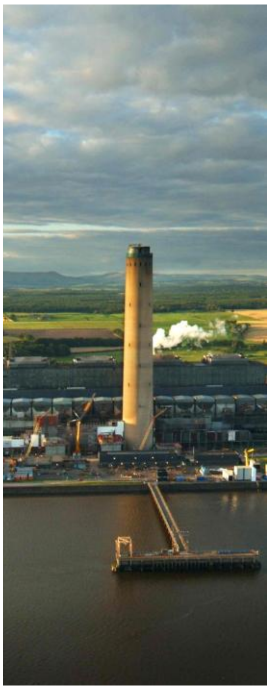  

UK Carbon Capture and Storage Demonstration Competition

UKCCS - KT - S7.20 - Shell - 003
Monitoring Technology Feasibility Report

April 2011
ScottishPower CCS Consortium

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DRAFT

KEYWORDS

Goldeneye, CO_2, Monitoring, MMV

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IMPORTANT NOTICE

Information provided further to UK Government's Carbon Capture and Storage ("CCS") competition to develop a full-scale CCS facility (the "Competition")

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Figures 4,10,22,24 and 34 are refined in size or resolution in Appendix 2

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1. Introduction

This report documents the potential monitoring technologies that can be used to detect CO_2 migration/leakage and to validate injection conformance. The technologies are screened against CO_2 scenarios specific to the geology and dynamics of the Goldeneye system i.e. site-specific to CO_2 storage in the depleted Goldeneye hydrocarbon reservoir. This screening results in a shortlist of technologies that are technically feasible for application at the Goldeneye storage complex. This list forms the basis for the development of the Monitoring, Measurement and Verification (MMV) plan.

The report outlines a number of CO_2 movement, migration and leakage scenarios that are derived from site characterisation and risk assessment. It does not discuss or rank risks. Ranking of risks is the topic of the Site Characterisation and Risk Assessment report.

2. Summary of Screened Technologies

This report concentrates on technologies for monitoring CO_2 movement within the store (conformance) leakage or migration from the subsurface store. These are listed in Table 1 which includes both commercial and emerging (R&D) technologies. Proven/standard technologies related to the monitoring of CO_2 in facilities and pipelines are covered in the surface facilities design FEED activity.

Table 1. Technology/technique screened for Goldeneye CCS project. Grey shows de-selected technology.

Domain	Data acquisition	Risk addressed	Technology/techniques
Seabed and Shallow Overburden	Water column profiling	Leakage from storage complex via: abandoned wells, development wells, conductive faults/fractures	Conductivity Depth and Temperature Sensor
	Seabed sediment, flora & fauna and pore gas sampling	Leakage from storage complex via: abandoned wells, development wells, conductive faults/fractures	Van Veen Grab Box Corer Gravity Corer Piston Corer Vibro Corer CPT rig fitted with BAT probe Hydrostatically Sealed Corer
	Pockmarks profiling	Leakage from storage complex via: abandoned wells, development wells, conductive faults/fractures	Multi Beam Echo Sounder Side Scan Sonar Echoscope
	Subsidence and uplift	Leakage from storage complex via: abandoned wells, development wells, conductive faults/fractures	GPS Acoustic Ranging Seafloor Pressure Gauges SAR and in SAR Tilt meter
	Shallow overburden seismic (<1000 m)	Leakage from storage complex via: abandoned wells, development wells, conductive faults/fractures	Boomers Chirps/ Pingers 2D lines/3D swath Enhanced Surface Rendering
	Hydrosphere sampling & pressure measurement	Leakage from storage complex via: abandoned wells, development wells, conductive faults/fractures	Westbay System Induced Polarization Spontaneous Potential
Overburden and Aquifer	Time lapse seismic	Leakage and migration from/within storage complex	Repeat 3D streamer OBC

Domain	Data acquisition	Risk addressed	Technology/techniques
		abandoned wells, development wells, conductive faults/fractures and lateral migration past spill point or in secondary storage complex	OBN 3D swath/ 2D lines Borehole VSP
	Microseismic	Migration surrounding borehole in storage complex due to fault reactivation and/or caprock failure	Borehole Microseismic
	Non-Seismic	Leakage and migration from/within storage complex abandoned wells, development wells, conductive faults/fractures and lateral migration past spill point or in secondary storage complex	Seafloor Geodesy measurement CSEM Gravimetry
Well and Reservoir	Well Integrity	Migration surrounding borehole in storage complex due to leak path from development wells	Cement bond logging Casing integrity logging Tubing integrity logging DTS DAS
	CO_2 Detection	Migration surrounding borehole into storage complex due to leak path from development wells and also movement of CO_2 filling the store (conformance)	U-tube Downhole sampling
	CO_2 Conformance	Migration surrounding borehole into storage complex due to leak path from development wells and also movement of CO_2 filling the store (conformance)	Sigma logging Resistivity logging Neutron porosity logging Acoustic logging
	Pressure conformance	Migration surrounding borehole into storage complex due to leak path from development wells and also movement of CO_2 filling the store (conformance)	PDG Long term gauge Cased-hole pressure and temperature
	Borehole stress regime	Migration surrounding borehole into storage complex due to fault reactivation and caprock integrity failure and also reservoir conformance	RTCI

Domain	Data acquisition	Risk addressed	Technology/techniques
		(pressure)	
	Fingerprint of CO_2 samples	Leakage and migration from/within storage complex abandoned wells, development wells, conductive faults/fractures and lateral migration past spill point or in secondary storage complex	Tracer

3. Important terms and definitions

The following definitions are taken from the EU directive on the geological storage of carbon dioxide[1] and are repeated here for clarity.

'**storage site**' means a defined volume area within a geological formation used for the geological storage of CO_2 and associated surface and injection facilities;

'**storage complex**' means the storage site and surrounding geological domain which can have an effect on overall storage integrity and security; that is, secondary containment formations;

'**leakage**' means any release of CO_2 from the storage complex;

'**migration**' means the movement of CO_2 within the storage complex;

'**CO_2 plume**' means the dispersing volume of CO_2 in the geological formation;

'**significant irregularity**' means any irregularity in the injection or storage operations or in the condition of the storage complex itself, which implies the risk of a leakage or risk to the environment or human health;

'**corrective measures**' means any measures taken to correct significant irregularities or to close leakages in order to prevent or stop the release of CO_2 from the storage complex;

The storage site and complex are illustrated schematically in Figure 1 derived from GD2[2].

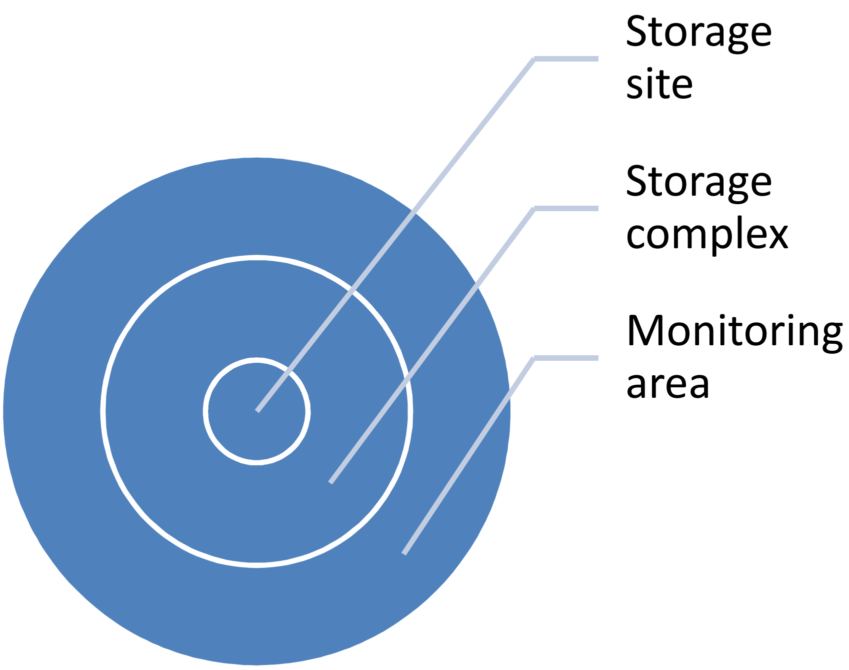

Figure 1. Schematic defining key terms based on CCS Directive

The following is taken from the draft technical guidelines for CO_2 storage from DECC:

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[1] DIRECTIVE 2009/31/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 23 April 2009 on the geological storage of carbon dioxide and amending Council Directive 85/337/EEC, European Parliament and Council Directives 2000/60/EC, 2001/80/EC, 2004/35/EC, 2006/12/EC, 2008/1/EC and Regulation (EC) No 1013/2006

[2] Implementation of Directive 2009/31/EC on the Geological Storage of Carbon Dioxide, Guidance Document 2, Site Characterisation, CO_2 Stream Composition, Monitoring and Corrective Measures; Draft document for consultation June 17, 2010

"A **monitoring plan** has to be prepared by the operator and submitted to DECC for approval. This plan will include the monitoring of the injection facilities, the storage complex including the movement of the CO_2 plume and the effects on the surrounding environment for the purpose of:

- Making a comparison between the actual and modelled behaviour of CO_2 and formation fluids (water and oil) in the storage site;
- Detecting significant irregularities;
- Detecting migration of CO_2;
- Detecting leakage of CO_2;
- Detecting significant adverse effects for the surrounding environment;
- Assessing the effectiveness of any corrective measures taken.
- Updating the assessment of the safety and integrity of the storage complex in the short- and long-term, including the assessment of whether the stored CO_2 will be completely and permanently contained."

4. CO_2 storage, migration and leakage scenarios

In order to screen technologies they need to be tested against site specific scenarios, specifically, it is important to understand:

- the expected behaviour of CO_2 on injection
- the various mechanisms through which CO_2 leakage/migration could occur.

The following section describes the site and the migration and leakage scenarios.

The Goldeneye CO_2 storage site in the outer Moray Firth consists of the original Goldeneye field and adjacent Captain Formation[3]. The primary seal is the Rødby Formation. The storage complex (see Figure 2) extends laterally in the adjacent Captain Formation and vertically up to the Lista mudstone. The complex is penetrated by five development wells and four abandoned exploration and appraisal wells. One development well has been side tracked.

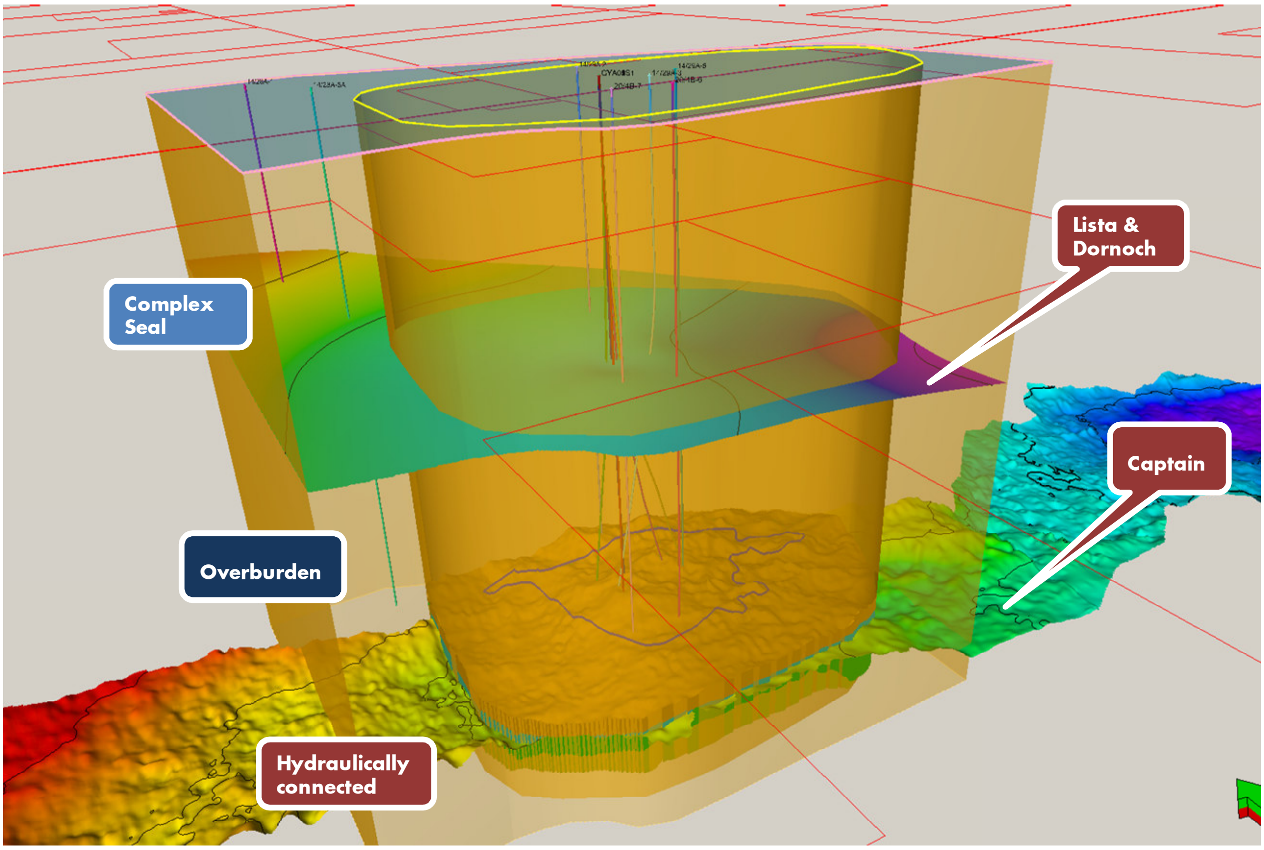

Figure 2. Cross section through Goldeneye storage complex showing primary and complex (secondary) seals.

4.1. CO_2 injection

CO_2 will be injected using the current reservoir penetrations. It will be injected into the upper part of the Captain D subunit where it will displace and mix with the remaining reservoir hydrocarbon and the aquifer water that has swept the reservoir during production. The CO_2 will refill the voided hydrocarbon structure. As the refilling takes place there will be a front of CO_2 moving though the original hydrocarbon volume, displacing the invaded water. Viscous forces will tend to dominate over

[3] The exact lateral extent of the site – i.e. the pore volume to be licensed – is the subject of a current dynamic simulation study and is not critical to the definition of scenarios for technique screening

gravity forces and there is potential for a tongue of CO_2 to move below the original hydrocarbon water contact (Figure 3). When injection ceases, gravity (buoyancy) forces will dominate and any down dip CO_2 will re-equilibrate and flow up structure.

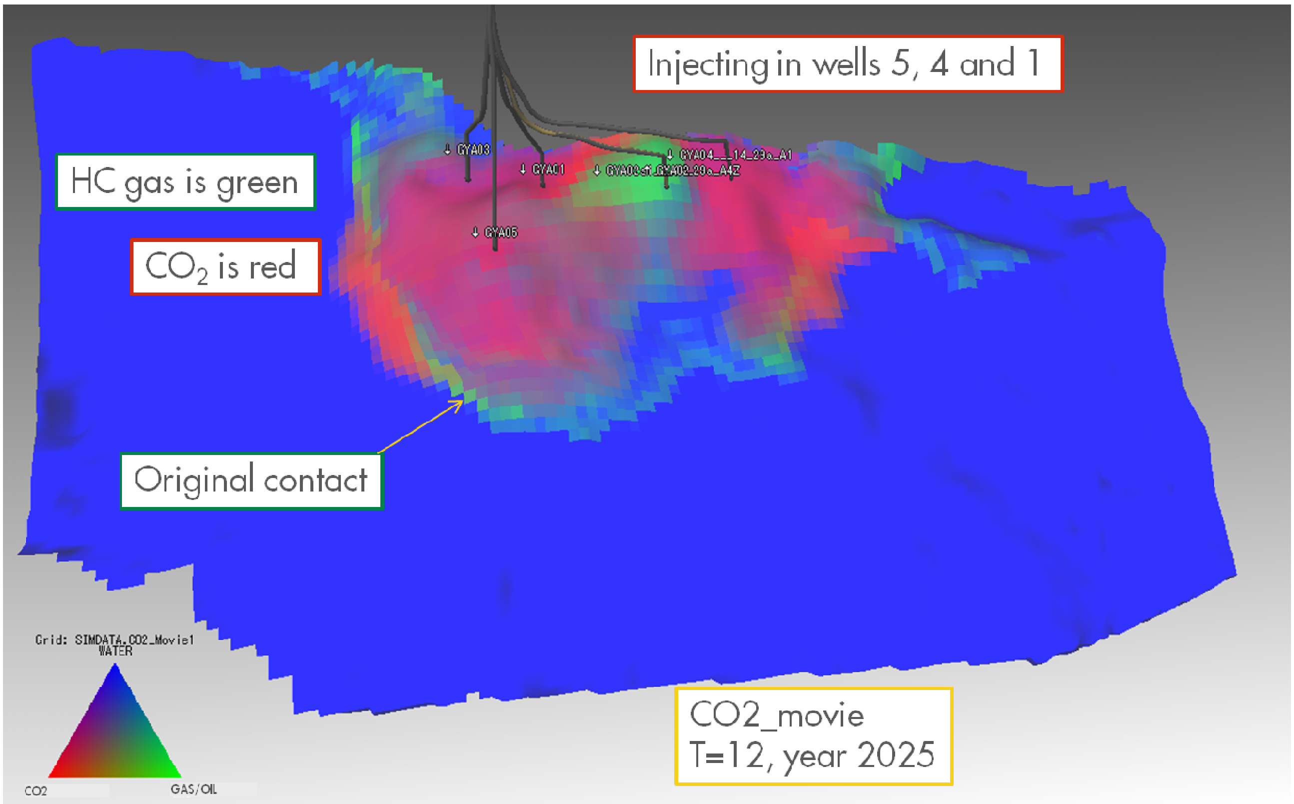

Figure 3. **Example CO_2 injection realisation while injecting in wells 5, 4 and 1. Red colour shows CO_2 plume and Green colour shows original-fluids-in-place.**

4.2. Leakage and migration mechanisms

Migration from the primary storage volume can take place laterally and/or vertically. For vertical migration to take place there must be a leak path – this could be a well bore; an open or re-opened fault/fracture; or a failure of the caprock matrix to contain CO_2.

The storage complex chosen has more than one seal. The complex seal for Goldeneye is the Lista mudstone. The Mey sandstone lies beneath the Lista and will provide a secondary storage volume. The intervening formations (between Rødby and Lista) also provide varying levels of seal and baffle, as do formations above the Lista, however the Lista is a good quality regional seal and is therefore chosen as the seal of the complex, which is referred as "complex seal".

If vertical migration takes place, in most cases it would pool underneath the Lista – and then migrate laterally. Only if migration takes place along a well conduit, fault and continuous fracture could it bypass the complex seal.

Lateral migration can potentially take place at Captain Sand level. If the injected CO_2 migrates to and below a local spill point (see Figure 4) the CO_2 has the potential to migrate out of the defined storage complex, and will continue moving until halted by capillary trapping and dissolution trapping (migration assisted storage). The plume also has the potential to interact with other potential leak paths – additional wells and faults – and also other hydrocarbon accumulations.

The leakage/migration mechanisms and destinations have been assessed (see Site characterisation and risk assessment report) and are summarised in Table 2.

Table 2. Leakage/migration mechanisms for Goldeneye CO_2 storage complex

Mechanism	Destination	Cause
Plugged and Abandoned Wells	Within storage complex (most likely), above storage complex and surface (less likely)	Lack of cement bond, casing integrity issue, and integrity of cement plugs both deep and near surface
Development Wells (during injection and post injection)	Well annuli, within storage complex, above storage complex and surface	Lack of cement bond, casing/tubing integrity issue
Conductive faults/fractures	Within storage complex (faults/fractures in Rødby), above storage complex and surface (faults/fractures in Lista)	Fluid conducting fault or fracture network
Reactivated fault/fracture	Within storage complex (faults/fractures in Rødby), above storage complex and surface (faults/fractures in Lista)	Stress induced movement
Caprock integrity issue	Within storage complex (faults/fractures in Rødby), above storage complex and surface (faults/fractures in Lista)	Chemical reactivity with acidic fluid
Lateral migration past spill point	Captain aquifer – still below primary seal, but potentially lateral complex boundary	Lateral migration from the primary storage (reservoir)

Effective monitoring will identify the leak or migration and trigger a corrective measure, it will also support validation of the CO_2 plume movement within the reservoir (storage site) during- and post-injection (conformance). The data acquired through monitoring is used as input to and calibration of reservoir modelling tools and increases confidence in the simulation of where the plume will migrate both vertically and laterally.

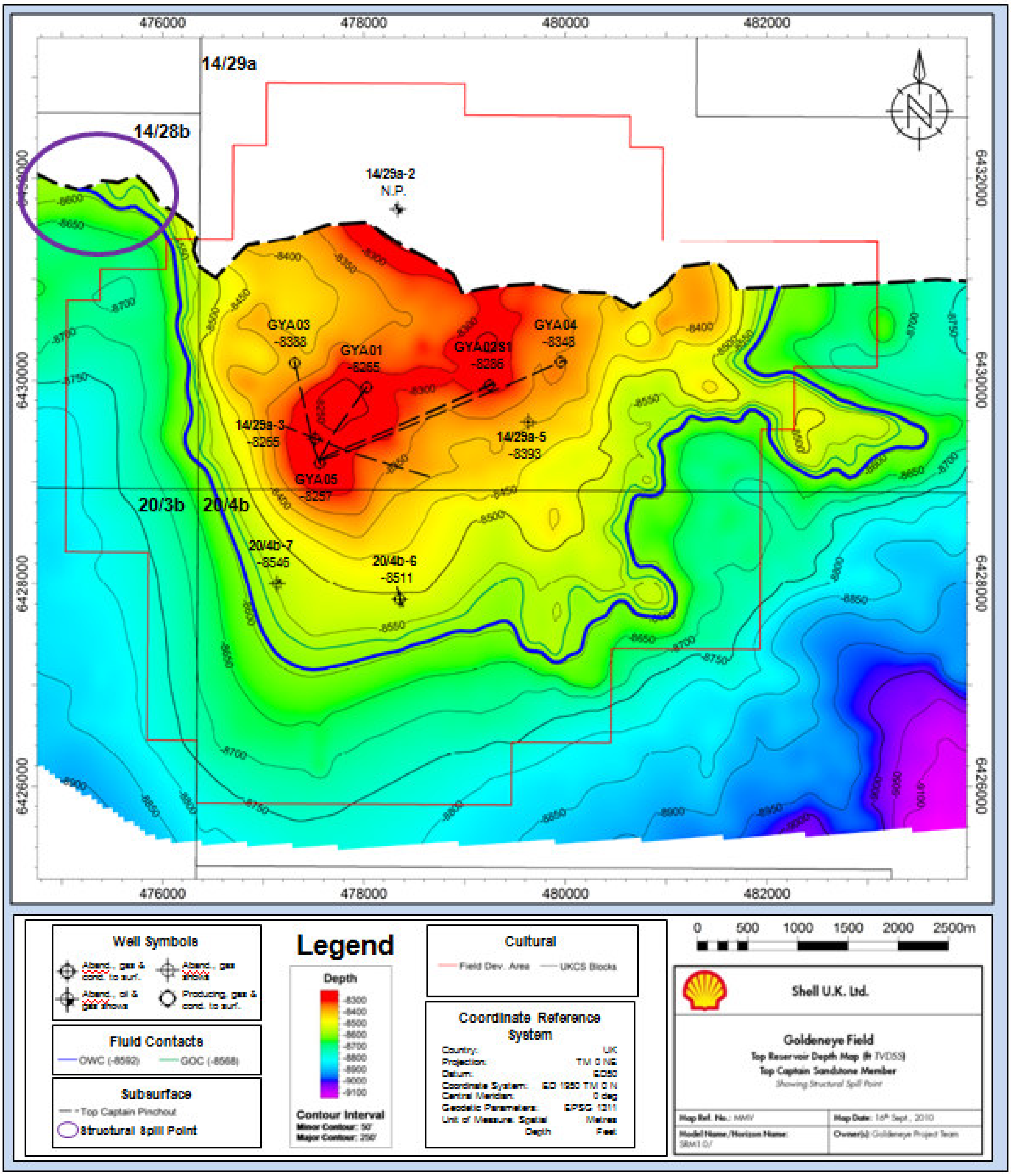

Figure 4. Goldeneye structural spill point on North West of the field

5. MMV Phases and Domains

The MMV plan addresses all phases of the project and includes what we term *the sensitivity domains* which range from proximal-to-storage-complex to the environmental interface. The phases of the project are defined as follows:

- Pre-injection
- During Injection
- Post-injection

Sensitivity domains can be ranked according to the measure of severity of risk associated with CO_2 leakage/migration and proximity of CO_2 release to environmental and public realms. The level of severity increases towards the seabed and water column for offshore sites. For MMV purposes these domains are therefore ranked as follows:

- Transport and Injection
- Seabed and Shallow Overburden
- Overburden and Aquifer
- Wells and Reservoir

The domains are categorized in an area wise and depth sense. The first domain, *transport and injection* is briefly mentioned since the monitoring details are covered in the facilities/topside scope of work[4].

The following subsection briefly describes each domain.

5.1.1. Transport and Injection

The main tools for leakage detection in this domain are the pipeline and plant monitoring systems from Longannet to the injection wells on the Goldeneye platform[4].

5.1.2. Seabed and Shallow Overburden

The domain covers the seabed surface down to the base of the formation above the complex seal – the Lista mudstone. Measurements in this domain monitor CO_2 leakage from the storage complex. With the exception of shallow seismic, all other techniques are point type tools and would be placed at locations deemed high local risk e.g. wells. These techniques also need well-defined baseline data since any CO_2 and CH_4 background from natural sources could vary seasonally and can be sourced from multiple shallow formation layers.

5.1.3. Overburden and Aquifer

The overburden and aquifer domain comprises formations between the top complex seal (Lista mudstone) and the base primary seal (Rødby Formation) vertically, and the Kopervik sand fairway trough laterally (the lateral continuation of Goldeneye Captain Sandstone which is thought to share the same aquifer). Techniques in this domain are based on geophysical principles (either seismic or non-seismic) and can cover large areal ranges. Detection ability is assured whilst quantification may require certain conditions; a combination of CO_2 concentration, volume and baseline conditions. For cases where these conditions are fulfilled, the feasible techniques in this domain could address all potential leakage/mechanisms listed in Table 1.

[4] See Shell 2010, Metering philosophy; Metering specification; and Metering and allocation strategy documents

5.1.4. Well and Reservoir

This domain comprises the storage site, the Goldeneye Captain reservoir and drilled wells within it. The focus is to monitor the exact location of the CO_2 plume to calibrate reservoir modelling. The validated reservoir model would then be able to predict further CO_2 plume movement in directions where wells do not exist. Well and reservoir monitoring requires installation of gauges (preferably in all wells) and detection of CO_2 presence in observation wells.

6. MMV Technology List and Description

6.1. Transport and Injection

Fiscal flow metering will be installed as detailed in the metering specification reports (see footnote 4 on p18) between the Longannet CO_2 recovery plant and St Fergus. At modification of the offshore per-well allocation metering is expected with the upgrading of the venturi meter currently in place. Other new metering devices related to safety are also planned, e.g., CO_2 Alarm and gas analyzer. These fall outside the scope of this document.

6.2. Seabed and Shallow Overburden

The marine biosphere is taken to include the water column, sediment water interface and the shallow overburden. Unlike geosphere and well monitoring techniques, marine biosphere monitoring is not generally used to monitor the early warning signs of migration from the storage complex. Marine biosphere technologies will primarily be used to determine if leakage outside the storage complex has reached the seabed and will aid in quantitative measurement of leakage. In order to monitor this domain a combination of sediment sampling, biological sampling, geophysical, acoustic sensing and geodetic monitoring methodologies can be used.

Possible indications of leakage to the marine biosphere could be identified in the following ways:

- Changes in present day pockmark topography or general seabed soil stability;
- Identification of bubble streams emerging from the seabed or near existing and abandoned wells (base line surveys need to identify and quantify any pre-existing bubble streams);
- Changes in stability of the platform
- Changes in flora and fauna species composition/richness;
- Changes in sediment pore gas composition.

6.2.1. Water column profiling

Water column profiles are measured by a Conductivity Depth and Temperature Probe (CDT)-Figure 5. CDT probes are small, autonomous data recorders designed to monitor conductivity, temperature and pressure for profiling water columns, but can also record pH, redox and salinity. They can be lowered through the water column on an umbilical cord to record real time data. Alternatively, they have the potential to be fastened onto a structure (e.g. platform leg, well head or weighted down on the sea bed), pre-programmed and left to continuously record data via battery power (lasting roughly six months). Currents in the area are likely to preclude the use of this tool to record subtle changes in the entire water column. A CDT probe attached to a wellhead or placed on the seabed, may be able to detect subtle changes in the sediment water interface, however, the sensitivity of this style of deployment requires testing before the technique can be confirmed in the monitoring plan. Testing could be undertaken in a laboratory environment prior to any pre-injection base line surveys. A probe could be placed in a flume tank with Goldeneye sediment with a microseep of CO_2 injected into the base of the sediment. Changes in pH and redox could be monitored.

Figure 5. CDT probe for water column profiling acquisition[5]

6.2.2. Seabed sediment, flora & fauna and pore gas sampling

Benthic sediment samples can be analysed for chemical composition, pore gas and their biological communities. There is a variety of commercially available, industry standard techniques for the sampling of benthic flora and fauna, which can also be used for chemical composition. Seabed sediment sampling for pore gas is not a routine activity in the oil and gas industry therefore specific equipment has not yet been developed. However several techniques have been identified that could potentially be used, such as: Van Veen Grab Samplers, Box Corer, Gravity Corer, Piston Corer, Vibro Cores, CPT rig fitted with BAT probe and Hydrostatically Sealed Corer.

6.2.2.1. Van Veen Grab samplers

A simple and reliable industry/Shell standard benthic sampling device, typically sampling an area of $0.1m^2$ but can be bigger. Depth of sediment penetration is limited compared to coring techniques and the mechanism is not sealed, therefore making it unsuitable for pore gas sampling as the gas will escape as the sampler returns through the water column.

6.2.2.2. Box corer

Gravity based benthic fauna sampling device similar to the Van Veen Grab. The mechanism is not sealed, therefore making it unsuitable for pore gas sampling as the gas will escape as the sampler returns through the water column. Mainly used in soft sediment areas so the sand/clay around Goldeneye would prove unsuitable for this device.

[5] www.generaloceanics.com/product.php?productid=1156&cat=3&page=1

6.2.2.3. Gravity corer

Gravity based coring device used for taking seabed core samples. The mechanism is not sealed, therefore making it unsuitable for pore gas sampling as the gas will escape as the sampler returns through the water column. Mainly used in soft sediment areas so the sand/clay around Goldeneye would prove unsuitable for this device. Small diameter of cores makes benthic flora and fauna sampling prohibitive as many replicate samples would be required compared to the Van Veen Grab.

6.2.2.4. Piston corer

Similar to the Gravity corer but in a frame which is placed on the seabed before a piston forces the core into the sediment. More suitable to the sediment conditions around Goldeneye, however the small diameter of cores makes benthic flora and fauna sampling prohibitive as many replicate samples would be required compared to the Van Veen Grab and the mechanism is not sealed, therefore making it unsuitable for pore gas sampling as the gas will escape as the sampler returns through the water column.

6.2.2.5. Vibro cores

Electrically powered corer, which vibrates a weight on top of the core barrel forcing the corer into the sediment. Cores are typically 1-5 m long with good recovery in sandy sediments. Cores are potentially suitable for pore gas sampling depending on the sealing mechanism but not for benthic fauna sampling as 20 (84mm dia.) cores would be required to obtain a similar surface area to 1 x $0.1m^2$ Van Veen Grab sample. The mechanism is described in Figure 6.

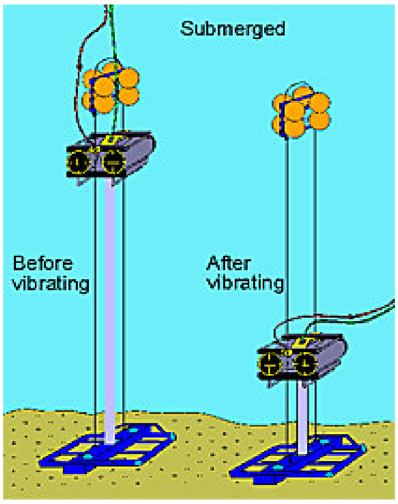

Figure 6. Vibro core sampling device[6]

6.2.2.6. CPT rig fitted with BAT probe

This is a probe that can take pore water/gas samples and is deployed using a Cone Penetration Testing (CPT) rig. Once the probe has penetrated the sediment to the desired depth a pressurised (at sea surface pressure) compartment is opened and, due to the pressure differential, pore water/gas is drawn through a filter into the compartment which is sealed when full. The resultant gas sample can be analysed using Gas Chromatography (GC) and the water can be tested for its chemical composition. This equipment is usually used downhole so its use on the seabed would be a novel

[6] Source: http://www.vibracoring.com/

application that would require testing/verification. Testing could be undertaken in a laboratory environment (flume tank style of experiment) prior to pre-injection base line surveys.

6.2.2.7. Hydrostatically Sealed Corer

The corer consists of a carousel of 12 (100 x 600mm) cores, which in combination take a sample equivalent to a 1 x 0.1m^2 Van Veen Grab sample. This corer can take benthic flora and fauna samples and potentially pore gas samples simultaneously. The manufacturer claims the corer takes 'undisturbed' sediment samples along with overlying supernatant water which contains the pore gas. It is believed that BP has used the corer to take pore gas samples, however at the time of writing this has yet to be confirmed. Therefore, before this corer could be recommended, testing/verification would be required. Testing could be undertaken in a laboratory environment prior to pre-injection base line surveys.

6.2.2.8. Flux Accumulation Chamber[7]

Accumulation chambers use a stainless steel probe fitted with a brass valve. Soil gas samples are collected from the ground and fed into laboratory analysis of CO_2 and tracer concentrations. Measurement flux determines the rate of leakage but it is worth considering that soil gas flux has seasonal fluctuations and variability. This technique is only applicable for an onshore environment.

6.2.3. Vegetative Integrity

6.2.3.1. Thermal Hyperspectral Imaging[8]

Hyperspectral imaging (HSI) sensors have been used for more than a decade to aid in the detection and identification of diverse surface targets, topographical and geological features. Techniques for scene characterization can utilize individual or combination spectral bands to identify specific features in an image/scene. To reduce the HSI data dimensionality and therefore the computational complexity, feature extraction can be performed on the spectral data before application of image pixel clustering. Principal component analysis is generally used to de-correlate data and maximize the information content in a reduced number of features. This technique assesses vegetative integrity around a site, and is only applicable for onshore environments.

6.2.3.2. CIR[9]

Colour infrared transparency films have three sensitized layers that, because of the way the dyes are coupled to these layers, reproduce infrared as red, red as green, and green as blue. All three layers are sensitive to blue so the film must be used with a yellow filter, since this will block blue light but allow the remaining colours to reach the film. The health of foliage can be determined from the relative strengths of green and infrared light reflected; this shows in colour infrared as a shift from red (healthy) towards magenta (unhealthy). The technology is applicable for onshore environment.

6.2.4. Acoustic Sensors

These technologies are typically used to map the seabed to identify changes in pockmark topography, general seabed soil stability, visual inspection of well heads, pipelines or identification of bubble streams, visually described in Figure 7.

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[7] http://www.co2captureandstorage.info/docs/co2conc.pdf

[8] Griffin, Michael, Characterization of clouds, fires, and smoke plumes in hyperspectral images, 11th conference on Satellite Meteorology and Oceanography

[9] http://en.wikipedia.org/wiki/Infrared_photography

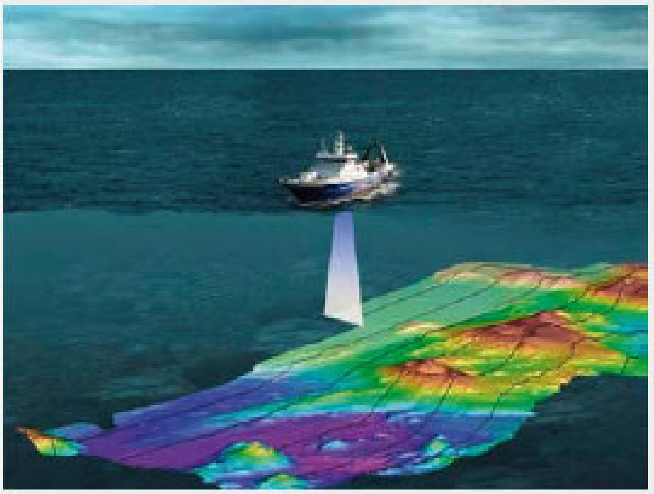


Figure 7. Acoustic Sensor data acquisition process.

6.2.4.1. Multi beam echo sounder (MBES)

MBES surveys provide a high resolution 3D image of the seabed. They are ideal for identifying change in seabed topography such as pockmarks and other seabed features. These instruments are often mounted on the hull of a vessel but can also be mounted on an underwater vehicle such as an ROV. When mounted to a vessel it can be used to acquire data over large areas quickly. MBES provides water depth data that can be processed to provide a geographically referenced digital terrain model (DTM) of the seabed. The resolution of the DTM is governed to a large degree by the operating frequency of the MBES and the height of the water column through which the acoustic pulse must travel, therefore high frequency/small water column equates to high resolution DTM, low frequency/large water column yields a low resolution DTM. For the highest resolution DTM, a MBES should be selected to provide the highest resolution possible for the expected water column height, remembering that high frequencies are attenuated quickly in water. Gas bubbles in the water column can be detected by a high frequency MBES, however the data must be processed to preserve these data points.

The compression and expansion of Captain reservoir in Goldeneye has been modelled and is below the resolution of MBES, however, MBES can have value in studying pockmark evolution.

6.2.4.2. Side scan sonar

These instruments are typically towed behind a vessel approximately 10-15m above the seabed, and provide what can best be described as an 'acoustic photograph' of the seabed. Seabed sediment variations and seabed features/objects can be detected and their positions on the seabed can be plotted. Heights of objects (such as boulders, pipelines, ship wrecks, etc.), can be calculated from the data. Water column features such as shoals of fish, thermoclines, marine mammals and gas bubbles can sometimes also be detected. The detail that any given side scan sonar can detect is dependent to a large degree on the operating frequency of the instrument. High frequency instruments (typically 500 - 1000 kHz), can detect objects of just a few centimetres in size, however high frequencies are attenuated rapidly in water and therefore these instruments have an imaging range of 75m or less. Lower frequency instruments (typically 100 kHz or less), provide a greater imaging range but reduced resolution of 1m or more. Unlike MBES surveys, side-scan sonar creates *only a 2D image of the seabed* with no depth information. Detection of water column objects is rather hit and miss. Side scan sonar data is prone to noise and therefore needs to be carefully interpreted by an experienced geoscientist. Typically these surveys are run in combination with MBES.

The compression and expansion of Captain reservoir in Goldeneye has been modelled and is below the resolution of side-scan sonar.

6.2.4.3. Acoustic cameras (Echoscope)

Acoustic cameras enable 'video-like' images and movies to be recorded from areas of very low visibility. They can be mounted to fixed points (such as a platform leg) and so may be used to monitor leakage risks that have a well defined and focused geographical location, such as a pock mark or wellhead. These instruments are not suitable for surveying larger areas as they are limited to a short range of investigation (~50m), which means that, to complete an areal survey, they would need to be mounted to a remotely operated vehicle – ROV. This would be much less time and cost effective than a vessel based surveying technique, such as MBES. The ability to record 'acoustic movies' means that this technique is capable of monitoring intermittent leakage events as it is 'always on'.

6.2.5. Geodetics techniques

Geodectic techniques refer to a suite of point measurement technologies that can monitor millimetre changes in the topography of the seafloor.

6.2.5.1. GPS

Fluid leakage to seabed could cause subsidence around the platform. Installation of a high resolution global positioning system (GPS) receiver on the former production facility would enable accurate and reliable continuous monitoring. Permanently installed receivers allow continuous monitoring by recording positional data either near real time (via communication link) or internally in the instruments. Subsequent post-processing provides precise xyz (height & horizontal) movement for the platform to an accuracy of 10 to 20 m. Regarding the accuracy of displacement rates, an accuracy of 1-5 mm/year could be reached, depending on the distance to the reference stations and the monitoring period (> 2-2.5 years).

Receivers can be deployed onto multiple platform legs to produce a 3D model of stability changes. However the pressure bowl effect (in the range of mm movement) from the CO_2 injectors needs to be fully understood, before it can be determined if GPS can distinguish between changes in soil stability caused by leaking CO_2 or pressure induced geomechanical heave created by CO_2 injection. This will be determined prior to the pre injection phase of the project.

6.2.5.2. Acoustic ranging

Acoustic ranging uses a type of permanent autonomous seafloor pressure sensor, which uses acoustic transponders mounted on the seafloor to measure sea floor horizontal strain. Stations are placed on the sea-floor and pulse sound to neighbouring stations. The accuracy is around 5-10 cm and repeatability in the order of 1 cm/km. This is an effective way to monitor a pressure bowl effect, if geomechanical heave in the subsurface is within magnitude of instrument detection limits. The Goldeneye area has a number of natural pockmark features which could be a monitoring target. However, it has been assessed that acoustic ranging is unlikely to detect changes in pockmark topography.

6.2.5.3. Seafloor pressure gauges

Seafloor pressure gauges are another type of permanent, autonomous seafloor pressure sensor that can measure differential pressure at the seafloor. They are an effective way to monitor a pressure bowl effect, if geomechanical heave in the subsurface is within magnitude of instrument detection ability. The technique provides sub-centimetre accuracy of subsidence. Stations are placed between

0.5-2 km apart. However, due to the spacing of the sensors the technique would miss small changes in pockmark topography. The technique is more expensive to use when compared to MBES technology. Therefore seafloor pressure gauges and acoustic ranging have been screened out in favour of MBES as it is a technique which can monitor changes in pockmark topography, general seabed stability and can be used for bubble stream identification.

6.2.5.4. SAR and inSAR[10]

Synthetic aperture radar (SAR) in combination with interferometry has the ability to measure topography or ground movement. The radar is mounted on the satellite. It can measure vertical differential movement occurring due to subsidence, slides, settling and creep. The typical horizontal spatial resolution obtained via current satellite SAR ranges from 8 – 150 m (25-500 ft) and 8 – 30 m (25-100 ft) for INSAR. The method works due to the phase shift measurement between radar passes affected by changes in reflectivity of the ground, changes in viewing perspective and changes in atmosphere. The technique is used in onshore environments to measure the effect on the surface due to changes in the subsurface initiated by CO_2 injection and movement in the storage and surroundings. There is a lower limit of where vertical movement is significant enough to be detected by the technique.

6.2.5.5. Tiltmeter[11]

The tiltmeter is built around a highly sensitive electrolytic bubble level; a high-tech carpenters level that can measure tile movements down to one nanoradian or one billionth of a radian. Tiltmeters are mostly deployed in surface arrays to pick up ground deformation but can also be deployed in wellbores to map fracture height and other dimensional parameters. The meters are polled every few minutes and results are fed into an inversion model to determine subsurface changes in relation to surface deformation detected. The reading is more sensitive to strain occurring at shallower depths in the overburden as these generate a larger expression at the surface. This is useful a tool to indicate leakage however the strain is not always initiated by CO_2 movement. The technique is applicable offshore but due to its sensitivity, the sensor requires frequent calibration which can be difficult and costly to perform.

6.2.6. Shallow Seismic

These are a suite of mainly 2D shallow seismic techniques, which could compliment information from either acoustic surveys or deeper penetrating 3D surveys. Site-survey vessels are typically used for seabed surveys for infrastructure planning and environmental assessments, but a vessel may also tow small seismic streamers that can obtain high resolution 2D seismic images of the near surface. The depth of investigation is less than 3D seismic, and can vary with source strength, local water depth and geology. For Goldeneye, these 2D images are certainly of good quality down to the top of the coal layers (700-800m depth). They may be usefully used to track or identify existing or new gas plumes in the shallow subsurface (less than 500m below the seabed). Note that this technique may detect *new* gas pockets for example caused by CO_2 plume movements or leaks in nearby wells, but cannot quantify changing gas saturations. Also caution should be applied with this technique in time-lapse mode, proper acquisition of correctly repeated source and receiver data is difficult with a single streamer vessel, because there is no cross-line redundancy. In 3D streamer surveys typically two additional streamers are deployed during acquisition to create redundancy and negate the effects of

[10] http://www.cflhd.gov/programs/techDevelopment/geotech/insar/documents/03_chapter_introduction.pdf

[11] http://www.halliburton.com/public/cem/contents/Papers_and_Articles/TECH/Monitoring%20technology%20enables%20long-term%20C02%20geosequestration.pdf

streamer feather. For Goldeneye, focused acquisition of 2D high resolution is recommended to monitor new gas pockets forming in the first 100 m below the seafloor or in areas where no high quality 4D data can be acquired, for example in the undershoot area near the platform. A comparison between 3D seismic data and Hi-Resolution 2D seismic is shown in Figure 8.

6.2.6.1. Boomers

A generalised name referring to a suite of towed instruments which produce a seismic pulse through electromechanical means. Boomers can be grouped by their towing configuration - surface towed, sub-towed (just below surface) and deep towed. Boomers provide a broadband high frequency pulse of stable character, which can produce a seismic section with vertical resolution up to 30cm and depths of sediment penetration up to 50m in soft clays, or 10m in sand. Deep towed boomers used to be Shell's preferred instrument for very high resolution sub-bottom profiling in water depths of 50 - 400m, however this is old technology and *these instruments are no longer commercially available and hence have been screened out of the monitoring plan.*

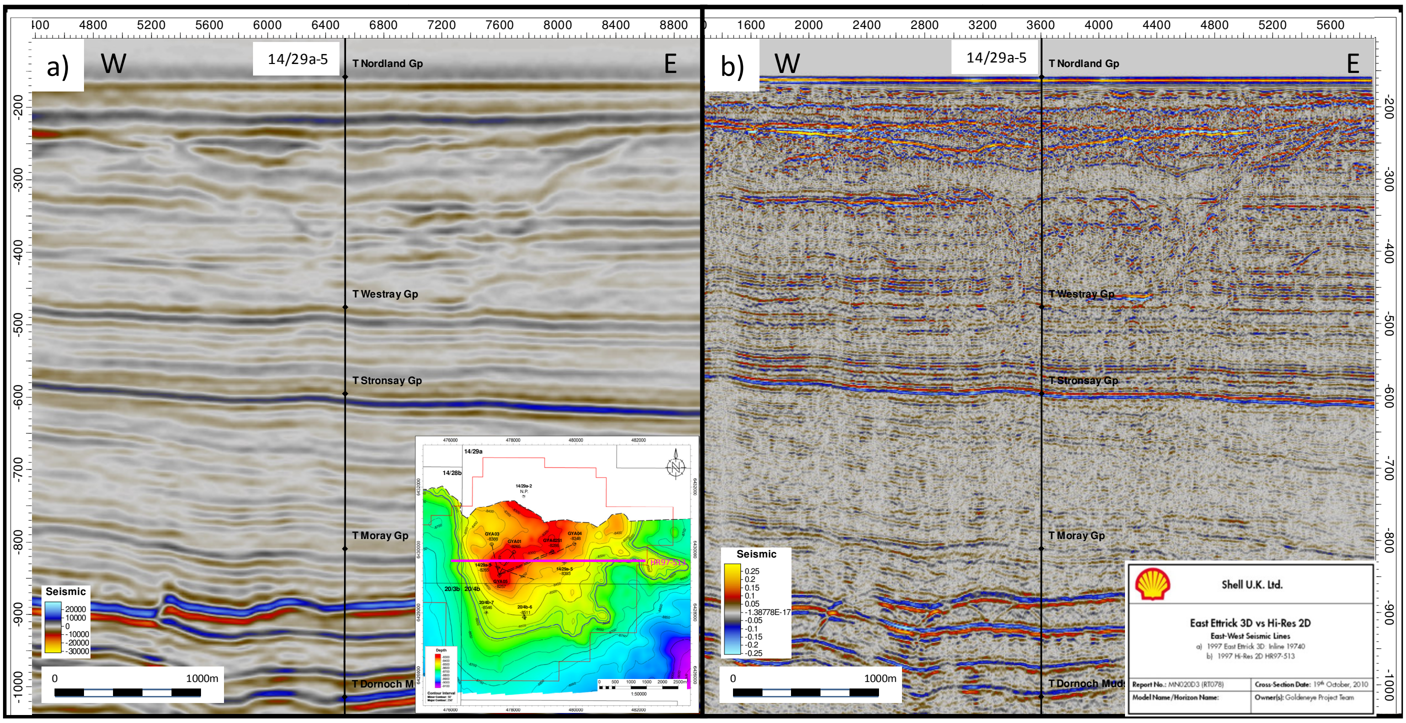


Figure 8 **Comparison between a) seismic data from 1997 Ettrick East 3D streamer survey (Pre-Stack Depth Migration, displayed in time (Inline 19740) and, b) Hi-Res 2D line HR97-513. Lines are approximately equivalent and are displayed at the same scale in time.**

6.2.6.2. Sparkers

Similar to boomers, but produce a seismic pulse by means of a spark between electrodes. They can be towed deep or shallow and provide similar results to boomers; however sparkers are not normally favoured by Shell. The pulse produced is variable and has low repeatability, often giving seismic records of inferior quality and resolution compared to chirps and pingers. Due to the inferior quality of the technique this bottom profiler has no potential use at Goldeneye.

6.2.6.3. Pingers

A generalized name referring to a suite of towed or vessel hull mounted instruments that produce a seismic pulse through a transducer array. Pingers are normally configured as 3 x 3 (9 transducer), or 4 x 4 (16 transducer) arrays. Pingers provide a high frequency, stable and highly repeatable seismic pulse that can produce a seismic section with vertical resolution up to 40cm and depths of penetration through shallow sediments up to 50m in soft clays or 5-10m in sand. Pingers are widely available and are quick and easy to use, however their performance in shallow water and sand (in particular) is poor when compared to boomers, due to ‘ringing’ (noise) and a typically broad seabed reflection that can mask very shallow buried features.

6.2.6.4. Chirps

Similar to a Pinger in that Chirps use a transducer array to produce the seismic pulse, however rather than emitting a single high frequency these instruments sweep a range of frequencies in the transmitted pulse. This provides high frequencies for high resolution in the shallow section (however, high frequencies are rapidly attenuated in the shallow sediments), and lower frequencies for increased sub-seabed penetration.

6.2.6.5. Enhanced surface rendering

This technique involves reprocessing 3D seismic data to provide optimal imaging of the shallow overburden. Seafloor pictures are generated from the water bottom pick of a 3D seismic survey and are used to highlight hydrates and debris flows. However, this technique is unsuitable for this area of the North Sea, as the water depths are too shallow (<300m). The seabed reflection on 3D seismic is often of poor resolution at these depths, because the 3D seismic data is processed to optimally image the reservoir section and not the shallow overburden.

6.2.7. Hydrosphere monitoring

6.2.7.1. Hydrosphere sampling[12]

The monitoring platform that is available commercially allows continuous monitoring of fluid pressure and discrete sampling of groundwater from multiple zones in a single borehole. The system features casings with multiple packers and valved ports to seal off and provide selective access to monitoring zones in two sizes. It is made of plastic and stainless steel. Instrumentation capabilities include measurement of pressure and temperature, collection of fluid samples and execution of hydraulic tests. The system avoids atmospheric exposure of groundwater and the discrete sampling method allows collection of fluid samples without repeated purging. Discrete sampling enables sampling at formation pressure whilst minimizing loss of dissolved gasses or volatile compounds and minimizing operator exposure to well fluids. The commercial example is Westbay system (Figure 9), which has been implemented in Orange County District (OCD) Southern California for monitoring of ground water supplies,. Hydrosphere sampling in Goldeneye field is not under consideration due to its offshore location and lack of fresh water aquifers.

[12] Schlumberger Technology sheet, Westbay System, Multilevel Technology for Groundwater Characterization and Monitoring

Figure 9. The Sketch of Westbay System installation in OCWD, California. Each Westbay well measures water pressure, and collects sampling/testing data from multiple discrete zones

6.2.7.2. Induced Polarization[13]

Induced polarization (**IP**) is a geophysical imaging technique used to identify subsurface materials, such as ore. The method is similar to electrical resistivity tomography, in that an electric current is induced into the subsurface through two electrodes, and voltage is monitored through two other electrodes. Time domain IP methods measure the voltage decay or chargeability over a specified time interval after the induced voltage is removed. The integrated voltage is used as the measurement. Frequency domain IP methods use alternating currents (AC) to induce electric charges in the subsurface, and the apparent resistivity is measured at different AC frequencies. The indication of ore can be important to make sure potable water at shallow depth is not contaminated. There is no potable water existing within Goldeneye field, and hence this hydrosphere monitoring technique is not required.

6.2.7.3. Spontaneous Potential[14]

The spontaneous potential (SP) method is a passive electrical technique that involves measurement of naturally occurring ground potentials. These can be generated from a number of different sources although all require the presence of groundwater to some degree. The two main sources of interest in environmental and engineering studies are streaming potentials, due to movement of water through porous subsurface materials, and diffusion potentials resulting from differing concentrations of electrolytes within the groundwater. SP measurements are made using a pair of non-polarising electrodes. These normally comprise a pot containing a copper electrode immersed in a saturated copper sulphate solution. A porous base to the pot enables the electrolyte to percolate out and make contact with the ground. The potential difference between the two pots is measured using a high impedance voltmeter. Anomalies in SP are a qualitative indication of potential problems in the components of ground/potable water. However, there is no potable water existing within Goldeneye field, and hence this hydrosphere monitoring technique is not required

[13] http://en.wikipedia.org/wiki/Induced_polarization

[14] http://www.geophysics.co.uk/mets2.html

6.3. Overburden and Aquifer

Geophysics-based techniques are the most effective tools available to monitor both the overburden and aquifer because they span a large vertical range and can be programmed, depending on sensor placement, to provide wide areas of investigation.

The geophysical technologies mentioned in this section are those that can be used for monitoring of the geosphere (*more than 500m depth*) and near the wells. To be an effective monitoring technique a geophysical technique must be able to detect a change in a physical parameter caused by CO_2 plume migration within the reservoir or larger container complex, or the technique must be able to detect container integrity failure related to Rødby caprock failure or fault movements opening unwanted CO_2 migration paths. Note that several technologies like MBES and Shallow 2D seismic can be used to monitor multiple sensitive domains, but in this section we focus only on their usage to monitor the CO_2 plume in the geosphere. Section 6.2 explains the use of MBES and Shallow 2D seismic surveys for hydrosphere monitoring.

6.3.1. Seismic

Seismic surveying can be used to create a reflectivity or acoustic impedance image of the subsurface in two dimensions (2D seismic), three dimensions (3D seismic) or over time (time-lapse seismic often called 4D seismic). Acoustic energy waves penetrate the subsurface and are (partially) reflected by layers with different acoustic properties. The image is constructed from recorded reflections of acoustic sources (shots) over time using multiple recorders (receivers). Shots can be generated by various sources including dynamite and truck mounted vibrator-plates on land and airguns or other acoustic sources in a marine environment. The recording arrays use geophones, hydrophones or accelerometers to record the reflected energy. Sources and receivers are deployed both at surface and in boreholes. Because these techniques use active sources these are often referred to as active seismic techniques. Another applications where only recording stations are used at surface or in a borehole to record releases of acoustic energy caused by stress changes related to injection or production are termed passive seismic, often referred to as or microseismic and are described in more detail in §6.3.1.2.

6.3.1.1. Time-lapse Seismic

Time-lapse seismic uses the differences in the acoustic images between a baseline and a monitor survey to detect changes in reservoir or overburden rock caused by extraction and injection fluids this is depicted in Figure 10. Variations in acoustic impedance or time-shifts have been shown in various settings to detect the effects of fluid contact movements, gas coming out of solution, pressure variations in reservoir and overburden due to compaction or dilation, and CO_2 plume migration.

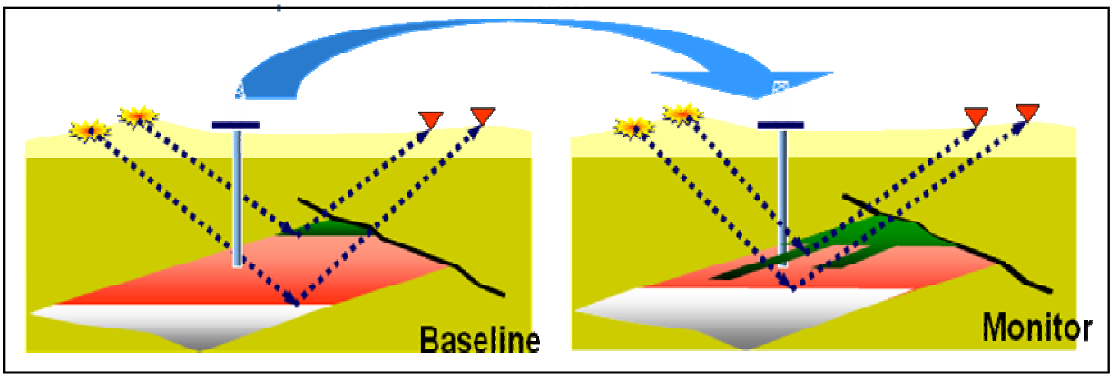


Figure 10. Principles of time-lapse seismic. Time-lapse seismic detects changes between the baseline and monitor surveys in the reservoir and overburden.

Several static and dynamic models have been constructed for the Goldeneye field using existing seismic 3D time and depth images. 4D seismic may be used during and after injection to prove CO_2 containment in the Goldeneye reservoir structure. 2D and 3D seismic lateral and vertical resolution decreases with depth due to energy absorption and varies depending on source frequency spectrum content, acquisition geometry, and background noise levels. For an airgun source typical lateral resolutions for Goldeneye vary from 10m (for depth less than 500m) to more than 100m (for depth greater than 2000m). Vertical resolutions vary from 5m near surface to 50m at reservoir level. 4D seismic resolution is often better than 3D seismic resolution as subtle variations in amplitude, impedance and time-shifts are easier to distinguish on a difference section.

The time-lapse seismic methods covered in this study include surface acquisition techniques like streamer seismic, Ocean Bottom Nodes (OBN), and Ocean Bottom Cables (OBC) all of which are able to acquire 3D and 4D seismic, plus borehole methods like Vertical Seismic Profiles and cross-well imaging techniques. Detailed feasibility results are found in section 7.2.

6.3.1.2. Microseismic

Microseismic is a passive method that is used to record the acoustic energy released by fault or by fracture slippage triggered by stress changes during fluid injection and extraction. The principles are shown in Figure 11. Proven applications are monitoring of hydraulic fracture growth, detection of fault reactivation and monitoring of caprock integrity. In hydraulic fracturing applications microseismic can monitor fracture orientation, height and length of the fracture. Monitoring of fault reactivation timing and geometry of the fault-slip events creates options for managing the threat of well failure. The seal integrity can be monitored by correlating the timing and location of the events with the known location of the reservoir seal. The feasibility study in section 7.2 describes in more detail potential applications and detection limits for the Goldeneye reservoir geology.

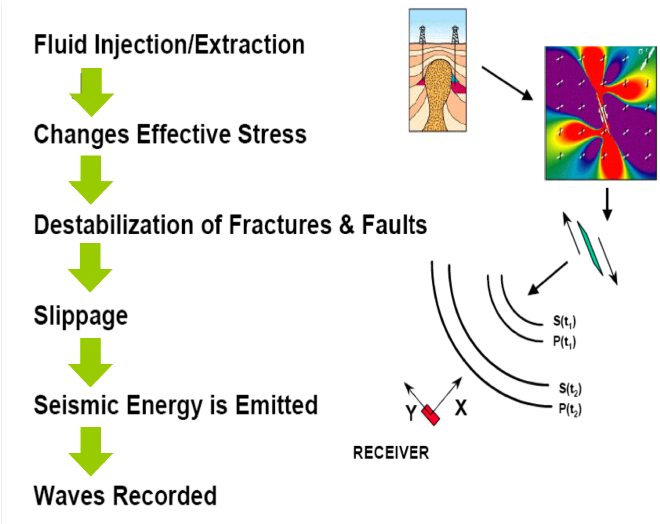


Figure 11. Principles of microseismic monitoring.

In CCS projects microseismic may be used to monitor fracture growth, fault reactivation and caprock integrity. Microseismic events have been recorded in the CCS pilot in the Weyburn-Midale oil field in Saskatchewan Canada. This pilot is part of a larger Enhanced Oil Recovery (EOR) project where CO_2 injection is used to increase oil production. In the pilot project a combination of microseismic and time-lapse seismic was used to track active faults/fractures, Figure 12. *Note that for the Goldeneye* *project the detailed geomechanics and reservoir engineering studies will determine if there is a requirement for caprock and fault monitoring with microseismic.*

6.3.2. Non-Seismic

Non-seismic techniques considered for geosphere reservoir and overburden monitoring included: seabed deformation and time-lapse seabed deformation; Controlled Source Electromagnetic Monitoring (CSEM); and gravity monitoring.

Seabed deformation: plume migration monitoring in the subsurface deeper *than 500m* is not feasible. Geomechanical modelling predicts a maximum of 4.6 cm of seafloor subsidence at the end of condensate production and an uplift (heave) of 3.6 cm after CO_2 injection. The *MBES* lower detection limit is 10-20cm of seafloor deformation (which can be further deteriorated by natural seafloor dynamics, in other words the seafloor deformation not being representative for deep subsurface displacements). *Seafloor acoustic ranging and pressure* monitoring have been screened out for Goldeneye because the inversion methods will have difficulty inverting for the depth of the CO_2 plume without additional constraints from seismic or other methods, the same applies for differential GPS.

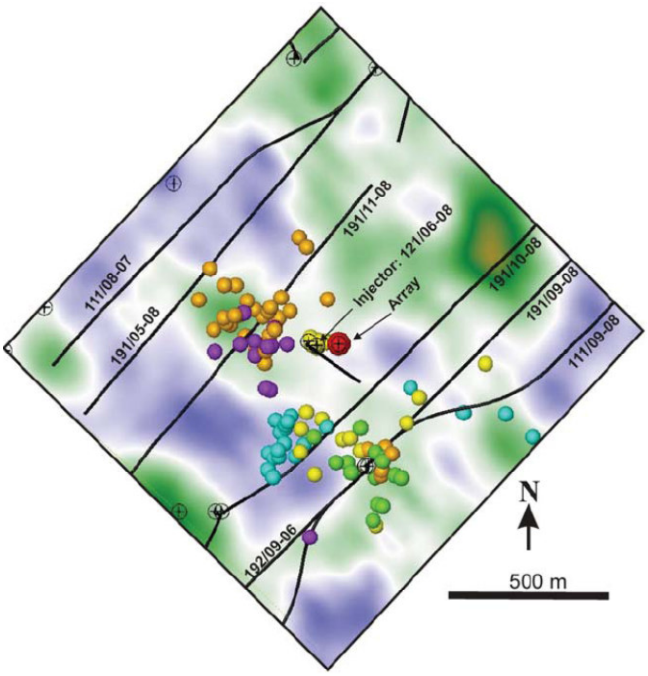


Figure 12. Weyburn – Midale CCS pilot example of microseismic event locations superposed on a time-lapse amplitude difference map[15].

Note that *Differential GPS* has screened positive and is recommended for platform safety monitoring. MBES has screened positive for pockmark growth monitoring and gas bubble detection as discussed in §6.2.5.

Seabed gravity requires large fluid mass movements to create a detectable signal. This makes gravity methods unsuitable for plume migration monitoring in Goldeneye.

[15] Source: Verdon, J.P., White, D.J., Kendall,J.-M., Angus, D., Fisher, Q. And Urbanic, T.. 2010. Passive seismic monitoring of carbon dioxide storage at Weyburn, *The Leading Edge* **29(2)**:, 200-209.

CSEM will not be suitable for MMV purposes because the resistivity change due to CO_2 fill is minor and is complicated by the effect of a resistive oil rim.

The technologies are briefly discussed in the following sections. Detailed feasibility results explaining why these methods were screened out for aquifer and overburden monitoring are discussed in §7.2

6.3.2.1. Seafloor Geodesy

The principles of time-lapse geodesy are explained in Figure 13. Compaction, fault slip, reservoir dilation and fracture dilation cause a deformation of the seafloor surface which can be detected with Multi-Beam Echo Sounder surveys, acoustic ranging sensors, differential pressure measurements and differential GPS.

MBES uses an acoustic pulse to measure the seafloor depth, correcting for tides this can be used to measure seafloor uplift/subsidence. Repeatability accuracy is 10-15 cm. Seafloor Acoustic Ranging sensors use acoustic transponders to measure horizontal strain variations in the seafloor. The transponders measure the acoustic pulse travel times between each other which are used to determine the distances between the sensors with millimetre accuracy. Repeatable accuracy is 5-10 mm/km. These transponders are also typically fitted with a highly accurate pressure sensor that measures pressure variations over time which, when corrected for tidal influences, allow to estimation of the water column height and hence vertical variations related to subsidence/dilation. Repeatable accuracy for the pressure sensors is approximately 20mm. Differential GPS only applies to platform installations since it needs a line of sight with the satellite. This technique is discussed in §6.2.5.1 and provides a single point estimate of the seafloor subsidence or uplift at the platform location.

Seafloor deformation measurements can be inverted for depth to interpret reservoir deformation, fault movements or fracture dilation if properly sampled across the structure. This technique has been successfully trialled in the marine environment using acoustic ranging sensors in deep water. Seafloor acoustic seafloor acoustic ranging has been trialled in shallow water, but results have been inconclusive so far.

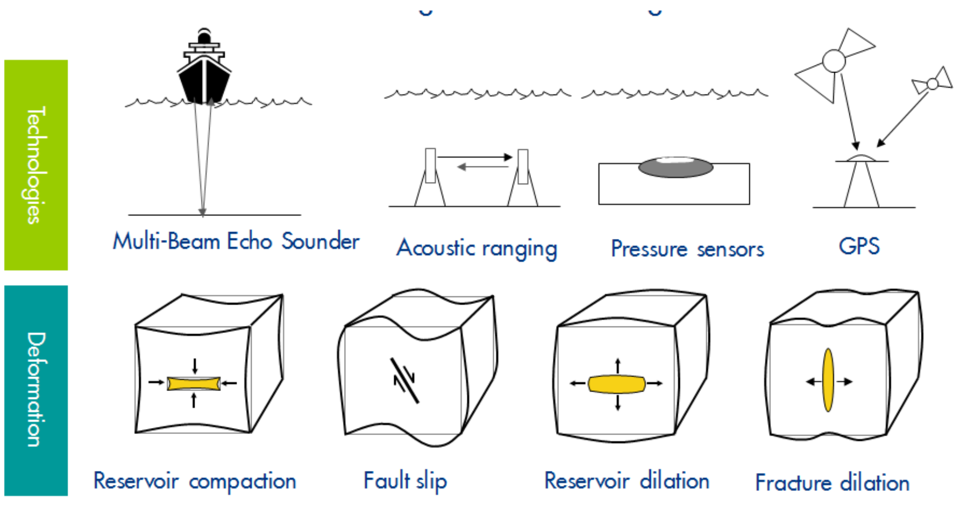


Figure 13. Principles of time-lapse geodesy

6.3.2.2. CSEM

Figure 14 explains the principles behind CSEM. Vessel towed CSEM has been successfully applied in marine environments to build a subsurface resistivity image to de-risk exploration prospects. The underlying idea is that fluid replacement e.g. water replaced by hydrocarbons (or CO_2 dissolved or mixed with water) will cause resistivity variations that can be measured by the receivers. Under favourable circumstances the technology can be deployed in time-lapse mode to detect fluid movements and may have applications for monitoring CO_2 plumes. The detection ability of a resistive fluid is a function of water saturation decreasing due to hydrocarbon or CO_2 replacement. Low water saturations cause high resistivity which may be detected by CSEM.

6.3.2.3. Gravity

The principles of time-lapse gravity monitoring are shown in Figure 15. Time-lapse gravity (gravimetry) monitoring may detect gas replacing liquids or vice versa. Lateral resolution is commensurate with reservoir depth. Significant mass variations are required, typically millions of tons of fluids or gas have to be displaced, to detect a discernable signal. Proven gravimetry applications are monitoring of aquifer influx into a gas reservoir, water injection in a gas cap and monitoring gas storage.

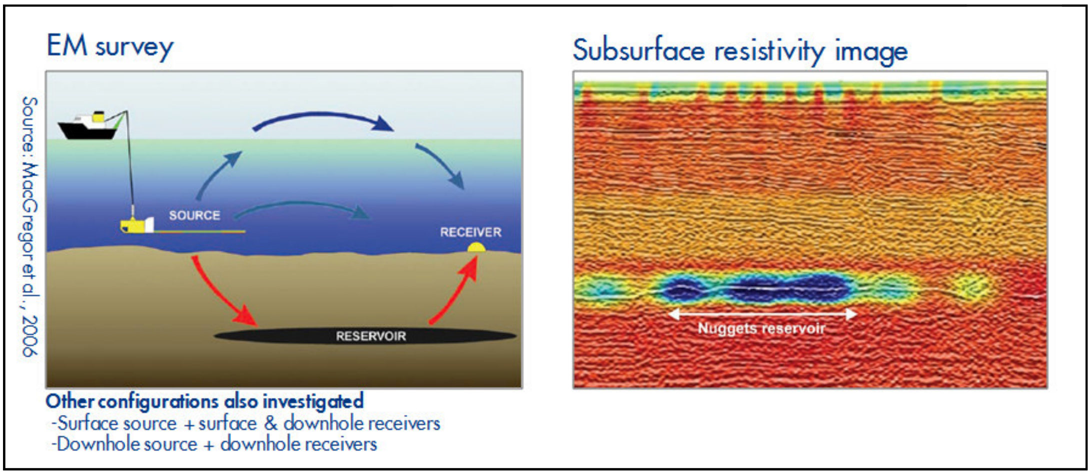


Figure 14. CSEM monitoring principles and applications[16].

In several offshore monitoring studies gravity data was acquired subsea using a highly accurate gravimeter placed on concrete monuments on the seafloor by an Autonomous Underwater Vehicle (AUV) or Remotely Operated Vehicle (ROV). Repeating these surveys over time allowed for the detection of subtle changes in the gravity field related to mass movement.

[16] MacGregor, L., Andreis, D.„ Tomlinson, J. and Barker, N. 2006. Controlled-source electromagnetic imaging on the Nuggets-1 reservoir. *The Leading Edge* **25(8)**: 984-992.

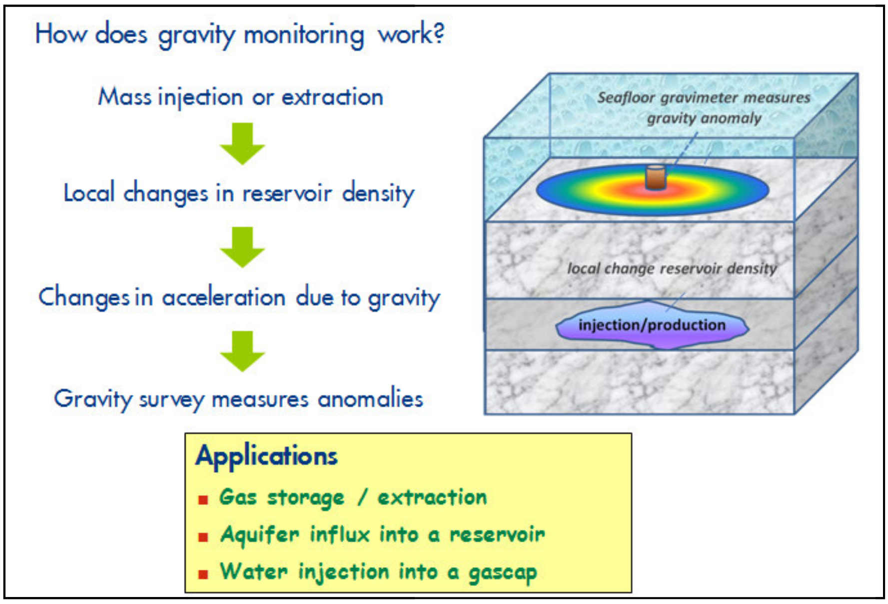


Figure 15. Seafloor gravity monitoring principle

6.4. Well and Reservoir

The techniques in this category consist of electric logging (including well integrity), fluid sampling and measurement gauges installed semi-permanently or permanently in wells. Well integrity logging is designed to detect CO_2 migration away from the wellbore, whilst the rest of the techniques address reservoir conformance.

6.4.1. Cement, Casing and Tubing Evaluation

Wells form a possible path for CO_2 leakage owing to degradation of materials including plugs, cement, steel and packers. Moreover, the mixture of CO_2 and water/brine generates corrosive acid which can potentially speed up the degradation process (for well materials exposed to the mixture). Existing holes or channels in a well could provide a path enabling CO_2 to escape from a containment complex and, over time, emerge at the mudline and contaminate sea life and the seabed ecosystem. This potential risk can be monitored (for accessible wells) by well integrity logging which will allow the implementation of mitigation measures prior to CO_2 reaching the mudline interface. The components that will be the focus of monitoring are the cement bond and tubulars (casing, tubing).

The cement bond tool uses an ultrasonic pulse as the basis of measurement. The pulse frequency ranges between 20-27 kHz and carries information on the quality of the cement bond between the formation and casing via wave propagation through the casing. It is measured in millivolts, deciBel attenuation or both. Reduced voltage or increased attenuation is indicative of a better cement bond. The CBL-VDL tool is available from 1.6 – 3.6" to use for $2^7/_8$" – $13^3/_8$" casing sizes. A more advanced cement bond tool analyses pipe to cement and cement to formation bonds and interprets casing condition. 360° cement and casing images can be provided by rotation of the transducer sub during logging. Fluid channels behind casing and damage within casing can also be seen provided they are of sufficient size. The transmitter emits ultrasonic pulses between 200-700kHz and measures the returning waveform reflected from internal and external casing interfaces. The rate of waveform decay allows quantitative assessment of the cement bond quality whilst casing resonant frequency measures the thickness of casing. Although the detection limit varies depending on conditions, there are a number of cases where fluid channels as narrow as 1.2 inches have been detected. The advance cement bond tool is available in 3.41 – 8.625" to cater for 4½ -$13^3/_8$" casing sizes. Casing internal diameters (ID) can be examined directly using multi-mechanical sprung arms or a calliper tool. The tool deploys an array of hard-surfaced fingers that expand and contract to measure the internal surface wall. The tool is kept centred by motorized centralizers equipped with rollers to minimize inner wall damage. Tool rotation is monitored using an inclinometer to measure well deviation too. The Caliper tool is available in 1.6875 – 5.5" to cater for tubing and casing 4.5-13" in size. Using the Cement bond tool with the calliper tool as indirect and direct measurement tools respectively provides a set of complementary data since direct measurement of casing ID can be used to calibrate the ID measurement from the indirect tool measurement and can therefore provide better interpretation and understanding of casing thickness variations. The Caliper tool can also be used in conjugation with another tool, the electromagnetic pipe scanner, which uses sensor pads to scan the interior surface and thickness of tubulars. The pipe scanner has an advantage in that it can be run in smaller size tubulars, i.e. tubing, without having to pull out the completion string. Also, it is fluid insensitive and can therefore be run in either liquid or gas environment, similarly to caliper. Diagnostic scans using time-lapse can provide corrosion rates, casing corrosion behind tubing and inner tubular radii.

6.4.2. Saturation and Porosity measurements

Providing the environment is approaching ideal condition and certain requirements (as mentioned in section 7.3.2) are fulfilled, saturation and porosity could potentially be obtained from Pulse Neutron Capture (PNC), commonly known as sigma and neutron porosity measurement

Both techniques are based on neutron interaction with the formation matrix and fluid. The two measurements are typically built into one tool with a diameter as small as 1 $^{11}/_{16}$". For both measurements CO_2 presence is indicated when CO_2 replaces water. However, modelling is important in order to establish the minimum concentration of injected CO_2 needed to produce a measureable change in reading. The Carbon Oxygen Logging (C/O) method has also been considered, however it is not suitable for the gas filled borehole environment.

6.4.3. Cased Hole Reservoir Character Logging (Resistivity and Acoustic)

6.4.3.1. Resistivity

When CO_2 is introduced into a low resistivity environment such as a water-bearing formation there is a resultant resistivity change. Depending on the initial resistivity, the contrast during and post- CO_2 injection will be more apparent for formations with a lower initial background resistivity. SPE paper number 126885[17] describes laboratory tests and concludes that resistivity increases with increment of the CO_2 fraction.

6.4.3.2. Acoustic

SPE paper number 126885 also describes measured changes in the velocity and amplitude of P-waves during CO_2 injection into water-bearing sandstones. Brine replacement by CO_2 caused a reduction in the velocities and amplitudes of propagated waveforms. The experiment demonstrated that the velocity reduction in P-waves was significant below 20% CO_2 saturation but remained constant on further CO_2 injection/saturation increment (Figure 3 in the SPE paper).

[17] Xue, Z. and Kim, J. 2009. Detecting and Monitoring CO_2 with P-wave Velocity and Resistivity from Both Laboratory and Field Scales. Paper SPE 126885 presented at the SPE International Conference on CO_2, Capture, Storage, and Utilization, San Diego, California, 2-4 November. (Figure 4)

6.4.3.3. Density

Density measurements are derived from and are proportional to the electron density in a subset of material, which consists of formation matrix and pore fluid content. Considering that the matrix will undergo insignificant changes during injection, the change in the density will depend on fluid content replacement. For Goldeneye storage, CO_2 will replace CH_4 and water, which will be reflected in the density log. However the difference may fall below detection limits. The density changes are most likely to be identified in high porosity intervals and where CO_2 replaces mostly water.

6.4.3.4. Gamma Ray

Gamma Ray measurements identify the natural amount of radioactive elements (K, Th, U) in a rock formation. The reading includes radioactive content of the matrix and fluid. For CO_2 applications, this type of logging is usefully utilized on radioactive tracers since it can identify and measure the concentration of a tracer surrounding an observation/monitoring well.

6.4.3.5. Optical logging

Optical logging is one alternative for well integrity checking. It is a camera system lowered into a cased-hole well to perform visual inspection. The field of view can be set to examine the integrity/damage of casing and components and has 360^o coverage of the casing wall too. The objective would be to identify corrosion, holes and/or loose joints which could provide a channel for fluid migration away from a wellbore.

6.4.4. Real Time Compaction Imager (RTCI)

The RTCI is continuous, real time monitoring of well deformation, reservoir compaction, and well integrity without physical intervention (Figure 16). The system provides high resolution, high sensitivity fibre optic strain measurement (using thousands of sensors spaced helically at 1cm intervals, each capable of measuring sub-micrometer deformations) which is sensitive to all tubular strains: axial, bending, crushing, pressure and temperature. The result is presented in three dimensional images of the well tubular.

This technique is currently under development and has undergone deployment testing where it was applied to the outer of casing with various wrap angles. It has succeeded in recording auxiliary data combined with Distributed Temperature Sensing (DTS) and Pressure Gauge (PDG). *RTCI for CO_2 monitoring applications is an area of active research in Shell, but has not been trialled in the field to date. Installation in Goldeneye is not possible for the existing wells because installation on the casing is required. For monitor wells the RTCI is deemed of limited use owing to the highly competent formations in the overburden.*

Figure 16. RTCI sensor wrapped around tubing for deployment testing in R&D centre

6.4.5. PDG

The permanent down hole gauge (PDG) equipment currently available is designed to deliver highly stable pressure and temperature measurements for long-term applications. Performance of PDG systems is validated in a controlled environment where drift stability is measured at ambient, atmospheric and simulated downhole pressure and temperature conditions. During this period gauges are also subjected to power on/off cycles and temperature cycling to simulate the most demanding conditions. Gauges are currently qualified for a 10 year life cycle and have a drift stability better than ± 7kPa at 82,740 kPa and 150° C (± 1° C at 12,000 psi and 302° C).

Completed gauge assemblies undergo repeated shock and vibration testing to meet the environmental qualification for well testing in production and injection wells. The long-term reliability of PDG systems relies on designs that include fully welded assemblies, high temperature electronic technology, metal to metal sealing and corrosion resistant alloys.

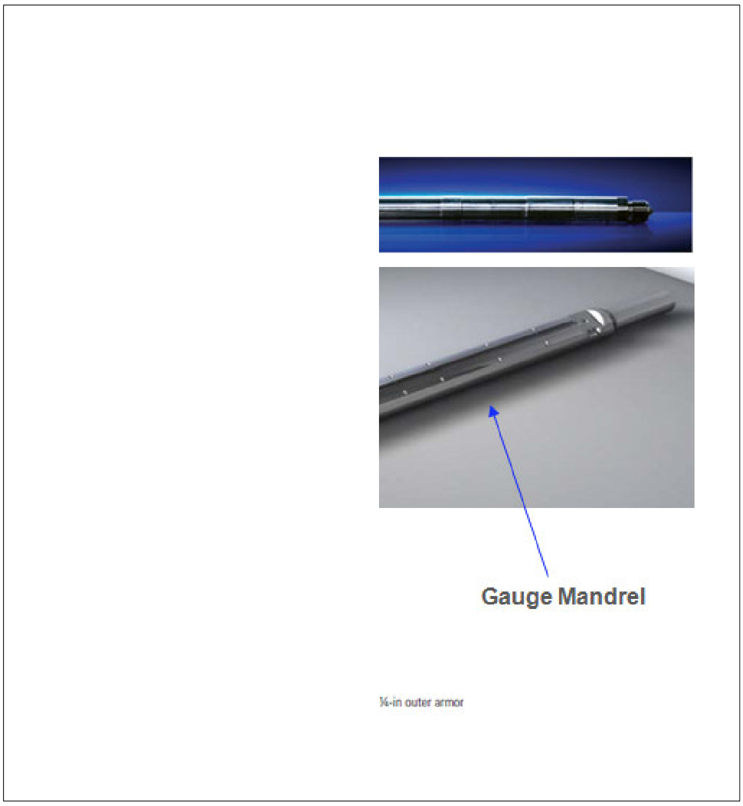


Figure 17. Pressure Gauge (PDG) device[18]

6.4.6. Distributed Temperature Sensing (DTS)

The DTS system is a permanent in-well reservoir monitoring system. The fibre can be used for sensing only or for high speed communication between downhole sensor and the surface unit. Once the data is received at surface, it can be transmitted to multiple remote locations for real-time identification of time, location and causes of changes in flow, inferred from temperature profile. The cable provides temperature measurement at approximately 1m intervals along the whole length of the cable producing a profile of temperature along the production string and when applicable along the mudline. The fibre-optic line can be monitored on a continuous or intermittent basis to provide rapid well diagnostics and can identify leaks in the injection tubing owing to the Joule-Thompson cooling as the leaking fluid expands across the leak orifice.

6.4.7. Distributed Acoustic Sensing (DAS)

DAS is a technology with a broad spectrum of envisaged in-well and areal monitoring applications including distributed flow measurement, sand detection, gas breakthrough, artificial lift optimisation, leak detection, smart well completion monitoring, near well bore monitoring, micro-seismic, borehole seismic and more. The technology can be deployed in new wells or retrofitted to most of the existing installations where standard telecoms optical fibres (so-called single-mode fibres) have been installed. The measurement system is comprised of an optical fibre placed in a protective cable strapped to a well tubular, and an interrogator placed at surface. The interrogator segregates the fibre into thousands of individual acoustic sensing sections of typically 5 to 10m long. Each sensing section acts as a microphone capable of recording full waveforms sampled at a frequency of up to 20kHz. The DAS interrogator system measures changes in the backscattered Rayleigh light. Advanced signal

[18] Source: http://www.slb.com/~/media/Files/completions/product_sheets/wellwatcher_sgm_ps.ashx

processing in the DAS light box then allows the detection, discrimination and location of acoustic events from downhole devices, leaks, flow, the reservoir, etc. One obvious use is to detect and monitor wellbore activities that have an acoustic signature mainly to monitor well intervention tools travelling up and down the well bore, perforation shots, and packer settings operations. *DAS technology is an area of active research within Shell but has not been field trialled for CO_2 applications to date.*

6.4.8. Tracers

Geochemical tracers are typically used in the hydrocarbon industry to monitor fluid flow between wells. However, tracers in a CCS project can be used to help identify the owner of migrating or leaking CO_2 within and outside a defined container complex. Tracers can either be natural (stable isotopes $\delta^{13}C$ and $\delta^{18}O$ of the injected CO_2) or introduced (noble gases, SF_6 and PFTs) into the CO_2 stream.

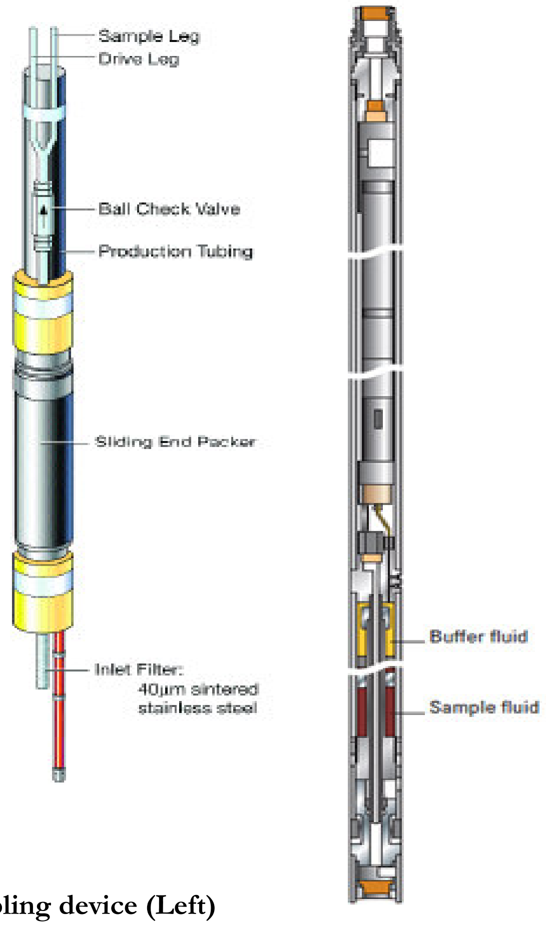


Figure 18. U-tube sampling device (Left) and Bottom-hole sampling device (Right)[19] [20]

[19] Left Figure source: Barry Frifeld, The U-tube : A New Paradigm for Borehole Fluid Sampling, doi:10.2204/iodp.sd.8.07.2009

[20] Right Figure source: http://www.slb.com/services/testing/reservoir_sampling/downhole_sampling/compact_production_sampler.aspx

6.4.9. Downhole Fluid Sampling

6.4.9.1. U-tube Sampling

The U-tube sampler is a simple positive fluid displacement pump which uses a high pressure gas drive to pump bottom hole samples to the surface recovery system. Wood (1973)[21] demonstrated this methodology for shallow vadose zone sampling using a porous cup inlet. Figure 18-Left shows a schematic of the U-tube sampler as configured for installation beneath a wellbore packer. At the core of the U-tube is the ball check-valve, which is the only moving part of the sampling system that is located in the well bore. The check-valve is located beneath a "tee" at the base of the U and it permits fluid to enter the loop but closes (by application of gas from the surface) when pressure in the U is increased above hydrostatic. A sintered stainless steel filter terminates the inlet beneath the check-valve to prevent the check-valve from plugging. To collect a sample, the U is first filled by venting the sample and drive legs to the atmosphere, thus allowing fluid to rise to the formation hydrostatic level. The sample is then recovered by supplying high-pressure N_2 (or another inert gas) to the drive leg, closing the check-valve, and forcing fluid out of the sample leg.

6.4.9.2. Bottom Hole Sampling

The best method to monitor CO_2 breakthrough at monitoring well(s) directly is downhole sample collection (Figure 18-Right) followed by laboratory fluid testing. This method categorically verifies CO_2 presence and provides better understanding of mixture mechanisms between hydrocarbon gas (methane) and CO_2. It can also provide geochemical samples for academic research into chemical reactive transport.

[21] Wood,W.,1973. A Technique using porous cups for water sampling at any depth in the unsaturated zone. Water Resour. Res., 9(2):486-488, doi:10.1029/WR009i002p00486

7. Feasibility Study and Detection Limit

This chapter describes detailed studies on MMV techniques to shortlist the potential technologies based on:

Risk relevance

How well the measurements provided by these techniques address/identify the subsurface risks associated with CO_2 containment within storage complex as defined in section 4.2.

Measurement ability

The ability to indicate properties contrast on injection / post injection phase compare to background condition (pre-injection) and whether the properties contrast exceed the detection limit for the technique.

Operational constraints

The ability to apply the technique in the Goldeneye environment based on its compatibility to offshore location, water depth, platform location, well location and borehole access in wells with current/planned completion strings.

Competitive application

If two or more technologies fulfil similar monitoring objectives, the study determines favours the technology having the least operational risk, the least cost and which gains optimal information.

Proven technology

The listed technologies in chapter 2 are either proven technology for CCS/EOR application, proven technology for hydrocarbon maturation or are in the research and development (R&D) process. The last two, are discussed briefly to evaluate the possibility of application at the project execution timeline. The detail of evaluation will be described separately in the Technology Maturation Report.

7.1. Seabed and Shallow Overburden

There is limited survey data for water properties, pore gas, sediment and the characteristics of the very shallow overburden formations at the Goldeneye Field location. Therefore, screening of selected techniques is mainly achieved by comparison between methods based on areal and time effectiveness of sample acquisition, maintenance of origin conditions for benthic, pore gas and sediment samples, and the use of gamma ray from shallow formation as a lithology indicator to determine suitable acoustic and seismic techniques.

The outcome of screening suggests that several techniques require baseline sampling to confirm capability to detect CO_2 leakage on the seabed or in shallow overburden formations. This is because baseline sampling provides information on background material/fluids including CO_2 concentrations which could be used to evaluate whether the detection limit conditions are passed.

The short-listed techniques are as follows:

- Water column profiling: CDT
- Seabed sediment, flora & fauna and pore gas sampling: Van Veen Grab, Vibro Corer, CPT rig fitted with BAT probe, Hydrostatically Sealed Corer
- Acoustic Sensors: MBES
- Geodetics: GPS
- Shallow Seismic: Chirps and Pingers

7.2. Overburden and Aquifer

To test the applicability of geophysical techniques for CO_2 plume migration, several scenarios have been built to accommodate the potential circumstances based on the understanding that Goldeneye is a depleted gas-condensate reservoir, with structural and stratigraphic trapping which enables Captain C, D and E Units to contain gas beneath the Rødby Formation caprock. The larger container complex consists of the Goldeneye reservoir plus the overlying Chalk and Montrose Groups.

The scenarios are as follows:

- CO_2 filling the reservoir Captain sandstone after condensate production
- CO_2 plume migration into the Captain sandstone aquifers and movement to a spill point
- CO_2 dissolution into the Captain sandstone aquifers and movement to a spill point
- CO_2 plume migration into high porosity Mey sandstone in the Montrose Gp
- CO_2 plume migration into Nordland Gp, near surface

In addition two scenarios were defined to test microseismic for the ability to detect caprock failure and fault movement events creating additional CO_2 migration pathways from the Goldeneye reservoir into the larger container complex:

- CO_2 plume migration path into the Chalk Gp caused by Rødby caprock failure
- CO_2 plume migration path into the Chalk Gp due to fault reactivation

The scenarios and their geological context are displayed in Figure 19.

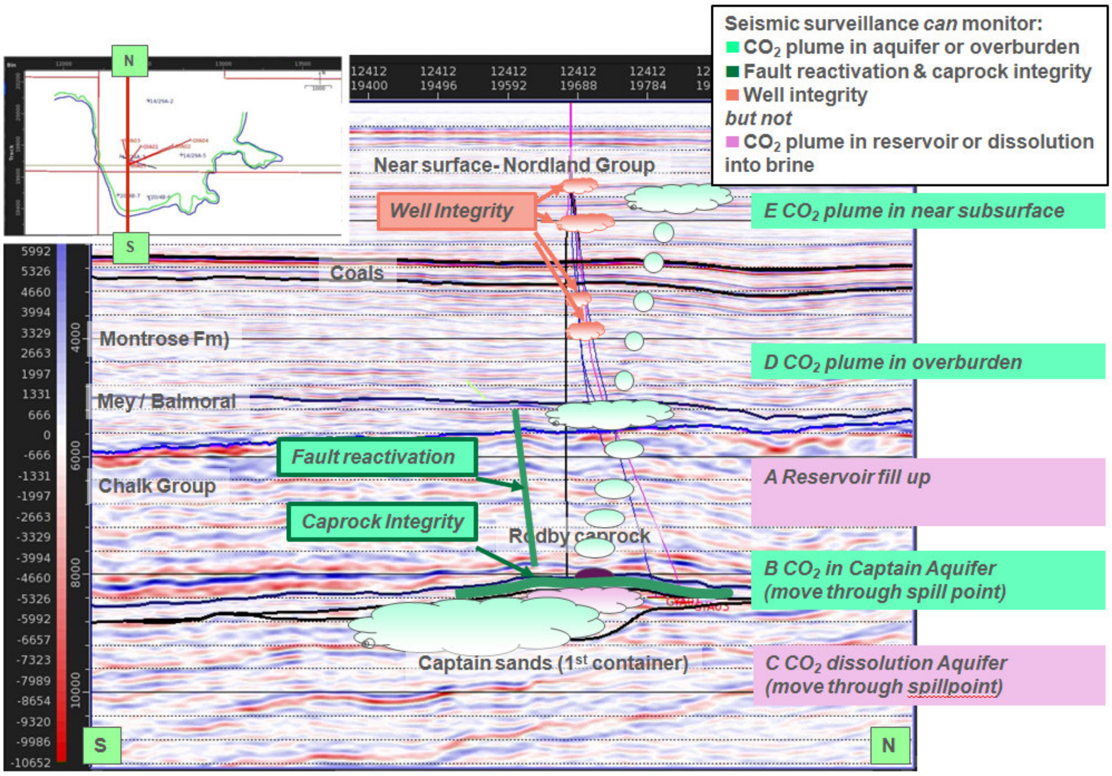


Figure 19. Geosphere monitoring scenarios

Seismic and non-seismic (seafloor geodesy, CSEM and gravity) methods are tested for their ability to monitor CO_2 plume migration within the Goldeneye reservoir (scenario A), migration 'sideways' beyond the primary container boundaries through one of the NE or SW spill points into the Captain Fairway (scenarios B and C), migration into the overburden Montrose Gp (scenarios D), and migration into the Nordland Gp near the seafloor (scenario E). The scenarios describing a CO_2 plume in the Montrose and Nordland Gp include scenarios where well integrity failure would lead to CO_2 plume discharge into these formations (scenarios D and E). Microseismic is assessed for its ability to detect caprock failure and fault movements which could create potential migration pathways for the CO_2 plume outside the captain reservoir sandstone or Captain Fairway (scenarios F & G).

7.2.1. Seismic techniques

The results of the detailed screening are summarised below with details given in the subsequent subsections.

Time-lapse/4D surface seismic: Plume migration can very likely be detected in the Captain aquifers, Captain Fairway and the overburden but not within the Goldeneye reservoir. Full field seismic is recommended for monitoring with seismic 3D swaths and 2D lines as the more economical options. 3D swaths and 2D lines can be used more often to monitor smaller areal such as high risk locations (for example wells and potential leak structures).

Borehole seismic: focused application of 3D VSP using permanent systems in a dedicated observation well or worked over injector could be considered for high-risk areas.

Microseismic: if reservoir engineering models or geomechanical studies shows a heightened risk of fracturing, fault reactivation or caprock integrity, then focused application of microseismic monitoring in the injector wells (fracturing, caprock integrity) or a dedicated observation well (fault reactivation in reservoir or near a potential leak structure) should be considered. *Crosswell seismic* was regretted for MMV because the technology currently requires a well spacing 500m or less. The existing Goldeneye wells have significantly larger inter well spacing at reservoir level (more than 750 m).

7.2.1.1. Time-lapse seismic

The feasibility of seismic for time-lapse (4D) monitoring was assessed by a seismic forward modelling study and a seismic noise study. The forward modelling study was used to determine if an expanding CO_2 plume replacing specific pore fills (e.g. brine or brine with residual gas) may cause a change on seismic synthetics and to generate synthetics of varying column heights as input for the noise study. The seismic noise study tries to quantify the impact of 4D noise on CO_2 column height detection ability.

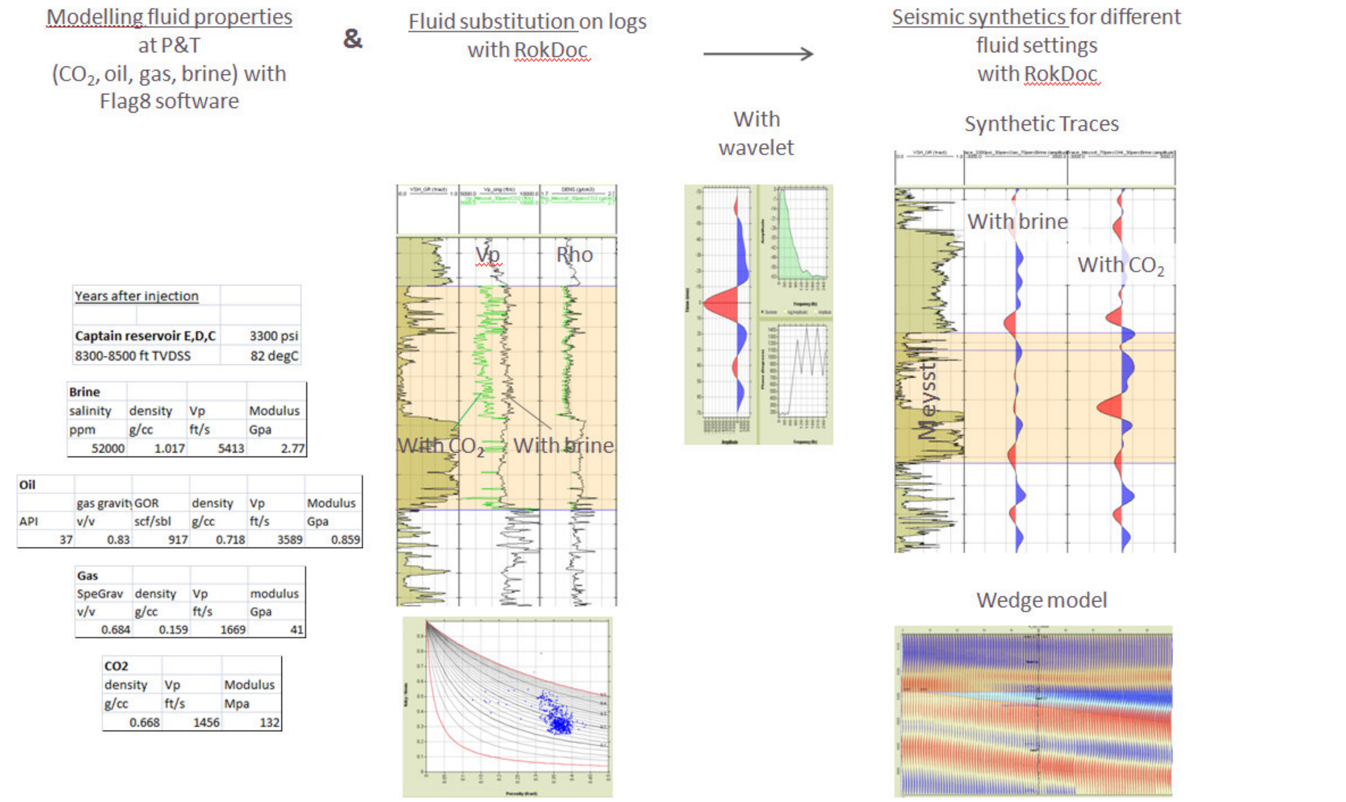
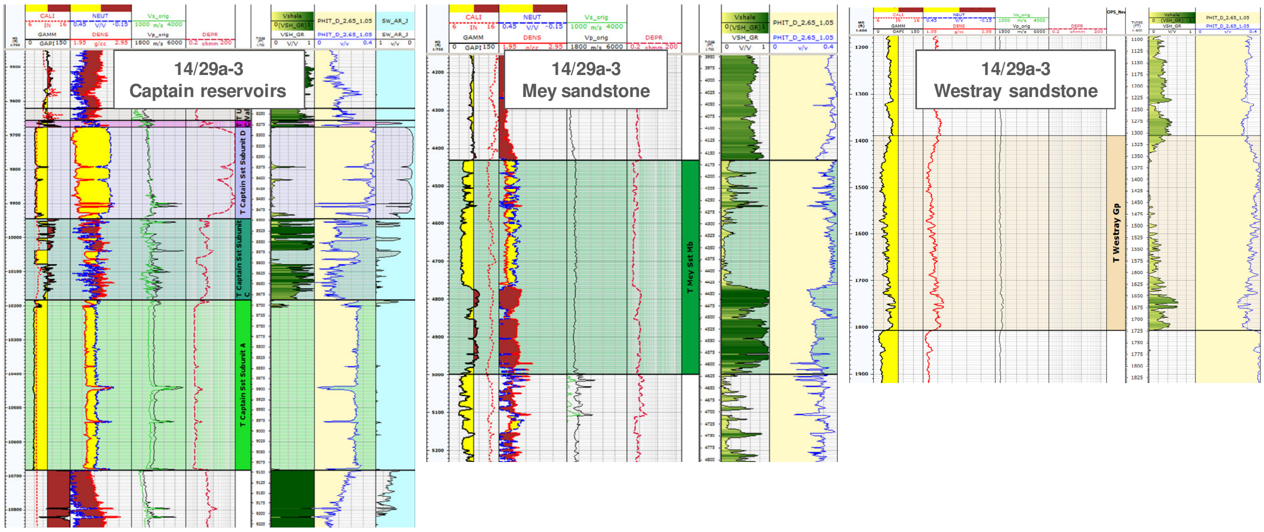


Figure 20. **1D Forward modelling workflow**



Rock Properties

Scenario	*Formation*	*Depth*	*Porosity*	*Thickness*	*NTG*
		(ft)	(%)	(ft)	(%)
A CO_2 filling reservoir	Captain D	8300-8500	28%	200	> 75%
B CO_2 in Captain aquifer			28%	200	> 75%
C CO_2 solution Captain aquifer			28%	200	> 75%
A CO_2 plume Mey	Mey	4300-4700	32%	800	> 75%
A CO_2 plume Westray	Westray	1300-1725	36%	425	> 75%

Figure 21. Rock properties for scenarios A-E and corresponding well log 14/29a-3 interpretations.

7.2.1.1.1. 1D Seismic forward modelling fluid substitution

Figure 20 describes the forward modelling workflow, including Gassmann fluid substitution and synthetic trace generation for the different fluid cases using both single traces and a wedge model. Fluid and rock properties are defined for each scenario in Tables 3a, b and c for pressure and temperature at different depths and project phases. Each table lists relevant fluid properties for the applied scenario. Scenarios A, B and C all apply to the Captain Sandstone. For these scenarios fluid properties were calculated for different project phases. For scenarios D and E, fluid properties were calculated using regional temperature and pressure trends for the Mey and Westray sandstones respectively. Fluid substitutions are carried out using the logs of well 14/29a-3. Representative well logs and bulk rock properties are shown in Figure 21. Subsequently seismic synthetic traces were generated for different fluid settings and acoustic impedance changes were calculated. Based on experience in other North Sea fields with similar geology, acoustic impedance changes of 5% or more can be detected by dedicated 4D seismic repeat surveys. Once a sufficiently large acoustic impedance response is found on the synthetics, wedge models are generated for the 4D noise tests in order to determine the detectable thickness of the CO_2 column. If no significant change in the acoustic impedance is found for different fluid cases, no further investigations are performed.

Table 3: Fluid property scenarios A, B & C – Captain Sandstone.

Properties are listed for pressure and temperature conditions at key stages in the project life-cycle. Before condensate production (initial reservoir conditions). Post condensate production (before start of CO_2 injection) and during injection (after several years of CO_2 injection).

Fluid Mixture Properties - Scenario A, B & C Captain sandstone

Initial reservoir conditions before gas production (end of hydrocarbon production)

Pressure 3820 psi Temperature 82 °C

Brine			
salinity	density	Vp	Modulus
ppm	g/cc	ft/s	Gpa
52000	1.017	5413	2.77

Oil					
	gas gravity	GOR	density	Vp	Modulus
API	v/v	scf/sbl	g/cc	ft/s	Gpa
37	0.83	917	0.68	3208	0.651

Gas			
SpeGrav	density	Vp	Modulus
v/v	g/cc	ft/s	Mpa
0.684	0.181	1778	53

Pre CO_2 injection – (post gas production)

Pressure 2200 psi Temperature 82 °C

Brine			
salinity	density	Vp	Modulus
ppm	g/cc	ft/s	Gpa
52000	1.017	5413	2.77

Oil					
	gas gravity	GOR	density	Vp	Modulus
API	v/v	scf/sbl	g/cc	ft/s	Gpa
37	0.83	917	0.712	3412	0.77

Gas			
SpeGrav	density	Vp	Modulus
v/v	g/cc	ft/s	Gpa
0.684	0.107	1478	21.7

CO_2		
density	Vp	Modulus
g/cc	ft/s	Mpa
0.449	761	24.2

During CO_2 injection (several years of injection)

Pressure 3300 psi Temperature 82 °C

Brine			
salinity	density	Vp	Modulus
ppm	g/cc	ft/s	Gpa
52000	1.017	5413	2.77

Oil					
	gas gravity	GOR	density	Vp	Modulus
API	v/v	scf/sbl	g/cc	ft/s	Gpa
37	0.83	917	0.718	3589	0.859

Gas			
SpeGrav	density	Vp	modulus
v/v	g/cc	ft/s	Mpa
0.684	0.159	1669	41

CO_2		
density	Vp	Modulus
g/cc	ft/s	Mpa
0.668	1456	132

Table 4: Fluid property scenarios – Mey sandstone. Properties are listed for representative pressure and temperature conditions.

Fluid Properties - Scenario D Mey Sandstone			
Initial conditions			
Pressure	1958 psi	Temperature 41 °C	
Brine			
salinity	density	Vp	modulus
ppm	g/cc	ft/s	Gpa
70000	1.046	5337	2.77
Gas			
SpeGrav	density	Vp	modulus
v/v	g/cc	ft/s	Mpa
0.684	0.128	1404	23.5
CO_2			
density	Vp	modulus	
g/cc	ft/s	Mpa	
0.72	1348	121	

Table 5: Fluid properties scenario E – Westray sandstone. Properties are listed for representative pressure and temperature conditions.

Fluid properites - Scenario E Westray sandstone			
Initial conditions			
Pressure	650 psi	Temperature 35 °C	
Brine			
salinity	density	Vp	modulus
ppm	g/cc	ft/s	Gpa
70000	1.048	5164	2.60
CO_2			
density	Vp	modulus	
g/cc	ft/s	Mpa	
0.184	2789	325	

7.2.1.1.2. Scenario A. CO_2 filling the reservoir Captain sands after condensate production

During injection the Goldeneye reservoir will go through various displacement processes displayed in Figure 22. Stage 1 shows the initial conditions before and after gas extraction (GE). At the end of the gas production phase a small gas cap will remain overlaying a layer of gas trapped by brine ingress from the aquifer. Stage 2 shows the conditions partway through during the injection phase where CO_2 runs above water and fingers towards the aquifer below original OWC. Stage 3 shows the potential movement of CO_2 (possibly mixed with hydrocarbons) into the aquifer (called a Dietz tongue). Finally stage 4 shows the fluid layers after gravity equilibration.

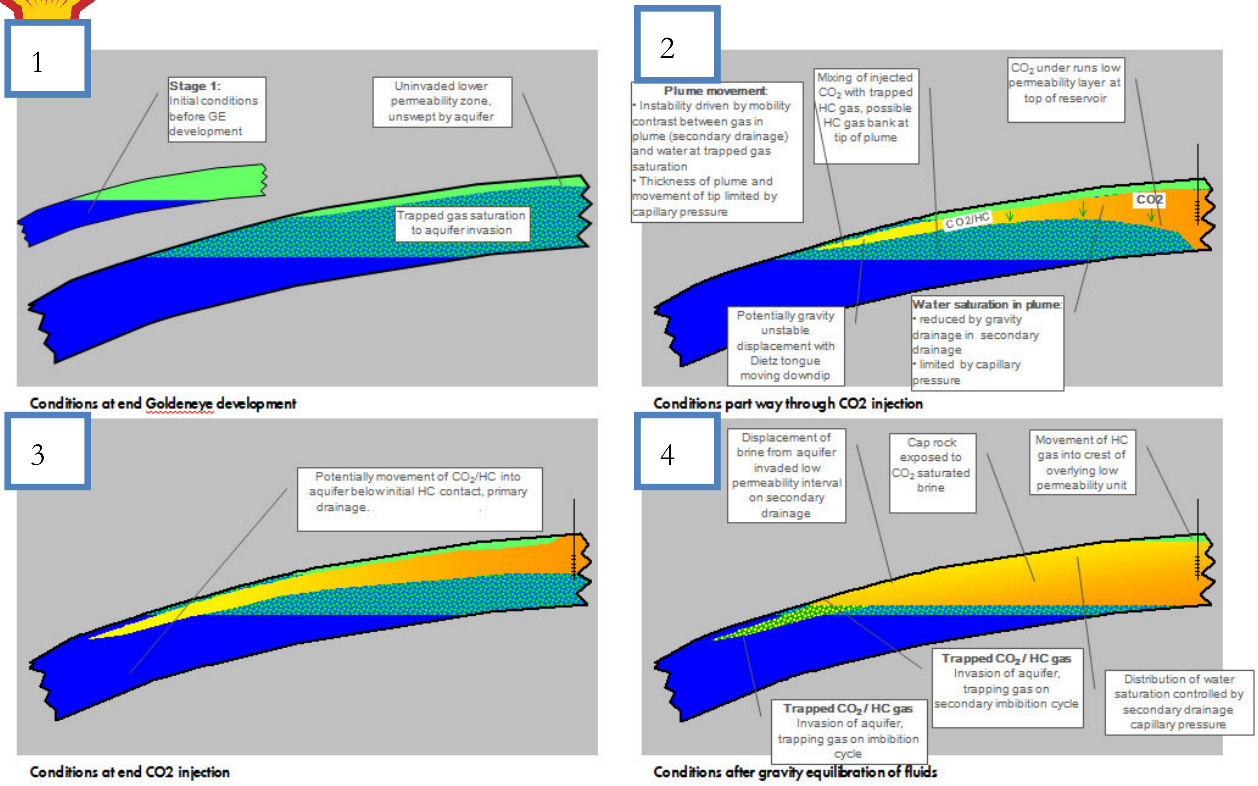


Figure 22. Goldeneye CO_2 injection reservoir displacement process life-cycle

A simplified block model was constructed for the forward modelling allowing comparison of fluid saturations of the initial reservoir (before gas production), the reservoir before CO_2 injection and the state after a few years of CO_2 injection (Figure 23). The CO_2, oil, gas and brine fluid mixtures are representative end-member cases obtained from reservoir models of the CO_2 injection. These end-member cases assume the residual gas has been flushed laterally by the CO_2 after injection. Fluid properties for this scenario are displayed in Table 3. A porosity of 28% (high case) was assumed for the Captain D sands providing more than 70% of the storage container space. The fluid properties were calculated for pressure of 151bar (2200 psi) and 227bar (3300 psi) representing the increase in pressure over time during the injection phase.

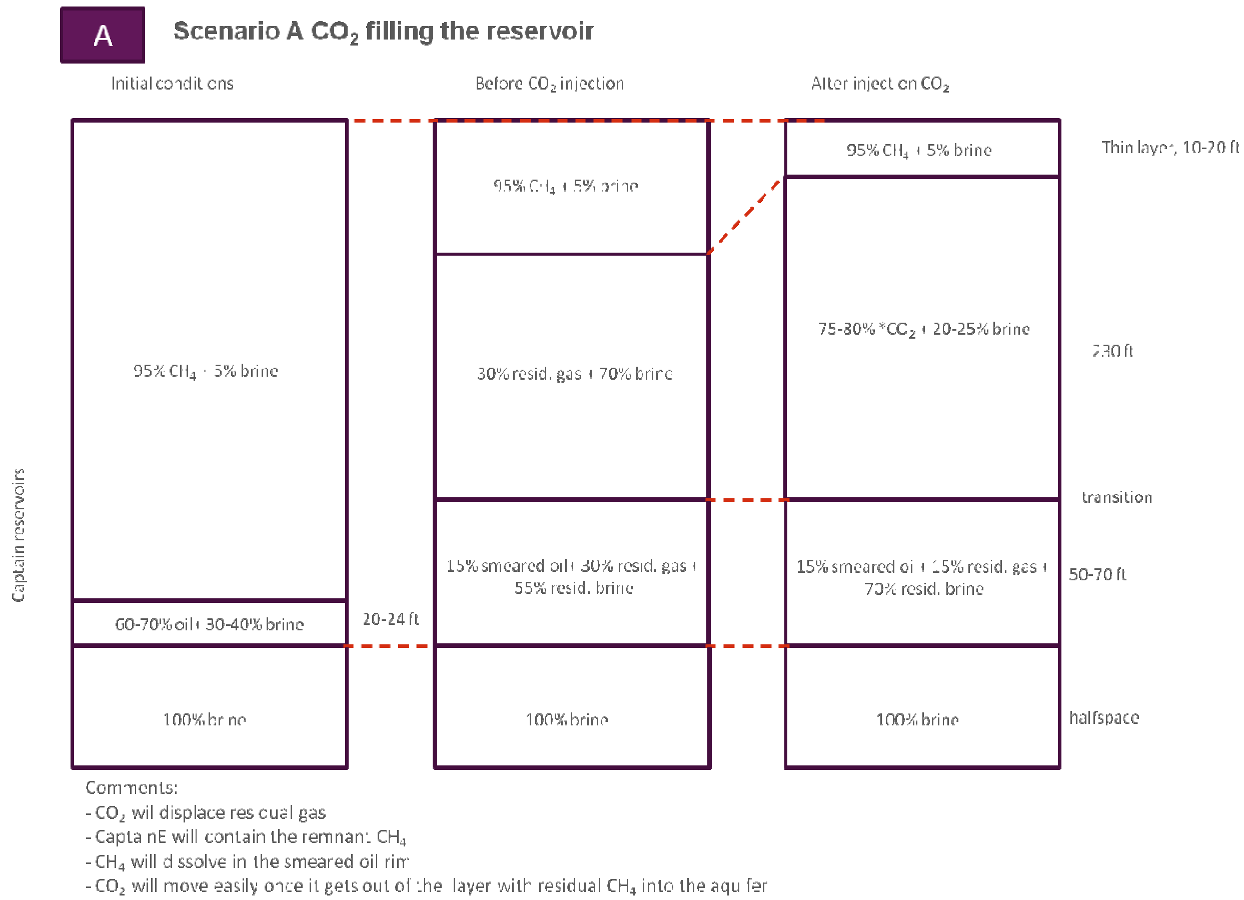


Figure 23. Scenario A CO_2 filling the Goldeneye Captain reservoir block model.

Figure 24 and Figure 25 show the calculated synthetic seismic traces pre-injection (30% gas, 75% brine) and post-injection (75% CO_2, 25% brine). The 100% brine case is plotted for comparison. The pre-injection and post-injection traces are virtually identical and show that it will be difficult if not impossible to monitor a CO_2 plume migration in the hydrocarbon reservoir Captain sands. The same is true when pressures are varied between pre-injection 151bar (2200 psi) and post-injection conditions 227bar (3300 psi). During production and subsequent CO_2 injection the original thin oil rim is smeared across the reservoir, but this does not lead to a visible change in the acoustic response.

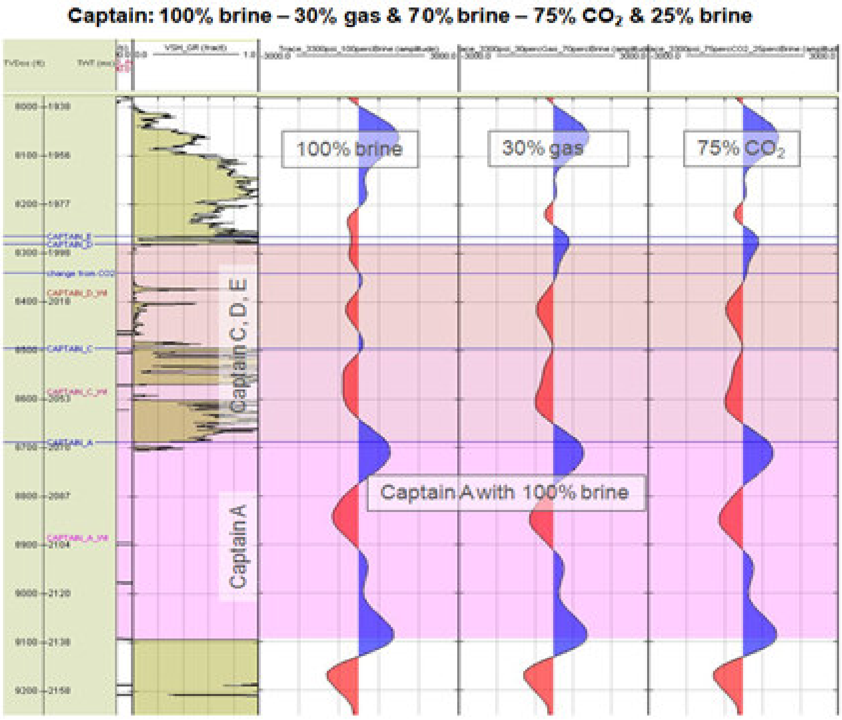


Figure 24. **Scenario A. Goldeneye reservoir Captain sands CO_2 injection amplitude response. Note: the remaining pore space of the 30% gas and 75% CO_2 case is occupied by brine.**

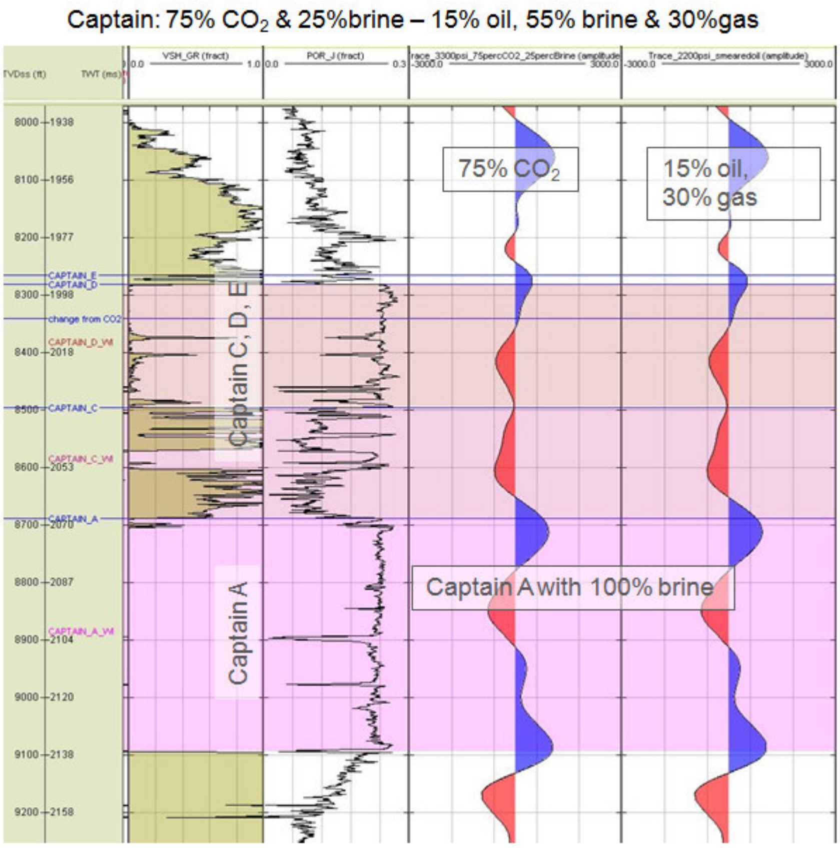


Figure 25. **Goldeneye reservoir Captain sands CO_2 injection smeared oil amplitude response. Note: the remnant pore space of the oil & gas case and CO_2 case is occupied by brine.**

7.2.1.1.3. Scenario B. CO_2 plume migration into the Captain sand aquifers and movement towards spill point

The reservoir models indicate that the CO_2 (possibly mixed with remaining hydrocarbons) will move laterally to the aquifer in the captain sands (Dietz tongue – stage 2 Figure 22) during injection, and before the reservoir equilibrates after injection stops. The end members for this scenario are presented by the block models in Figure 26. Fluid properties are again taken from Table 3. The forward modelling for various saturation levels of CO_2 shows a strong seismic response for saturations of 10% and higher (Figure 27). Methane which could be pushed ahead of any CO_2 would cause an even stronger response because it is more compressible than CO_2.

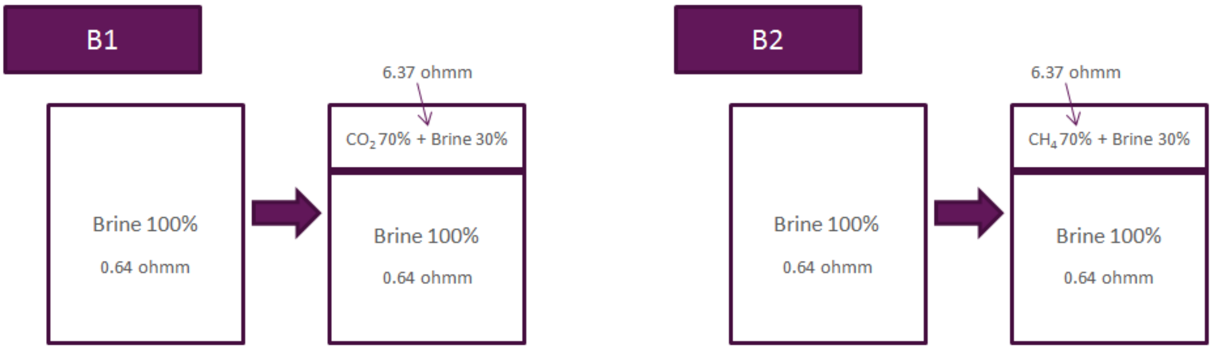


Figure 26. Scenario B. CO_2 plume migration into the Captain aquifers and movement towards spill point. CO_2 plume (B1) and methane plume (B2)

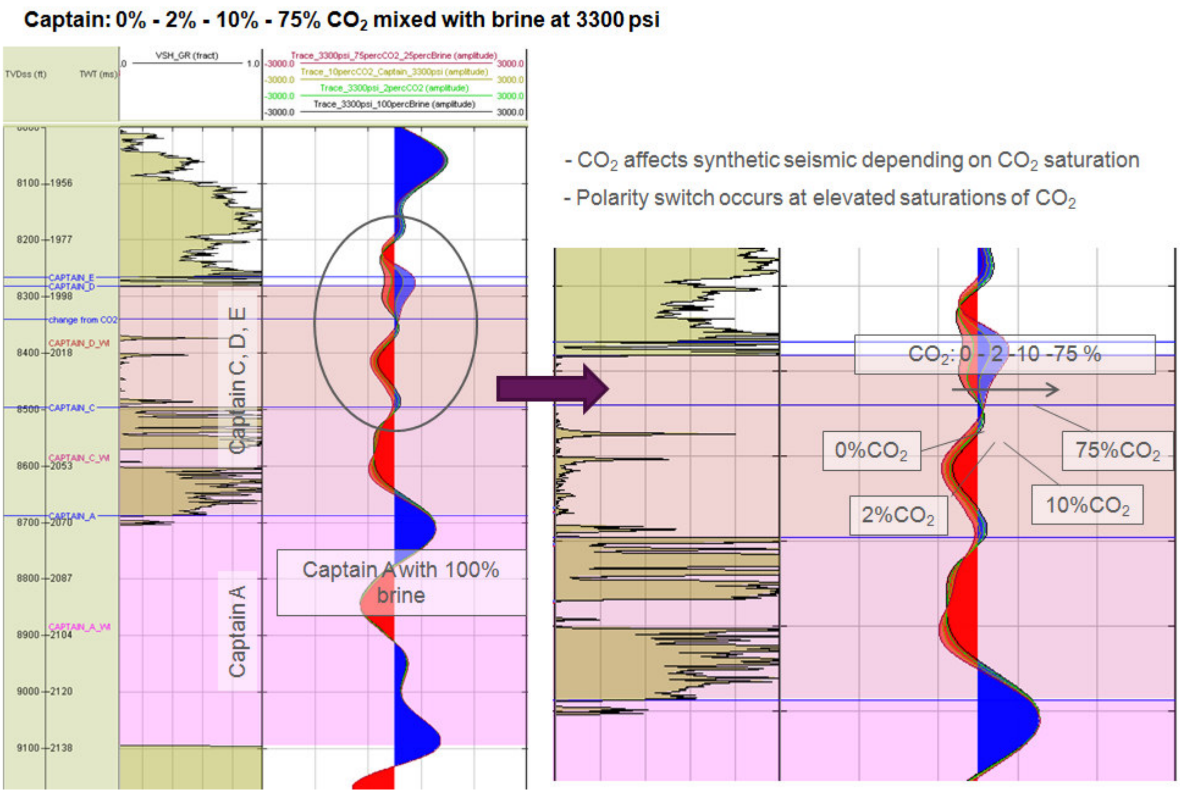


Figure 27. Scenario B. Captain sands aquifer amplitude response. Note that the remnant pore space of the different CO_2 cases is filled with brine.

7.2.1.1.4. Scenario C. CO_2 dissolution into the Captain sand aquifers and movement towards spill point

During the project lifecycle around 2% of CO_2 could dissolve in the aquifer. This will cause a small change in density and velocity which means that the acoustic impedance change will stay below the detection limit. This scenario will therefore not be detectable by time-lapse seismic. The block model is shown in Figure 28.

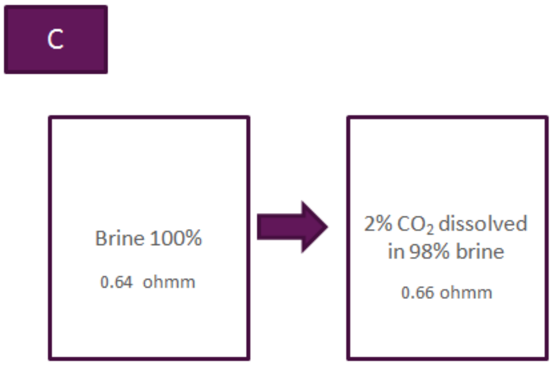


Figure 28. Scenario C. CO_2 dissolution into Captain sand aquifer

7.2.1.1.5. CO_2 plume migration into high porosity Mey sandstone in the Montrose Formation

For this scenario we choose the Mey sandstone properties (depth approximately 1200 m TVDSS) for the forward modelling. The Mey sandstone is very permeable and has high average porosity of approximately 30% which could, therefore, act as a secondary container if CO_2 escapes from the Goldeneye reservoir. Figure 29 shows a block model of the Mey initial conditions with possible gas content. However the model is made for various CO_2 concentration only, considering the other gas, CH_4, has similar effect. The modelled seismic response in Figure 30 is very strong for CO_2 saturations larger than 10%, but saturations of 2% may still be detectable. Acoustic impedance changes of up to 30% may be expected. The response is expected to be even stronger than for CO_2 in the Captain aquifers because CO_2 will be more compressible with lower pressures at shallower depths.

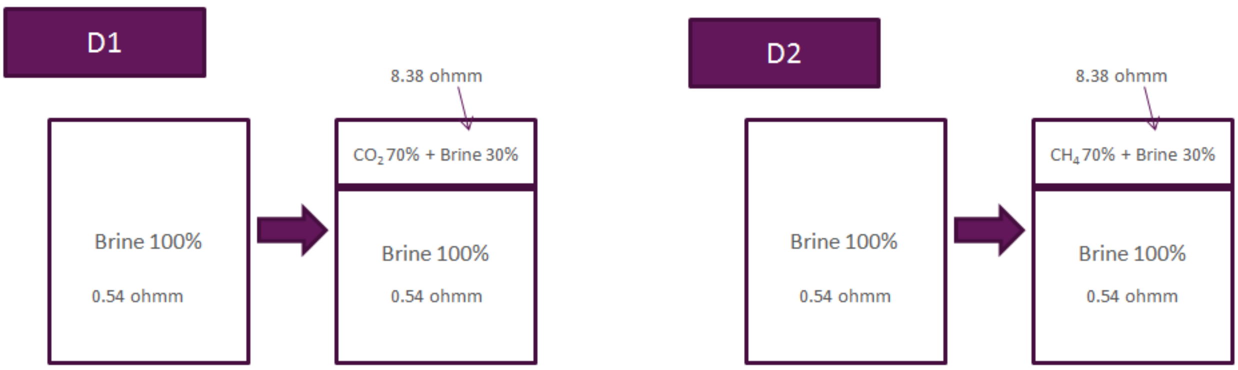


Figure 29. Scenario D. CO_2 migration into overburden - Mey sandstone

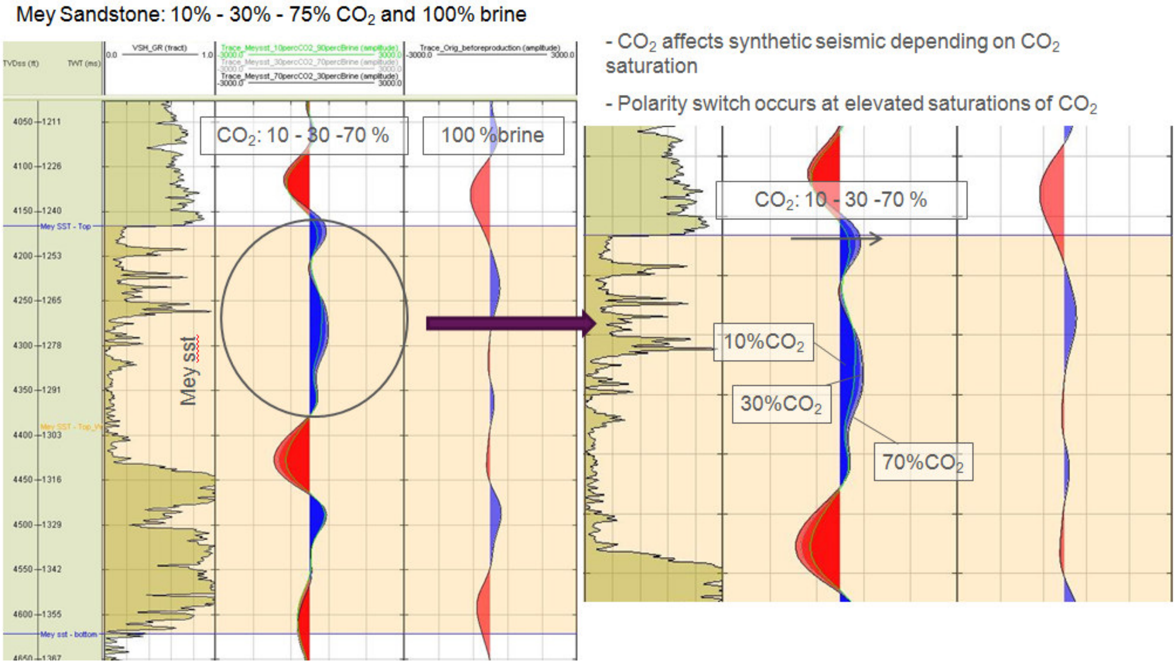


Figure 30. Scenario D Mey sandstone CO_2 amplitude response. Note that the remnant pore space of the different CO_2 cases is filled with brine.

7.2.1.1.6. Scenario E. CO_2 plume migration in the Nordland Group

For forward modelling this scenario the Westray Formation was chosen. The block model is shown in Figure 31. Again a good seismic response is expected for CO_2 saturations 10% and higher because the CO_2 will always be in the gas state which will cause a very strong response. A good amplitude response should be visible for a column thickness of several feet and further brightening occurs with increasing layer thickness.

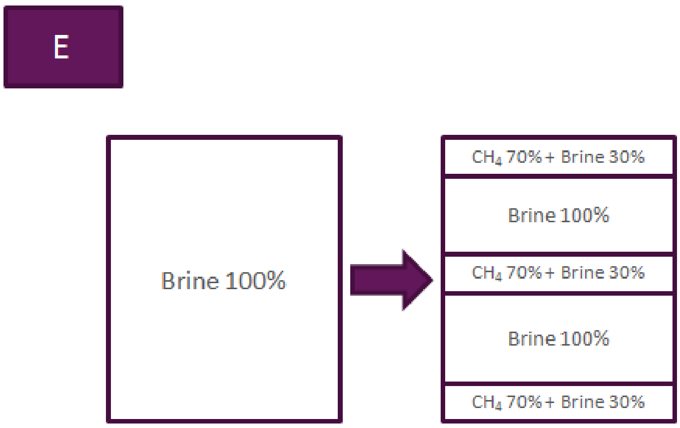


Figure 31. Scenario E. CO_2 plume migration into Nordland Group near surface (Westray Formation).

7.2.1.2. Impact of time-lapse seismic noise on CO_2 column height detection ability

The forward modelling study shows that a CO_2 plume movement may be detected in the Captain reservoir aquifer and the overburden (scenarios B, D and E). The detection ability will greatly depend on column height and seismic noise level and depend less on saturation level. In general, 4D seismic is more sensitive to CO_2 column height changes than 3D seismic. Table 6 compares the estimated interbed resolution and 4D seismic vertical resolutions. The 3D interbed was calculated using the Rayleigh criterion which states that the top and bottom of an interface (here the CO_2 column) can be detected if the column height is larger than $\frac{1}{4}^{th}$ of the dominant wavelength. 4D seismic resolution was estimated using a Normalised Root-Mean-Square (NRMS) difference of 30% between base and monitor surveys[22]. This value is typical for North Sea fields similar to Goldeneye consisting of a complex overburden including shallow coals and thick chalk packages. In the table we can see that seismic resolution decreases with depth due to absorption.

Table 6. Comparison of 3D interbed and 4D seismic CO_2 column height detection ability

	Depth	Velocity (average)	3D Interbed resolution * (top-bottom CO_2 column)		4D difference resolution (CO_2 column height) **
			@25 Hz	@50 Hz	Seismic-to-Well tie wavelet
Near surface (Westray)	0-500m	1750 m/s	12.5 m	25 m	~5 m (15 ft)
Secondary container (Mey)	1200-1500m	2050 m/s	14 m	28 m	~10 m (30 ft)
Primary container (Captain)	2500-2750m	2550 m/s	17.5 m	36 m	~13 m (40 ft)

Note: * Rayleigh criterion $1/4\lambda$; ** Gassman wedge model estimate

7.2.1.3. Time-lapse seismic acquisition techniques

Time-lapse seismic requires the acquisition of baseline survey and one or more monitor surveys. The technique can be applied to surface seismic and borehole seismic techniques, provided that the seismic baseline and monitor surveys are acquired with the same surface or borehole acquisition technique.

7.2.1.3.1. Surface seismic acquisition techniques

There are three main technologies to acquire surface seismic (3D & 4D) data. The first and most commonly used is a streamer survey where a vessel tows a number of streamers and airguns generate seismic pulses. The reflections are recorded on the vessel during deployment.

The second technique called OBC acquisition uses geophone cables which are placed on the seafloor or in a trench created in the seabed. The cable is hooked up to a boat or platform where the date is recorded during the survey. Once the cables are position a small shot vessel with an airgun array is used to generate the shot points. Permanent cables are ideal for time-lapse seismic because the receiver positioning is fixed.

The third technique uses a large number of so-called OBN that are placed on the seabed by a vessel with crane or with an AUV or ROV. The nodes contain geophone sensors. Like with OBC a separate air gun vessel is used to generate the shot points. The nodes will record data during the survey and are retrieved afterwards for data loading and processing. The different acquisition techniques are illustrated in Figure 32.

[22] Kragh, E. and Christie, P. 2002. Seismic repeatability, normalized rms, and predictability, *The Leading Edge,* **21,** 640-647

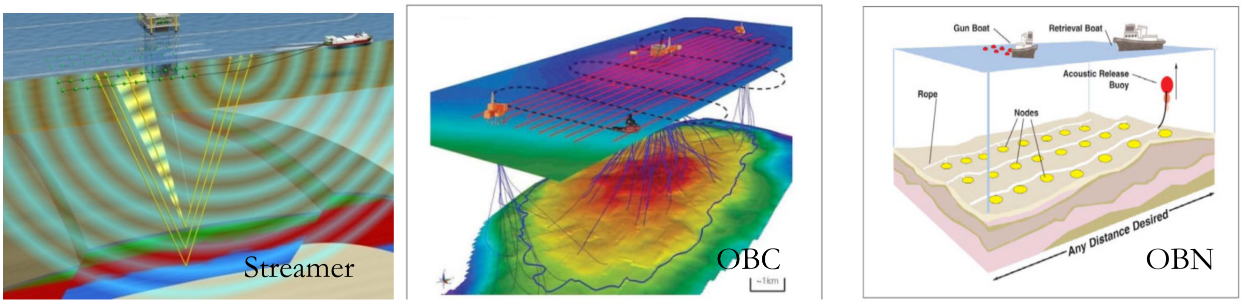


Figure 32. Seismic 'surface' acquisition technologies [23][24]

For time-lapse seismic streamer surveys in areas with surface infrastructure it is important to mitigate the illumination gap in the monitor surveys caused by the presence of the platforms, FPSOs, loading buoys or other infrastructure and related vessel exclusion zones (Figure 33). To fill the gap an often expensive 4D undershoot is required where an additional source vessel tries to undershoot the gap when the streamer is sailing on the other side of the platform. For OBC and OBN this is less of a limitation because they can deploy a small shot vessel without a streamer that can operate much closer to surface infrastructure. Streamer vessels may tow multiple arrays (typical 6 or 8 separated 75-100m apart) with lengths of up to 10km, which limits manoeuvrability in the presence of infrastructure. For streamer surveys one can consider a so-called platform undershoot which will require a dual boat operation.

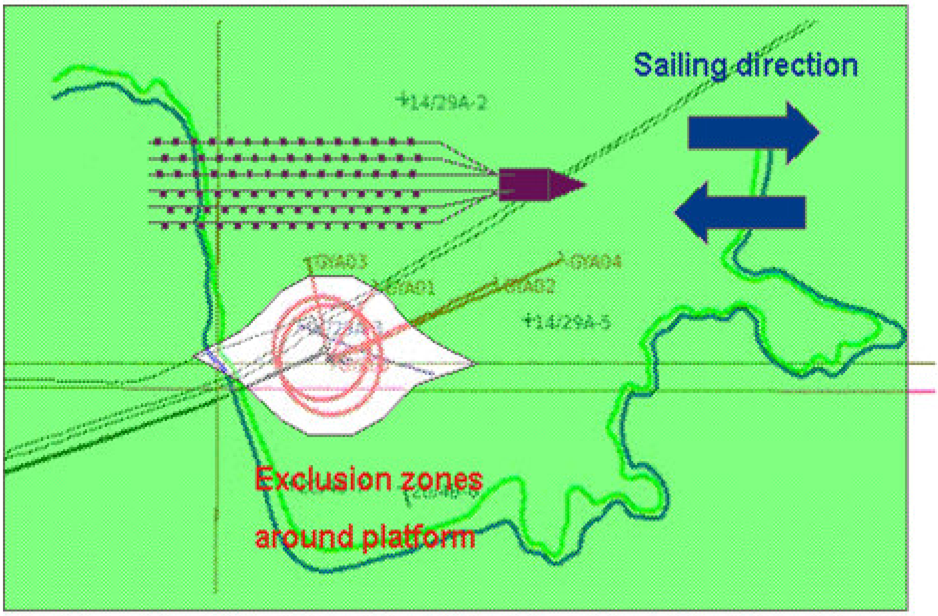


Figure 33. Illumination gap causes by the seismic streamer vessel manoeuvring around surface infrastructure (for example platform, loading buoys).

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[23] Middle Figure source: Van Gestel, J.-P., Kommedal, J.H., Barkved, O.I., Mundal, I., Bakke, R. and Best, K.D. 2008. Continuous seismic surveillance of Valhall field. *The Leading Edge* **27(12)**: 1616-1621.

[24] Right Figure source: A new 'node' of acquisition. Steve Mitchell, Fairfield Industries. Published in Hart Energy Publishing 4545 Post Oak Place, Ste, 210, Houston TX 77027 USA 713 993-9320

7.2.1.4. Borehole seismic – Vertical Seismic Profiles and Crosswell seismic

7.2.1.4.1. Vertical Seismic Profiles (VSP)

Vertical seismic profiling is a seismic acquisition technique where the geophones or hydrophones are placed in a well to record surface shots by seismic source array at surface, Figure 34. Because the geophones are closer to the monitoring target VSPs will often produce a more detailed image near to the wellbore than surface seismic. The aperture is, of course, limited because geophone positions are limited by the well trajectory.

VSPs require a good coupling to the formation which is achieved by clamping the tools to the casing or cementing them into the completion. The casing needs to be properly coupled to the formation by a good cement bond.

For time-lapse purposes permanent receivers are recommended. The geophones are typically placed about 1000m above the area to image (typically the reservoir). Vertical resolution is typically 1.5-2 times better than surface seismic within the imaged area. For Goldeneye focussed application may be considered in dedicated observation well if frequent monitoring is required upon analysis of reservoir or geomechanical study results. It may be difficult to use the existing injector wells for this purpose, due to the cement configuration outside the reservoir zone. Proper coupling with formation is critical.

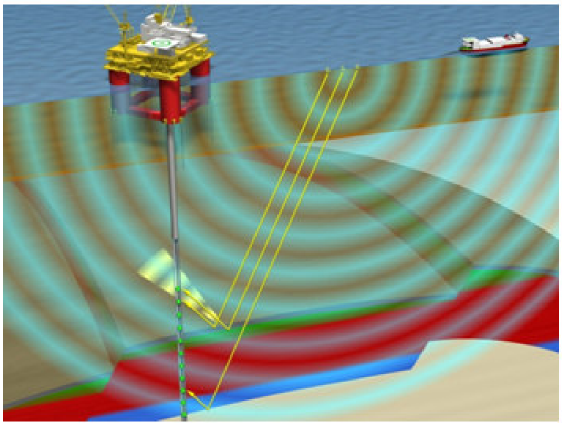

Figure 34. Geophones are place in the well, sources are at surface.

7.2.1.4.2. Cross-well seismic

In cross-well seismic profiling both the source and receivers are placed in separate wells (Figure 35). Because the sources and receivers are placed close to the target, high-resolution images can be acquired of the section between the wells. Because the sources are weak compared to surface seismic sources typical industry applications use well pairs of up to 250m apart. This precludes the use of crosswell seismic for Goldeneye because all existing well pairs are approximately 750m or further apart at reservoir level.

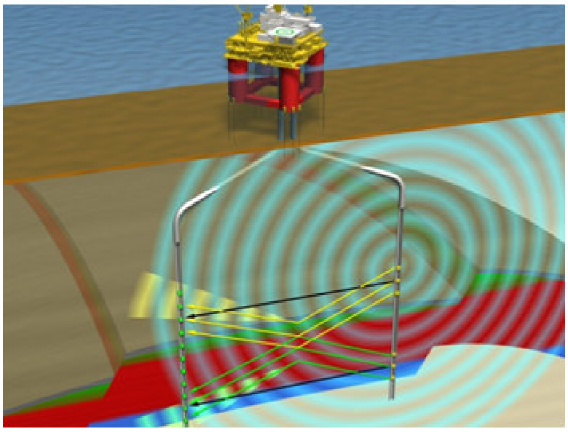

Figure 35. Crosswell seismic profiling – both source and receivers are deployed downhole.

7.2.1.5. Seismic technologies – areal coverage and vertical resolution

Figure 36 shows the difference in areal and vertical coverage between seismic imaging techniques:

3D seismic surveys (streamer, OBC, OBN) can cover the full field (with some care taken to undershoot the illumination gaps created by surface infrastructure as explained in §7.2.1.3.1). They create a true 3D image. Note that, for proper 3D imaging, typically a migration rim is required with a width dependent on target depth and structural dips.

3D swaths are 'mini' 3D surveys (streamer, OBC or OBN) and cover only a limited area. These are typically used over high risk areas or to demonstrate the ability of 4D seismic to track the plume before full field deployment. For 3D swaths synergy should be sought with other planned surveys in the area to limit the high mobilization/demobilization costs for a 3D vessel.

2D lines are acquired by a single streamer (often low-cost) seismic streamer vessel. The image will also have limitations related to the correct imaging dips in case of strongly dipping structures or in the presence of multiples.

Shallow 2D high resolution seismic acquisition can be used to detect gas pockets in areas that cannot be properly covered by 3D seismic (for example in the exclusion zone near the platform). Care should be exercised since this technology is not well suited to 4D monitoring.

3D VSP cover a 3D cone with a base radius of up to 750m around the observation well.

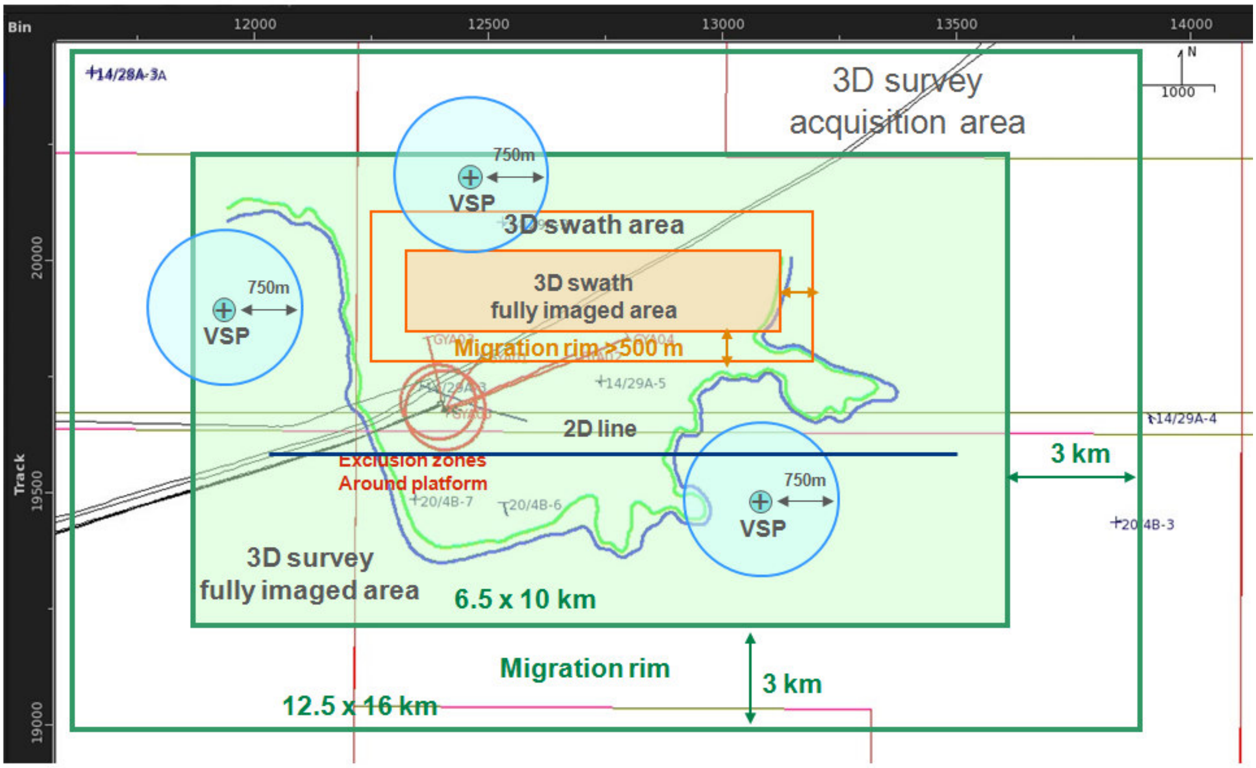

Figure 36. Comparison of areal and vertical coverage between seismic imaging techniques

7.2.1.6. Time-lapse seismic summary

Seismic forward modelling results

The study outcome for each of the scenarios can be summarised for time-lapse seismic as follows (Goldeneye gas is in this model is assumed to be CH_4):

Scenario A: CO_2 filling the Captain reservoir sands after condensate production. Condensate production will be difficult to detect. CO_2 replacing CH_4 in the gas-cap and the CH_4-brine mixture have similar seismic signatures.

Scenario B: Plume migration into the Captain Sandstone aquifers and move to a spill point maybe detectable for CO_2 saturations of as low as 2%, and will likely be detected at saturations of 10% CO_2 and higher. CO_2 columns with a thickness of more than 40 ft are detectable for noise levels similar to the high definition 1997 Ettrick East 3D seismic survey.

Scenario C: CO_2 dissolution into the Captain Sandstone aquifers will be difficult to detect because the acoustic impedance changes will be minimal. There is only small density and Vp velocity contrast between brine and brine with CO_2 dissolved.

Scenario D: CO_2 plume migration into high porosity sandstone in the Montrose Fm below the Lista. CO_2 saturations of as low as 2% may be detectable, CO_2 saturations of 10% or more are very likely detectable for CO_2 columns with a thickness of more than 30 ft.

Scenario E: CO_2 plume migration into Nordland Group near surface, is very likely detectable for CO_2 saturations of 10% with a thickness of more than 15 ft.

Figure 37 plots estimated acoustic impedance changes for the scenarios against the time-lapse seismic detection limit of 2%. Scenarios B, D and E have acoustic impedance changes that are comfortably above the 4D seismic detection limit. Scenario C is clearly below the detection limit. The estimated resolution for a CO_2 column of 4D seismic and interbed resolutions for 3D seismic were discussed in §7.2.1.2 and displayed in Table 6.

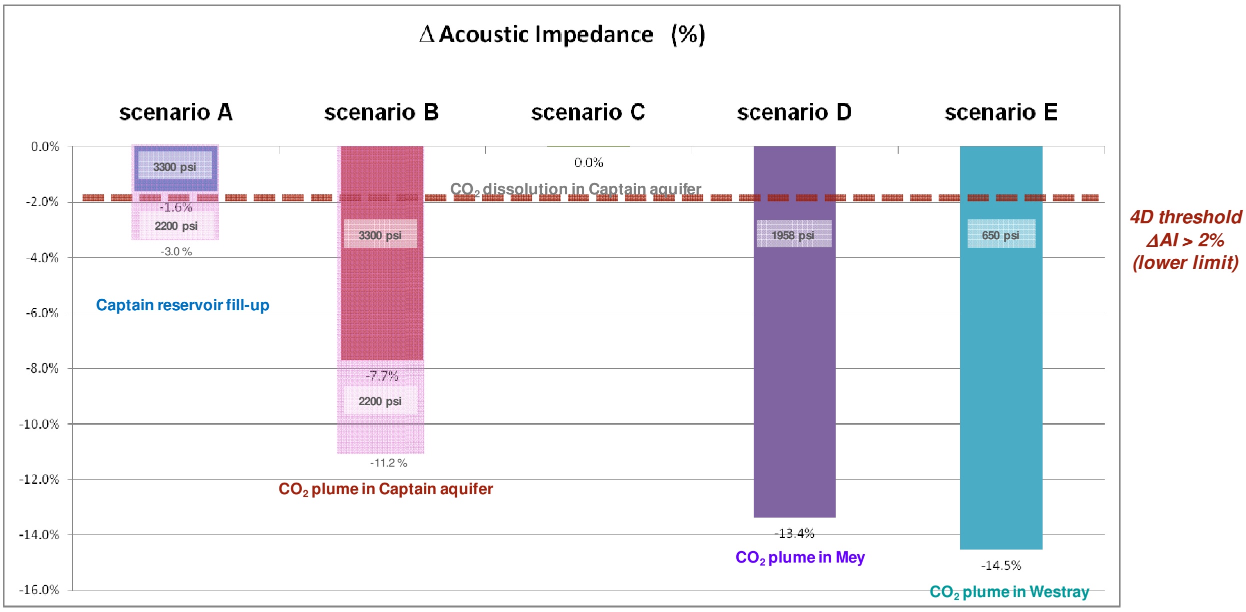

Figure 37. Comparison of areal and vertical coverage between seismic imaging techniques. In this figure scenario A compares 70% CO_2- 30% brine and 70% CH_4- 30% brine saturations. Scenario B, D and E were calculated for a 10% CO_2 saturation in a virgin aquifer. Scenario C is the CO_2 solution case for which minimal acoustic impedance changes are expected.

Seismic acquisition techniques

In principle surface seismic acquisition techniques (2D and 3D streamer, OBN and OBC) and borehole Vertical Seismic Profiles should be able to detect CO_2 plume movements in time-lapse mode in the Captain aquifers and the overburden as shown in the Gassmann feasibility study. The 3D surface seismic techniques covered have the advantage that they can cover any part of the field. OBN and OBC provide better coverage under the Goldeneye platform compared with seismic streamer seismic needing a dedicated platform undershoot. VSPs have limited areal coverage but may be cost effective to monitor high-risk areas like wells, and potential spill points but would require a dedicated observation well. High resolution 2D shallow seismic may be able to detect a new gas cloud near the seabed but is not useful to monitor at reservoir depth or in time-lapse mode.

7.2.2. Microseismic

7.2.2.1. Microseismic feasibility study objectives

Previous hydrocarbon production from Goldeneye has resulted in an underpressured reservoir. Repressurisation during CO_2 injection and injection causing related hydraulic or thermal fracture growth could potentially lead to failure of the Rødby Fm caprock (scenario F) or to fault reactivation in the reservoir or Chalk Group (scenario G) leading to the creation of new unwanted CO_2 migration pathways from the Goldeneye reservoir into the larger container complex. A feasibility study was carried out to understand if microseismic can potentially monitor these scenarios. The study consisted of a small literature study to find analogue examples of microseismic application in existing CO_2 storage or EOR projects, detection ability and error location modelling to understand if microseismic sensors in a observation well can detect and delineate reservoir caprock failure or fault reactivation. It concluded with some initial recommendations on tool selection for focussed application.

7.2.2.2. Microseismic application in existing CO_2 storage and EOR projects

Several examples of microseismic application in CO_2 EOR and CCS projects were found. Microseismic is used to track CO_2 movement and containment in the Aneth oil field in San Juan County, Utah[25]. The reservoir depth is 1707-1768m. During CO_2 injection a significant number of induced microseismic events with seismic moment magnitudes of -1 to 0 were monitored. They were possibly related to reactivation of a fault at 1.5km distance. Another example is the application of microseismic to track active faults and fractures during injection in the CCS pilot in the Weyburn-Midale oil EOR project in Saskatchewan, Canada. Microseismic events with magnitudes of -2.5 to -1.0 were located up to a distance of 500m from source and successfully correlated with various stages in the WAG (water alternating gas) cycle[26]. For Goldeneye, the geomechanics and reservoir engineering feasibilities are in progress and initial results indicated that caprock failure is a very low risk.

7.2.2.3. Event detection ability and location errors

The modelling in our study assumed that fault movement or caprock failure will trigger microseismic events with a seismic moment magnitude of -2.0 or smaller. The tested array configurations assume an 8 level 3-component geophone installation in the proximity of the reservoir and caprock. Since we are testing a single well configuration, our detection criterion requires that P and S wave arrivals can be picked on at least 4 geophones in order to locate the event. In the inversion algorithm we assume a picking uncertainty of 2ms for both P and S waves. Based on experience in similar projects we assume that events in the same layer as the geophone are easier to detect than in layers above or below. Therefore dip uncertainty is set to 45° and azimuth uncertainty is set to 5°. Seismic absorption is assumed the same for P and S; a Q value of 120 is used for the modelling. For noise level we use 2.0×10^{-8} m/s for installation in a 'quiet' dedicated observation well and $1.0e\times10^{-6}$ m/s for a 'noisy' live injector well. To determine the approximate detection range we initially use a constant velocity model assuming using estimated chalk velocities (Vp = 4295m/s and Vs = 2148 m/s). A Shell proprietary tool is used to calculate microseismic event detection ability and location error uncertainty. Figure 38 shows the results for the quiet observation well.

The impact of noise is shown in Figure 39. In the low noise environment in the quiet well events with a seismic moment magnitude of -2.0 or less can be detected up to approximately 600m. In the noisy injector environment the modelled detection range reduces to approximately 250m for -2.0 magnitude events.

Typically the number of geophones is determined by the budget available for monitoring because the cost increases with the number of levels deployed (4 or 8 level systems are typical), but the length of the array is a matter of choice. The benefits of increase detection ability for a larger aperture array will have to be balanced against the lowered chance of detecting the event on multiple geophones.

[25] Zhou, R., Huang, L. And Rutledge, J. 2010. Microseismic event location for monitoring CO_2 injection using double-difference tomography. *The Leading Edge* **29(2)**: 208-214.

[26] Verdon, J.P., White, D.J., Kendall,J.-M., Angus, D., Fisher, Q. And Urbanic, T.. 2010. Passive seismic monitoring of carbon dioxide storage at Weyburn, *The Leading Edge* **29(2):, 200-209.**

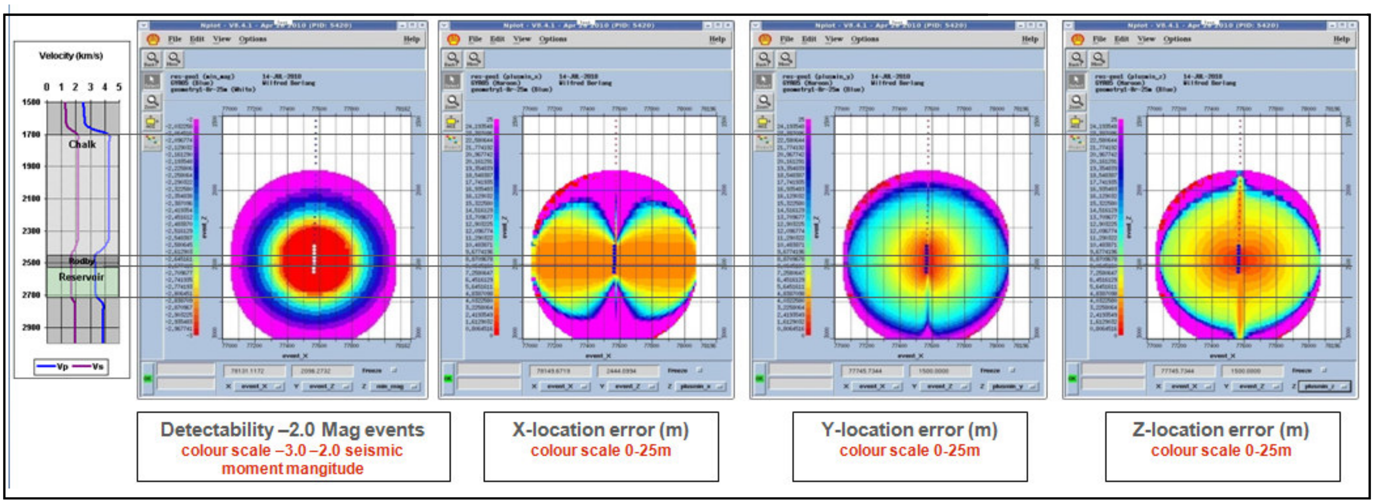

Figure 38. Microseismic feasibility – detection ability of events with seismic moment magnitude > 2.0 and associated X, Y and Z location uncertainty

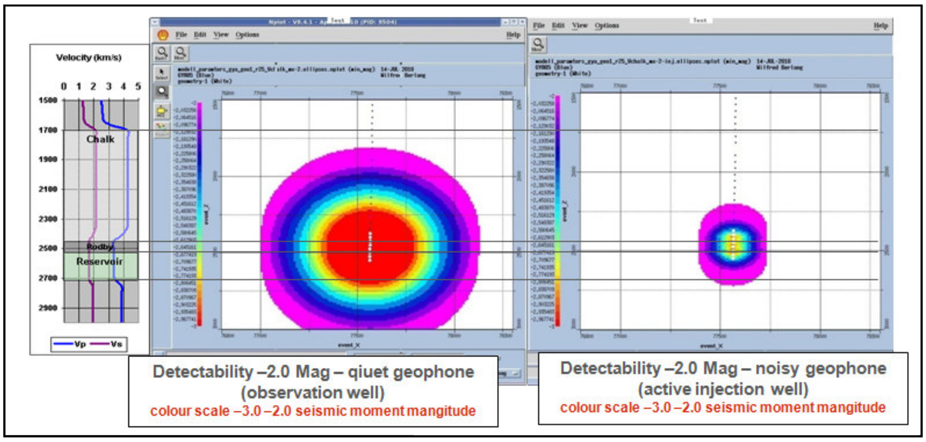

Figure 39. Microseismic feasibility – detection ability of events with a seismic moment magnitude > 2.0 comparing a 'quiet' low noise monitoring well (left) with a 'noisy' injector well (right)

The areal coverage of microseismic arrays deployed in multiple wells is shown in Figure 40. The grey envelopes show the detection range for the existing five Goldeneye wells assuming all were dedicated, quiet observation wells. The coloured insets show the coverage for use in live injectors. This figure clearly illustrates that it is a challenge to cover the full field with a limited number of microseismic arrays. To monitor a risk area the sensors need to be installed in a well nearby. Locations should be carefully chosen based on simulations of modelled fracture lengths related to CO_2 injection, seismic fault location, and geomechanical risk analysis.

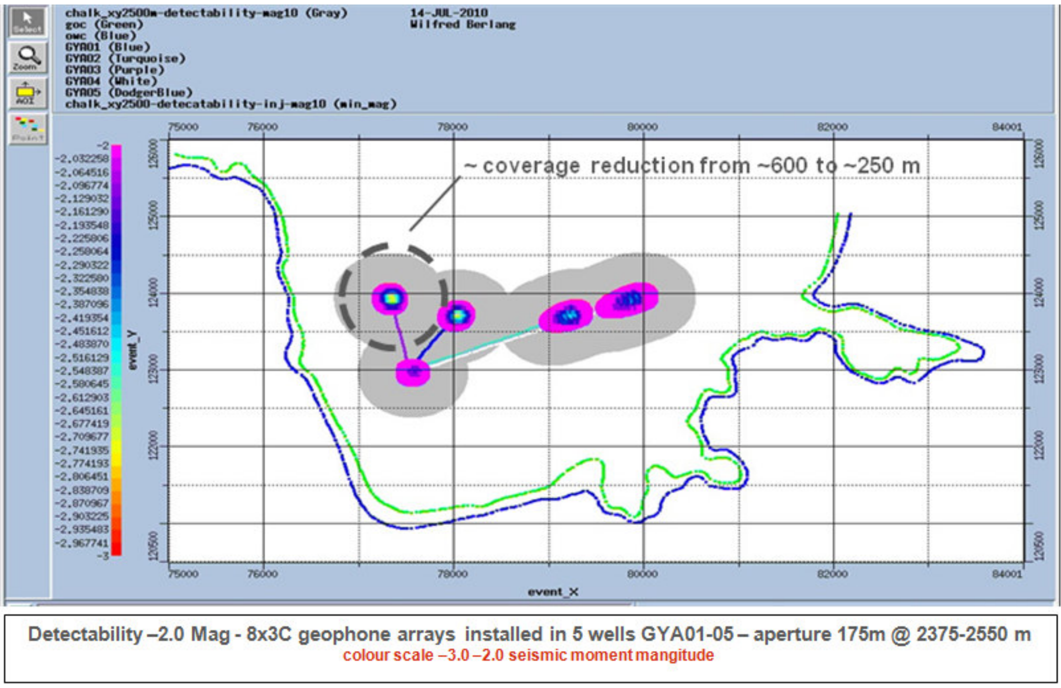

Figure 40. Detection feasibility for events with a seismic moment magnitude > 2.0 assuming microseismic arrays are deployed in five wells across the Goldeneye field. The grey outlines represent the detection ability contours for 'quiet' dedicated observation wells. The coloured outlines for 'noise' injector wells

7.2.2.4. Microseismic monitoring preference

There are two types of microseismic deployment techniques one uses downhole receivers to detect the release of seismic energy, the other uses a surface or seabed geophone array.

The use of surface arrays is a more recent development. On land regular seismic geophone arrays can be used or geophones can be permanently cemented in place in shallow observation wells just below the weathering layer. In the offshore environment OBC can be used.

Downhole receivers can be deployed permanently with geophones either clamped to the casing or cemented in the completion or for shorter periods, using a wireline string where geophones are clamped to the casing using a spring or magnetic lock system. The array is typically installed in a well close to the risk area that requires monitoring for fault movement, fracture growth or caprock integrity. The same system can be used for VSP acquisition, saving on total installation costs.

For Goldeneye the feasibility study only considers borehole microseismic because of the depth of the monitoring objective (approximately 8200ft / 2500m TVDss) and the absence of OBC cables (which would be very costly to install).

For microseismic installation the following points are important:

- Contact with the casing or formation is required – this means pulling the tubing – which excludes the use of a wireline for a live injection well.
- For a limited time period clamping wireline tools can be employed
- Faults, fracturing, seal integrity monitoring is typically required over longer periods of time which makes a wireline application costly.
- Proper coupling to the casing or formation is important and can be achieved with a cemented geophone or some kind of clamping system. Schlumberger's Omega-Lok system is an

example of a clamped tool that is be suitable for application in the Goldeneye monitoring wells.

- Another option to consider is installation of geophones cemented behind casing. The latter is only an option for a newly drilled dedicated observation well.

Microseismic tools require good coupling, proper cement bonds and closeness to the monitoring target. For a dedicated observation well a good cement bond and sensor placement is not a problem, for the existing injectors the absence of proper cement in non-reservoir zones may be a problem.

7.2.2.5. Microseismic summary

The requirement for microseismic monitoring should be assessed based on the results of the injection fracture modelling, and fault slip, geomechanical studies that assess potential risk for leaks through fault reactivation, caprock failure or hydraulic fracturing. Initial results indicate a very low risk.

Detection ability and location error modelling indicate that in a low noise environment (dedicated observation well), seismic moment magnitudes larger than -2.0 can be detected up to approximately a distance of 600m with a location accuracy of less than 25m. In a high noise environment like a 'live' injection well detection distance decreases to approximately 250m. Because of the limited detection range full field coverage is not possible and therefore focused application is recommended if needed. Note that the modelling results depend on parameter assumptions and uncertainties related to seismic velocity, Q, corner frequency and noise level estimates.

If risk assessment and value of information warrant, then permanent tool installation in a observation well is recommended; examples are Schlumberger Omega-Lok and behind casing geophone systems.

If microseismic is selected as a monitoring tool then an extended feasibility study is recommended to determine optimal geophone spacing and array aperture.

7.2.3. Non-seismic techniques

7.2.3.1. Seafloor Geodesy

7.2.3.1.1. Seafloor geodesy study objective.

The objective of this feasibility study is to test the feasibility of seafloor geodesy for CO_2 plume migration monitoring (scenarios A – E) which can be implemented by various techniques including GPS, pressure measurements and seafloor acoustic ranging. We focus on scenarios A and D assuming that a large volume of CO_2 has been injected and is stored in the Goldeneye reservoir Captain sandstone or has migrated to the Mey sandstones.

7.2.3.1.2. Geomechanical modelling seafloor deformation

To determine if seafloor geodesy can be used to de-risk the five CO_2 plume migration scenarios, a geomechanical study was carried out to estimate the possible seafloor deformation (subsidence or uplift) range related to CO_2 injection. Results from an extensive geomechanical study for Goldeneye predict that the maximum seafloor subsidence and uplift due to reservoir depletion from hydrocarbon production are approximately 46 mm and 36 mm respectively, see Figure 41. The rock properties used in the study are shown in Table 7 and were derived from Vp, Vs and density logs.

Table 7. Rock properties input for subsidence estimation in geomechanical study

Formation	Young's modulus (Gpa)	Poisson's ratio	Density (kg/m^3)
Nordland	2	0.46	2200
Coals	2	0.46	2100
Dornoch ss	4	0.43	2140
Ekofisk, Tor, Hod	32	0.32	2550
Rodby	10	0.38	2440
Humber, Heron	20	0.3	2300

Geodesy techniques that require deployment on the seafloor to monitor surface and reservoir deformation have been screened out for Goldeneye, only GPS on the platform is considered.

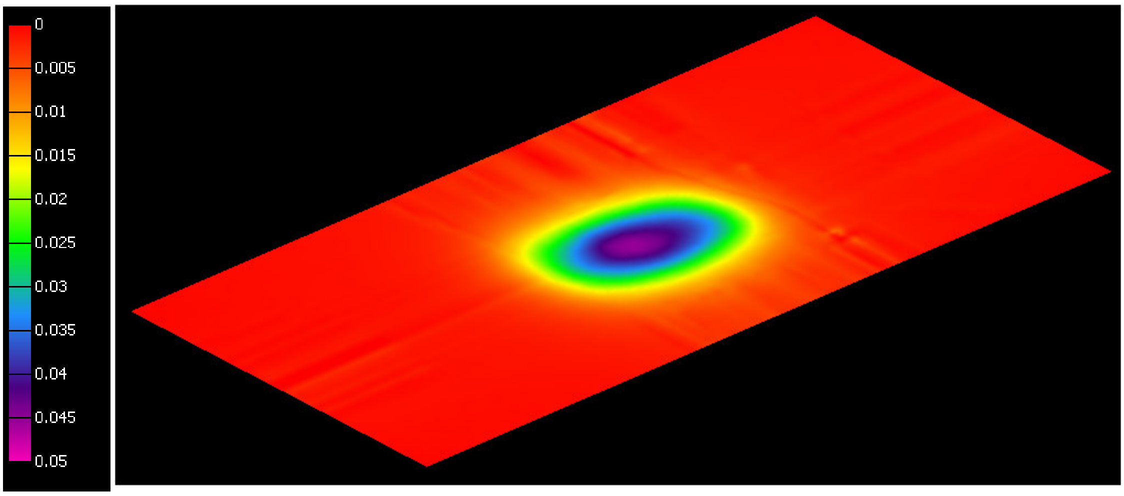

Figure 41. Geomechanical modelling predicts a maximum of 46 mm of seafloor subsidence related to hydrocarbon production. This image shows a bird's eye view of the sea-floor with subsidence (max 4.6 cm) after production. Colour scale ranges between 0 and 0.05m.

7.2.3.1.3. MBES

MBES sensitivity is typically 10-20cm or less. Seafloor subsidence uplift is expected to be much smaller which rules MBES out to monitor any of the plume migration scenarios.

7.2.3.1.4. Seafloor pressure and acoustic ranging sensors

Although a properly dimensioned seafloor network of pressure or acoustic ranging sensors may be able to delineate the plume to some extent after five years, the resolution will not be better than typically a third of the reservoir depth which is more than 800 m at best. This means that seafloor geodesy may have some use to test scenario A (fill up of the Captain sandstone in the Goldeneye reservoir), but it will be very difficult to delineate the plume to test scenario B (CO_2 plume migration in the Captain sandstone aquifer) given the low resolution. Migration of large enough volumes of CO_2 into shallow layers required to cause a difference signal is not expected and although detectable would be difficult to distinguish from scenario A because the inversion algorithms are currently not able to constrain the results in depth without additional information from seismic, gravity, CSEM or other methods. This screens out application of pressure sensors and seafloor acoustic ranging for CO_2 plume migration monitoring. In addition it should be noted that seafloor acoustic ranging trials have not been conclusive for (shallow) water depths similar to the Goldeneye water depth.

7.2.3.1.5. Differential GPS

Differential GPS measurements with one or more GPS sensors on the platform or the platform legs will be able to detect seafloor deformation signal as well. GPS sensors are typically inexpensive and the information may be useful to monitor platform safety however it is not applicable for monitoring CO_2 plume migration.

7.2.3.1.6. Seafloor geodesy summary

The expected maximum seafloor uplift 36mm or less is below the detection threshold of MBES which screens this technology out for plume migration monitoring.

Seafloor acoustic ranging or pressure sensors can pick up small deformations but with the current limited resolution and depth discrimination of the signal this technology will have difficulty to delineate the extent of the plume migration in size and depth which screens this technology out.

Differential GPS may be able to detect significant platform subsidence or uplift if larger than 10-20mm over the project lifetime. As the predicted maximum uplift due to CO_2 injection is estimated at 36mm, GPS will provide useful information about platform integrity and safety and can act as an early warning of unexpected events (a MMV trigger). The technique is relatively inexpensive and therefore we recommend installation of one or more sensors. Mounting sensors on the platform legs may help to detect tilt.

7.2.3.2. CSEM

7.2.3.2.1. CSEM feasibility study objectives

The objective of this study is to asses if CSEM can be used to detect changes in resistivity due to gas/fluid substitutions in the reservoir by computing the CSEM response of a 3D reservoir model in a 1D background. From the five CO_2 plume migration scenarios, scenario A CO_2 filling up the reservoir, and scenario D plume migration into a high porosity Mey sandstone in the Montrose Group were evaluated. These scenarios were chosen because they are the only scenarios in which the bulk rock resistivity change was significant enough for possible detection with CSEM. For both scenarios the 1D background model is the same and is calculated based on the resistivity log of well 14/29a-3. The end members for both scenarios were studied assuming that 20 million tons of CO_2 were either stored in Goldeneye reservoir or had leaked in its entirety into the Montrose Group sandstones.

7.2.3.2.2. Scenario A. CO_2 filling the reservoir Captain sands after hydrocarbon production

For scenario A the reservoir was represented by a block with an area of 4800m by 4500m with a height of 67m (220ft) representing the Captain D reservoir interval including aquifer. The resistivity after fill up was calculated as 6.4 ohm m assuming 70% CO_2 saturation. Figure 42 shows the modelled CSEM amplitude and normalized amplitude responses for this block model. The computed CSEM amplitude is above the noise level (10e-15 V/Am^2). The normalized amplitude or relative signal change due to the CO_2 injection is shown on the bottom right. The ratio between the CSEM response before and after CO_2 injection should be at least 15% in order to be interpreted with confidence. At the optimum offset of 8.5km the computed ratio doesn't exceed 1 % and hence this scenario is not detectable.

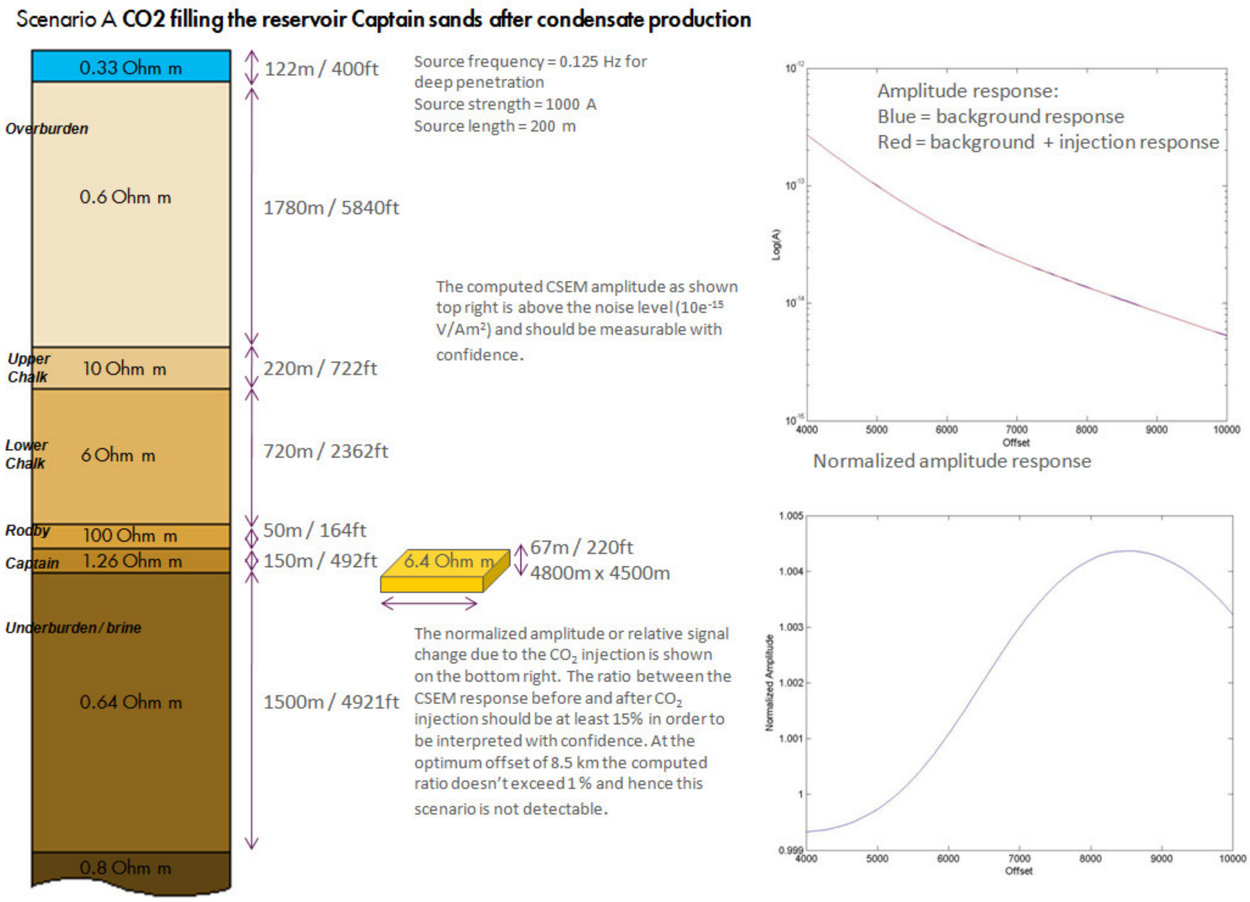

Figure 42. CSEM modelling results for scenario A CO_2 filling the reservoir captain sands after production. This end-member scenario assumes that 20 million tonnes of CO_2 have been injected and are securely stored in the reservoir. Left: background model. Right: amplitude &Z normalized amplitude response. Unit for offset is meters.

7.2.3.2.3. Scenario D. CO_2 plume migration into high porosity Mey sandstone, Montrose Group

For scenario D the reservoir is modelled as block with an area of 2275 by 2200 m and a height of 52 m (170 ft) presenting the Mey sandstone 'container'. The resistivity assuming a 70% CO_2 saturation was computed as 8.4ohmm. Figure 43 shows the modelled CSEM amplitude and normalized amplitude responses for this block model. The computed CSEM amplitude is above the noise level (10e-15 V/Am^2). Because the secondary container is much shallower the CSEM response is significantly stronger than for the target at reservoir depth. The size and relatively low expected resistivity of the CO_2 plume causes by the relative signal change to be just over 11%. Because the ability to discriminate the plume depends highly on the overburden resistivity, CSEM data processing for shallow water settings is highly complex and the large uncertainties in the overburden sensitivity levels. We expect that the signal will be difficult to detect.

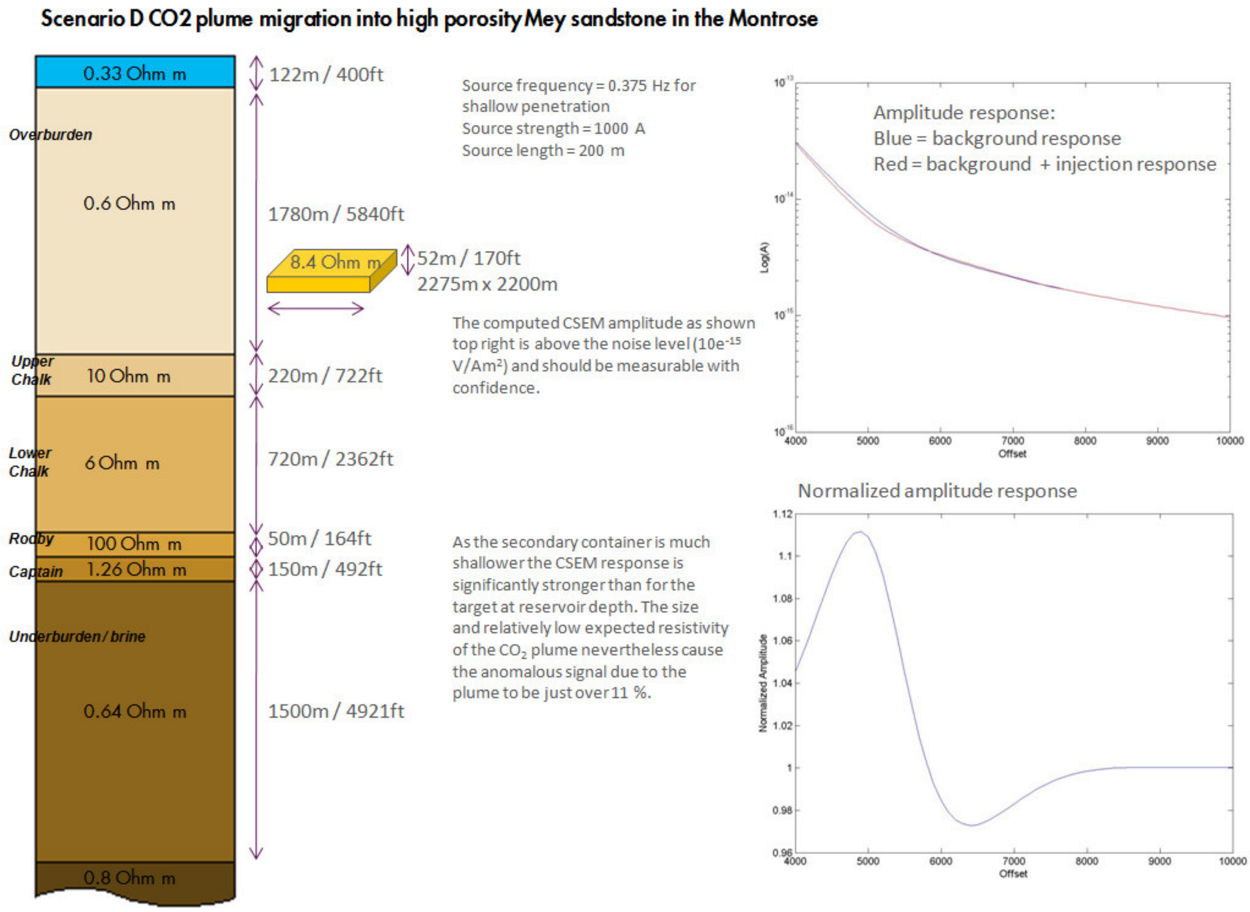

Figure 43. **CSEM modelling results for scenario D CO_2 plume migration into high porosity Mey sandstone in the Montrose Group. This end-member scenario assumes that 20 Million tonnes of CO_2 have migrated to the Mey. Left: background model. Right: amplitude and normalized amplitude response. Unit for offset is meters.**

7.2.3.2.4. CSEM summary

The simple block models and end-member scenarios assuming 20 million tonnes of CO_2 stored in the reservoir (primary container) or migrated to the Mey sandstone (secondary container) to study the electromagnetic response show that CSEM is not an appropriate technique to monitor CO_2 injection and plume migration in Goldeneye. In both cases the modelled signal is below the detection threshold. *For Goldeneye CSEM is not suitable and has been screened out.*

7.2.3.3. Gravity

7.2.3.3.1. Gravity feasibility study objective

The objective of the gravity feasibility study work is to determine if a network of seafloor gravimeters can be used to monitor the CO_2 plume geometry and verify containment or leakage from the primary container, the Goldeneye reservoir. From the five CO_2 plume migration scenarios, scenario A – CO_2 filling up the reservoir – and scenario D – plume migration into the high porosity Mey sandstone – were first evaluated because they are expected to give the strongest gravity signal. The current precision of seafloor gravity is assumed to be 3-20 microGal. The 3 microGal level requires a number of operational factors (multiple gravity sensors, frequent benchmark reoccupation, precise relocation and orientation of the sensors, etc)[27]. In this study, we assume a 10 microGal detection ability level. To forward model the gravity signal, a sensor spacing of 300m has been assumed. Surveys are assumed to take place before and after injection of 20 million tonnes of CO_2.

7.2.3.3.2. Scenario A: CO_2 filling the reservoir Captain sands after hydrocarbon production

For scenario A, a comparison was made between the initial state of the reservoir and Mey sandstone where no CO_2 was injected and the state of 20 million tons of CO_2 stored in the reservoir at 2600m depth. For the Mey sandstone a similar scenario was run assuming a scenario where 20 million tons of CO_2 have migrated into Mey at an estimated depth of 1220m. For both scenarios we assume a change in fluid content in part of the subsurface (either in the reservoir or in a shallower container). For simplicity, these parts are assumed to be cubic and have a homogeneous density. The density of the remainder of the subsurface is assumed to stay unchanged, which implies that the brine has been displaced to an adjacent reservoir. In reality, some of the brine will remain in place, resulting in an increased pressure and a smaller density change. Note that the modelled case presented here is the most favourable scenario for signal detection, as it overestimates the amount of brine displaced. Simple reservoir models were used to calculate the cubic container sizes. The reservoir extent was approximated by a 4000 x 4000m square box with an initial fluid column height before hydrocarbon production of 24m. After condensate production this column is filled with a mixture of brine and the remaining hydrocarbon. CO_2 injection will replace some of the brine. The fluid density of 609 kg/m^3 was computed for a pressure of approximately 206bar (3000psi) and a temperature of approximately 80°C. The gravity signal and scenario presented as box models are found in Figure 44. The maximum modelled amplitude change is -7.6 microGal which is below the assumed detection limit of 10 microGal.

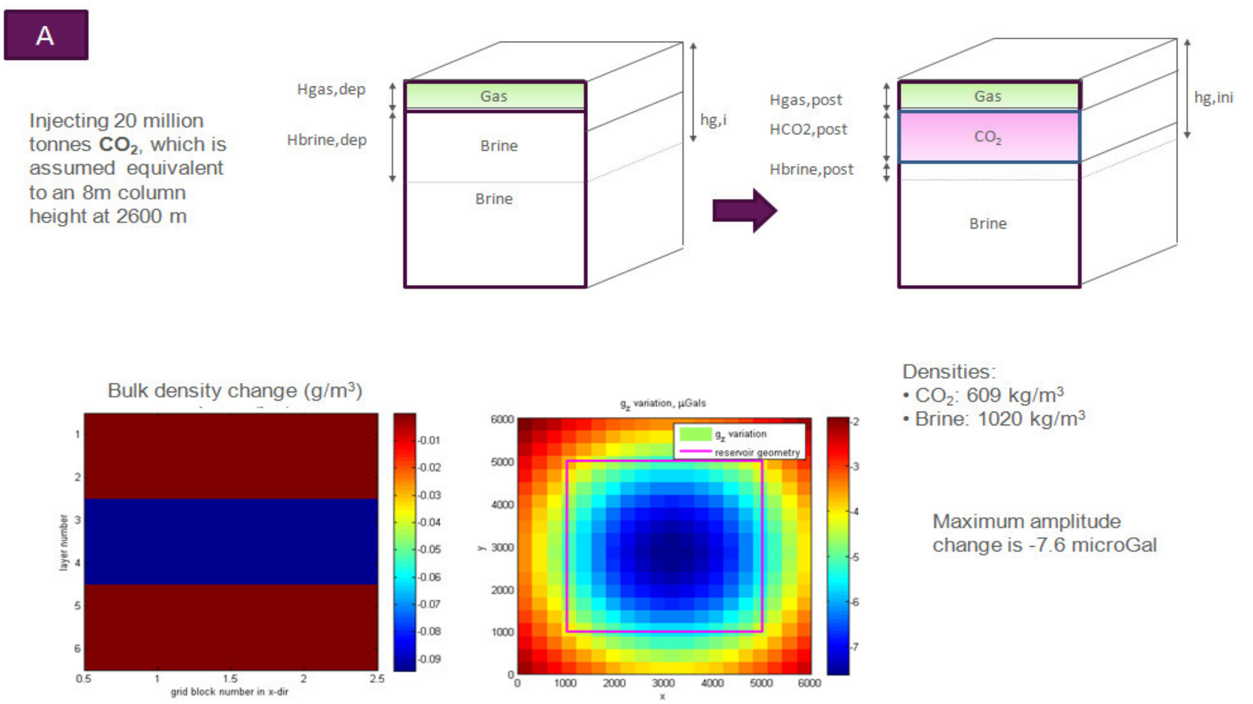

Figure 44. Scenario A. CO_2 filling the Captain sandstone reservoir. The unit for x-y cross plot in lower middle is meter

[27] M.Zumberge et,al., Precision of seafloor gravity and pressure measurements for reservoir monitoring. Geophysics Vol 73 , no 6 (Nov – Dec 2008), PWA 133-141

7.2.3.3.3. Scenario D: CO_2 plume migration into high porosity Mey sandstone, Montrose Group

For the Mey sandstone scenario we assumed that all the CO_2 has escape from the reservoir. Using a simple reservoir model we estimate that in the Mey the plume size will be approximately 2275m x 2275m, with a column height of 52m. The fluid density was computed as 736 kg/m^3 for a pressure of approximately 125bar (1810 psi) and a temperature of 40°C. Figure 45 sketches the evaluated scenario with the box models and shows the modelled gravity response. The maximum modelled amplitude change is -11.8 microGal, which is larger than the amplitude in scenario A and just above the detection limit. This is expected since the gravity signals are easier to detect with decreasing depth. Note that although the gravity signal is somewhat above our detection ability limit it would require the total injected volume of CO_2 in the Goldeneye reservoir to escape from the primary container and migrate to the Mey sandstones which is unlikely. In addition, it would be difficult to constrain the depth of the plume without additional information. Therefore, we can draw the conclusion that gravity will not be able to detect and delineate CO_2 plume migration within the larger container complex for the reservoir conditions assumed.

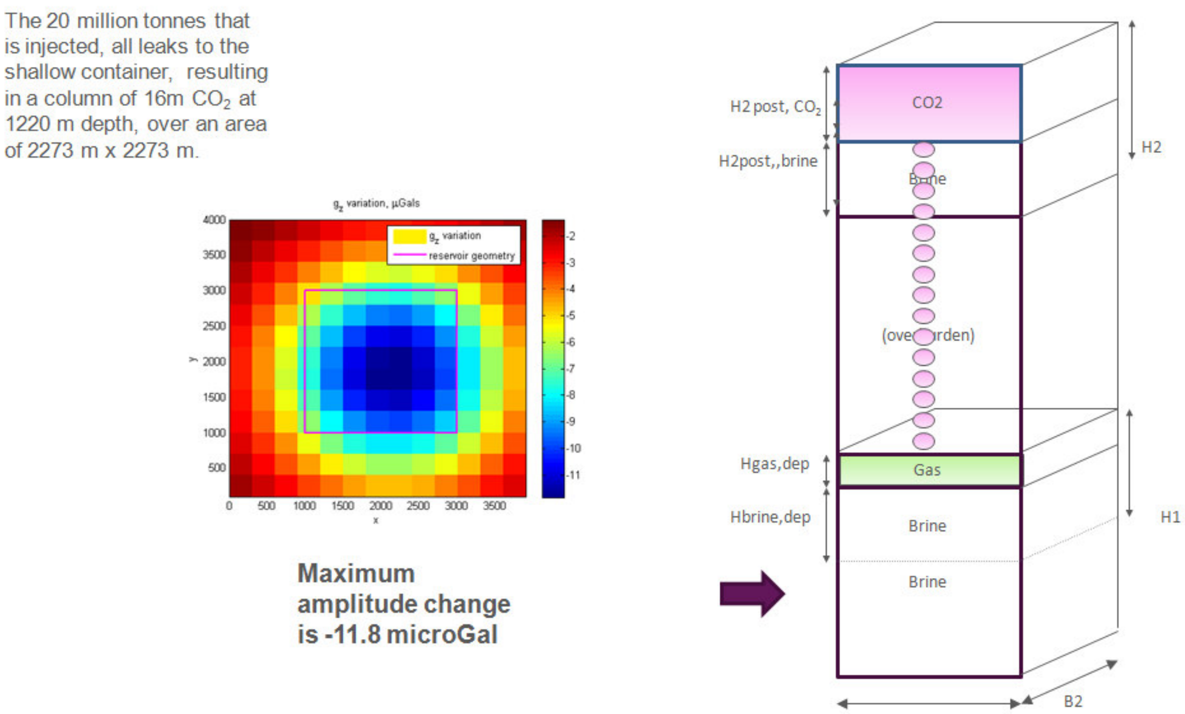

Figure 45. Scenario D: CO_2 migration to Overburden – Mey sandstone. The unit for x-y cross plot in lower middle is meters

7.2.3.3.4. Gravity summary

The simplified gravity feasibility study shows that CO_2 injection for Goldeneye given the reservoir depth and thickness is below the detection limit of the technique. A CO_2 leak into a shallower reservoir is at the edge of detection ability. Increasing the amount of CO_2 leakage (and injection) would lead to a detectable signal, but it will be difficult to determine the depth of such a plume with some certainty. For these reasons seafloor gravity has been screened out as a monitoring technique for Goldeneye. *For Goldeneye application of time-lapse gravimetry has been screened out.*

7.3. Well and Reservoir

7.3.1. Cement , Casing and Tubing Evaluation

Within Goldeneye field, five development wells are accessible from the surface platform. Four exploration wells have been plugged and abandoned at seabed. Since the exploration wells are inaccessible, the leakage risk is assessed using well schematics based on cement bond logging and plugging & abandonment procedure. The detail is further described in the Well Abandonment Concept report.

For these types of applications, well integrity logging consists of cement bond, casing corrosion and tubing integrity evaluation. Well integrity logging is performed directly inside the casing in instances where there is no existing tubing. This evaluation is possible during conversion of the development wells into injector wells, when the upper completion string is being replaced in preparation for the change of well function. Tubing integrity logging can be performed in all development wells, preferably once, prior to injection for stand-by wells and periodically for injector wells since the corrosion risk is much higher. Early identification of tubing corrosion or holes allows preparation of tubing replacements which minimizes the potential of CO2 leakage although the corrosion is unlikely due to 13Cr steel material that make up upper and lower completion. This material prevents corrosion when the injected CO_2 inlet stream is in dry condition and has limited O_2 concentration. Both are measured prior to injection.

The logging string recommended for cement bond and casing integrity tools is ultrasonic cement evaluation tool in tandem with basic cement evaluation (i.e. CBL) and Gamma Ray cartridge with optional addition of a Caliper. For tubing integrity it is recommended to run a Caliper and Electromagnetic tubular evaluation tool to check the condition of the inner and outer surfaces of the tubing.

7.3.2. Sigma and Neutron Measurements

7.3.2.1. Sigma

Sigma is derived from the rate of capture of thermal neutrons – mainly by chlorine – and is measured using capture gamma rays. Sigma measurements are stated in c.u. units and require sufficient formation fluid salinity to discriminate water from hydrocarbon and CO_2.

7.3.2.1.1. Reservoir Application

The objective of these tools is to indicate CO_2 break through at monitoring wells and where possible, identify the thickness of the CO_2 layer to update dynamic simulation modelling. The monitoring well(s), converted from production, may still contain hydrocarbon residues prior to CO_2 injection and will also contain the old lower completion, both of which will contribute to background 'noise'. A baseline reading will be required prior to CO_2 injection to minimise these effects. Subsequent readings are planned periodically during injection until it is completed.

The Goldeneye reservoir brine salinity is 50kppm, porosity is assumed approximately 28% and it is homogeneous sandstone with low shale content. A sigma response at varying pressures and compositions has been modelled to verify the difference between pre-, during- and post-injection response (ideal condition).

During the course of injection the pressure is expected to rise from 2000psi [138bar] to 3200psi [220bar], the temperature is modelled at 83^o C. Sigma is calculated as the sum of the individual materials that make up the Captain D reservoir, these are matrix (sand), water, CO_2 and CH_4. The equation used is as stated below:

$$\Sigma_{LOG} = (1-\phi)\times\Sigma_{SAND} + \phi\times S_{CH4}\times\Sigma_{CH4} + \phi\times S_{CO2}\times\Sigma_{CO2} + \phi\times S_W\times\Sigma_W$$

Where : $\sum_{Log}$ = Total Sigma reading (c.u.)

ϕ = Porosity (v/v)

$\sum_{sand}$ = Sigma Sand matrix (c.u.)

S_{CH4} = CH_4 Saturation (v/v)

$\sum_{CH4}$ = Sigma CH4 (c.u.)

S_{CO2} = CO_2 Saturation (v/v)

$\sum_{CO2}$ = Sigma CO_2 (c.u.)

S_W = Water Saturation (v/v)

$\sum_W$ = Sigma Water (c.u.)

Sigma at pre- and post-injection is derived based on estimated pressure, temperature and density for each material at such conditions. The sigma during injection will be calculated using a linear relationship between these two end-members. The references for sigma of materials are explained as follows:

Sandstone Matrix

Sandstone matrix typically has 6-13 c.u. sigma units[28]. In the North Sea, the average value used for sand is 10 c.u. Based on track record that this assumption when integrated into total sigma calculation, is relatively fit to actual logging. The same number is utilized for this feasibility study.

Water (Brine)

Using brine salinity, temperature and pressure (initial and final), water sigma is then derived from GEN-13 Capture Cross Section of NaCl water solution[29]. At 50 kppm, 83° C and 2000 to 3200 psi, water sigma is 38 c.u.

CH_4 (hydrocarbon gas)

CH_4 sigma is determined from following equation:

$$\Sigma_{CH4} = \frac{602.2}{GMW}\times\rho\times(n_C\times\sigma_C + n_H\times\sigma_H)$$

Where: $\sum_{CH4}$ = CH_4 sigma (c.u.)

GMW= Gross Molecular Weight

ρ = CH_4 Density (g/cc)

n = number of atoms present in the molecule

σ = Microscopic capture cross-section (barns)

Using GMW equal to 16, and microscopic capture cross-section for C and H (0.0034 and 0.332 barns), the expected CH_4 sigma at pre- and post-injection are 4 and 6.2 c.u. respectively.

CO_2

[28] James J. Smolen, *Cased Hole & Production Log Evaluation*, Chapter 5, Page 47

[29] Schlumberger, Log Interpretation Chart 2005, GEN 13, page 19

CO_2 sigma is calculated using similar equation for CH_4 but using CO_2 properties. The CO_2 GMW is 44 and microscopic cross capture for O is 0.00027 barns. Using this information the expected CO_2 sigma at pre- and post-injection are 0.019 and 0.033 c.u. respectively.

Two scenarios have been built, designed to model situations where injected CO_2 replaces CH_4-Water and where injected CO_2 replaces CH_4 only. The sigma response based on varying porosity has not been tested since the porosity of 28% is relatively homogeneous.

Scenario 1. Injected CO_2 replaces CH_4-Water

The Sigma response is simulated at $^1/_3$, $^2/_3$ and full injection stage which will have an impact on reservoir pressure and fluid composition. Since the measurements would be performed in a monitoring well with quite a distance from the injection wells, stage 1 shows no CO_2 breakthrough at the monitoring well. The pressure is calculated linearly at each stage whilst the composition is assumed as detailed in Table 8. The total/elemental sigma result is displayed in Table 9.

Table 8. Fluid composition in Scenario 1 Sigma modelling

Stage	1	2	3
CO_2 (v/v)	0	0.25	0.5
CH_4 (v/v)	0.3	0.25	0.15
Water (v/v)	0.7	0.5	0.35

Table 9. Sigma modelling in each stage of scenario 1

Stage	Pressure (psi)	Total Sigma(c.u.)	Sand (c.u.)	Water (c.u.)	CH_4 (c.u.)	CO_2 (c.u.)
1	2200	15.022	7.2	7.454	0.367	0
2	2800	12.924	7.2	5.338	0.383	0.002
3	3200	11.209	7.2	3.743	0.261	0.004

Scenario 2. Injected CO_2 replace CH4 only at residual water saturation

Sigma response is simulated in stages as for scenario 1 whilst keeping pressure constant. The fluid composition at each stage, and results, are stated in Table 10 and Table 1Table 11 respectively.

Table 10. Fluid composition in Scenario 2 Sigma modelling

Stage	1	2	3
CO_2 (v/v)	0	0.3	0.5
CH_4 (v/v)	0.7	0.4	0.2
Water (v/v)	0.3	0.3	0.3

Table 11. Sigma modelling in each stage of scenario 2

Stage	Pressure (psi)	Total Sigma(c.u.)	Sand (c.u.)	Water (c.u.)	CH_4 (c.u.)	CO_2 (c.u.)
1	2200	11.252	7.2	3.195	0.857	0
2	2800	11.019	7.2	3.203	0.613	0.002
3	3200	10.761	7.2	3.208	0.348	0.004

Observations

Based on the results from the 2 scenarios, several conclusions can be drawn:

- Total sigma is dominated by the Sand matrix and water elements.
- Gases, CH_4 and CO_2, have low sigma values, therefore, CH_4 could not be differentiated from CO_2
- The sigma difference between stages, when CO_2 increases by 0.25 fractions and replaces water, is good at approximately 2 c.u. change. On the case when CO_2 replaces only CH_4 the sigma change is only 0.3 c.u.
- CO_2 breakthrough is indicated by a reduction of total sigma. Baseline logging is important in order to **quantify** the CO_2 thickness interval from remaining hydrocarbon gas.

Overall, the sigma method is feasible when the sigma reduction is more than the amount arises from tool error margins. An SPE paper[30] number 30598 states that the absolute errors (absolute difference between tool reading and assigned database value) are 0.22 c.u. based on 900 borehole points in varying lithology, borehole size, porosity, salinity and completions.

7.3.2.1.2. Overburden Application

CO_2 migration from a borehole is one of the main risks for every CO_2 storage project. Well integrity logging gives an indication of the potential route for leakage but does not measure directly whether gas exists in the upper part of the wellbore above the reservoir. Monitoring for CO_2 along the wellbore in the overburden is important but it is highly limited by well architecture and upper completion design. For Goldeneye, monitoring or injector wells are both completed with tubing. Therefore, the tool must be able to measure formation conditions through 5" or 7" tubing, 9⅝"casing and 12¼" hole size. For the cases where the cement bond is of good quality, the expectation is to read the saturation in adjacent formations. If there is no cement in between, the tool will only read the fluid flow in the channel between casing and formation. The challenges for tool measurement are depth of investigation and the influence of casing metal thickness. Typical depths of investigation are 6-10" from the logging tool periphery. When the distance is marginal, the logging tool can be run eccentering to minimize the distance to formation. Together, metal thickness and distance affect the signal generated by the neutron burst by introducing a borehole signal which influences the decay period. The dynamics of the signal are then interrupted depending on the complexity of materials between tool and formation. This may require additional pre-job preparation to adjust the signal monitoring window.

Figure 46 displays the standoff between tool and formation for different scenarios as follows:

30 Plasek, R.E., Adolph, R.A., Stoller, C., Willis, D.J., Bordon, E.E. and Portal, M.G. 1995. Improved Pulsed Neutron Capture Logging with Slim Carbon-Oxygen Tool Methodology. Paper SPE 30598 presented at the SPE Annual Technical Conference & Exhibition, Dallas, Texas, 22025 October.

Logging through 9$^5/_8$" casing and 5" tubing, tool centred
Logging through 9$^5/_8$" casing and 5" tubing, eccentering
Logging through 9$^5/_8$" casing and 7" tubing, eccentering
Logging through 9$^5/_8$" casing without tubing, eccentering

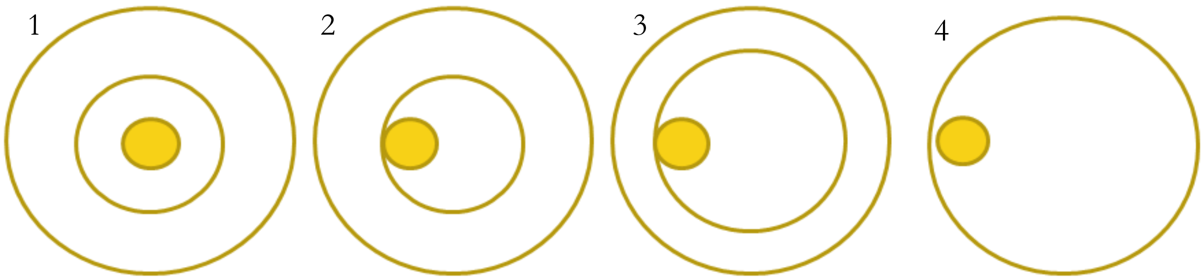

Figure 46. Various standoffs between measuring tool and formation interface

The range of standoff between scenarios is 2 to 5.65" suggesting that the logging may be considered for all scenarios.

After confirming standoff is within range and understanding the need to set the correct observation window, the important issue is to have the right fluid in the borehole. Since the objective is to identify CO_2 migration away from borehole into the formation, it is important to minimize the background gas concentration i.e. gas in the borehole. SPE paper[31] details a successful attempt to measure sigma and locate a GOC through casing and tubing in wells with similar hole and tubular size, however, the boreholes were filled with liquid where gas concentration can be measured more easily.

In the case where a well (injector/monitoring)becomes full of CO2, the phase at static conditions depends on pressure. Higher pressure causes a shallower contact between gas and liquid phases. For reference, at 2000psi [138bar] the contact sits at approximately 4800ft TVDSS. This depth coincides with Top Chalk, meaning it may be possible to log and check if any CO_2 is present in the Chalk as a result of migration from a borehole. As injection progresses and pressure increases, observation underneath the Lista mudstone/storage complex seal, may be possible.

The measurement tool is normally used in single-casing conditions and therefore, will not work correctly if default/generic settings are used. SPE 110501 explains that the pre-job preparation is extend to the several first passes of sigma run, to correctly select part of the spectrum the decay need to be measured. This is an effort to customize the interpretation with regards to string of tubular configurations. The feasibility in Goldeneye environment is highly depending on effect of Goldeneye completion string and well architecture, which currently are unknown. This, however, will become clear during baseline logging.

7.3.2.2. Neutron Porosity

Neutron porosity is based on measuring the Hydrogen Index (number of hydrogen atom per unit formation volume) of formations. Hydrogen is the atom that has nuclear mass similar to a neutron and so it has the largest influence in slowing fast neutrons into a thermal state comparable to the other atoms in the formation. The detector measures the quantity of remaining neutrons either in a thermal or epithermal state. Neutron porosity can potentially help the sigma method in identifying

[31] Desport,O. and Crowe, J., 2008. Pulsed Neutron Logging Through Multiple Casings. Paper SPE 110501-MS presented at SPE Western Regional and Pacific Section AAPG Joint Meeting, Bakersfield, California, 29 March-2 April. DOI: 10.2118/110501-MS

CO_2 concentration since it would not recognize pore space occupied by CO_2 due to absence of hydrogen atoms.

To simulate the neutron porosity response, a spreadsheet has been built to accommodate multiple possible scenarios: CO_2 replacing CH_4-water and CO_2 replacing CH_4 only. Each scenario is modelled at different stages of CO_2 injection which reflect changes in fluid composition. Several steps are required to calculate neutron porosity, explained below:

Hydrogen Index of formation fluid

The expression to derive hydrogen index for the fluids existing in Goldeneye Captain D sand are:

Brine: $H_W = \rho_W \times (1 - P)$

Light Hydrocarbon: $H_{CH4} = 2.2 \times \rho_{CH4}$

Where: H_w = Hydrogen index of water

ρ_w= Water density (g/cc)

P = NaCl concentration (ppm)/10^6

H_{CH4}= Hydrogen index of CH_4

ρ_{CH4}= CH_4 density (g/cc)

There is no hydrogen index for CO_2 due to the absence of hydrogen atoms in the molecular structure.

Excavation Effect

When light hydrocarbon is in the form of a gas, it attracts larger neutron clouds and therefore fewer neutrons are detected by the tool. This causes incremental porosity which needs to be corrected for. The correction (without an invasion effect due to cased-hole conditions) can be written as:

$$S_{WH} = S_W \times H_W + S_{CH4} \times H_{CH4}$$

Where: S_{WH} = Apparent bulk hydrogen saturation

S_W = Water saturation (v/v)

H_W = Hydrogen index of water

S_{CH4} = CH_4 saturation (v/v)

H_{CH4} = Hydrogen index of CH_4

The amount of correction is then calculated as follows:

$$\Delta\phi_{NEX} = K \times (2\phi^2 S_{WH} + 0.04\phi) \times (1 - S_{WH})$$

Where: $\Delta\phi_{NEX}$ = Neutron log correction (v/v)

K = lithology dependent constant value (sandstone = 1)

ϕ = Porosity (v/v)

S_{WH} = Apparent bulk hydrogen saturation

Neutron Porosity

The actual porosity and measured neutron porosity in gas bearing formation are linked by this equation:

$$\phi_N = \phi \times \left[\frac{H_{CH4}}{H_W} \times S_{CH4} + S_W \right] - \Delta\phi_{Nex}$$

Where: ϕ_N = Neutron porosity (v/v)

ϕ = Porosity (v/v)

H_{CH4} = CH_4 Hydrogen Index

H_w = Water Hydrogen Index

S_{CH4} = CH_4 Saturation (v/v)

S_w = Water Saturation (v/v)

$\Delta\phi_{Nex}$ = Neutron log correction (v/v)

There is no element of CO_2 in the calculations workflow since neutrons are not sensitive to CO_2 presence. Based on the physical interaction, neutron would be unaffected by the space occupied by injected CO_2. Therefore, once injection starts, the calculation refers to reduced pore space occupied only by the CH_4-water fraction, and the saturation ratio of CH_4-water (adds up to 1, excluding the CO_2 fraction).

Scenario 1. Injected CO_2 replaces CH_4-Water

Neutron porosity is simulated for one-third, two-thirds and completed injection stages, which will impact reservoir pressure and fluid composition. Pressure is calculated linearly for each stage of injection. Composition is assumed as detailed in Table 12. Neutron porosity results are displayed in Table 13.

Table 12. Fluid composition for scenario 1 Neutron Porosity modelling

Stage	1	2	3
CO_2 (v/v)	0	0.25	0.5
CH_4 (v/v)	0.3	0.25	0.15
Water (v/v)	0.7	0.5	0.35

Table 13. Neutron Porosity modelling at each stage of scenario 1

Stage	Pressure (psi)	Neutron Porosity (pu)	S_{wH}	$\Delta\phi_{Nex}$
1	2200	0.178	0.725	0.034
2	2800	0.137	0.716	0.020
3	3200	0.101	0.750	0.009

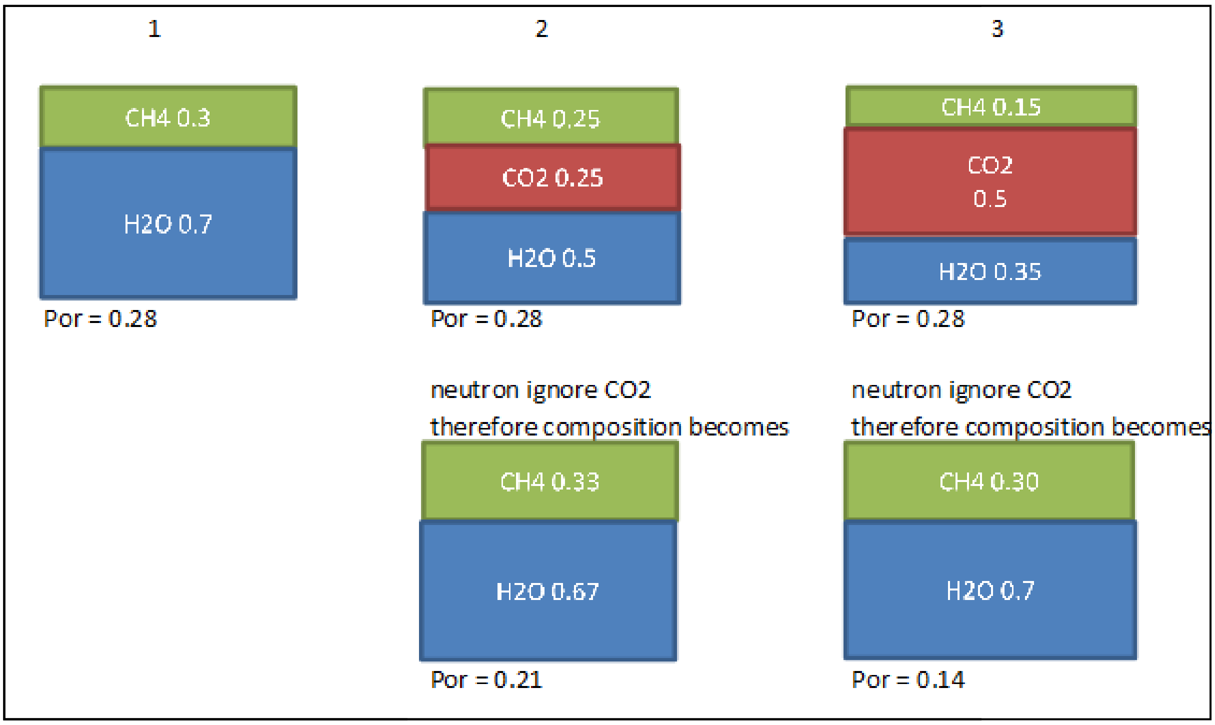

Figure 47. Fluid composition in each stage of Scenario 1. Lower boxes represent fluid composition which affects neutron activities

Scenario 2. Injected CO_2 replaces CH_4 only at residual water saturation

Neutron porosity response is simulated in similar stages to scenario 1 whilst keeping pressure constant. The fluid composition for each stage and results are shown in Table 14 and Table 15 respectively.

Table 14. Fluid composition for scenario 2 Neutron Porosity Modelling

Stage	1	2	3
CO_2 (v/v)	0	0.3	0.5
CH_4 (v/v)	0.7	0.4	0.2
Water (v/v)	0.3	0.3	0.3

Table 15. Neutron Porosity modelling - scenario 2

Stage	Pressure (psi)	Neutron Porosity (pu)	S_{wH}	$\Delta\phi_{Nex}$
1	2200	0.078	0.420	0.045
2	2800	0.090	0.546	0.023
3	3200	0.090	0.682	0.010

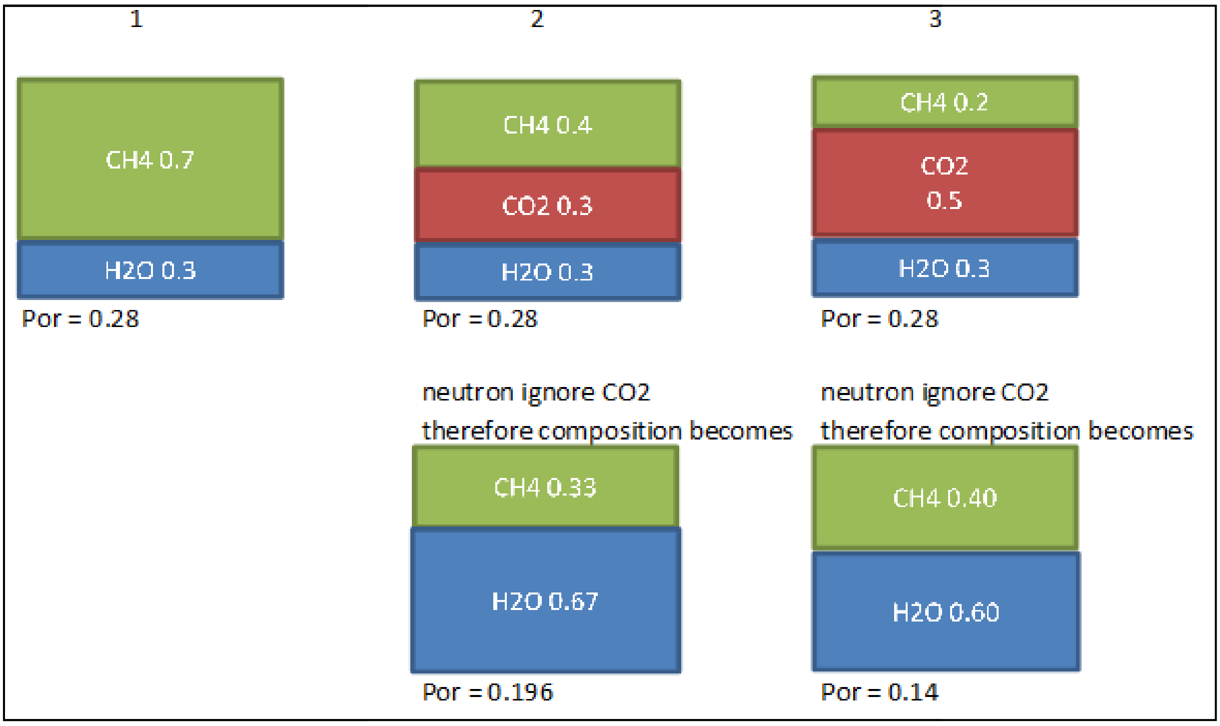

Figure 48. Fluid composition for each stage of Scenario 2. Lower boxes represent fluid composition which affects neutron activities.

Observations

The following statements are the conclusions from both scenarios:

- Water needs to be present above residual concentration in the interval to observe CO_2 breakthrough. Neutron porosity changes by 4 pu when CO_2 replaces water and CH_4, whilst it changes by 1 pu or less when CH_4 only is replaced.
- Where CO_2 replaces CH_4 only, CO_2 breakthrough may be observed by reducing the excavation effect.

For both Sigma and neutron porosity methods, water presence is important. Therefore, one criterion in selecting a monitoring well is that it must be watered-out in order to enable these methods to work. Fluid contacts cannot be assured in production wells that have not been evaluated for cased-hole saturation or production logged. Therefore, observation well selection will be also based on water production history from development wells. The first wells to water cut water during production were GYA03, 04 and 05.

There are several tools available that deliver sigma and neutron porosity measurements. Ideally, it would be good to include Carbon Oxygen logging (C/O), too, since CO_2 injection would change the Carbon Oxygen composition in the formation but, again, the tool requires a liquid environment and will not work in a gas phase.

7.3.3. Cased Hole Resistivity and Acoustic Logging

7.3.3.1. Resistivity

The Goldeneye CO_2 store is a depleted water invaded gas field with substantial amounts of residual gas remaining underneath the current OWC. This residual gas will affect the resistivity readings. The actual resistivity at the current contact has not been logged but is expected to be 1.03 ohmm by reverse calculating using 30% residual gas in the Archie equation (Rw = 0.055 ohmm at 50kppm, porosity = 0.28 v/v, saturation exponent = 1.91 and cementation exponent = 1.77). CO_2 injection pushes water downwards due to relative buoyancy effects and resistivity would change reflecting the new fluid composition. Using a similar method to calculate resistivity, 70% CO_2 concentration would increase resistivity to 5.2 ohmm.

Operationally, the Cased-Hole Resistivity tool induces current upwards and downwards before returning to the surface in a fashion similar to a laterolog tool mechanism. For conductive casing, most of the current stays within this and only a small proportion is released to the formation behind casing. The tool measures leaked current which is proportional to formation conductivity. The potential difference generated by leaked current can be as small as a nanovolt, and therefore requires good contact between casing and formation with a full cement bond. The tool is affected by borehole environmental factors, therefore a good quality measurement depends on the correction for casing resistivity, cement resistivity and the impact of scale and corrosion. One example of a Cased Hole Formation Resistivity tool is available in 2 sizes (2.125" and 3.375") to cater for $2^7/_8$"–$9^5/_8$" casing sizes.

In Goldeneye wells, the resistivity measurement has to measure through a 4" sand screen and a 7" slotted liner with gravel pack in between on the lower completion, which makes the measurement technique non-applicable in this case.

7.3.3.2. Acoustic

Scenarios were built to model acoustic properties in the Goldeneye Captain reservoir for input into the seismic feasibility study using a Gasmann fluid substitution method. To examine if acoustic measurements can be used to determine different gas content in the reservoir during injection, Vp was calculated in one well (Figure 49) for CO_2-Brine and CH_4-Brine cases with free-water-level (FWL) as the fluid contact. The Vp shows very little difference in this ideal simulation and could potentially be masked by background effects during actual logging. The most influential effects are the cement quality, poorly bonded sections causing reading of a casing signal rather than formation signal, but in some cases the shear wave is still detected. The Dipole Sonic tool combines monopole and dipole sonic acquisition. It is used in open holes but can be applied in cased holes with adjustments and further waveform processing. Dipole sonic tools cater for casing sizes between 4¾ and 21 inches. However, the existing completion width (smallest opening in the completion) for the Goldeneye development wells is 2.75", which is significantly smaller than the size of the tool. Therefore, this application is not-feasible due to operational constraints.

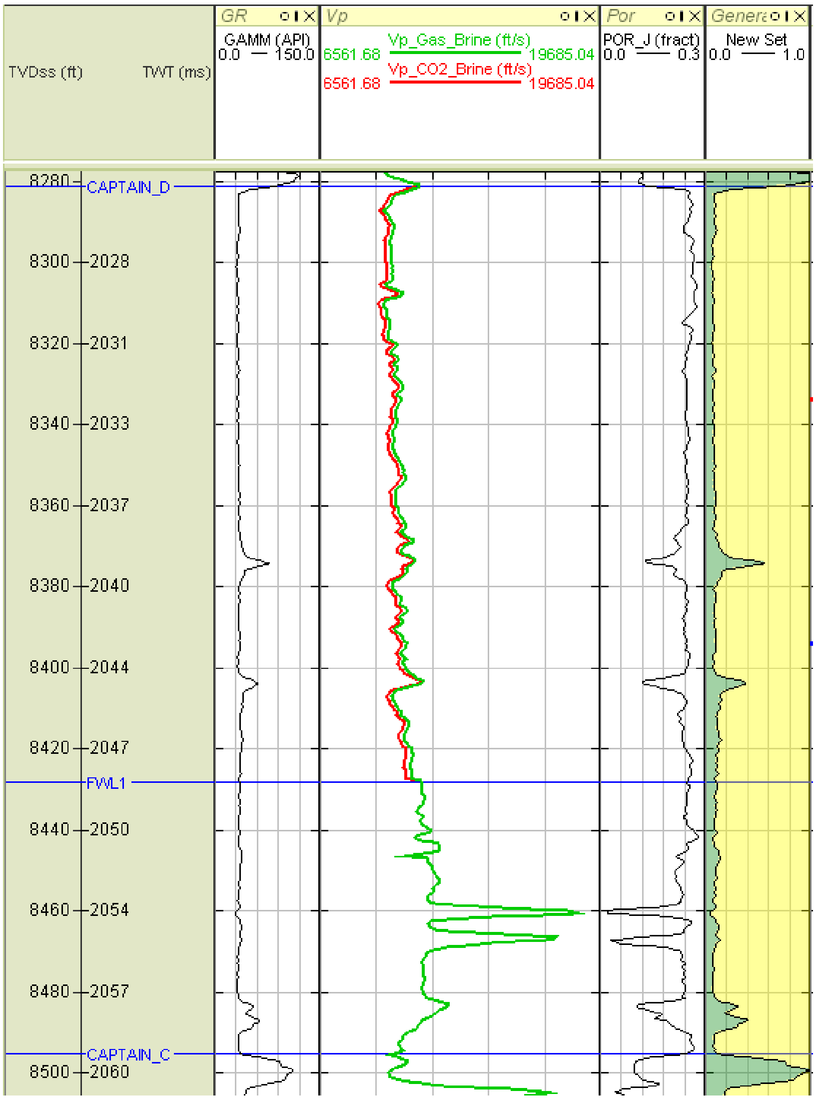

Figure 49. **Vp comparison of CO_2-Brine fluid (Red) to CH_4 -Brine fluid (Green). The interval above the FWL is filled with gas (CO_2 or CH_4) whilst below the FWL is filled with brine.**

7.3.4. Pressure and Temperature Gauges

7.3.4.1. PDG

A PDG (Permanent Downhole Gauge) system for Goldeneye would ideally consist of a two-level PDG system with 100m offset so that fluid densities can also be calculated in addition to pressure and temperature information. The majority of PDG suppliers, including Shell's current supplier of PDG equipment, have the facility to "multi-drop" up to four gauges onto a single encapsulated electrical cable that is run to surface. In addition to the electrical cable, up to three fibre-optic lines for a Distributed Temperature System can be run inside the same cable encapsulation with no additional exit requirements at the wellhead. PDG would be installed during recompletion of the upper completion on dedicated injector wells. Current technology can be expected to continue to transmit data for up to 10 years. PDG systems supplied for use in Goldeneye wells will meet or exceed the following specifications;

Sensor type:	Quartz.
Calibrated working pressure range:	Atmospheric to 10,000 psi.
Calibrated Temperature range:	25 ° C to 130 ° C.
Initial pressure accuracy:	+/- 2 psi over full scale.
Pressure resolution:	0.005 psi at 1-s sample rate.
Pressure drift stability:	+/-1 psi per year over full scale.
Temperature resolution:	0.005° C at 1-s sample rate.
Temperature drift stability:	Less than +/- 0.1° C per year at 150° C.
Long term qualification test, equivalent lifecycle:	10 years at 12,000 psi and 150° C.

This gauge is applicable for installation on planned upper completion, which the details is described in well engineering report no CW020D3 (Upper Completion Review).

7.3.4.2. Long Term Gauges

LTMG (long term memory gauges) usually have a nominal Outside Diameter (OD) of 1 $^{11}/_{16}$" or 1½" and are suitable for installation into Goldeneye wells that are re-completed as injectors. LTMG are installed into the wells using standard wireline methods. LTMG are a suitable option for obtaining accurate Bottom Hole Pressure & Temperature (BHP&T) information should the PDG fail. LTMG have evolved from relatively simple mechanical, helically wound bourdon tube, stylus and chart with a maximum recording duration of around 240 hours, to sophisticated electronic gauges with electronic components housed in evacuated sealed internal chambers filled with argon. These measures, and longer battery life, make the electronic gauge particularly suitable for longer-term operations (up to one year), HPHT conditions and in highly corrosive fluids. Windows-based software packages can produce screen-plots, printouts and export files at the well site.

Typical operating parameters for LTMG are as follows:

Pressure;

Resolution:	0.01 psi
Accuracy:	+- 0.02% FSO
Range:	5,000 psi, 10,00 psi or 16,000 psi.

Temperature;

Resolution:	0.01° C
Accuracy:	+- 1.0 ° C
Range:	25 – 165 ° C
Transducer type:	Quartz resonator
Memory Size:	720,000 data sets
Memory type:	Non Volatile Flash
Sample rate:	1 second to 10 minutes
Battery life:	Dependent on sample rate and BHT.

7.3.4.3. Cased Hole Pressure and Temperature

Pressure and temperature measurements are a necessity for all CO_2 monitoring, logging and sampling programs and are included in bottom-hole sampling and sigma-neutron porosity logging tools. The sensor mandrel houses gamma ray and Collar locator (CCL) to correlate to casing/tubing points and measures temperature and pressure using a quartz pressure gauge. It can also used as a contingency plan to acquire reservoir pressure and temperature if the planned techniques (PDG and DTS) fail. Tool acceleration is monitored to ensure a good quality data reading.

The tool size is 1.6875 inch OD to cater for $2^3/_8$" hole sizes and above. The working ranges for pressure and temperature are 0.1-103 MPa and -25 – 150° C respectively, with an accuracy of ± 6,894 Pa and ± 1 ° C.

7.3.5. Distributed Temperature Sensing[32]

Fibre-optic distributed temperature measurement uses an industrial laser to launch 10ns bursts of light down an optical fibre. During the passage of each packet of light, a small amount is backscattered from molecules in the fibre. This backscattered light can be analyzed to measure the temperature along the fiber. Because the speed of light is constant, a spectrum of the backscattered light can be generated for each meter of the fibre by using time sampling that allows generation of a continuous log of spectra along the fibre (Figure 50**Error! Reference source not found.**). There is no need to calibrate points along the fibre or for calibration of the fibre prior to installation.

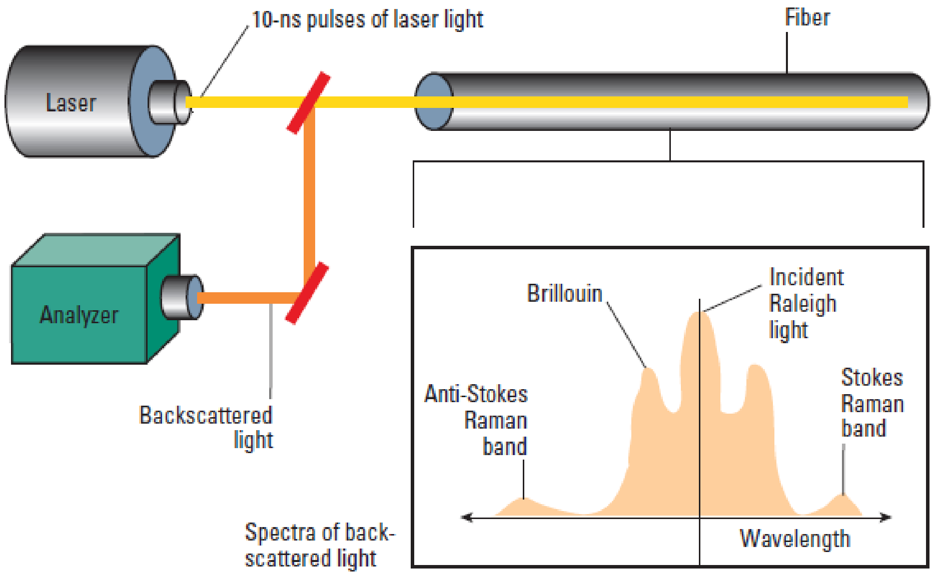

Figure 51 shows NTS and TTS data acquired from both ends of a 9,000-m fibre installed in a double-ended configuration in a well with a depth of 4,500 m. The fibre turnaround sub is at the bottom of the well. The counts decrease exponentially with fibre length and there is a noticeable light loss effect at connection to the wellhead. Usually a measurement interval of 1.0165 m is used to allow measurement of up to 12 km of fibre. Longer fibres, up to 30 km, can be used, but they require longer measurement intervals of up to 10 m.

[32] Schlumberger, The essentials of Fiber-Optic Distributed Temperature Analysis

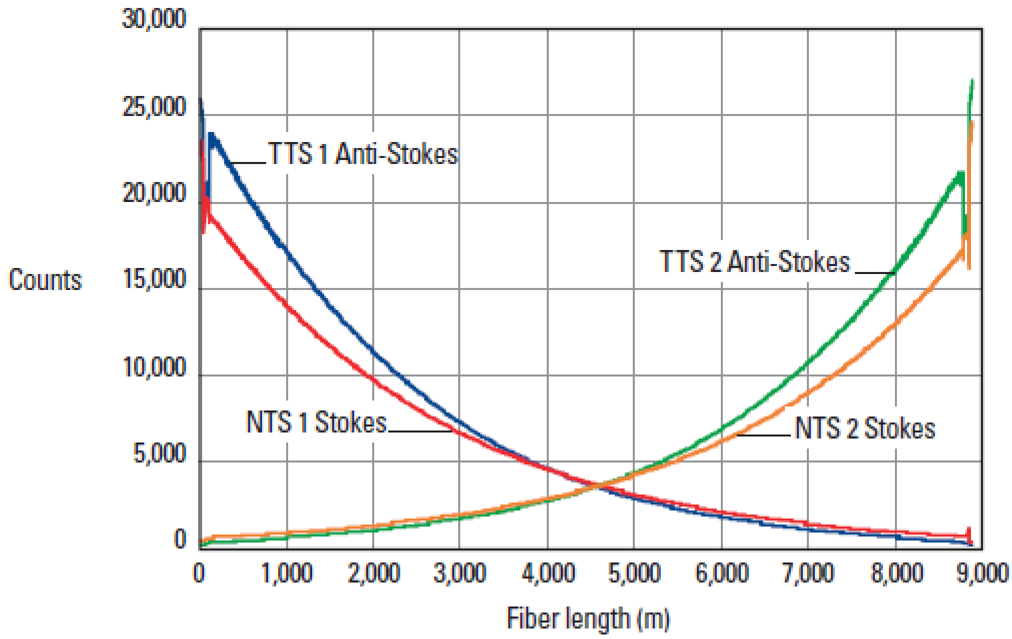

Figure 51. NTS and TTS data along a 9,000m fibre

There are four primary advantages of differential-light-loss-compensated (double-ended) measurements over single-ended measurements:

- The absolute accuracy of a double-ended measurement can be specified, which is not the case for a single-ended measurement due to uncertainties in light-loss correction.
- Non-uniform light-loss in single-ended measurements can result in apparent thermal anomalies that can be misinterpreted to be flow or other well events.
- Single-ended temperature measurements can change over time as the loss characteristics of the fibre changes (e.g., new connections, reconnected fibres, different DTS, fibre deterioration).
- The fibre can easily be pumped out and replaced for a double-ended installation if necessary.

DTS is applicable for installation in all re-completed Goldeneye wells. The measured data will be used to provide real time distributed temperature data in order to monitor transient cooling effects in the completion and annuli, and to detect CO_2 leakage from production tubing into the A annulus. Detail on installation is available in the well engineering report, Upper Completion Review.

7.3.6. Tracers

Ideal geochemical tracer characteristics to be applied for CCS application are:

- Non reactive and stable over time
- Experience minimal partitioning
- Low detection limits
- Low environmental impact
- Low cost

Noble gas tracers fulfil the criteria above, compared to SF_6 and PFTs. The SF_6 tracers have greenhouse gas warming potential, and PFT abundance is increasing in the atmosphere. There are five stable noble gas elements (He, Ne, Ar, Kr, and Xe) which comprise 23 different isotopes and span a mass range from 3 to 136 amu which can be used for CO_2 monitoring.

Investigation of whether a geochemical tracer (noble gas) needs to be added to the Goldeneye CO_2 stream is taking place at present. At the time of writing, the use of a noble tracer in the CO_2 stream has not been ruled out. The Shell internal geochemical database indicates that there is abundant CO_2 in the basin. Most historical CO_2 samples have ***not*** been isotopically fingerprinted. It is hypothesised that Tertiary lignite coals may also contain biogenic CO_2 which could potentially lead to a mix of thermogenic and biogenic isotope signals (based on examples from literature[33]). If a new monitoring well is drilled, it is recommended that fluid and gas samples be taken from the major lithostratigraphic units within the overburden and special attention given to the lignite coal layers. Isotopic fingerprinting ($\delta^{13}C$ and $\delta^{18}O$) of the remaining deeper basin gas, identified using the Shell database, would also be beneficial. From this, a CO_2 isotopic mixing curve can be calculated and a decision as to whether or not to spike Goldeneye CO_2, with a noble gas tracer can be made.

7.3.7. U-Tube Sampling

Conceptually U-tube sampling is straightforward and the ability to independently control pressure on both the drive and sample legs presents numerous options for collecting and processing of fluids at surface. By repeating sample collection cycles, the borehole fluid can be flushed and fresh samples can be drawn in from the formation. The volume of the recovered sample is dependent on the formation pressure and the internal diameter of the U-Tube. For an installation at a depth of 1 km, a 6mm or 9mm diameter tube with a 1.2 mm wall thickness has a U-tube volume of 20 litres or 68 litres, respectively.

The first deep borehole application in which the U-Tube was deployed was the Frio Brine Pilot, Dayton, Texas. It was a demonstration program for the geosequestration of CO_2 in saline aquifers led by the Texas Bureau of Economic Geology[34]. In September 2004, 1600 t of CO_2 were injected into the Frio Sandstone at a depth of 1.5 km over a time span of ten days. A second experiment conducted in 2006, at the same site, consisted of an injection of 350 t of CO_2 in sand at a depth of 1.6km. The objectives of the Frio Brine Pilot tests included understanding the hydrological and geochemical impact of the CO_2 on the subsurface, and evaluation of the U-Tube and various other monitoring tools to provide information on the shape and distribution of the CO_2 plume.

In contrast to the simplicity of the downhole U-Tube, surface processing of the recovered fluids can be quite complex. In the case of the Frio Sandstone Pilot, the surface recovery system consisted of six individual manifold assemblies to allow for careful control of sampling conditions and complete system purging between samples. To facilitate reproducible sampling and minimize the potential for operator error, the sampling operation was automated with pneumatically operated valves and control software that was specifically developed for the test. Figure 52 shows the complexity of the surface manifold system. However, if the well pressure is low enough and the sampling regime is relatively straight forward the system can be reduced to a simple regulator on each leg, and the N_2 can be supplied from standard gas bottles.

[33] Flores, R.M., Rice, C.A., Stricker, G.D., Warden, A. and Ellis, M.S. 2008., Methanogenic pathways in the Powder River Basin: The geologic factor : *International Journal of Coal Geology* **76(1-2)**: 52-75.

[34] Hovorka S.D.., Benson, S.M., Doughty, C., Freifield, B.M., Sakurai, S., Daley, T.M., Kharaka, Y.K., Holtz, M.H., Trautz, R.C., Nance, H.S., Myer, L.R. and Knauss, K.G. 2006. Measuring permanence of CO_2 storage in saline formations : the Frio experiment. *Environmental Geosciences* **13(2)**: 105-121.

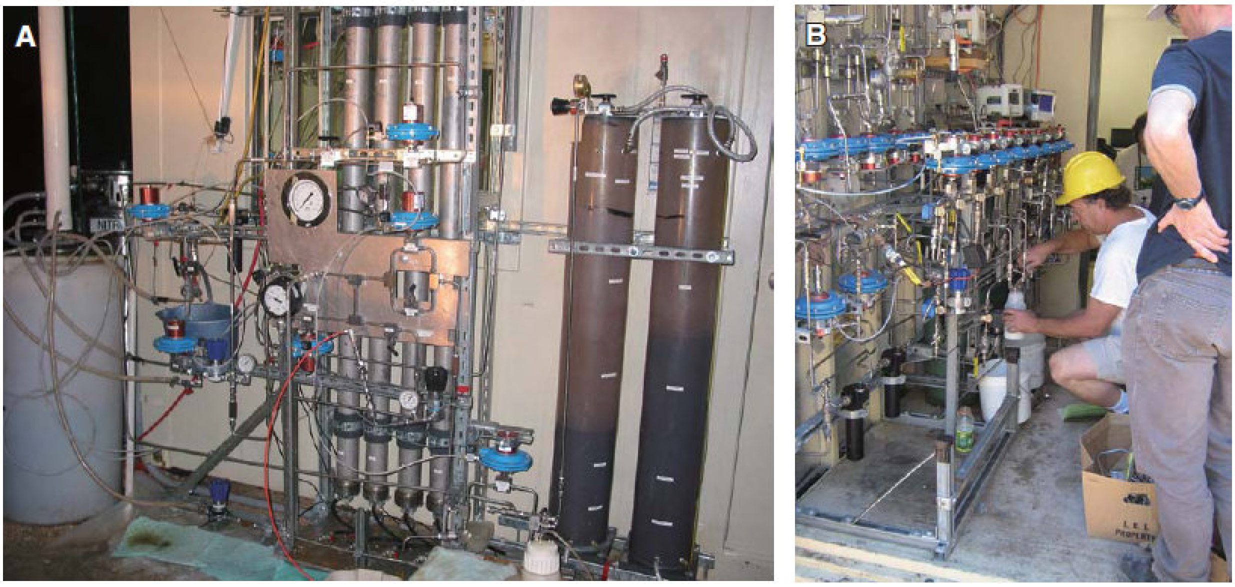

Figure 52. The Frio brine pilot surface sampling systems. (A) Four 13 L high pressure sample vessels mounted in sliding sleeves and resting on strain gauges to measure fluid density. (B) Computer -operated valve manifolds used to operate the U-tube samplers (see Footnote 18)

Whilst the basic premise underlying the U-tube is not new, the system is unique because careful attention was given to processing the recovered two-phase samples. Strain gauges mounted beneath high-pressure sample vessels at the surface measure the ratio of recovered brine to supercritical CO_2, providing gas-brine densities at reservoir conditions. A quadrupole mass spectrometer provides real-time gas analyses, allowing measurement of CO_2 (and potentially tracer) breakthrough, and providing information on CO_2 saturation.

Three options are investigated for the future monitoring wells in Goldeneye for the installation of the U-tube:

Workover. Normally the U-tube with the required control lines are strapped to the external part of the tubing. A workover in the monitoring well will be required for this operation. This is the best option as the new tubing can be installed keeping the well integrity. There is enough space in the well to install the U-tube plus other permanent monitoring devices. Due to the weight of the existing 7" completion this workover will most likely require a rig.

Retrofit. Another option is to run the control lines and the U-tube tool inside the current 7" tubing. This would be cheapest option. The downhole section of the U-tube can be placed down in to the tubing and most likely above the FIV in the lower completion due to its restriction. The control lines will obstruct the current SSSV in the well. In case of an emergency it will fail to close due to the obstruction created by the control lines in the internal part of the tubing. This option is not possible due to lack of well integrity. This retrofitting will require as a minimum coil tubing in order to push down the control lines (drive and sample leg).

Retrofit with insert string. Another option is to run an insert string (plus the required control lines) in the current 7" completion.

The existing SSSV can be locked open. A tubing with a new TRSSSV can be run in the well. There are two options to keep the integrity of the well. Run a new packer which might be set at the existing production tubing; or run an ASV. Again, the downhole section of the U-tube can be placed down in to the tubing and most likely above the FIV in the lower completion due to its restriction. The control lines will be strapped to the new insert tubing. The ASV option between the new tubing and the existing completion will be complex due to the presence of the control lines required for the U-tube sampling. Furthermore, the ASV reliability is considered poor against the normal SSSV.The packer option will be complex as the new packer will be set in the existing completion without cement behind it. The long term integrity is questionable due to the packer expected life. Potentially this retrofitting can be executed by coil tubing.

Based on three options, the installation of an U-tube sampler in the monitoring wells in Goldeneye will require heavy and expensive well modifications. The preferred option is to carry out a workover in the well to install a U-tube. The second option involves the installation of an insert string plus the required control lines for the U-tube with different safety devices (e.g. ASV or packers) downhole in the well. There are concerns about the long term integrity considering this option. Additionally, it will involve a heavy well intervention which most likely will required a rig. Retrofitting the U-tube in the existing completion by installing the control lines inside the existing completion will jeopardize the well integrity. Therefore it is not recommended

7.3.8. Bottom Hole Sampling

Bottom hole sampling is run using a wireline standalone set up from the Goldeneye platform. The sampling mechanism works based on positive displacement sample-filling and is mercury–free. It is compatible with a production logging intervention string (the tool to measure sigma and porosity) allowing a single run. One of the examples has chamber capacity of 100 cm^3, with maximum working range between 68 MPs and 150 ^{o} C. The tool is only available in one size 1 $^{11}/_{18}$ inch, small enough to pass the minimum restriction of 2.94 inch (or potentially landing nipple at 2.125 inch).

Bottom hole sampling from observation wells on Goldeneye is feasible using wireline intervention in the string as described above. It is best to obtain samples periodically during injection until breakthrough of the CO_2 and some value may be gained from sampling up until the end of injection. Ideal frequency and timing for first sample collection depends highly on dynamic simulation results of the expected rate and timing of CO_2 breakthrough at the monitoring well. It is critical to get sample collection timing correct as the time when CO_2 reaches the monitoring well is required to update simulation monitoring.

8. Conclusion

Based on the feasibility study, the summary of techniques applicable for CO_2 storage at the Goldeneye and which potentially satisfy the minimum requirements for detection limit are listed in Table 16.

Table 16. List of feasible techniques to monitor potential CO_2 migration/leakage from Goldeneye storage

Domain	Data acquisition	Risk addressed	Technology/techniques
Seabed and Shallow Overburden	Water column profiling	Leakage from storage complex via: abandoned wells, development wells, conductive faults/fractures	CDT
	Seabed sediment, flora & fauna and pore gas sampling	Leakage from storage complex via: abandoned wells, development wells, conductive faults/fractures	Van Veen Grab Vibro Corer CPT rig fitted with BAT probe Hydrostatically Sealed Corer
	Pockmarks	Leakage from storage complex via: abandoned wells, development wells, conductive faults/fractures	MBES
	Subsidence and uplift	Leakage from storage complex via: abandoned wells, development wells, conductive faults/fractures	GPS
	Shallow Overburden Seismic	Leakage from storage complex via: abandoned wells, development wells, conductive faults/fractures	Chirps/ Pingers 2D lines/3D swath
Overburden and Aquifer	Time lapse seismic	Leakage and migration from/within storage complex abandoned wells, development wells, conductive faults/fractures and lateral migration past spill point or in secondary storage complex	Repeat 3D streamer OBC OBN 3D swath/2D lines Borehole VSP
	Microseismic	Migration surrounding	Microseismic

Domain	Data acquisition	Risk addressed	Technology/techniques
		borehole in storage complex due to Reactive fault and Caprock integrity	
Well and Reservoir	Well Integrity	Migration surrounding borehole in storage complex due to leak path from development wells	Cement bond logging Casing integrity logging Tubing integrity logging DTS
	CO_2 Detection	Migration surrounding borehole into storage complex due to leak path from development wells and also movement of CO_2 filling the store (conformance)	Downhole sampling
	CO_2 Conformance	Migration surrounding borehole into storage complex due to leak path from development wells and also movement of CO_2 filling the store (conformance)	Sigma logging Resistivity logging Neutron porosity logging Acoustic logging
	Pressure conformance	Migration surrounding borehole into storage complex due to leak path from development wells and also movement of CO_2 filling the store (conformance)	PDG Long term gauge Cased-hole pressure and temperature
	Fingerprint	Leakage and migration from/within storage complex abandoned wells, development wells, conductive faults/fractures and lateral migration past spill point or in secondary storage complex	Tracer

These techniques are recognized and available at the present time and will be complemented by new and emerging technologies whilst the MMV plan is continuously adapted and updated towards the start of injection, during- and post- CO_2 injection.

9. Abbreviations

AUV	Autonomous underwater vehicle
BP	Beyond Petroleum
BHP&T	Bottom Hole Pressure and Temperature
CBL	Cement Bond Logging
CCS	Carbon, Capture and Storage
CDT	Conductivity Depth and Temperature
CHFR	Cased Hole Formation Resistivity
CO_2	Carbon Dioxide
C/O	Carbon Oxygen Logging
CPT	Cone Penetration Testing
CSEM	Controlled Source Electromagnetic Monitoring
DAS	Distributed Acoustic Sensing
DECC	Department of Energy and Climate Change
DSI	Dipole Shear Sonic Imaging
DTM	Digital Terrain Model
DTS	Distributed Temperature Sensing
EU	European Union
EMIT	Electromagnetic Pipe Scanner
EOR	Enhanced Oil Recovery
FPSO	Floating Production Storage and Offloading
FWL	Free Water Level
GC	Gas Chromatograph
GD2	Guidance Document 2
GPS	Global Positioning System
GR	Gamma Ray
ID	Inside Diameter
LTMG	Long Term Memory Gauge
MBES	Multi Bean Echo Sounder
MMV	Monitoring, Metering and Verification
OBC	Ocean Bottom Cable
OBN	Ocean Bottom Node

OCWD	Orange County District
OD	Outside Diameter
PDG	Pressure Gauge
PMIT	Platform Multifinger Imaging Tool
ROV	Remotely Operated Vehicle
RST	Reservoir Saturation Tool
RTCI	Real Time Compact Imager
VDL	Variable Density Log
VSP	Vertical Seismic Profile
WAG	Water Alternating Gas

Full well name	Abbreviated well name
DTI 14/29a-A3	GYA01
DTI 14/29a-A4Z	GYA02S1
DTI 14/29a-A4	GYA02
DTI 14/29a-A5	GYA03
DTI 14/29a-A1	GYA04
DTI 14/29a-A2	GYA05

APPENDIX 1. Screened Out Techniques

Domain	Data acquisition	Techniques	Reason for exclusion
Seabed and Shallow Overburden	Seabed sediment, flora & fauna and pore gas sampling	Box Corer Gravity Corer Piston Corer	All three methods are unsealed and unsuitable for pore gas collection. (measuring ability)
	Pockmarks	Side Scan Sonar Echoscope	Expected signal is below the detection limit (measuring ability) Limited visibility at Goldeneye area (measuring ability)
	Subsidence and uplift	Acoustic Ranging Seafloor Pressure Gauges SAR and inSAR Tiltmeter	Expected signal is below detection limit(measuring ability) Expensive and alternative available (uncompetitive application) Onshore application (operational constraint) Onshore application (operational constraint)
	Shallow Overburden Seismic (<1000 m)	Boomers Enhanced Surface Rendering	Commercially unavailable Require deeper water depth (operational constraint)
	Hydrosphere sampling & Pressure Measurement	Westbay System Induced Polarization Spontaneous Potential	All three methods are not relevant because no potable water exists within the field
Overburden and Aquifer	Non-Seismic	Seafloor Geodesy CSEM Gravimetry	Shallow depth application (<500m) (operational constraint) Expected Resistivity is below detection limit (measuring ability) Expected gravity change is below detection limit (measuring ability)
Well and Reservoir	Well Integrity	DAS	Unproven technique currently in R&D process, undergo technology maturation and may become available at the time of execution. (unproven technology)
	Saturation	Resistivity logging	High operational risk, alternative available (uncompetitive

Domain	Data acquisition	Techniques	Reason for exclusion
	quantification	 Acoustic logging U tube	application) Operational constraint Operational constraint
	Borehole stress regime	RTCI	Useful for stress regime indication, which is considered low risk in Goldeneye field table. Expensive and still in R&D process. (risk relevance)

APPENDIX 2. Figures Refinement

This appendix contains refinement of figures 4, 10,22,24 and 34 from main document in size or resolution.

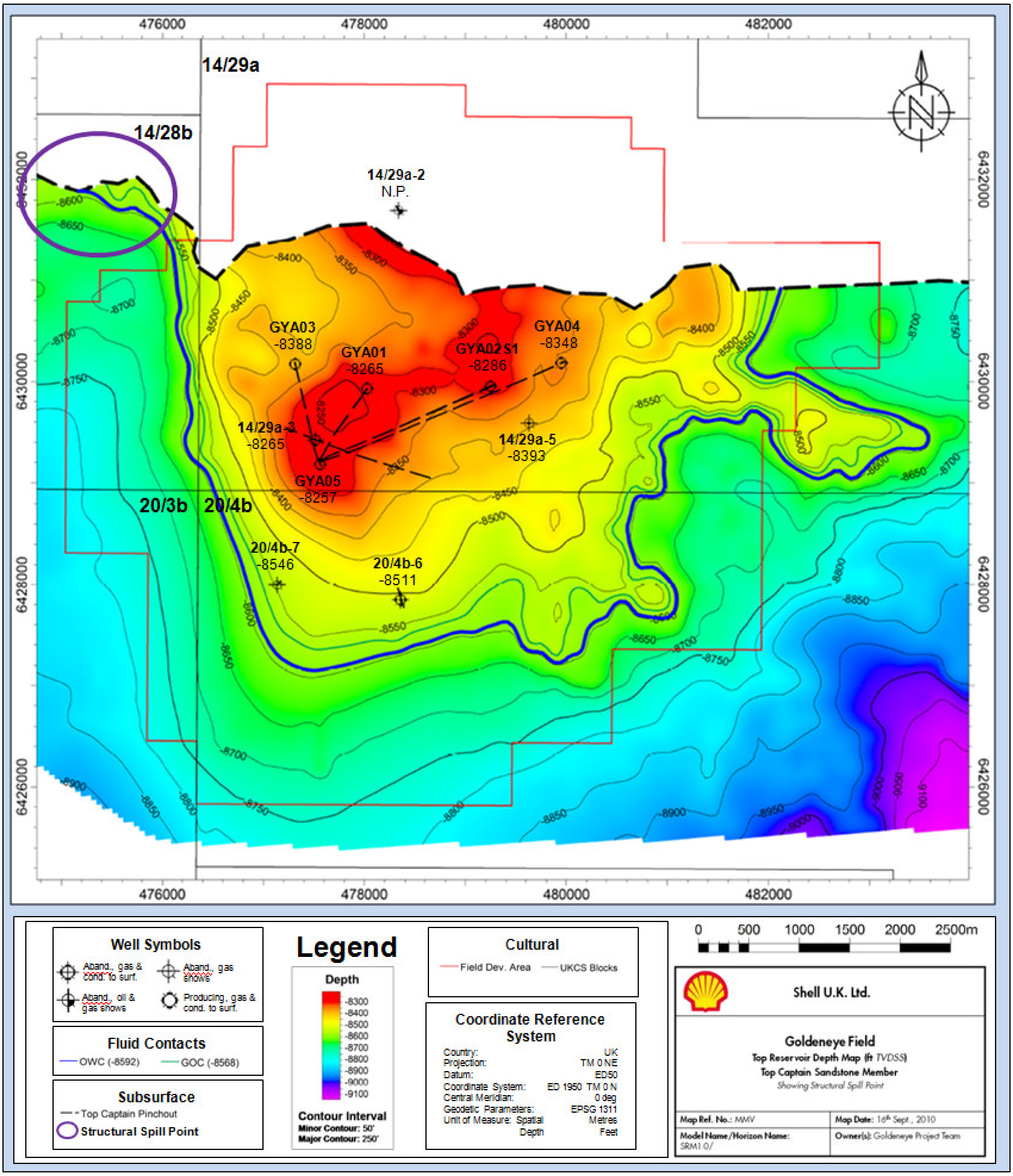

Figure 53. Goldeneye structural spill point on North West of the field

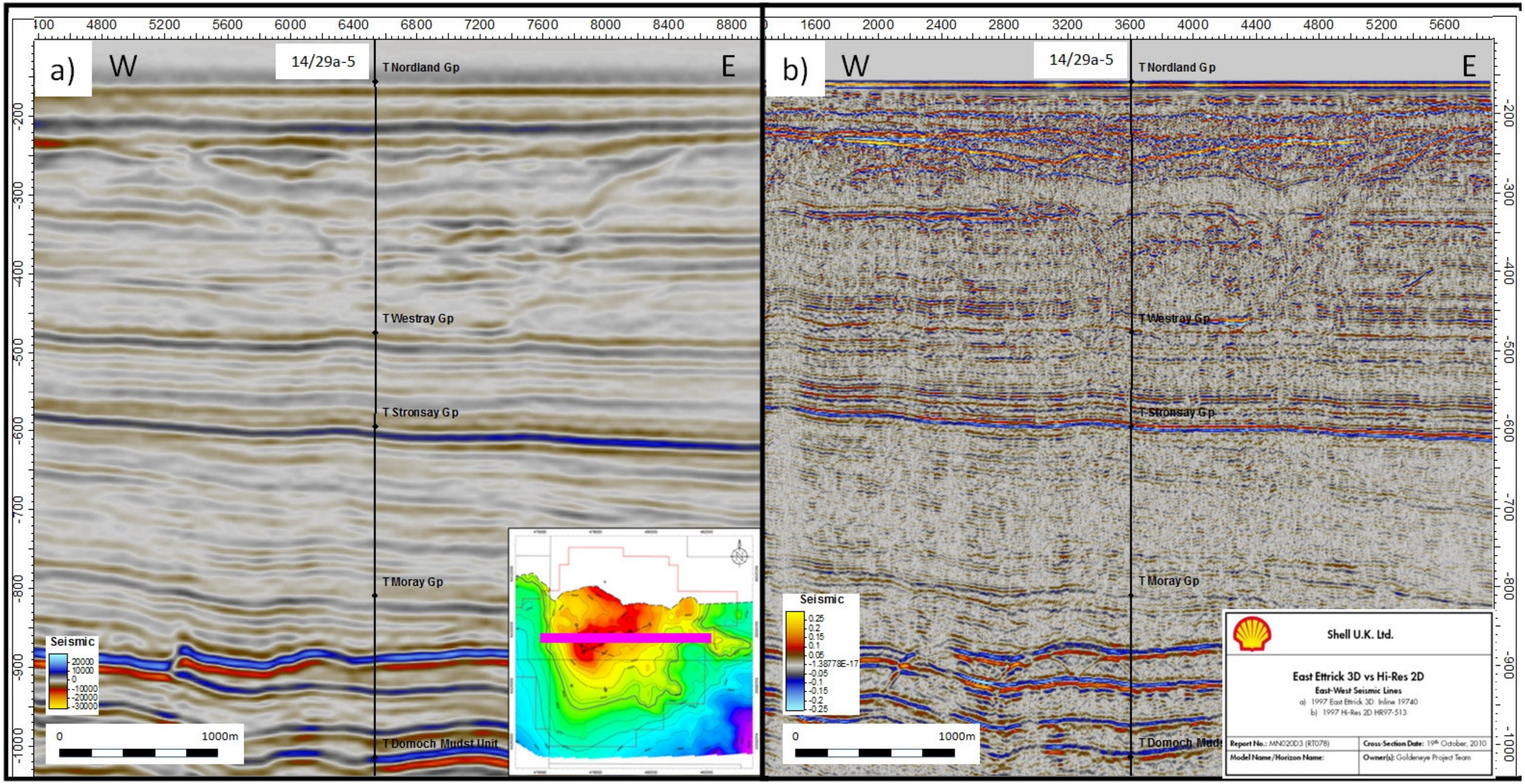

Figure 54. **Comparison between a) seismic data from 1997 Ettrick East 3D streamer survey (Pre-Stack Depth Migration, displayed in time (Inline 19740) and, b) Hi-Res 2D line HR97-513. Lines are approximately equivalent and are displayed at the same scale in time.**

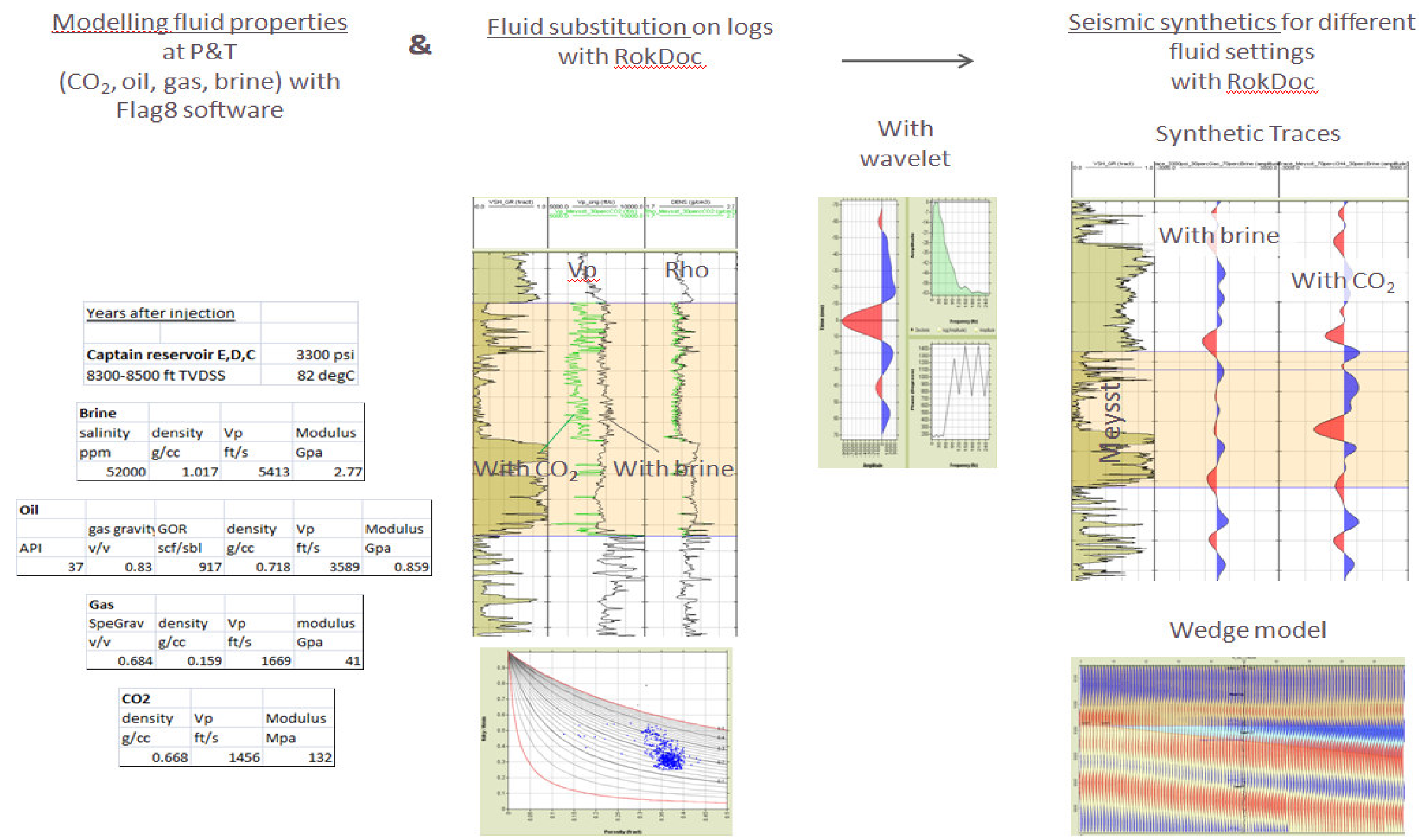

Figure 55. **1D Forward modelling workflow**

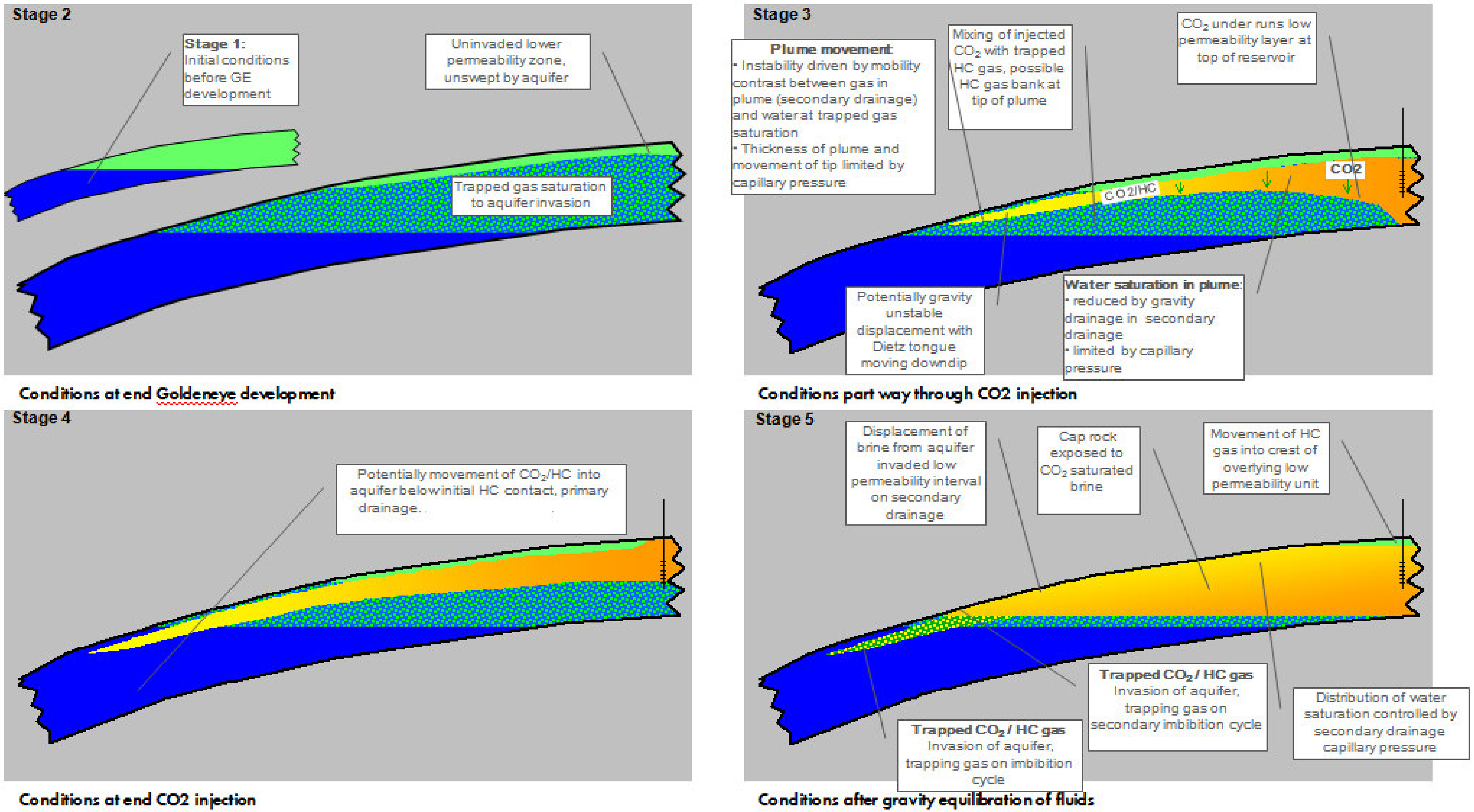

Figure 56. **Goldeneye CO_2 injection reservoir displacement process life-cycle**

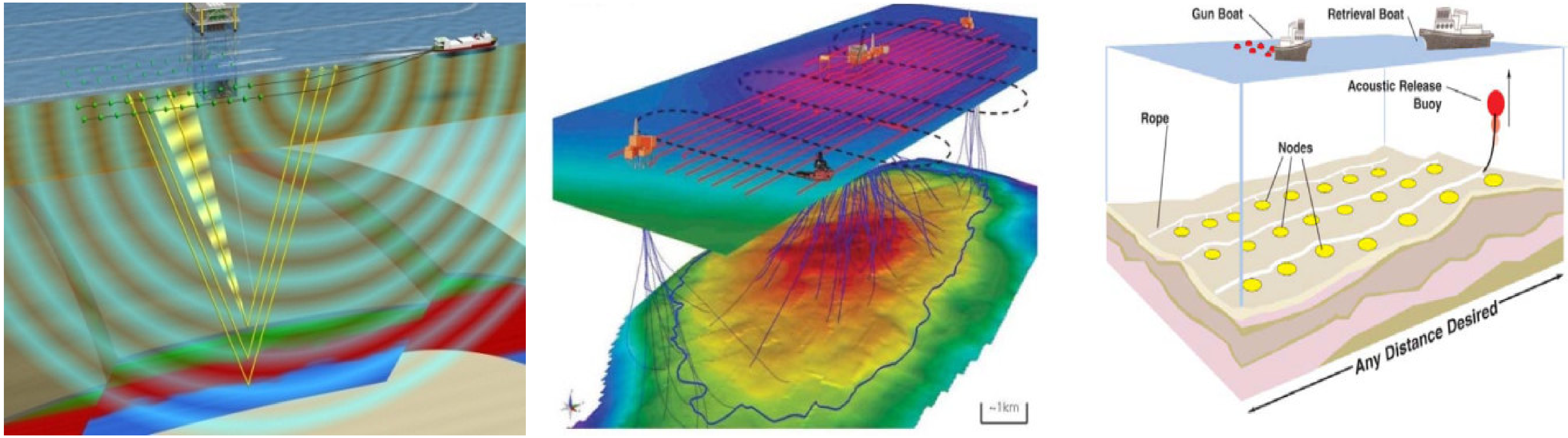

Figure 57. Seismic 'surface' acquisition technologies [35][36]

[35] Middle Figure source: Van Gestel, J.-P., Kommedal, J.H., Barkved, O.I., Mundal, I., Bakke, R. and Best, K.D. 2008. Continuous seismic surveillance of Valhall field. *The Leading Edge* **27(12)**: 1616-1621.

[36] Right Figure source: A new 'node' of acquisition. Steve Mitchell, Fairfield Industries. Published in Hart Energy Publishing 4545 Post Oak Place, Ste, 210, Houston TX 77027 USA 713 993-9320