Measurement, Monitoring, and Verification: Enhanced Oil Recovery and Carbon Dioxide Storage

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Executive Summary

This report assesses the differences between monitoring technology requirements for CO_2 storage in a saline or depleted hydrocarbon reservoir and in a hydrocarbon reservoir, when CO_2 injection is used for enhanced oil recovery (EOR).

First order factors dictating technology choice including geological and geographic parameters are assessed before addressing differences introduced by the choice of process (EOR or storage). A brief review of the most common monitoring technologies suitable for use in either CO_2 storage operations or in CO_2-EOR projects are found to not vary significantly, however the measurements and analysis do. Specific differences are highlighted, however, it is found that the largest differences in monitoring technology usage is not process related, rather it is controlled by site specific geology and geography. Where differences do exist due to process choice it is shown to be largely related to the level of characterization, baseline assessment, likely infrastructure in place and pressure management during operations.

No specific different technologies or monitoring strategies are recommended for EOR over CO_2 storage in either saline or depleted oil and gas reservoirs. Rather, it is recommended to assess the local site-specific conditions of any CO_2 injection project including the geology, geography and the level of knowledge and understanding of the reservoir and then to build a risk based approach to selecting the appropriate monitoring technologies and deployment strategies.

Contents

1. Introduction

Carbon capture and storage (CCS) seeks to capture carbon dioxide that would otherwise be emitted into the atmosphere and instead store it in a sub-surface geological formation.

Geological storage options for CO_2 include (Fig. 1, CO2CRC):

1. **Depleted hydrocarbon reservoirs**
2. **Use of CO_2 in enhanced oil recovery (EOR)**
3. **Deep saline water-saturated reservoirs**
4. **Deep unmineable coal seams**
5. **Use of CO_2 in enhanced coal bed methane recovery**
6. **Other options (basalts, oil shales, cavities)**

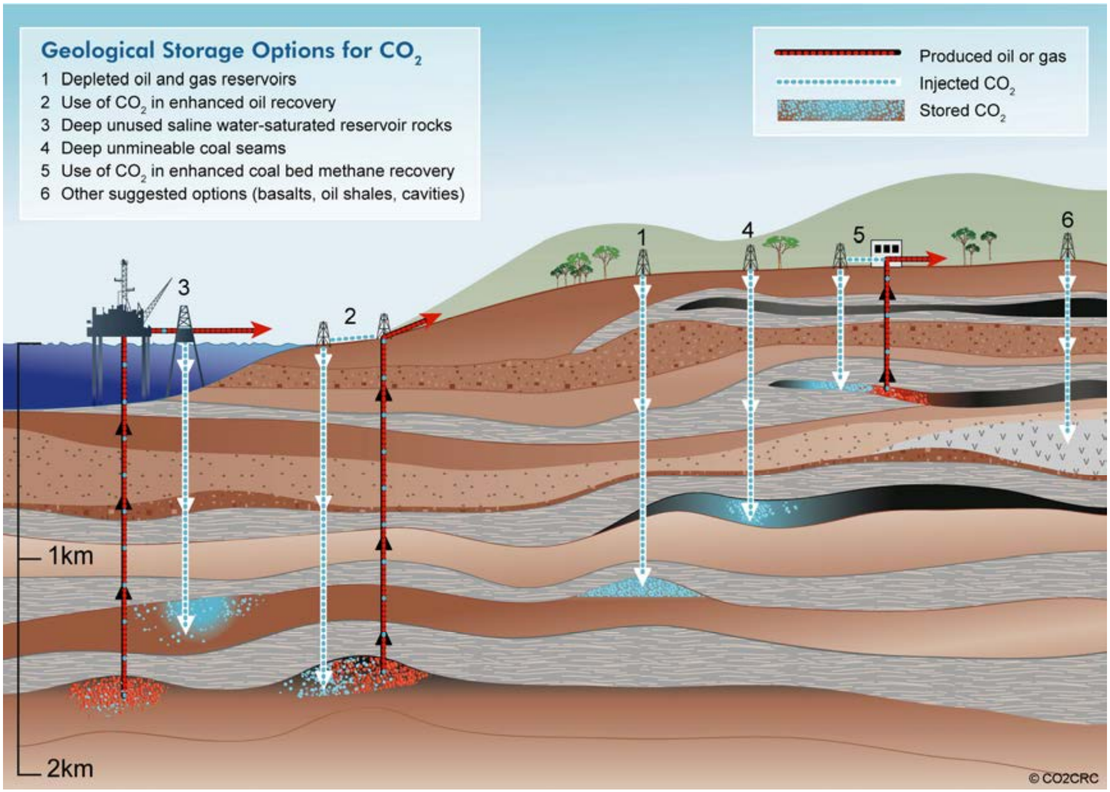

Figure 1. Geological Storage Options (CO2CRC).

The Intergovernmental Panel on Climate Change (IPCC, 2005) indicates that the global potential storage capacity is 675 Gt for depleted hydrocarbon reservoirs (Option 1) and 1000 Gt for deep saline water saturated reservoirs (Option 3). In addition, primarily due to the economic benefits of producing incremental oil, enhanced oil recovery (EOR) using CO_2 and the associated CO_2 storage (Option 2) is being considered as a form of CO_2 storage. Storage of CO_2 in options 4-6 above provides negligible capacity at a global scale and is explored no further in this report. To date most research has concerned storage in saline aquifers as they provide the larger share of the storage capacity and in general each saline storage reservoir is much larger than an oil or gas field (IPCC, 2005).

To ensure the safety of storage and verification of CO_2 stored, any CCS operation will be required to deploy measurement, monitoring and verification (MMV) programs.

1.1 Report Objective and Structure

This report explores the differences in MMV requirements for CO_2 storage into saline reservoirs and depleted hydrocarbon reservoirs and in CO_2-Enhanced Oil Recovery (CO_2-EOR) (by nature into an oil reservoir) projects where it is assumed monitoring is required to verify stored CO_2.

An introduction to both CO_2-EOR and MMV is provided in section 1 of this report.

To assess the difference in MMV technology and strategy needs between the processes the first order factors (i.e. those irrespective of process) that may influence the operation of MMV technology and deployment strategy firstly need to be considered. Section 2 of this report details this.

Once the first order factors have been assessed the differences in the three processes (saline reservoir storage vs depleted oil and gas reservoir vs CO_2-EOR) that can lead to a change in MMV technology must be assessed. Section 3 of this report details this.

Section 4 follows with a brief review of specific MMV technologies, examples of where they have been used and highlights the likely impact of process and suitability of a particular technology to the different processes.

Lastly, Section 5 provides recommendations and conclusions and highlights areas for future research.

1.2 Enhanced Oil Recovery

Enhanced oil recovery is usually undertaken as a tertiary stage of oil extraction. The primary phase is where oil naturally rises under pressure to the surface after a well is drilled, and can also include artificial lift devices, such as pump jacks. The secondary phase is typically increasing production (countering decline) by increasing the pressure in the reservoir through water injection. It is not uncommon for these two phases to leave 75% of the oil in the reservoir. The third stage is referred to as enhanced oil recovery and can be achieved by three mechanisms; miscibility, thermal, and chemical. Between these three mechanisms there are up to 20 different methods of EOR (Taber et al., 1997). The method chosen is dependent on a variety of factors, including, for example, the density of the oil in the reservoir, the availability and economics of solvents, the perceived sweep efficiency to date and the geology and physical and chemical properties of the reservoir. Thermal methods, such as steam-flooding are more successful when recovering heavier oil, whereas miscible flooding which uses CO_2 or other inert gases work well on lower density oils. Chemical flooding using polymers, gels and surfactants targets light and medium density oils (Taber et al., 1997).

Aside from CO_2, other gases used for miscible flooding are natural gas, flue gas and nitrogen. The pressure needed to achieve dynamic miscibility with CO_2, is lower than that required for the other gases (Shaw and Bachu, 2002). This lower pressure threshold means that there are a significantly larger number of potential EOR projects with CO_2 flooding than for other miscible EOR methods.

When CO_2 is injected for enhanced oil recovery it acts like a solvent and mobilises residual oil to waterflood. The pressure criteria for CO_2-EOR to work are that CO_2 must be in a dense phase and it should be above the minimum miscibility pressure (MMP). The MMP encapsulates phase behaviour and flow; above it CO_2 will be miscible with oil and therefore recovery of oil will work, however below it CO_2 and oil will not be miscible and recovery will be less efficient. The MMP depends on oil composition and density, and reservoir temperature (Shaw and Bachu, 2002). The minimum reservoir pressure requirement means that the ratio between reservoir pressure and MMP should normally be greater than 1. In reality, CO2-flood EOR is still possible when this ratio is 0.95 (Shaw and Bachu, 2002).

CO_2 will extract hydrocarbons from the oil until it attains a composition that is miscible with the oil above the MMP. If more CO_2 is present, a CO_2 rich phase with dissolved light hydrocarbons will be formed. Since it will be more mobile (less dense), it will flow faster, contact fresh oil, and dissolve to saturation levels in the oil (Brown, 2002). Figure 2 shows what the ideal behaviour of CO_2-EOR would look like (a), under the influence of buoyant CO_2 (b), and with viscous fingering effects (c).

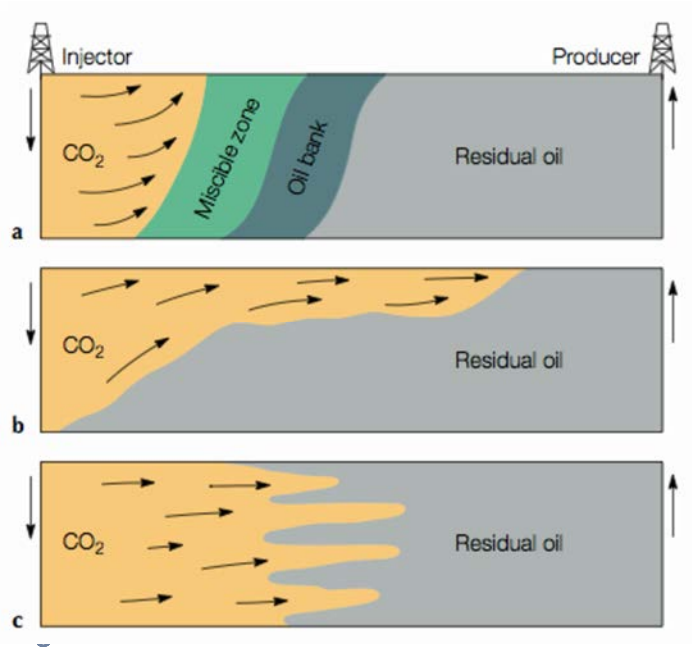

Figure 2: Phase behaviour and flow dynamics in miscible flooding (a) idealised CO_2-EOR fluid flow, (b) during the influence of fluid density and (c) in the setting of viscosity contrasts, which produce fingering of the CO_2 into oil (Lake et al., 1992).

A common technique used in EOR is water-alternating-gas (WAG). The idea is that by alternating between injecting water and CO_2, the sweep efficiency (i.e. how much of the reservoir is contacted by the injected fluid) is improved. If more oil is contacted by CO_2 then more oil should be produced. However, since sweep efficiency is dependent on a number of parameters including: injection pattern, reservoir permeability and heterogeneity, reservoir thickness, position of fluid contacts, density and viscosity of fluids, then WAG does not always improve oil production any more than just injecting CO_2.

1.3 Measurement, Monitoring and Verification

Measurement, monitoring and verification (MMV) programs are deployed both to ensure risk of CO_2 leakage is minimal and to verify the security of CO_2 storage. The latter is particularly important in CCS operations where financial credit is gained by the avoidance of emissions of CO_2 or in the form of carbon credits for storage. MMV can also be used to ensure that the injected CO_2 is migrating as predicted and if not allow the iteration of reservoir models to fit the new observations. Furthermore, MMV programs can significantly contribute to the identification and location of the front and transition zones between CO_2 and oil during CO_2-EOR operations. This information greatly helps engineers to optimize injection and production rates. For the correct interpretation of measurements, a baseline survey of the reservoir prior to CO_2 injection is typically necessary. Clearly the ideal monitoring technology would have the ability to directly measure the mass of CO_2 stored. The measurements required to calculate the mass of CO_2 stored in-situ are the spatial extent of CO_2 in the subsurface, CO_2 saturation, and CO_2 density. In the absence of directly calculating the in-situ stored mass of CO_2 an MMV program aimed at identifying migration within the storage complex and leakage out with the complex can be deployed. Under the current EU CCS directive there is a requirement to quantify any leakage out with the storage complex.

The lateral spatial extent of CO_2 in the subsurface may be obtained using three-dimensional (3D) seismic imaging, gravity or electromagnetic surveys. Obtaining the vertical height of the CO_2 plume is more difficult. CO_2 will rise in a plume, the diameter of which will be determined by the permeability and porosity of the rock, and the density contrast and mobility ratio between CO_2 and the interstitial fluid. The plume will rise until it reaches an impermeable rock, where it will flow out laterally. The thickness of the current is dependent on the relative strength of the capillary forces and pore-size distribution (Golding et al., 2011). CO_2 density can be determined with accurate pressure, temperature and composition measurements. CO_2 saturation cannot be measured directly unless a monitoring well is present and fluids can be sampled or well-logs run. Saturation can be estimated indirectly from electrical resistivity and inverting geophysical attributes. The amount of CO_2 dissolved in water or oil can be determined from chemical parameters measured in produced fluids (Johnson et al, 2011).

Table 1 gives examples of monitoring technologies that have been used at different types of CO_2 storage projects. Where gaps exist and there is no field data, then the success of the technique can only be assessed by experience in a different type of storage project and by theoretical modeling.

Table 1: Examples of monitoring techniques that have been carried out at different types of CO_2 storage project. (Vp = P-wave velocity, Vs = S-wave velocity).

Monitoring technique	What is measured?	Onshore EOR project	Offshore EOR project	Onshore saline aquifer	Offshore saline aquifer

Geochemical Monitoring	Isotope ratios / noble gases / PFCs	Weyburn	Lula (planned)	Frio	
Subsurface Pressure and Temperature	Pressure and Temperature	Weyburn	Lula (planned)	Nagaoka	
Seismic Imaging	Vp, Vs, Amplitude	Weyburn		In Salah	Sleipner
Gravity	density	Cranfield		In Salah	Sleipner
Passive Seismic Monitoring	Natural and induced microseismic events	Weyburn		Aquistore (planned)	Sleipner
Electromagnetic techniques	Conductivity, resistivity	Lost Hills EOR project, California		Ketzin, In Salah	
Surface deformation	Tilt, uplift			In Salah	

2. First order Factors that influence MMV technology choice and deployment strategy

Both the MMV tools chosen and the deployment scenario of an MMV campaign for either EOR or storage will be dictated by a number of factors. The primary factors that govern these decisions are:

- **Geology: the properties of the reservoir into which CO_2 will be injected**
- **Geography: the physical location of the project**

Geological properties of individual sites whether they be for CO_2 storage or EOR govern the effective transmission of fluids and as such may impact on the ability to use specific MMV tools and the strategy in which they are deployed. Permeability and porosity of the reservoir impact greatly on both injectivity and pressure transmission in the reservoir and for example could mean that where permeability is low microseismicity will become an important tool to monitor CO_2 migration by location of source events. Similarly, low permeability giving rise to low injectivity means that injection wells in both storage and EOR will have a smaller spacing to achieve similar capacities of injection than a higher permeability reservoir. This has significant implications for the spatial coverage and deployment of direct well-based monitoring strategies. The mineralogy of the reservoir may also affect the monitoring tool choice. For example, the difference in reactivity of a carbonate to a silicate rock to CO_2 presence will significantly affect the geochemical parameters measured in sampled fluids. Similarly higher reactivity leading to greater amounts of dissolution and precipitation reactions can alter the physical properties of the rock matrix and thus impact on technologies or methods that use these parameters to resolve CO_2 saturation or plume location.

The depth of the reservoir, albeit not strictly a geological property, has a very large impact on which technologies may be used. Pressure and temperature both increase with depth and significantly impact fluid properties (e.g. density, viscosity, miscibility). Many indirect technologies (see section 4) rely on the changing fluid properties of the reservoir as CO_2 displaces native fluids. Hence some technologies have a sensitivity that is a product of depth.

The geographical location of the proposed project may arguably be the largest controlling factor on which technologies can be used. The difference between technology choice and deployment strategy between onshore and offshore projects is vast. Where onshore may result in a number of either production or monitoring wells for any one project, an offshore project may have only one or a few wells from which to monitor from. Even within these distinctions (onshore vs offshore) geography further determines technology use. For example where surface deformation may be useful in a desert setting, beneath a vegetated surface will be less effective. Conversely, looking for vegetation changes as an identifier of CO_2 leakage will be much harder in a desert than in a well vegetated area. Although CO_2-EOR has long been practiced in the oil and gas industry the only off-shore project is the Lula field, offshore Brazil, operated by Petrobras. CO_2 EOR began in 2013 (WAG) (Grava, 2014). Little information is published on the field although Grava (2014) indicates that 4D seismic monitoring has begun at the field with a baseline dataset and a first post-CO_2 injection dataset both acquired. However, offshore CO_2-EOR is where the main knowledge and experience gap exists.

None of the above parameters are unique to either storage in saline or depleted oil and gas reservoirs or EOR projects. Yet these first order factors will greatly influence both the choice of monitoring tool and the deployment strategy. In section 4 of this report technologies are assessed for their suitability against such first order factors and recommendations are given in section 5.

3. Effects of differences in CO_2-EOR and CO_2 injection into saline reservoirs and depleted oil and gas fields

Whilst the first-order factors which determine technology use can be said to be independent of the process to be applied there are a number of factors that are influenced by whether the operation will be for storage in depleted oil or saline reservoirs or whether it will be for EOR. These factors are largely due to the level of existing level of knowledge and intervention in the reservoir, namely:

1. **The level of existing characterization and knowledge of the injection reservoir**
2. **The extent of historical infrastructure in place**
3. **The extent of anthropogenic modification of the reservoir to date and planned**

Hence at this point it is necessary to distinguish the three processes and the specific impacts this will have on the MMV technologies used and strategy deployed.

Generally oil and gas reservoirs will be much better characterized than saline reservoirs due to the historical development of these sites. This existing knowledge base in conjunction with the fact that oil and gas reservoirs are known to contain buoyant fluids reduces risk and uncertainty when considering CO_2 storage relative to a saline reservoir with little historical or operational information. This in turn can lead to different decisions on monitoring technology deployment when approached from a risk-based approach. Risk and uncertainty in saline reservoirs can be countered by thorough baseline characterization at such sites. JafarGandomi and Curtis (2012) show that in the case of CCS in saline reservoirs, baseline survey and prior information about the storage formation have a significant impact on the ability to monitor the reservoir. This is typically not an issue for CO_2-EOR or storage in depleted hydrocarbon reservoirs because hydrocarbon reservoirs are well characterized and valuable information is available from history matching time-lapse measurements. However, interpreting indirect observations is significantly more complicated for CO_2-EOR and CCS in depleted hydrocarbon reservoirs than for CCS in a saline aquifer. This complexity arises because during CO_2-EOR and in depleted hydrocarbon reservoirs up to four fluid phases are present, whereas with CCS in a saline reservoir, only two fluid phases co-exist. For monitoring CO_2 storage in a saline reservior, accurate measurements and calculations of CO_2 saturation, and the amount of CO_2 dissolved in brine are required, but with CO_2-EOR and in depleted hydrocarbon reservoirs additional measurements and calculations of oil saturation, and the amount of CO_2 in the CO_2-oil enriched phase are needed. Direct and indirect methods of monitoring CO_2-EOR are therefore likely to be required to gain an accurate understanding of carbon dioxide storage in the depleted oil reservoir.

In contrast, the consequence of the existing knowledge and historical infrastructure of oil and gas reservoirs compared with deep saline reservoirs is that they are penetrated by many wells of variable quality and integrity, which themselves may constitute leakage paths for the stored CO_2. However, the knowledge of the location of these potential leakage paths can again be considered in a risk-based approach to a monitoring program allowing monitoring tools to be deployed at these locations. In addition, the number of wells encountered in an existing oil and gas field (assuming it is not decommissioned) can be used to great effect in terms of direct monitoring in the reservoirs allowing a much greater spatial coverage of direct methods.

Although depth of reservoir and thus pressure and temperature effects are largely considered to be independent of the process, arguably in many cases EOR will be deeper due to the need to achieve MMP whereas CO_2 storage operations need only to reach dense phase. Even if this is not the case reservoir pressure will certainly be affected by the extent of anthropogenic activity to-date and by planned activities. Depleted oil and gas fields may be under-pressured due to fluid extraction, or may be at similar pressure conditions to when found due to secondary water flooding techniques. EOR projects by their nature will both inject and produce fluids thus managing pressure. Saline reservoirs are very likely to see a pressure increase (unless they are very large and unconstrained) without intervention to produce fluids from the reservoir. These factors can greatly affect the risk assessment for the storage site which will inform the MMV campaign, especially when considering caprock integrity and induced seismicity.

A summary of 45 US CO_2-EOR projects shows that when CO_2 is injected for EOR, approximately 40% of the CO_2 is produced along with the oil (Shaw and Bachu, 2002 and references therein). This CO_2 is then separated and re-injected, recycling it into the reservoir. Over time the production of oil will reduce, and amount of CO_2 produced and recycled will increase. Recycling will result in the isotope signature of the CO_2 injected and that that is naturally present in the reservoir eventually becoming mixed and no longer distinct. The timescale on which mixing would take place will vary from site-to-site depending on many parameters including rock and fluid properties, number of production/injection wells etc. Similarly, the isotopic signature of water may be influenced by the recycling of fluids and hence some of the direct geochemical methods for assessing CO_2 presence will be impacted by the EOR process.

In general terms the above factors equally apply to EOR projects or storage in depleted oil and gas fields as being distinct from saline reservoir storage hence it is important to re-iterate that many of the effects will be site specific and that no simple distinction between EOR and storage can be drawn without consideration for the specific reservoir the CO_2 will be injected into. In the MMV technology review (Section 4) of this report the individual technologies are assessed for the impact of the process-related differences highlighted above and recommendations to suitability are given in section 5.

4. MMV technology Review

MMV techniques can generally be categorised as being direct or indirect observations. Indirect observations include geophysical subsurface and remote sensing techniques, whilst direct observations take measurements from injection, monitoring, and producing wells or from direct surface/seabed fluxes. In the following a brief overview of the common technologies used is provided.

4.1 Direct Monitoring

Geochemical Monitoring

A combination of tracers, geochemical measurements (e.g. pH, alkalinity, cation, anion, TDS) and thermodynamic calculations are the only monitoring methods to determine the amount of CO_2 dissolution in the fluid phase present. Currently, the technique does not vary between saline aquifer and depleted hydrocarbon reservoirs or CO_2-EOR but analysis is different since there are different fluids present for the CO_2 to partition into. Tracers have been used at some onshore saline aquifer CO_2 storage sites, and many CO_2-EOR storage sites, because production of fluids is part of the EOR process. Tracers have not been used in offshore saline aquifer CO_2 storage sites largely due to the expense of drilling a second/monitoring well.

Carbon or oxygen isotopes are commonly used to trace the injected CO_2 if the isotopic signature of injected CO_2 is distinct from the reservoir fluids (Nowak et al., 2013). By measuring the changing isotopic content of C and O in the produced water, the amount of CO_2 dissolution can be calculated (Johnson et al., 2011).

CO_2 dissolution in oil can be calculated using a thermodynamic model. Perez et al. (2006) model the fluid interaction at Weyburn, and determine that the distribution of CO_2 after almost two years is 15% in the free phase, 45% dissolved in water and 40% dissolved in oil, with the water becoming saturated with CO_2 in less than a year (Figure 3). The isotopic signature of oxygen was used at an CO_2-EOR project in the Pembina field, Alberta, Canada to determine the amount of CO_2 dissolved in water, and where the water is saturated, the free phase pore-space saturation of CO_2 (Johnson et al., 2011). The water - CO_2 interaction was modelled as a twocomponent system independent of the oil in the pore space and measurements were taken on produced fluids. Thus it is unable to provide quantification of pore-space saturation away from the wells.

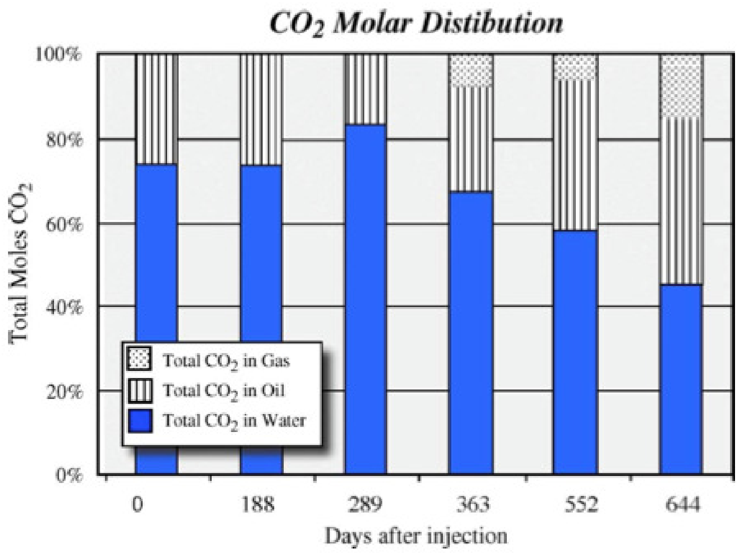

Figure 3: Results from a partition model, showing CO_2 distribution in the reservoir fluids at subsurface conditions through time. This graph shows the CO_2 dissolution modeled in the reservoir from measurements taken at one representative well at Weyburn. Taken from (Perez et al., 2006).

Noble gases are also used as a tracer in CO_2 storage because they track CO_2 migration through a reservoir, by dissolving in the injected supercritical CO_2 and as the CO_2 rises up a production/monitoring well and forms a gas, the noble gas exsolves (Nimez and Hudson, 2005). Although noble gases solubilities in brine and some hydrocarbons are known from laboratory pressure-temperature experiments, little field data has been collected to understand the solubility/partitioning in the conditions of a CO_2 storage site (Nimez and Hudson, 2005).

The Dulang field, offshore Malaysia is an EOR project that injects water and gas alternatively and has conducted multiphase flow measurement using tracers (Bohari et el., 2003). The natural gas used for EOR contains almost 50% CO_2. Gas tracers used to track the gas were Argon and Helium, (Bohari et el., 2003).

At the Frio project in Texas, where CO_2 was injected into a saline reservoir, perfluorocarbon (PFT) conservative tracers were used to track the CO_2 migration (McCallum et al., 2005). At the Cranfield Field, Mississippi, CO_2 is injected into a depleted oil and gas reservoir. Tracers including: perfluorocarbons, noble gases, and SF_6 tracers have been used (Hovorka et al., 2011). The tracers are only used to track the CO_2-brine components of the system qualitatively and the amount the tracers partition into oil and natural gas has not been documented.

Frequent geochemical monitoring of offshore fields is more logistically challenging and expensive due to the need for multiple wells to gain spatial coverage and frequent sampling of fluids to determine breakthrough and CO_2 saturations. However, developments are being continuously made in this field with particular relevance for offshore technology. One example are 'intelligent chemical tracers', which are smart plastic and chemical compounds combined into a matrix that resembles strips of plastic. The matrix releases a unique chemical fingerprint which is different depending on whether it is contacted by gas, water or oil. These tracers can be positioned at different points in the well to provide information on flow to different parts of the well (Williams and Nyhavn, 2012).

Subsurface pressure and temperature

Reservoir pressure and temperature measurements are vital to accurately determine the density of CO_2 (and oil) in the reservoir. Measurements will be carried out in much the same way for saline aquifer and CO_2-EOR. The main difference is that there will be a minimum of one well for saline aquifer storage and two for CO_2-EOR. Monitoring bottom hole pressure on either the producing or injection wells can also determine to what extent the CO_2 and oil are miscible in the reservoir i.e. to what extent the CO_2 is dissolving in the oil. Down-hole pressure and temperature sensors have improved significantly including developments in electrical and fiber optic down-hole sensors (Wright and Womack, 2006). Therefore monitoring will enable EOR performance to be optimised but also to help quantify the amount of CO_2 stored (Ren et al., 2011). Down-hole temperature and pressure measurements can be used to constrain the inversion of seismic datasets (either from surface or well-based measurements) which leads to more accurate estimates of saturation. In addition down-hole gauges can be used to improve history matching of reservoir simulation models, which provides another tool for determining distribution of CO_2 in the reservoir

At Ketzin, 34 thousand tonnes of CO_2 was injected into a saline aquifer over 2 years. Continuous pressure and temperature measurements were recorded using is a single-point fiber optic pressure gauge with no downhole electronics. The aim of the real-time monitoring was for pressure transient analysis and reservoir characterisation (Giese et al., 2008). Distributed temperature sensing was used for almost continuous temperature profiles along the length of the well at Ketzin, measured by fiber-optic sensor cables which were installed behind the borehole casing.

Surface/Seabed measurements

Direct measurements at the surface or seabed can detect CO_2, to infer containment (through lack of leakage detected) or detect if it is leaking to the surface. Soil-gas sampling has been carried out at onshore CO_2 storage projects in saline aquifers and oil reservoirs (e.g. In Salah and Weyburn). The technique does not vary between storage type because both projects were tracing CO_2 leakage (White and Johnson, 2009). Since the number of offshore CO_2 storage projects planned is increasing, techniques are being developed to detect leakage at the seabed or in the water column including: fluorescence to detect liquid hydrocarbons at the seabed, sampling and spectroscopic methods, gas trapping technology (SPE Presentation, H Johansen, Rio 2012; Figure 3). If leakage from CO_2 storage in a depleted oil or gas reservoir occurred, natural gas would reach the surface first because it is more buoyant.

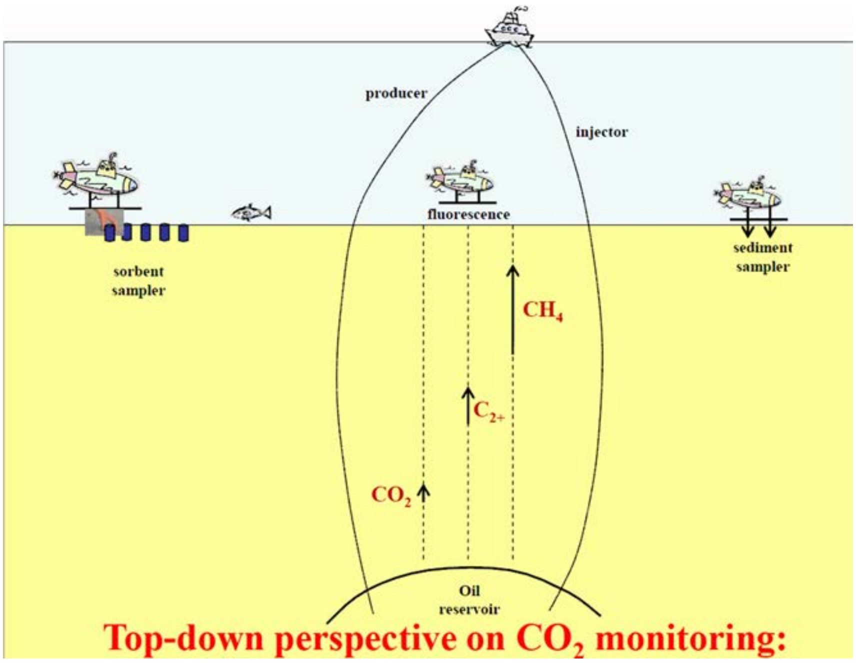

Figure 4: Monitoring strategy for an offshore CO_2-EOR project. Taken from (SPE Presentation, H Johansen, Rio 2012).

Well logs

Although different sites may use different well-log suites, all types of well logs can be used in all types of CO_2 storage. The most useful well logs for monitoring carbon dioxide storage include: sonic, density and resistivity. Gaining accurate measurements of P-wave velocity and density is crucial in order to accurately be able to process and interpret data from seismic imaging.

4.2 Indirect Monitoring

The aim of indirect monitoring is using indirect measurements, mostly geophysical attributes, to determine the lateral extent of CO_2 and petrophysical properties like CO_2 saturation.

Time lapse 3D seismic imaging

Seismic imaging has been used to monitor carbon dioxide migration during onshore CO_2-EOR projects (e.g. Weyburn) as well as onshore and offshore saline aquifer storage projects (e.g. In Salah and Sleipner). The seismic imaging equipment is the same for monitoring EOR and saline aquifer projects, but different for onshore and offshore projects. The main difference for seismic imaging of CO_2 injected into a hydrocarbon reservoir and a saline aquifer is the different reflection amplitudes that will result from injection of CO_2. CO_2-saturated rock has a much larger impedance contrast to brine-saturated rock than oil-saturated rock. Figure 5 illustrates the impedance contrasts expected from a brine-CO_2, CO_2-oil, and CO_2-gas interface, based on physical properties from the reservoirs at the Sleipner and Weyburn fields. Despite the small impedance contrast, seismic imaging of the CO_2 injection into the oil reservoir at Weyburn highlighted the areas of the reservoir contacted by CO_2 (Brown, 2002). This observation is confirmed by Figure 5, which shows that the impedance contrast is bigger for oil against CO_2 (2), than for brine against oil (1).

The smallest impedance change is between CO_2- and a gas-saturated rock (Figure 5(3)). For this reason, at the Otway project where CO_2 is injected into a depleted gas reservoir, 4D VSP (Vertical Seismic Profiles) were used for imaging reservoir changes and CO_2 migration. 4D surface seismic was also used at Otway for monitoring the overburden, and verifying CO_2 containment (Urosevic et al., 2009).

Crosswell tomography has been carried out at Nagaoka, Japan, an onshore saline aquifer storage project. It was not found to be very useful, because the velocity decrease resulting from CO_2 injection, was found to be much lower than that measured by sonic logging (Saito et al., 2006). Crosswell tomography could be useful at EOR storage projects by determining the attenuation due to the injected CO_2. Harris et al. (1996) present laboratory, field and synthetic data to show that injection of CO_2-alternating-water into an oil reservoir results in P-wave attenuation. Seismic waves are recorded before and after injection in a crosswell geometry from two wells in a Texas oil field.

Forward modelling of rock physics and reservoir simulations can predict the seismic impedance changes, which can then be compared to the data collected. Rock physics models how P- and S-wave velocity changes with varying fluids, fluid saturation and pressure, whereas reservoir simulations model the fluid saturations and dynamics of flow through a reservoir. Inversion of seismic attributes for CO_2 saturation has been carried out for both CO_2 storage in a saline aquifer and for EOR projects. Inversion is typically be more complicated in a CO_2-EOR setting due to the increase in the number of fluids present.

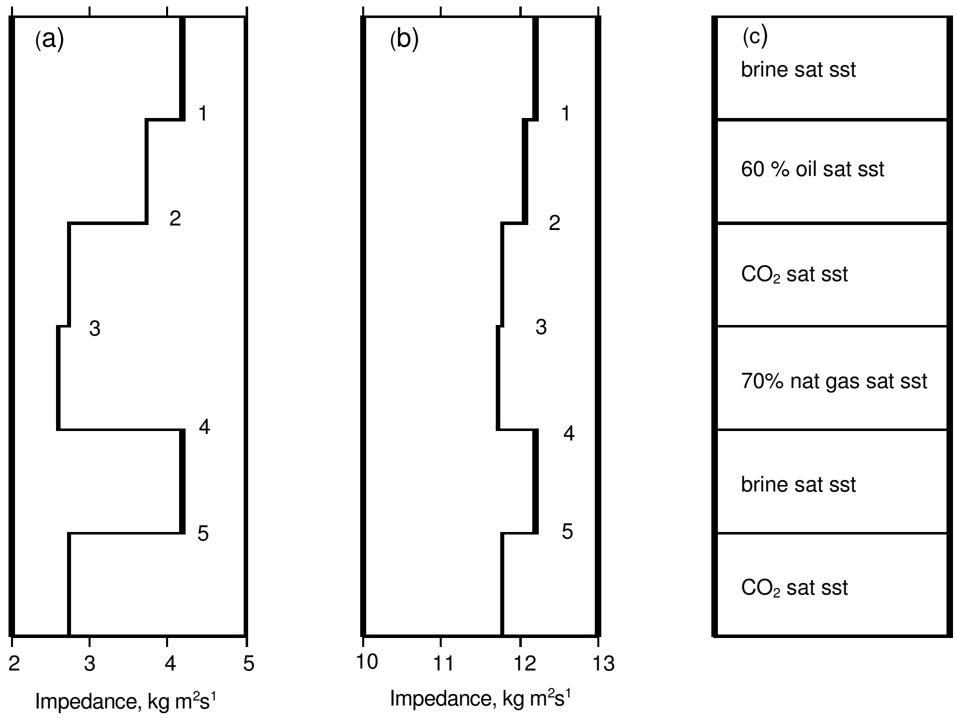

Figure 5: (a) Impedances for varying pore-fluids, based on Utsira Sandstone rock properties (35% porosity, 36^{o}C, 10 MPa) at Sleipner (Boait et al., 2012). (b) Impedances based on Midale Carbonate rock properties (Vuggy unit: 12% porosity, 60^{o}C, and 15 MPa) at Weyburn (Brown, 2002). (c) Cross-sectional sketch to show different layers used in the impedance plots. 60% oil and 70% natural gas is ideal saturation for EOR and EGR (Shaw and Bachu, 2002).

Passive seismic monitoring

As CO_2 is injected into either a hydrocarbon reservoir or saline aquifer it will cause pore pressure changes within the reservoir. Induced microseismic events are recorded and using measurements of source location and magnitude, source characteristics, and S-wave splitting, geo- mechanical models of deformation can be constrained (Verdon et al., 2011). The monitoring aims to track stress changes that might compromise the integrity of the seal as well as providing indirect evidence of the migration of the CO_2 plume and the pressure field. The equipment does not vary between storage in a saline aquifer or hydrocarbon reservoir.

Passive seismic monitoring has been used in both onshore saline reservoir storage projects (e.g. In Salah) and in several CO_2-EOR projects (e.g. Weyburn, Pembina). Due to expensive equipment, passive seismic monitoring is yet to be used to monitor an offshore project (either saline reservoir or EOR). The offshore equivalent to geophones are ocean bottom seismometers (OBSs) or ocean bottom cables (OBCs), which sit on the seafloor. OBSs use batteries can be deployed for up to two weeks. A permanent installation requires an OBC. This technology has been used in to image in detail subsurface sedimentary structures and although used in some field (e.g. Clair, Valhall) has not been widely used as a monitoring device for offshore oil, gas or CCS projects, due to expense. As well as passively monitoring seismic activity, the deployment of OBSs or an OBC can also be used for time-lapse seismic imaging.

Current large scale CO_2 storage projects are limited to saline aquifers which are large, unconfined sandstones where measured pressure perturbation has been minimal (e.g. Sleipner). Since depleted oil and gas reservoirs are typically smaller, and therefore more likely to be confined reservoirs, passive seismic monitoring may become a more useful monitoring technique where presuure perturbation creates microseismic events which enable the tracing of the CO_2 plume.

At the Weyburn CO_2-EOR project, 8 geophones were deployed in a disused vertical production well. Less than 100 events have been recorded since 2003, documenting a relatively low amount of microseismicity. The events are not clustered around the injection well, suggesting CO_2 injection is not causing fractures to form (Verdon et al., 2011). At the Aneth Oil Field, Utah, CO_2 is injected for EOR and 4D passive microseismic monitoring takes place. No consistent correlations between seismicity and injection/production rates were found in the study area. Source locations suggest stress changes driven by reservoir compaction over the field's 50 years of production history may account for seismicity (Rutledge, 2009).

Controlled source electromagnetic monitoring

Controlled source electromagnetic monitoring (CSEM) has been widely used as a geophysical technique to detect hydrocarbons, and it has more recently been applied to detecting CO_2 migration in storage sites. EM techniques were used in the Lost Hills EOR project in the San Joaquin Valley, California to track CO_2 injected into an oil reservoir (Kirkendall and Roberts, 2002). Both hydrocarbons and CO_2 have a higher electrical resistivity than their surroundings. Oil does have a higher resistivity than CO_2, but the difference is small and there is sparse field data to assess the sensitivity and usefulness of EM monitoring on CO_2 injection into an oil or gas reservoir. Kirkendall and Roberts (2002) showed that the difference between electrical signatures of oil and CO_2 increases over time, they documented a 0.4% change after 3 months of CO_2 injection (Figure 6). They also found that there was not a measurable difference between the resistivity of different phases of CO_2.

CSEM uses an electric dipole source and receivers that record the electric and magnetic fields. Due to the closer proximity to the source, onshore CSEM obtains higher quality data because electrodes are deployed down boreholes, and either surface and downhole measurements (if only one well) or cross-hole (multiple wells) electrical resistivity tomography (ERT) can be undertaken. Offshore CSEM uses an electric dipole source which is towed by a vessel. The source should be as close to the seafloor as possible, to avoid attenuation of the source before it penetrates the subsurface. Seafloor receivers are deployed and record the energy propagating back to the seafloor. Offshore CSEM is a much coarser measurement than ERT, but can detect the lateral extent of CO_2 in a storage project (JafarGandomi and Curtis, 2011). Although technical advances have made improvements so that the air waves that result from shallow water depths can be removed, they still reduce the amplitude of the signal. JafarGandomi and Curtis (2011) highlight the need for site by site characterisation to see if CSEM will be useful, as well as water depth being a problem, highly resistive layers in the over- or under-burden will strongly effect the signal. Since the resistivity detection between CO_2 and oil is small, then site characterisation will be even more important for CO_2 –EOR projects.

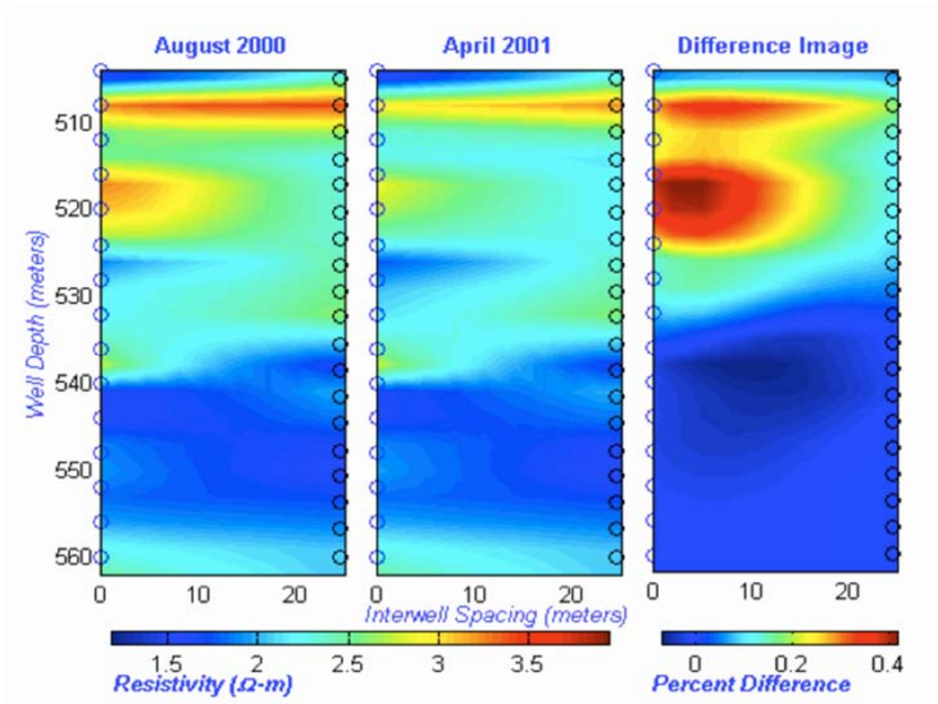

Figure 6: Two-dimensional images of CO_2 flooding in the plane between the two observation wells before injection (left) and after 3 months of injection (centre). Ωm = Ohm-metres (resistivity). The circles on the left side of each image represent the well containing the receiver antenna while those circles on the right side of the images contain the transmitting antenna. The difference image (right) is the pre-injection image subtracted from the during-injection image and shows the areas of change quite clearly. A positive percent difference suggests CO_2 is entering the area. Taken from (Kirkendall and Roberts, 2002).

The low sensitivity of using offshore CSEM suggests that at best it could measure the lateral extent of the injected CO_2 into an oil or gas reservoir. Since measuring electric and magnetic fields onshore has a higher sensitivity, then EM is likely to be more useful for onshore projects where it is more likely to be able to detect CO_2 injection into hydrocarbon reservoirs. ERT successfully monitors CO_2 injection into a saline aquifer at Ketzin (Bergmann et al., 2012) and laboratory experiments on core from Nagaoka has accurately predicted CO_2 saturation.

Gravity

Gravity measurements can detect the lateral extent of CO_2 in a storage project by identifying areas of density change. The density difference between CO_2 and brine is larger than between CO_2 and oil (which can be zero or even reversed), therefore a smaller change in gravity will occur when CO_2 is injected into an oil reservoir than a saline aquifer, which will be less easily detectable. CO_2 injected into a natural gas reservoir should have the strongest gravity signal, since supercritical CO_2 is much denser than natural gas.

No publications document gravity measurements used to track CO_2 injected into an oil reservoir; however at the Cranfield EOR/Storage project (SECARB), borehole gravity was used to monitor CO_2 injection into an oil field. A measurable change was observed on the first well the CO_2 reached but not on any further wells (SPE Presentation, R. Dino, Rio 2012).

Gasperikova and Hoversten (2008) model gravity measurements for a CO_2-EOR project, where injection is into a relatively shallow reservoir at a depth of 1150-1350m. The gravity changes calculated at the surface were below the level of repeatability found in current field studies (~5 μGal). However gravity changes calculated on gravimeters deployed down boreholes were found to be sensitive enough to detect the CO_2 injection.

As the depth of the storage reservoir increases, the amplitude of gravity measurements at the surface decreases, i.e. the minimum detectable density change increases with depth. JafarGandomi and Curtis (2011) calculate the detectable density change for increasing saturations of CO_2 in a saline aquifer and increasing depth to plume and conclude that although the gravity signal is sensitive to the bulk volume of CO_2, it does not provide detailed resolution either laterally or vertically.

Surface Deformation

Measuring surface deformation provides a blunt tool to monitor CO_2 migration and pressure changes. Various instruments can measure surface deformation including: InSAR, tilt meters, GPS, and hyperspectral imaging of land surface. Surface deformation measurements track subsurface pressure changes that are inferred assuming a geomechanical model of the reservoir and overburden. Independent constraints on pressure can help to constrain geomechanical models. Since its use for quantifying stored CO_2 and monitored any leaked CO_2 is quite limited, it has not been widely used at CO_2 injection sites. There are no documented EOR projects that use surface deformation as a monitoring technique. The increase in the number of fluid phases and the relative compressibility of these fluids for an EOR project would make determining a unique geomechanical model more difficult.

The equipment would not differ from an EOR or saline aquifer storage project. However, when injecting into a saline aquifer, one would expect the surface to uplift, because no fluids are being produced. During an EOR project, prior to CO_2 injection, oil production may have caused some subsidence and hence a pre-injection baseline is imperative. When CO_2 is injected, the net input of fluid will determine whether uplift occurs and if it does, when and to what extent.

The In Salah project in Algeria injects CO_2 into a 20 m thick sandstone ~2 km beneath the surface. The depth of the CO_2 makes monitoring the fluid movement difficult. One technique that has been useful is satellite synthetic aperture radar interferometry (InSAR) which has imaged surface uplift rates of ~5 mm yr^{-1} surrounding the 3 injection wells. InSAR measures the vertical and horizontal surface displacement using interferometry.

Measuring surface deformation is more difficult offshore. Options include putting tiltmeters on the seabed or down wells. There has been an increase in the use of tiltmeters technology as the hydraulic fracturing industry has expanded because it can directly measure hydraulic fractures (Sweatman et al., 2012).

5. Recommendations and Conclusions

In this report it is shown that MMV technologies are largely similar for CO_2 storage in depleted oil and gas and saline reservoirs and for CO_2-EOR projects and that the largest differences in MMV technology usage is controlled by site specific geology and geography rather than being process related. However, specific differences do exist based on the process as highlighted in section 4 of this report. Generalizations that be drawn from these differences include:

- **Baseline Measurements**

  Baseline measurements are typically less complex for saline reservoirs due to the unaltered state of the reservoir at the onset of a storage project. Virtually all technologies require a thorough baseline assessment and as such operations in depleted oil and gas reservoirs and EOR projects will typically require greater assessment of baseline conditions due to their altered state which may not have reached equilibrium by the time of the project start.

- **Characterization**

  Depleted oil and gas reservoirs and CO_2-EOR projects will invariably be better characterized before injection begins than a saline reservoir. This increased characterization in conjunction with the knowledge that these reservoirs have retained fluids on geological time scales reduces the risk of unplanned CO_2 migration. This in turn could lead to less monitoring being required over aerially extensive areas as would likely be required in an uncharacterized saline reservoir. Thorough characterization of a saline reservoir, though costly, would also reduce the risk of unplanned CO_2 migration and hence reduce monitoring requirements.

- **Number of wells**

  Depleted oil and gas reservoirs and CO_2-EOR projects will have more wells penetrating the reservoir than a saline reservoir. On the positive side this opens up more possibilities to deploy direct (well-based) monitoring technologies. A potential negative side is that more potential CO_2 migration routes are introduced. However these routes are easily identifiable and monitoring campaigns devised to manage this risk.

- **Pressure**

  CO_2-EOR projects will effectively manage pressure by fluid production, reducing the risk of exceeding caprock integrities, re-activating faults and inducing seismic events. This reduced risk will impact and likely reduce the intensity of monitoring required to assure CO_2 storage integrity. Depleted oil and gas reservoir storage may in some cases (where water flooding has not occurred) have a reduced pressure at the beginning of injection and hence also have a lower risk of pressure induced effects outlined above and thus benefit from a less intensive monitoring campaign. Saline aquifers conversely may have to actively manage pressures to reduce this risk or otherwise have more monitoring in place to detect any such effects.

In conclusion, no specific different technologies or monitoring strategies are recommended for EOR over CO_2 storage in either saline or depleted oil and gas reservoirs. Rather, it is recommended to assess the local site-specific conditions of any CO_2 injection project including the geology geography and the level of knowledge and understanding of the reservoir and then to build a risk based approach to selecting the appropriate monitoring technologies and deployment strategies.

Further Research

Whilst current monitoring technologies do not significantly vary between storage in a saline aquifer and an oil reservoir, several knowledge gaps exist for storage in a hydrocarbon reservoir that should be tackled in order to correctly interpret monitoring data. First, since tracers are likely to be used in most CO_2-EOR projects, then a greater understanding of how different tracers partition between CO_2-brine-oil (or gas) is necessary. For example it is not common practice to measure CO_2 and chemical tracer dissolution into oil. Secondly, gravity and the electromagnetic response to CO_2 injection into an offshore hydrocarbon reservoir has not yet been modelled in published work, and it would be useful to quantify the expected responses.

JafarGandomi and Curtis (2012) assess the geophysical detectability of CO_2 saturation in saline aquifers by inverting six geophysical parameters (Vp, Vs, Quality Factors, density, and electrical resistivity). Applying the inversion to CO_2 injection into depleted oil and gas reservoirs would highlight the parameters that contribute the most overall information.

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