'site monitorability' is defined by a combination of the following factors:

- Survey practicality/cost.
- Geophysical spatial resolution.
- Petrophysical detectability.
- Petrophysical parameter resolution.

Thus, a site is assumed to be monitorable, if geophysical monitoring is possible from a practicality and cost point of view; if there is sufficient spatial resolution to image potential positions of subsurface CO_2; if changes in geophysically measurable signals due to CO_2 injection are detectable; and if there is sufficient resolution or uncertainty-reduction in petrophysical and fluid parameter estimates to fulfil monitoring objectives such as detecting leakage, or exceeding the volume and saturation thresholds.

Figure 5.1 shows the workflow for assessing monitorability of a site and designing a corresponding monitoring strategy, and the linkages to other work packages in the CASSEM project. In the following sections, detectability, petrophysical resolution and, to some extent, geophysical spatial resolution components are explained. It is assumed that there are no practical or cost barriers to geophysical monitoring.

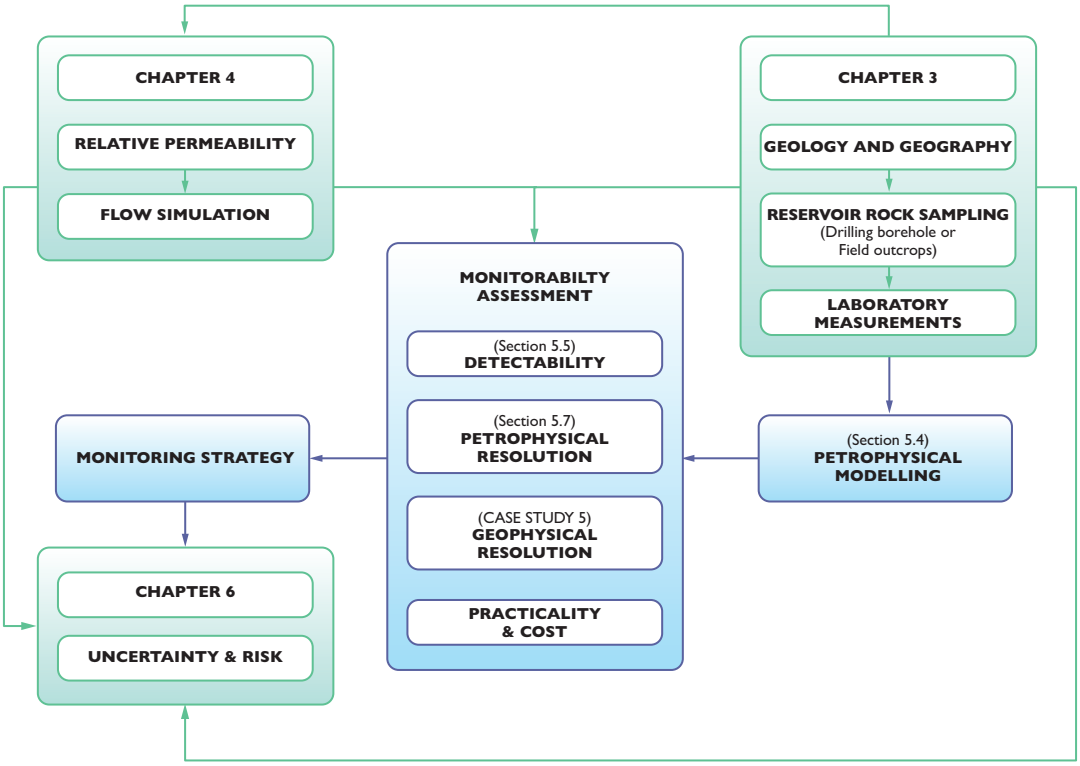

Figure 5.1 Monitorability assessment workflow. Blue boxes represent work carried out in this chapter. Section numbers refer to sections in this chapter. Yellow boxes indicate information derived from other chapters.

5.4 PETROPHYSICAL MODELLING (PREDICTING GEOPHYSICAL PROPERTIES OF CO_2-BEARING ROCKS)

The main physical parameters of rocks to which various geophysical methods are sensitive are:

- Bulk and shear moduli, corresponding to P- and S-wave seismic velocities.
- Density.
- Electrical conductivity.
- Magnetic permeability.

Each of these may have apparent variation with the direction of measurements (this property is called anisotropy). All of the geophysical methods are sensitive to one or more of these parameters. The physical parameters of rock pre- and post-CO_2 injection depend on the mineralogical composition, porosity, pore fluid content (including the saturation of CO_2), and in situ pressure and temperature of the rock, as well as on the physical parameters of the injected CO_2. Rock and fluid physics measurements and theoretical modelling show that the presence of CO_2 may affect the bulk and shear moduli, the density and the electrical resistivity of the reservoir (more details on this are given in Chapter 4). No change is expected in magnetic properties of rocks due to CO_2 injection.

There are a range of petrophysical models that are used to investigate the effect of CO_2 saturation (S_{CO2}) on geophysical parameters of the reservoir rocks, such as the models proposed by Pham et al. (2002), Pride and et al. (2003) and also the Archie (1942) model to calculate electrical resistivity of reservoir rocks. Figure 5.2 shows calculated P-wave velocity (the subsurface equivalent of acoustic

speed of sound in the air) and electrical resistivity of a reservoir rock with 22.6% porosity and 5% clay content (for information about the other material parameters used in the petrophysical model see Table 6.1 of JafarGandomi and Curtis, 2010), with respect to a range of S_{CO2} (1–99%) and frequency in the case of P-wave velocity. Because the fluid content of rock has no effect on the shear modulus, any variation of the shear or S-wave velocity with S_{CO2} occurs primarily due to density changes.

Figure 5.2a implies that in terms of monitoring CO_2 storage sites using seismics, the purpose of monitoring has a significant effect on selecting the appropriate monitoring methods. For example, if the purpose of monitoring is simply to detect the presence of CO_2 in the storage formation or to detect CO_2 migration or leakage into the surrounding rocks, time-lapse (repeated) reflection seismics with a low-frequency content may be appropriate because it will show significant changes in the recorded signals, even with a small amount of CO_2 in the brine. However, if the purpose of monitoring is to evaluate the amount and spatial distribution of injected CO_2 (i.e. to estimate S_{CO2} in the brine), low-frequency methods such as time-lapse reflection surface seismics may not be appropriate since their sensitivity is minimal to saturations beyond about 10–20%; higher frequency techniques such as sonic logging in wells, or cross-well methods may have to be applied. Nevertheless, in many injection scenarios one may expect up to ~5% CO_2 dissolved in brine over the majority of the reservoir volume, in which case surface seismic methods may well suffice.

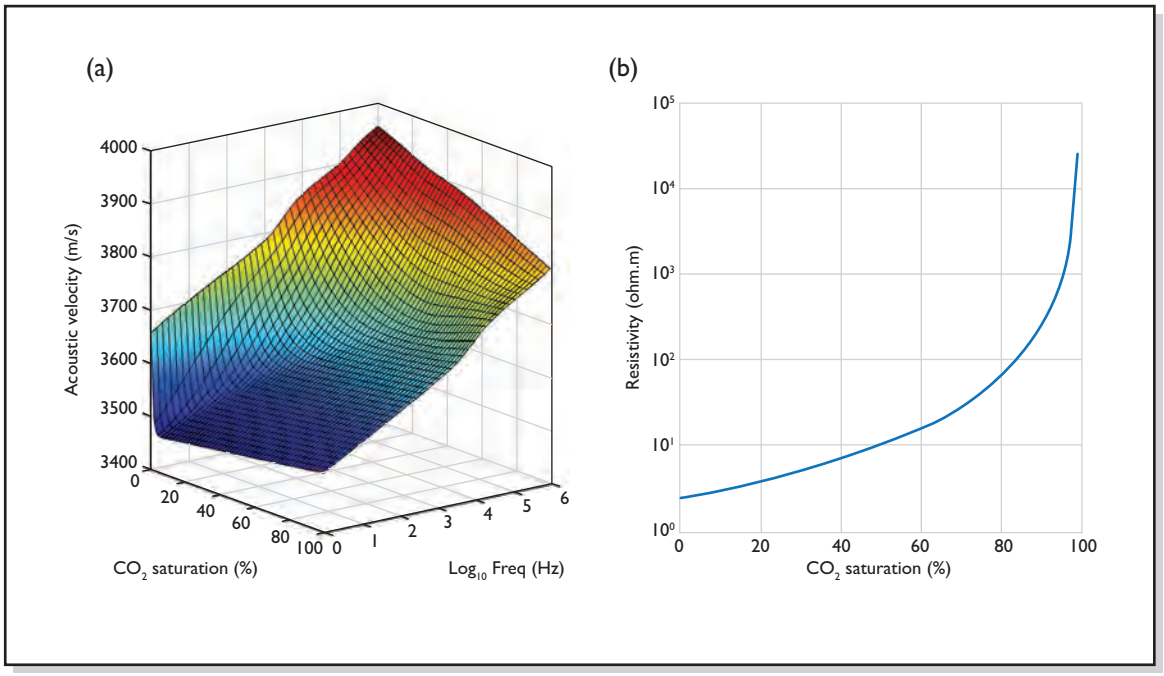

Figure 5.2 Variation of (a) acoustic velocity and (b) electrical resistivity against S_{CO2} and seismic wave frequency for the reservoir rock. Colours reflect the height of the surface in (a). Low, intermediate and high frequencies correspond to the marine reflection seismic method, well-based seismic measurements, and laboratory measurements, respectively. Note the strong nonlinearity of acoustic velocity variation with respect to CO_2 saturation at lower frequencies and its linearity at higher frequencies.

5.5 DETECTABILITY

As mentioned earlier, any geophysical monitoring method employed should at least be able to detect where some minimum threshold volume or saturation of CO_2 has been exceeded within the reservoir. This minimum threshold is used to define the detectability. In this section a set of diagnostic parameters are defined for three geophysical methods:

- Gravimetry (sensitive to the density of rocks).
- Controlled source electromagnetic (sensitive to electrical resistivity of rocks).
- Seismics (sensitive to (an)elastic properties of rocks).

Each method is used to assess the detectability of changes in geophysical parameters of reservoir rocks due to increased S_{CO2} for one geophysical model. These changes are calculated by comparing expected or modelled geophysical responses of the reservoir before and after injecting CO_2.

Detectability parameters

The following general form for the detectability parameters is introduced:

$$\delta x = \frac{X - X_0}{std(X)} \tag{5.1}$$

where X_0 and X are values of geophysical parameters measured with a particular geophysical method before and after injecting CO_2, respectively, and *std(X)* is the uncertainty or noise level involved in estimating X, which dictates the minimum required changes in geophysical parameters to produce distinguishable geophysical signals. Equation 5.1 is used to evaluate the different geophysical methods. In the rest of this section two examples of the application of detectability parameters to gravimetry and controlled-source electromagnetic (CSEM) measurements are shown. The seismic method can quickly be used to detect P-wave velocity changes to about 1–2% accuracy, so the detectability of a particular saturation change at different frequencies can be inferred from Figure 5.2a. Further investigation of seismic detectability based on seismic amplitude variation with offset is given in JafarGandomi and Curtis (2011).

Gravity survey (gravimetry)

Once CO_2 is injected into brine-saturated rocks (saline aquifer reservoirs), it will partially replace the brine and consequently change the bulk density of reservoir rocks. Studies have shown that it is possible to detect the presence of CO_2 in the storage formation by gravimetry, which is sensitive to the density changes in the reservoir (e.g. Alnes et al., 2008). The depth of storage formation and inherent resolution of the technique has significant impact on the feasibility of gravimetric detection of CO_2 migration. As the depth of the storage formation increases, the amplitude of changes in gravity measurements at the surface decreases rapidly.

To design a gravimetry survey to detect CO_2 migration, modelling is necessary to see whether the expected amplitude of signals generated on the surface are sufficiently large to be detected using current technology. The current accuracy of time-lapse gravity measurement is around 5 $^{\mu Gal}$ (e.g. Stenvold et al., 2008). In this chapter a simplified CO_2 plume shape (a vertical cylinder) is used to estimate its detectability by repeated surface gravity measurements. The gravity signal is calculated on the axis of this vertical cylinder of homogeneous density perturbation.

The gravimetric detectability is calculated for a range of reservoir rock porosities and S_{CO2} and is shown in Figure 5.3. In this figure, the coloured area highlights the detectable zone using surface gravity measurements for storage formations with thickness (cylinder height) of h = 20 m, 100 m and 200 m, and cylinder radius-to-depth ratios of 0.2, 0.5 and 1.0, in a matrix form. Any value of corresponding detectability parameter greater than one falls within the detectable zone of gravimetric measurements. This figure shows how the area of the detectable zone, with respect to porosity and saturation, increases either with plume thickness or with its radius-to-depth ratio.

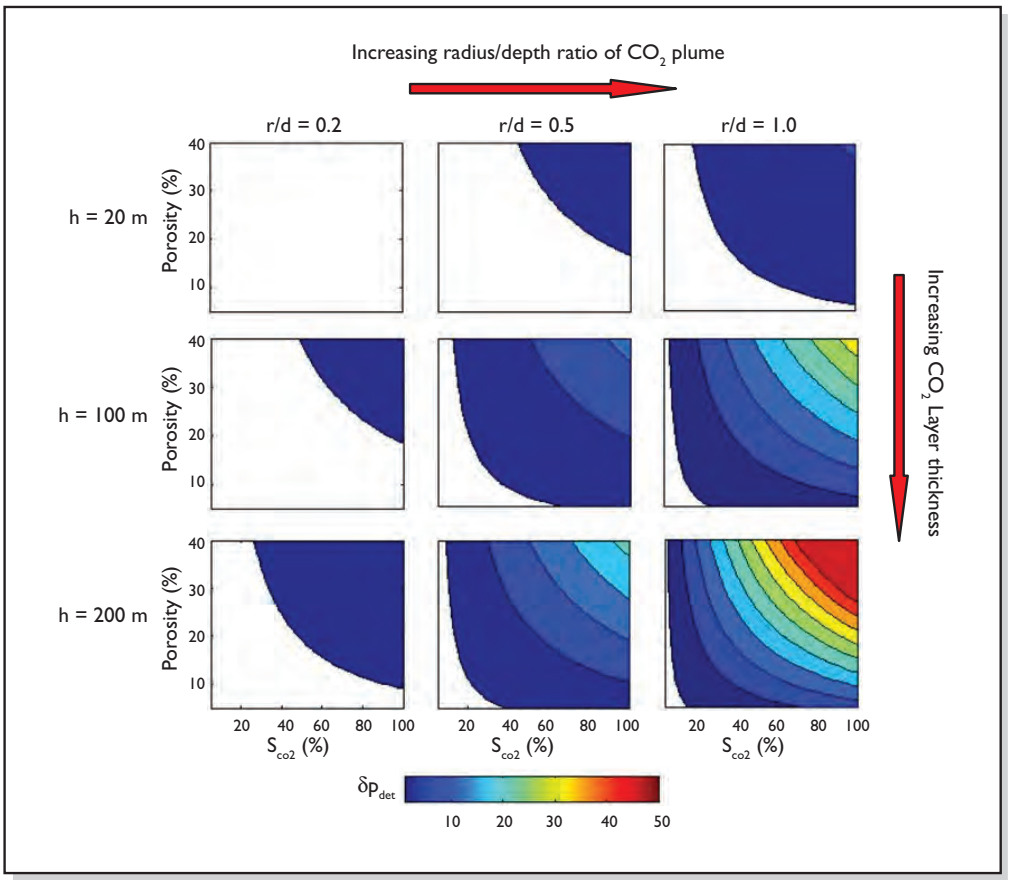

Figure 5.3 Density detectability parameter versus S_{CO2} and rock porosity for different values of thickness and radius-to-depth ratio of the CO_2 plume within the storage formation. Coloured areas represent detectable plumes. In this figure, moving from left to right corresponds to increasing the CO_2 plume size and/or reducing its depth. Moving from top to bottom represents increasing the CO_2 layer thickness.

Applicability

The above calculations for simple cases confirm that gravimetry has the potential to be used to detect subsurface stored CO_2, particularly for higher porosity reservoirs, for higher saturations and when the lateral extent of the plume is comparable to its depth. Calculating the gravimetry detectability parameter for each individual storage site and the expected plume shape will help to design an appropriate and efficient monitoring strategy. However, while gravity can be used to detect the presence of a plume, it will not constrain its shape or its internal saturation heterogeneity because the spatial resolution offered by surface gravity is generally very low.

5.6 CONTROLLED-SOURCE ELECTROMAGNETIC METHOD

Even though CO_2 injection into brine-saturated sandstones significantly increases the resistivity of rocks (Figure 5.2b), detectability of these changes remains a challenge, particularly in the case of offshore storage sites. Controlled-source electromagnetic (CSEM) data typically result in far lower spatial resolution than reflection seismic data. There have been several studies on the feasibility of monitoring CO_2 storage by electrical methods (e.g. Gasperikova and Hoversten, 2006). For offshore monitoring, the marine controlled-source electromagnetic method has recently been tested.

Um and Alumbaugh (2007) demonstrated that the efficiency of marine CSEM for detecting high-resistivity relatively thin layers (e.g. hydrocarbon and CO_2 reservoirs) at depth is strongly dependent on the source-receiver configurations and on the site characteristics, and is only possible within a certain source-frequency range. In particular, the thickness and depth of the storage formation and electrical structure of the overburden have a profound effect on detectability. This limits the ability to draw general conclusions about the electromagnetic detectability of SCO_2 stored in a saline aquifer.

The standard strategy to design a CSEM experiment or survey is to make the received signal as large as possible for the shortest possible transmitter-receiver offset, in order to increase the lateral resolution while maintaining an appropriate signal-to-noise ratio (e.g. Constable and Weiss, 2006). To illustrate this we consider a simple model of a storage formation with initial (pre-storage) resistivity of 1 ohm-m and thickness of 100 m at a depth of 1000 m below the seabed, within a background medium consisting of a lower half-space with the resistivity of 1 ohm-m. We model the CSEM responses for a single receiver located on the seabed for a series of inline electric dipole transmitters from 0–20 km horizontal offset from the receiver and at 50 m above the seafloor. We use the OCCAM1DCSEM code of Key (2009) to calculate the synthetic responses. It is assumed that the resistivity of the storage reservoir increases to 20 ohm-m after injecting CO_2. To see the effect of CO_2 injection on the CSEM measurements, the CSEM responses of the model are calculated before and after injecting CO_2, for a range of frequencies from 0.1–100 Hz, and for transmitter-receiver offsets from 1–20 km (Figure 5.4a), and use the corresponding detectability parameter (equation 5.1) to assess detectability of resistivity changes in the reservoir.

In order to investigate the effect of the overburden and underburden on CSEM monitoring, a high-resistivity layer with 20 m thickness and 200 ohm-m resistivity (corresponding, for example, to a basalt layer) is moved vertically from just below the seabed to 4000 m depth below the seabed, in 200 m steps, and at each step the detectability parameter is recalculated. Different values of uncertainties (noise level) for horizontal and vertical components of recorded electrical fields (1×10^{-15} V / Am^2 and 5×10^{-15} V / Am^2, respectively) are considered because the vertical field measurements on current systems are generally more contaminated by instrumental noise than horizontal components (Constable et al., 2006). Figure 5.4b shows variation of the detectability parameters for each component, versus the depth of the high-resistivity layer. The variation of detectability indicates that in the overburden, as the high-resistivity layer gets closer to the reservoir, its effect decreases, while this is the opposite when the high-resistivity layer is in the underburden. The detectability parameter converges to the corresponding values for the homogeneous background at about 1000 m below the reservoir (3000 m depth).

Applicability

The significant effect of the underburden as well as overburden on the monitorability of reservoirs with the controlled-source electromagnetic method has been investigated for the first time in CASSEM. The main lesson to be learned, however, is that the potential effectiveness of the controlled-source electromagnetic monitoring method must be assessed on a site-by-site basis. This will require

significant prior information about the electrical resistivity structure of the reservoir, overburden and underburden. This is significant since exploration wells tend not to be drilled into the underburden in current exploration practice. Of course, performing electromagnetic monitoring from borehole wells may reduce the susceptibility of these methods to surrounding high-resistivity layers, but this susceptibility will never be completely removed, particularly if such layers are close to (above or below) the reservoir (e.g. Um & Alumbaugh, 2007).

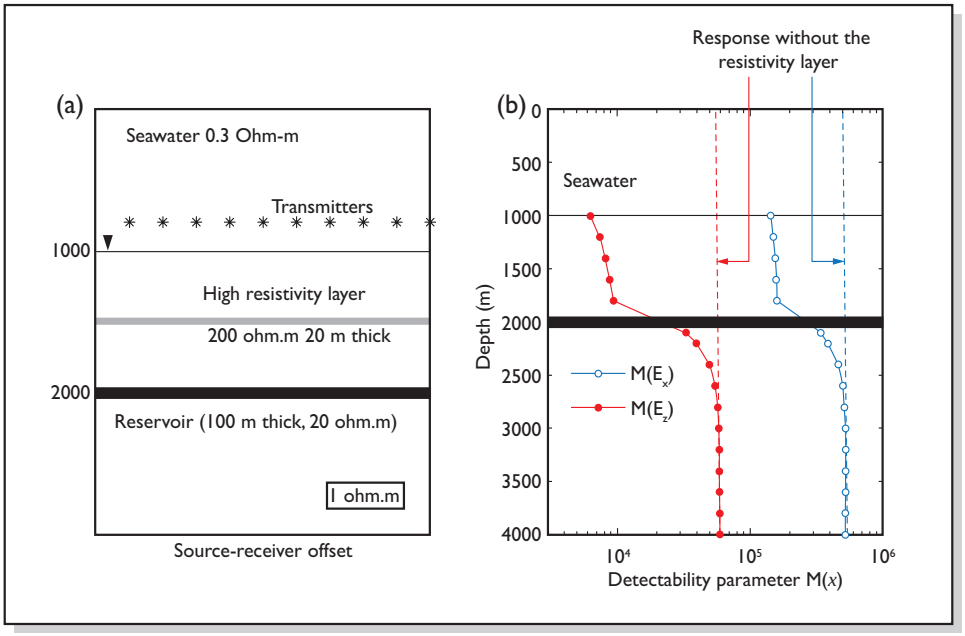

Figure 5.4 (a) Resistivity structure model and transmitter-receiver configuration (*=inline electric dipole transmitter). (b) Variation of the detectability parameters for horizontal and vertical components of the electric field with respect to the depth of the thin (20 m thick) high-resistivity (200 ohm-m) layer. Vertical dashed lines represent the detectability parameter in the absence of the high-resistivity layer. Note that the high-resistivity layer affects the detectability parameter even when it is in the underburden.

Large dolerite sills (with high resistivity) are characteristic of the geology of the Midland Valley of Scotland. It may be anticipated that such volcanic bodies/layers are present in the overburden and underburden of the Firth of Forth target aquifer reservoir and are indicated in the well-log of the Firth of Forth-1 borehole and seismic sections. Thus, further detailed geological and geophysical investigation of the overburden and underburden of the Firth of Forth site would be required before an appropriate monitoring strategy can be designed.

5.7 COMPARISON OF DIFFERENT GEOPHYSICAL PARAMETERS FOR CO_2 MONITORING

The purpose of geophysical monitoring of subsurface stored CO_2 has a significant effect on the selection of appropriate monitoring technique(s). Some of the most desirable goals of monitoring are: detecting the presence of CO_2 at different locations in the storage formation, and estimating the spatial distribution of S_{CO2} within the brine-filled aquifer and monitoring seal integrity. Based on the effect of S_{CO2} on the petrophysical parameters of rocks, and on their corresponding detectability parameters constructed in previous sections, the utility of each of the rock properties can be derived for different purposes of monitoring.

The detectability of stored CO_2 is strongly dependent on site characteristics (not only for electrical methods). For example, site geography (onshore or offshore), and the depth of the storage formation have first-order effects on the applicability (and cost) of all monitoring methods. In the following, the relation between the petrophysical parameters of rocks and their utility to detect CO_2 presence, migration, saturation, and seal integrity of a typical offshore storage site is discussed.

Based on the methods described above it is possible to summarise the results by assigning a qualitative ranking to each of the physical parameters of rocks for the various different purposes of monitoring the subsurface stored CO_2. The scale A, B and C is used where these are defined as follows. A: when geophysical monitoring is highly sensitive to the parameter with few limitations. B: when the parameter is only conditionally detectable, depending on the specific site or reservoir. C: when the parameter represents either very low sensitivity to S_{CO2}, or if current geophysical technology is not usually able to detect the corresponding petrophysical changes. Table 5.1 gives the ranking of each petrophysical parameter for each of four monitoring purposes. Such a ranking table is useful in the sense that it captures the overall likelihood that a parameter could be monitored by a surface geophysical method to detect the four types of changes due to CO_2 injection.

	Density	Vp	Vs	Qp	Qs	Resistivity
Presence	B	A	C	B	B	B
Migration	B	A	C	B	B	B
Saturation	B	B	C	B	B	B
Seal integrity	C	A	A	C	C	C

Table 5.1 Relative ranking of geophysical parameters for different monitoring purposes (Presence: detecting existence of the CO_2 plume regardless of the saturation. Migration: detecting lateral or vertical movement and growth of the plume. Saturation: quantitative estimation of exact CO_2 saturation. Seal integrity: detecting cap rock quality and leakage of CO_2 into it).

While we suspect that most entries in Table 5.1 will be correct for a number of sites based on the methods of analysis herein, the results given in Table 5.1 cannot be directly used for any particular storage site. For each specific site, the table must be updated using modelling methods similar to those used above, and using petrophysical models tailored to represent specific reservoirs or overburdens.

5.8 PETROPHYSICAL PARAMETER RESOLUTION

In Sections 5.5 and 5.6 the detectability of expected changes in petrophysical parameters due to CO_2 injection in each geophysical measurement was examined. We now examine petrophysical resolution: the ability to distinguish between different potential values of inverted petrophysical parameters such as SCO_2 in the reservoir. In this section, an inversion approach is used to investigate the effect of petrophysical resolution on the monitorability of changes in petrophysical parameters of saline aquifer rocks, in order to estimate SCO_2. This is particularly important to estimate the volume of migrated CO_2, either within the reservoir or leaked into the overburden. Such information will be used to assess associated risks.

Technical details

Recently, inversion using the Monte Carlo method has been widely used for estimating hydrocarbon reservoir parameters (e.g. Bosch et al., 2007). The method estimates expected uncertainties in key petrophysical parameters, which assists in operational decision-making, given various qualities

of geophysical parameter estimates. This in turn identifies key contributions to uncertainty and allows an appropriate selection of targeted geophysical monitoring technique(s) to reduce overall uncertainty on petrophysical parameters. To quantify the information in post-inversion probability density functions (pdfs) of S_{CO2}, Shannon's information concept is used (for details see Curtis, 2004a, b; Guest and Curtis, 2009; JafarGandomi and Curtis, 2010). Here, Shannon information is a measure of how much information about S_{CO2} can be obtained from the inversion of geophysical parameters.

Petrophysical parameters are calculated, corresponding to the reservoir rock used in Section 5.3, for a range of S_{CO2} (1–99%). Figure 5.5 shows the post-inversion histograms of inverted S_{CO2} from P-wave impedance (IP) (top row) at low frequencies (30 Hz) that may typically be measured from reflection seismics, with three different values for the uncertainty in estimated IP (1%, 2%, and 3%) and their corresponding calculated Shannon information (bottom row). Both are plotted against the true value of S_{CO2}. The higher values of information at very low and high S_{CO2} are due to the hard boundary conditions at 0% and 100% saturations (these boundaries can not be exceeded, which is a form of additional, definitive information). This is very important because, in principle, the higher hard boundary condition can even be moved to lower values by conditioning the process of S_{CO2} estimation by the prior relative permeability estimates of the reservoir rock. According to relative permeability measurements the S_{CO2} in the reservoir rocks cannot exceed a certain value. This value depends on the characteristics of the reservoir rock, but generally it may vary between around 30% to around 60%. The same information curves have been calculated for density and electrical resistivity (not shown here).

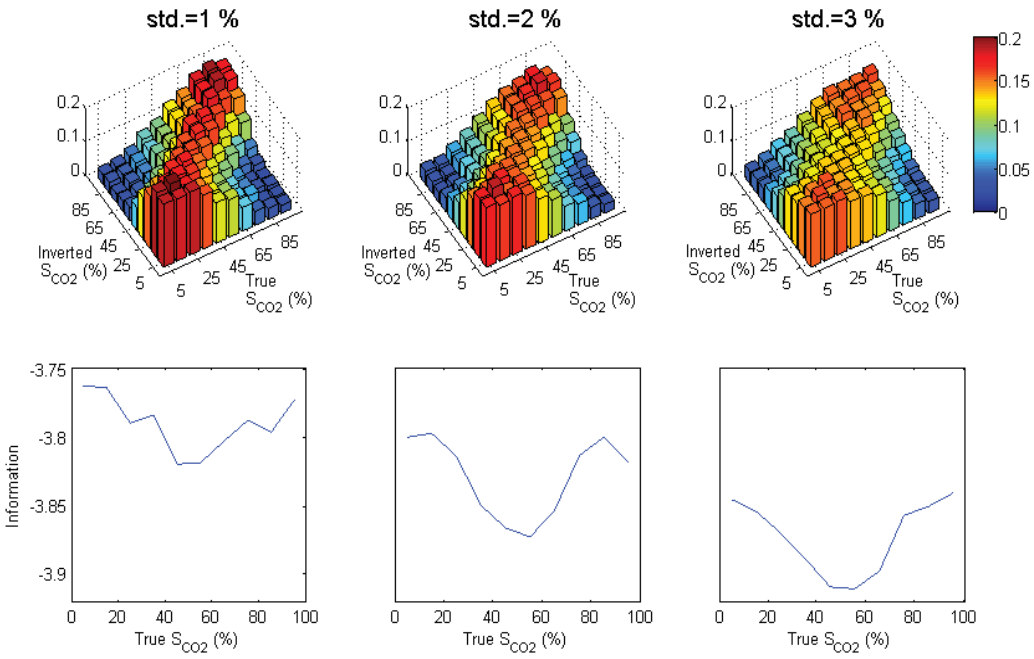

Figure 5.5 Posterior histograms (top row) and information values (bottom row) for Ip measurements as a function of S_{CO2}, with I_p uncertainties of 1%, 2%, and 3%, and seismic frequency of 30 (Hz). Note the higher values of information that can be obtained near the highest and lowest CO_2 saturations. In the top row tighter histograms represent higher monitorability.

Information interpretation

As expected intuitively, increased uncertainty in the geophysical parameter estimate increases the uncertainty and decreases the information obtained about S_{CO2}. The same analysis for different geophysical parameters at three different frequencies, representing reflection seismics, borehole and lab measurements, shows that borehole measurements can significantly increase the level of information obtained. Compared with the other geophysical parameters, the information from electrical resistivity presents far higher values. This indicates that electrical resistivity has the potential to aid S_{CO2} monitoring, if it can be estimated reasonably accurately across the reservoir. The negligible sensitivity of electrical resistivity to the frequency of electromagnetic measurement over the frequency range of interest in geophysics may also be an advantage. Joint inversion of electrical resistivity and elastic parameters may significantly reduce the uncertainty in inversion results and improve monitoring capability.

Laboratory measurements

Repeated seismic and electromagnetic methods are two of the geophysical techniques to be used to monitor CO_2 movement and saturation in a variety of reservoirs. In contrast to hydrocarbon-bearing reservoir rocks, there are very few data available for seismic and electromagnetic responses of the CO_2-bearing reservoir rocks. Most available laboratory measurements on rock samples are for low CO_2 saturations (e.g. Lei and Xue, 2009). In practice, very high CO_2 saturations may occur near the wellbore, or in highly fractured zones, which may act as potential leakage pathways.

In order to better understand the monitoring potential of the seismic and electromagnetic techniques, a range of laboratory experiments have been carried out to measure the ultrasonic and electromagnetic properties of the reservoir sandstones of the CASSEM analogue storage sites, while saturating the samples with a range of different proportions of brine versus supercritical CO_2, and under a range of stress conditions (Fisher et al., 2010). These experiments are conducted on four sandstone samples: two from the Clashach Quarry (CL1 and CL2), which is considered to be geologically analogous to the reservoir formation expected at the Firth of Forth site, and two samples from the Sherwood Sandstone formation (SSK2451 and SSK2454), which is the reservoir formation at the Lincolnshire site.

The elastic parameters of the reservoir sandstones were measured for a wide range of CO_2 saturations (0–100%). These measurements, especially for high CO_2 saturations, provide some of the basic data for monitorability assessment. The measurements indicate that the elastic parameters of the Sherwood Sandstone samples present a greater sensitivity to CO_2 saturation than the Clashach Quarry samples. This implies that (neglecting the effect of the overburden for the moment) the seismic monitorability potential of the former is greater than the seismic monitorability potential of the latter.

CASE STUDY 5: MONITORABILITY OF THE FIRTH OF FORTH SITE

In the CASSEM project, two representative UK North Sea saline aquifer near-shore storage sites were used as case studies to develop corresponding methodologies. In this section, monitorability of S_{CO2} in the Firth of Forth site is assessed. A description of this site is given in chapter 3 and in Jin et al. (2010).

In order to assess monitorability of S_{CO2}, the petrophysical model has to be calibrated to the reservoir rocks. Ideally, rock samples taken from boreholes intersecting the reservoir will be used for this purpose. However, since no borehole was drilled into the Firth of Forth reservoir, measurements from the two rock samples, CL1 and CL2 above, were used for calibration, to estimate acoustic and electromagnetic properties of the reservoir rocks. Calibration of petrophysical model

Figure 5.6 shows the variation of measured P-wave and S-wave velocities with respect to S_{CO2} at different effective pressures on sample CL1 (Fisher et al., 2010). The expected range of pressure in the Firth of Forth around the injection point is approximately between 3500 psi to 4000 psi. Laboratory measurements indicate that while S-wave velocity does not change significantly with S_{CO2} there is more than 200 m/s drop in the P-wave velocity once the sample is fully saturated with CO_2, indicating a high sensitivity of the P-wave velocity of the sample to S_{CO2}. The electromagnetic measurements (not shown here) indicate that electrical resistivity of the brine-saturated samples is about 3 ohm-m.

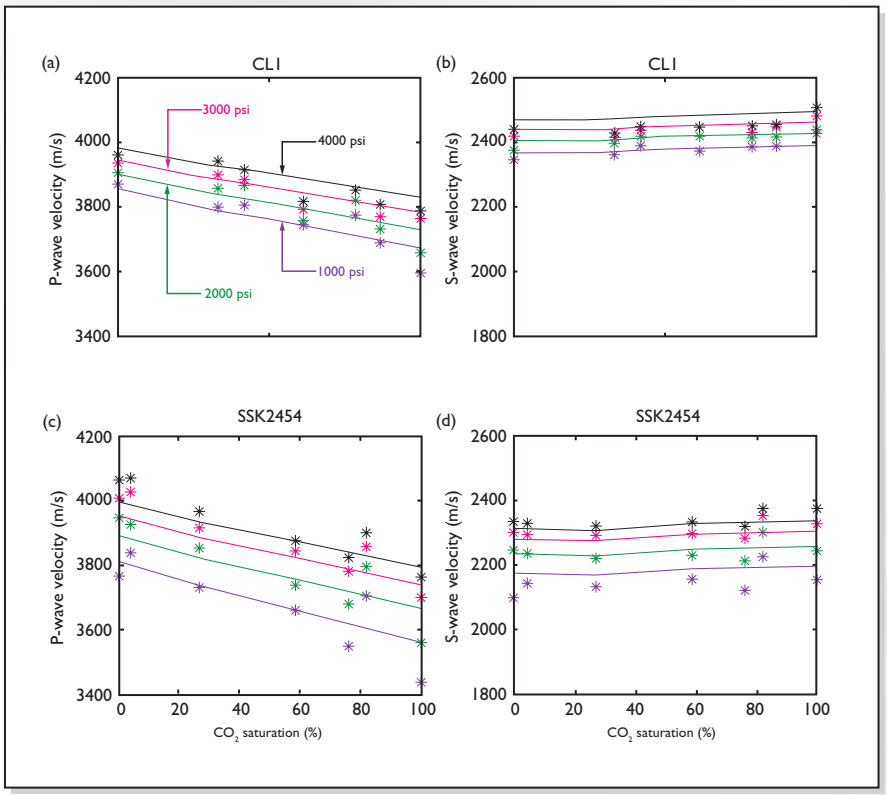

Figure 5.6 Variation of measured P-wave (a and c) and S-wave (b and d) velocities of samples SSK2454 and CL1 at different effective pressures and values of S_{CO2}, and the corresponding petrophysical model fitted to the measurements (solid lines).

We now assume that time-lapse reflection seismics and CSEM surveys have been deployed over the reservoir. Synthetic cross-sections of geophysical parameters (Density, Ip, Is, Qp, Qs, resistivity) along the reservoir interval based on CO_2 flow simulation results for a single injection well after ten years of injection are estimated. CSEM data typically result in far lower spatial resolution than reflection seismic data. To represent these different resolutions the CSEM data are spatially averaged: a smoothing function is applied to the porosity and saturation values by averaging them over many surrounding cells. Then, for each cell, the petrophysical model is used to calculate resistivity from the averaged porosity and saturation. The overall average porosity and permeability of the aquifer are about 0.135 and 60 mD, respectively. More details about the injection scenario and reservoir are given in Chapter 4 and in Jin et al. (2010).

The geophysical parameters are inverted using the Monte Carlo approach (Section 5.3) to estimate S_{CO2} in the reservoir. In time-lapse (repeated) geophysical monitoring strategies, the reservoir is characterised by a benchmark survey (pre-injection) from which reservoir parameters such as porosity, permeability and clay content are known with some level of uncertainties (in this case assumed to be 1%). We assume an optimistic approach and assign 4% and 2% uncertainties to the corresponding CSEM and seismic geophysical parameters, respectively. This assumption may not be far from reality because in time-lapse monitoring, reservoir parameters, except saturation, are constrained by pre-injection surveys.

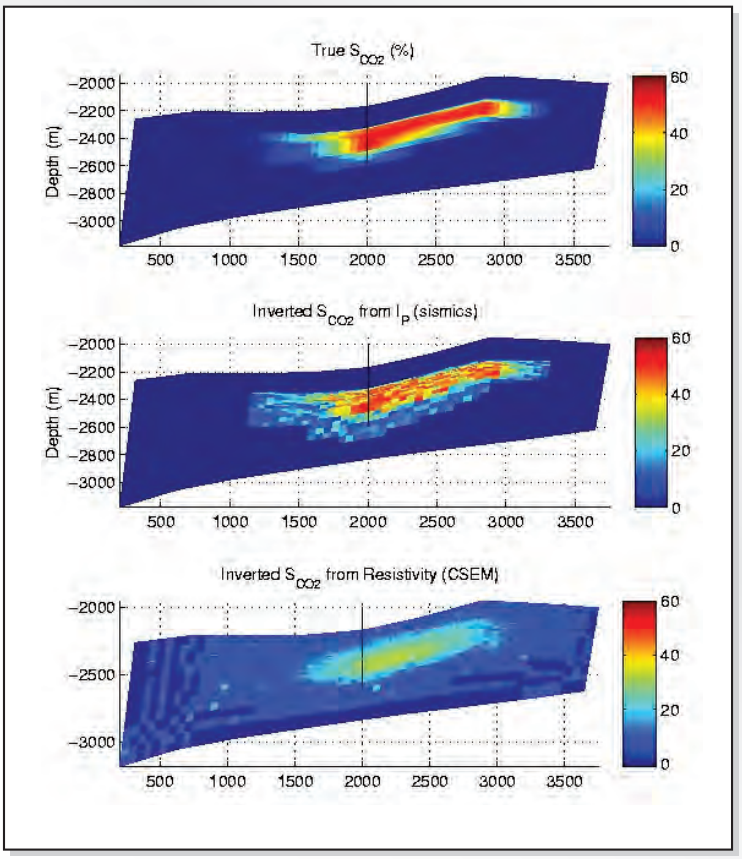

Figure 5.7 Distribution of true S_{CO2}, calculated from a flow simulation along an East–West slice of the Firth of Forth model (top), and MAP estimates of S_{CO2} from the inversion of IP (middle) and of resistivity (bottom). Note that while electrical resistivity is very sensitive to CO_2 saturation, low spatial resolution of the CSEM method significantly diminishes its applicability. In such cases, well-based EM measurements are recommended.

A uniform pre-inversion (a priori) probability distribution between 0% and 100% is used for S_{CO2}. This means that we assume we have no previous knowledge about S_{CO2} in the reservoir before the survey. It is common to use maximum a posteriori (MAP) values as the optimal representative values of the post-inversion (posterior) probability distributions. The MAP value at each grid cell is the post-inversion value of S_{CO2} that has the highest likelihood of being true given the measured geophysical data. Figure 5.7 depicts inverted S_{CO2} from Ip and from resistivity, over the reservoir. For comparison, the true S_{CO2} values in the reservoir are also shown. This figure shows the information that we might expect from seismics and CSEM surveys (with current technology) after ten years of injection.

It is known from laboratory measurements of two-phase (CO_2 and brine) relative permeability that once CO_2 is injected into brine-saturated reservoir rocks, it can not fully replace the brine. Based on the relative permeability measurements on the representative reservoir rock samples of the Firth of Forth (see previous chapters), the prior distribution of S_{CO2} can be constrained to be between 0% and 60%. Figure 5.8 indicates the effect of applying this constraint on the monitorability of S_{CO2}. In this figure, probability density functions (pdfs) of the true S_{CO2} and inverted S_{CO2} from IP (seismics), with and without this additional constraint, are shown, where the pdfs are histograms of S_{CO2} values over the entire section in Figure 5.7. The pdf of the constrained inversion is much closer to that of the true S_{CO2}. This implies that integrating auxiliary data, such as lab measurements and flow simulation modelling, with geophysical data can significantly improve monitoring capabilities.

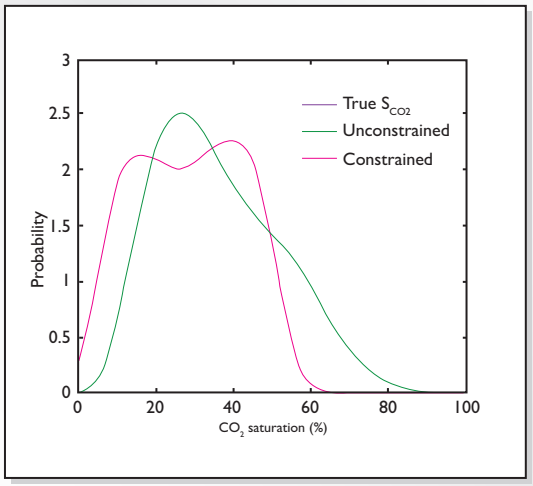

Figure 5.8 Probability distribution (normalised histograms) of S_{CO2} across the cross-section in Figure 5.7 (blue curve), and of inverted S_{CO2} from IP (seismics) with and without relative permeability constraints (red and green curves, respectively). Integrating relative permeability data with geophysical data significantly improves the distribution of estimated CO_2 saturations.

Interpretation

The information of the marginal post-inversion probability distributions of S_{CO2} is calculated in each cell (not shown here). As shown in the previous sections, information for low S_{CO2} is greatest. This indicates that inversion of IP near the CO_2 plume boundaries (where S_{CO2} is the lowest) gives a relatively high level of information. In addition to the true value of S_{CO2}, other reservoir parameters such as porosity and permeability have significant effects on the information obtained. Overall, marine reflection seismics is found to be an appropriate method to map the extent of the CO_2 plume, while, because of the low spatial resolution, CSEM is not an appropriate method for that purpose. The high sensitivity of reflection seismics to low concentrations of CO_2 is also a valuable characteristic that results in the applicability of this method to detection of leakage and of plume migration. However, the low sensitivity to higher CO_2 concentrations may be a significant issue that limits its application to S_{CO2} estimation, particularly if pure CO_2 is injected – see Eke et al. (2009) – and highlights the need for borehole resistivity or EM measurements in such cases.

5.8 SUMMARY

Monitorability is a major investment uncertainty to be quantified as far as possible in the early stages of site selection and evaluation, in order to inform business decisions regarding site development. An efficient monitoring strategy must address the degree to which changes in the 3D distribution of CO_2 can be observed and tracked in a given store: insufficient storage site monitorability is a potential showstopper.

The CASSEM project has developed a workflow for geophysical methods of assessing monitorability of S_{CO2} in a saline aquifer. A site is considered to be monitorable, if geophysical monitoring is possible from practicality and cost points of view, if there is enough geophysical spatial resolution to identify the spatial extent of subsurface CO_2, if geophysical changes due to CO_2 injection are detectable, and if there is sufficient resolution of petrophysical parameters of interest.

The effect of S_{CO2} on the geophysical parameters of rocks (density, P- and S-wave velocities and attenuations, and electrical resistivity) is investigated by applying existing petrophysical models that include poroelastic effects. Variation of P-wave velocity and attenuation of rocks is strongly dependent on the frequency of measurements. This frequency dependence has a significant influence on selecting appropriate monitoring techniques (e.g. choosing between well-based or surface measurements). A set of detectability parameters are defined for different geophysical methods (seismics, electromagnetics and gravimetry), to assess the detectability of changes in the geophysical properties of reservoir rocks due to changes in S_{CO2}. This analysis shows that the detectability of expected geophysical changes depends on the porosity and clay content of the rock and on S_{CO2} in the brine, as well as on the thickness and depth of the storage formation. In particular, the density and resistivity changes are detectable only above a certain threshold saturation that increases significantly with increasing depth and decreasing thickness of the storage formation

To assess petrophysical resolution, a Monte Carlo inversion scheme is developed. The results show that the monitorability of S_{CO2} is strongly dependent on the level of geophysical uncertainty and on the true value of S_{CO2}. In the case of seismic measurements, it is also dependent on the frequency of measurements. The seismic attenuation may contribute significantly to the overall information obtained. Combining different geophysical parameters and methods (e.g. seismics and electromagnetic) may significantly increase the overall information obtained, improving monitorability and quantification of S_{CO2} in saline aquifers. This can be achieved by designing an optimal combination of borehole and surface measurements; borehole measurements are recommended to increase both spatial and petrophysical resolution near to and potentially between pairs of wells, while surface measurements provide relatively lower spatial resolution, but over a more comprehensive and meaningful rock volume for reservoirs of large areal extent.

Overall, the following comments are made on geophysical monitorability of CO_2 storage sites:

- Monitorability of CO_2 storage sites is a site-specific problem and strongly depends on the overburden and underburden structure of the particular reservoir.
- The purpose of monitoring (e.g. leakage detection, S_{CO2} estimation, detection of plume migration, etc.) has a significant impact on selecting an appropriate geophysical monitoring method.
- A combination of seismic and non-seismic (e.g. electromagnetic, gravimetry, etc.) methods from the surface and from boreholes may have to be applied.
- While the comprehensive spatial coverage required to map laterally large CO_2 plumes might be achieved by surface measurements, borehole measurements may have to be used to achieve higher petrophysical and spatial resolution.
- In principle, electromagnetic measurements have the potential to estimate CO_2 saturation accurately. However, with current technology their spatial resolution is of major concern.
- Integration of auxiliary data, such as flow simulation and laboratory measurements, with geophysical data significantly improves the results of geophysical inversion and ultimately improves the site monitorability.