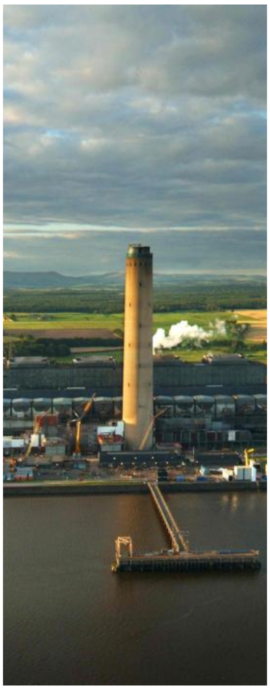

UK Carbon Capture and Storage Demonstration Competition

UKCCS - KT - S7.20 - Shell - 002
MMV Plan

April 2011
ScottishPower CCS Consortium

SCOTTISHPOWER nationalgrid
Carbon Capture & Storage Consortium

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1. Executive Summary

The Goldeneye measurement, monitoring and verification (MMV) plan has been developed to address the following:

- The need for 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."

The CO_2 sequestration in storage site and storage complex as secondary containment is addressed from two angles: by showing conformance of monitoring results with 3D dynamic earth models; and by monitoring for indications of loss of containment or significant irregularities. The containment monitoring programme is based on two key tenets:

1. Monitoring is focussed on areas and features highlighted by the risk assessment as being of higher risk of potential leakage.
2. Monitoring is built on a staircase of increasing focus and cost; it starts by aiming to detect a potential irregularity then, if an irregularity is suspected, the programme focuses on delineation and confirmation that the suspect is an irregularity (contingency monitoring). The final step – performed in conjunction with the corrective measures plan – is to quantify or define the magnitude of any leak.

MMV is divided into phases: *pre-injection* or baseline; *during injection*; and *post-injection/closure*. The baseline is key to ensuring that the project has a well defined starting point from which to measure any changes. This activity lays down both an environmental and a subsurface baseline. *During injection* a base plan is executed, informed by the risk assessment and aimed at detecting any irregularities. After injection has ceased another base line is taken to compare the before and after state of the system. This is complemented by additional monitoring over the subsequent years, again informed by the risk assessment.

A vital point to note is that the risk assessment and the monitoring plans are dynamic. They are updated as new information from conformance and containment monitoring is received.

After a significant set of screening and modelling exercises the following main monitoring techniques have been selected as suitable for use in the Goldeneye field specific situation:

- Environmental baseline monitoring using multi-beam echo sounding, seabed sampling and continuous injection tracer.
- Well integrity monitoring using pressure and temperature gauges, distributed temperature sensors, tubing integrity logging and seabed CO_2 detection below the platform.
- CO_2 injection conformance using pressure, saturation and flow monitoring
- Lateral and vertical irregularity and plume conformance using time lapse seismic

The timing and frequency of monitoring is informed by the risk assessment and varies from technique to technique. This is explained in detail in the report.

Until detailed design and tendering exercises have been performed the costs retain a moderate level of uncertainty.

2. Scope of this report and MMV objectives

The purpose of this document is to describe the risk based approach and deployment strategies of the measuring monitoring and verification (MMV) plan for the proposed Goldeneye Carbon Capture and Storage Project, in the UK sector of the central North Sea.

The Goldeneye monitoring plan aims to comply with both emerging UK and EU regulations by combining the aims of monitoring with a risk based, site-specific approach to the development of a monitoring plan. The monitoring plan is risk based and site-specific due to the heterogeneity of the subsurface and the unique migration/seepage pathways of the Goldeneye storage complex. This section outlines the Goldeneye monitoring objective and scope; and describes the guidelines, objective, strategy and management approach, as well as defining the storage complex, injection plan and monitoring domains. Section 3 describes the Goldeneye site specific risks that lead to the likeliest leakage scenarios – which are addressed by the monitoring plan. Section 4 will briefly highlight the technologies screened. It provides the pool of feasible technologies for the MMV base plan selection in the pre-injection, during injection and post-injection/closure phases, described in section 5. Section 6 details the contingency monitoring plans. Section 7 covers the need to update the monitoring plan regularly. Appendix I presents the three MMV precedents in the North Sea and explains why the Goldeneye MMV will be different in approach and design.

Important terms with regards to the geological storage of carbon dioxide are taken from the relevant EU directive[1] and are repeated here for clarity:

- the '**storage site**' is a defined volume area within a geological formation used for the geological storage of CO_2 and associated surface and injection facilities;
- the '**storage complex**' is the storage site and surrounding geological domain, which can have an effect on overall storage integrity and security – *i.e.*, secondary containment formations;
- '**leakage**' refers to any release of CO_2 from the storage complex;
- '**migration**' means the movement of CO_2 within the storage complex;
- '**CO_2 plume**' is the dispersing volume of CO_2 in the geological formation;
- '**significant irregularity**' is 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**' are 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 2-2 derived from GD2[2].

[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

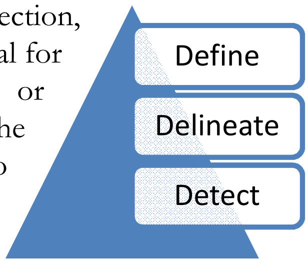
2.1. Objective

The Goldeneye monitoring plan is designed to fulfill four main objectives:

- Monitor for HSE purposes to detect early warning signs of significant irregularities or actual leakage emissions (*e.g.*, loss of wellbore integrity) and, if deemed necessary, to activate the recovery measures that can be put in place to bring the potential leakage hazard under control.
- Verification and validation (or conformance) of dynamic earth models in the short term, to estimate the long-term behaviour of CO_2 plume, to inform the frequency and duration of the monitoring plan and to confirm secure containment.
- Accounting for seepage of CO_2 back to the atmosphere under the CDM crediting period and for the EU ETS.
- Provide support for transfer of liabilities pursuant to *The Storage of Carbon Dioxide (Termination of Licences) Regulations 2011*[3] (and receipt of a termination notice) by showing that: "that all available evidence indicates that the stored CO_2 will be completely and permanently contained".

To achieve these aims, all phases of the project (*i.e.*, *pre-injection*, *during injection* and *post-injection/closure)* need to be monitored. This can only be achieved against agreed base levels for each domain, which allow accurate accounting of CO_2 entering and possibly leaving the storage complex.

Irregularities (migration) and leakage monitoring are focused on detection, delineation and definition (quantification). Detection and delineation are crucial for both prevention and correction to identify possibly deleterious migration or pressure effects[4] and act to contain it to domains where it does not leak to the biosphere. Definition/quantification is imperative in the event of leakage to the biosphere or interference with other users of the subsurface, in order to determine the level of environmental and commercial damage.



For the *post-handover* phase (when responsibility for the security of the site is passed to the UK Competent Authority), the monitoring plan will formed based on data collected in the *during injection* and *post-injection/closure* phases. It will be discussed further in the next phase or the next MMV plan update.

2.2. Strategy

To ensure the MMV plan reaches its objectives, the following strategies have been selected:

1. Profile the current state of the site and complex *pre-injection* by acquisition of baseline data across the environmentally sensitive domains (see §2.3 on p10 for definition of the domains). The information will be used to update the risk assessment, ensure the effective selection of injection patterns, and forms the reference for subsequent monitoring across project phases.
2. Utilize continuous monitoring and reservoir conformance data as first indicator (detection) of irregularities subject to the technical detection limits of each technique. One of the five planned injectors will initially be used as a monitoring well. This well (GYA-03) will function as a backup injector when the monitoring function has ceased.

[3] This currently draft legislation is expected to come into force on 6th April 2011.

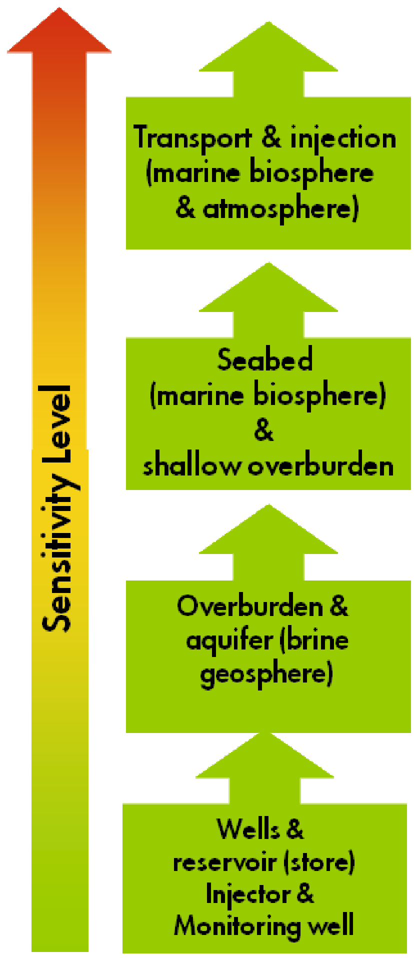
[4] Which can be the precursor to migration

3. Employ the base monitoring plan (section 5) to trigger initiate additional monitoring efforts described in the MMV contingency plan (section 6) to confirm and locate (delineate) any suspected irregularity. This approach maximizes the efficiency of the monitoring activity.
4. Develop options for *post-injection/closure* monitoring. Decisions on the precise monitoring programme will be made with reference to actual monitored storage performance during the injection phase.
5. Define specific contingency monitoring plans to cater to each of the likeliest leak events identified from the risk assessment. These form the basis of any response were a suspected irregularity to occur during store operation. The actual response *on the day* will naturally be tailored to the specifics of the state of the store and irregularity suspected and the time.

2.3. MMV domains

It is useful to separate the spheres of potential project influence into a number of MMV domains which can be ranked according to the 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 areal and depth sense. The first domain, transport and injection is only briefly mentioned since the monitoring details are covered in the facilities/topside scope of work[5]. The following subsections briefly describe each domain.

2.3.1. Transport and injection

The main tools for leakage detection in this domain are plant monitoring systems from Longannet, the pipeline monitoring systems, the monitoring systems for the Goldeneye platform and the injection wells. This domain is also referred to as the atmospheric domain because any CO_2 leakage will have direct contact with atmosphere

2.3.2. Seabed and shallow overburden

This domain covers the seabed down to the base of the formation above the secondary seal complex (Dornoch/Lista mudstone), and is commonly referred to as the marine biosphere and shallow geosphere. 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 assessed as 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] See Shell 2010, Metering philosophy, Metering specification and Metering and allocation strategy

2.3.3. Overburden and aquifer

The overburden and aquifer domain includes the deeper geosphere – the formations between the top secondary seal (Dornoch/Lista mudstone) complex and the base primary seal (intra-Upper Valhall Formation) vertically, and the Captain sand fairway laterally (the lateral continuation of the Captain sandstone reservoir, 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 §3.3 on p25.

2.3.4. Well and reservoir

This domain comprises the storage site (the Upper and Lower Valhall Formations from the top of the Captain Sandstone Member down – see §2.5) and wells drilled 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 the installation of gauges and the measurement of saturation in observation wells. Figure 2-1 shows the 5 planned injection wells GYA01 to GYA05 of which one, GYA03, is planned as a monitoring well early on in the project

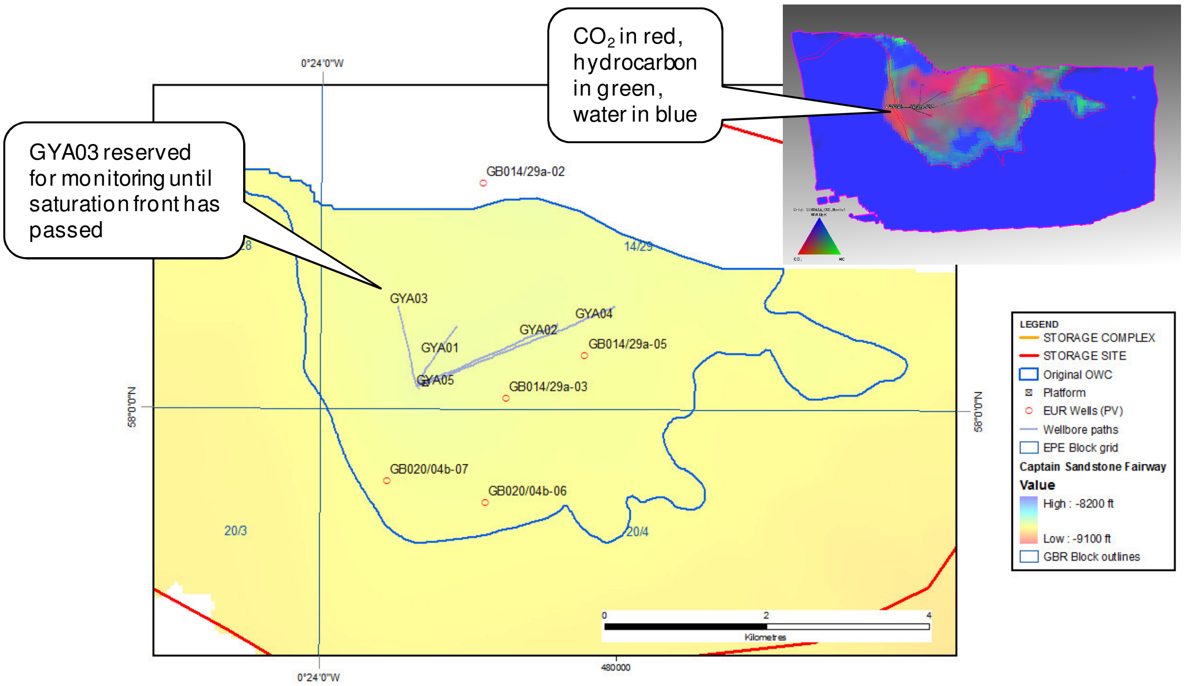


Figure 2-1 Well and reservoir domain showing wells and potential CO_2 plume

2.4. Life-cycle risk management approach

The frequency of monitoring and verification will change over time because the risk profile of the storage complex changes over time. This is reflected in the monitoring intensity and duration. The first stage will involve creating a reliable baseline for each domain to establish a "*pre- injection*" condition. The "*during injection*" phase will be a period of intensive monitoring to validate and update numerical models and ensure safe injection operations. The "*post-injection/closure*" phase will see a reduction in monitoring. Prior to transfer of liability from project proponent to host country, a final check is made on the stability (*i.e.*, behaviour according to predictive numerical models) of the CO_2

plume. The monitoring duration and intensity of the "*post-injection/closure*" phase will be influenced by the behaviour of the plume during injection and the forward modelling results. The monitoring plan will be flexible to respond to unexpected events and incorporate improvements in monitoring technologies over time.

2.5. Storage Site and Storage Complex Definition

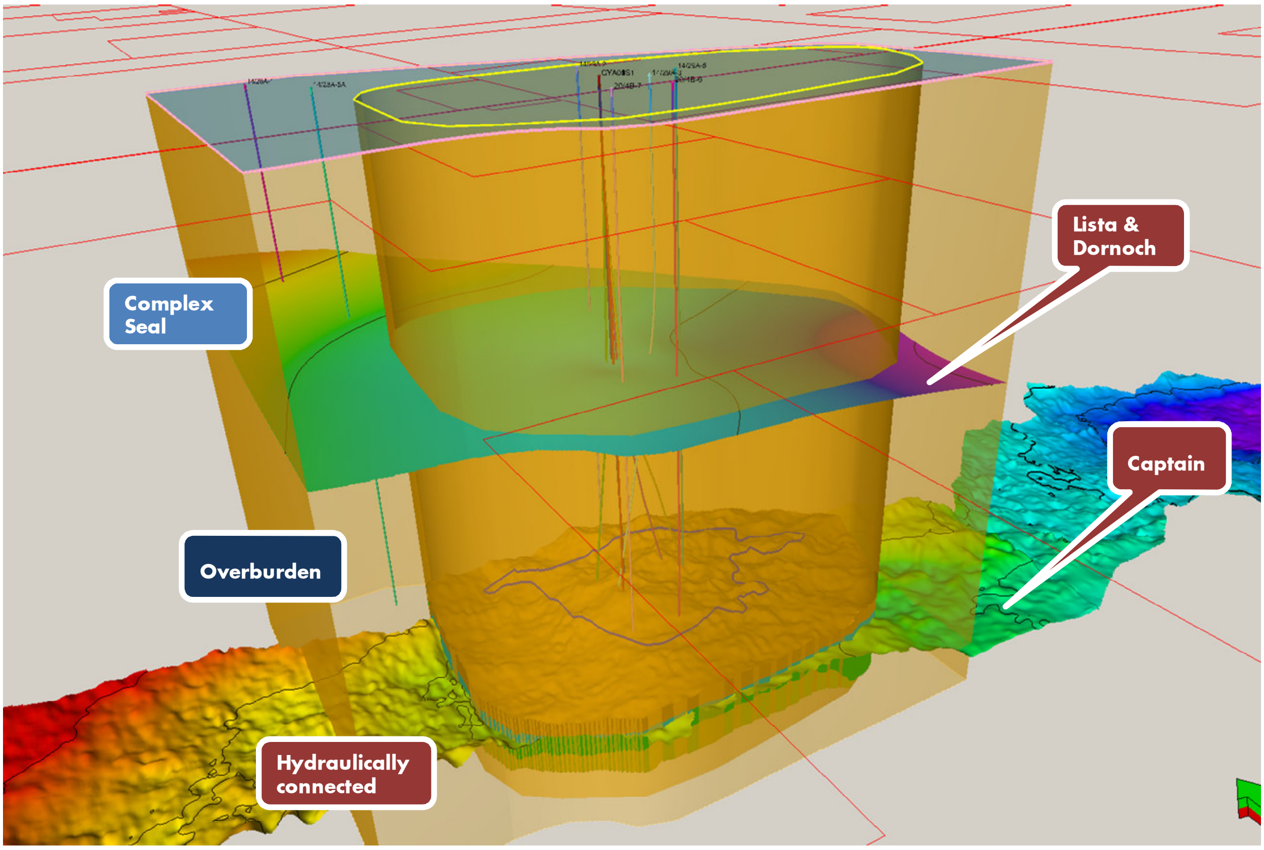


Figure 2-2 Cartoon to show the storage site (solid 'cylinder'), storage complex (transparent pink 'cylinder') and complex seal (shallower coloured surface within pink 'cylinder'). The base of the Captain Sandstone Member aquifer is represented by the lower coloured surface that extends beyond the storage complex

Figure 2-2 shows a schematic of the Goldeneye storage complex and project boundaries to be monitored. The storage complex consists of a 'storage site', a 'storage seal' and 'secondary containment formations'[6]. For the purposes of this report, the storage site is defined as the pore volume in that part of the Upper and Lower Valhall Formations (which includes Captain sandstone reservoir of the Goldeneye field but excludes the thin section of Upper Valhall Group mudstone that surmounts the Captain sandstone) that exist within a short distance of the original oil-water-contact (OOWC) of Goldeneye – as calculated within the static reservoir model SRM1[7] (Figure 2-3).

Vertically, the *storage site* includes all rock between the mapped base of the Lower Valhall Group – which, in this area, is coincident with the top of the Kimmeridge Clay Formation – and the mapped

[6] 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

[7] Shell 2010. Static reservoir modelling (field) report

top of the Captain Sandstone Member. The pore volume that is proposed to be licensed beyond the original boundary of the gas condensate field at Goldeneye to the east, south and west, is intended to accommodate the expected movement beyond the OOWC of a plume of CO_2 at the top of the storage volume in the form of a 'Dietz tongue', propelled by the pressure of injection (Figure 2-4, 2). This 'tongue' is predicted to migrate up to 700m beyond the OOWC in the west of the field (Figure 2-4, image 3). After cessation of injection, the buoyancy of the CO_2 with respect to the aquifer brine and the energy of the aquifer itself will return any free CO_2 that remains within this tongue to the pore volume that exists above the original oil-water contact of the Goldeneye field (Figure 2-4, 4). The extension to the north, which encompasses an area where no Captain Sandstone Member rocks have been encountered, is to accommodate uncertainty around the position of the northerly pinchout of the reservoir.

The *storage seal* comprises the part of the Upper Valhall Formation that sits atop the Captain Sandstone Member and the Rødby Formation shales. It is also includes the Hidra Formation and Plenus Marl Bed of the Chalk Group, which overlay the Rødby Formation with no obvious unconformity and which will also act as a sealing caprock to the flow of fluids from the storage site.

The elements of the secondary containment include the following:

- Secondary storage (hydraulically connected). The geographical limit of the storage complex (as opposed to the 'storage site') extends between 2.5km and 5km from the OOWC (Figure 2-3). The extension in the east-west direction is intended to reflect the expected migration of aquifer water made dense by the dissolution of carbonic acid out of the storage complex. This will move down dip within the Captain Sandstone Member aquifer. The base of the hydraulically connected storage complex is the same as for the storage site. However, the inclusion of underburden formations in the 'hydraulically connected storage complex' does not imply that it is believed that all of the permeable formations in these strata are in hydraulic connection with the Captain Sandstone Member aquifer.
- Secondary storage (overburden). The formations of the Chalk Group and the Tertiary-aged Montrose and Moray Groups that exist between the top of the Plenus Marl Bed and the base of the Dornoch Mudstone Unit of the Dornoch Formation are expected to sequester such volumes of CO_2 that have bypassed the storage seal and migrate vertically upwards through the overburden (Figure 2-5). Sequestering will happen either structurally, below regional mudstones and shales – *e.g.*, the mudstone that occurs at the top of the Lista Formation, in the Montrose Group – through mineralisation, through reaction with the carbonate minerals of the Chalk Group or via capillary trapping. The extension of the storage complex to the north-west reflects the regional dip of the Montrose Group and assumes that any escaped free CO_2 will move preferentially in this direction under the influence of buoyancy forces. This is indicated by modelling of the extent of CO_2 plume movement within the Mey Sandstone Member of the Lista Formation.
- Complex seal. The 'ultimate seal' of the storage complex is identified as the Dornoch Mudstone Unit, of the Dornoch Formation and Lista mudstone, of the Lista Formation. The Dornoch mudstone is a regionally correlatable mudstone that has been seen in every well within the area of the storage complex. To the west of the Goldeneye field it 'merges' with the mudstone at the top of the Lista Formation as the Lower Dornoch Sandstone Unit pinches out. Other regional mudstones are believed to exist at shallow levels above the Goldeneye field but inconsistent sampling during the drilling of exploration, appraisal and development wells in the area mean that correlation of these layers is uncertain.

The storage site and secondary containment volumes defined in this report are indicative only and are not intended to indicate the volume that would be included in any future license application that would be required to enable the execution of this project.

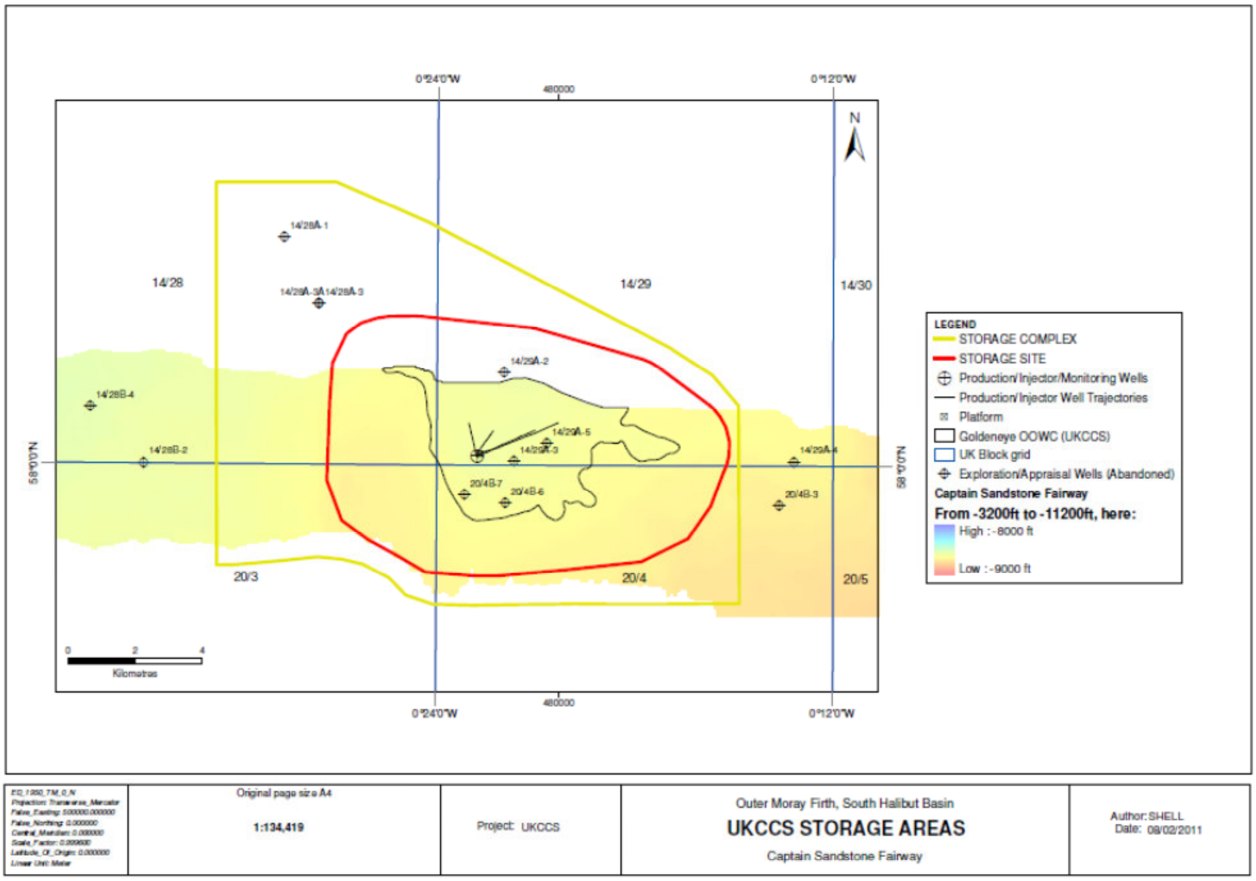


Figure 2-3 Map to show the geographical extent of the storage site and storage complex with extent of Captain Sandstone Member aquifer indicated

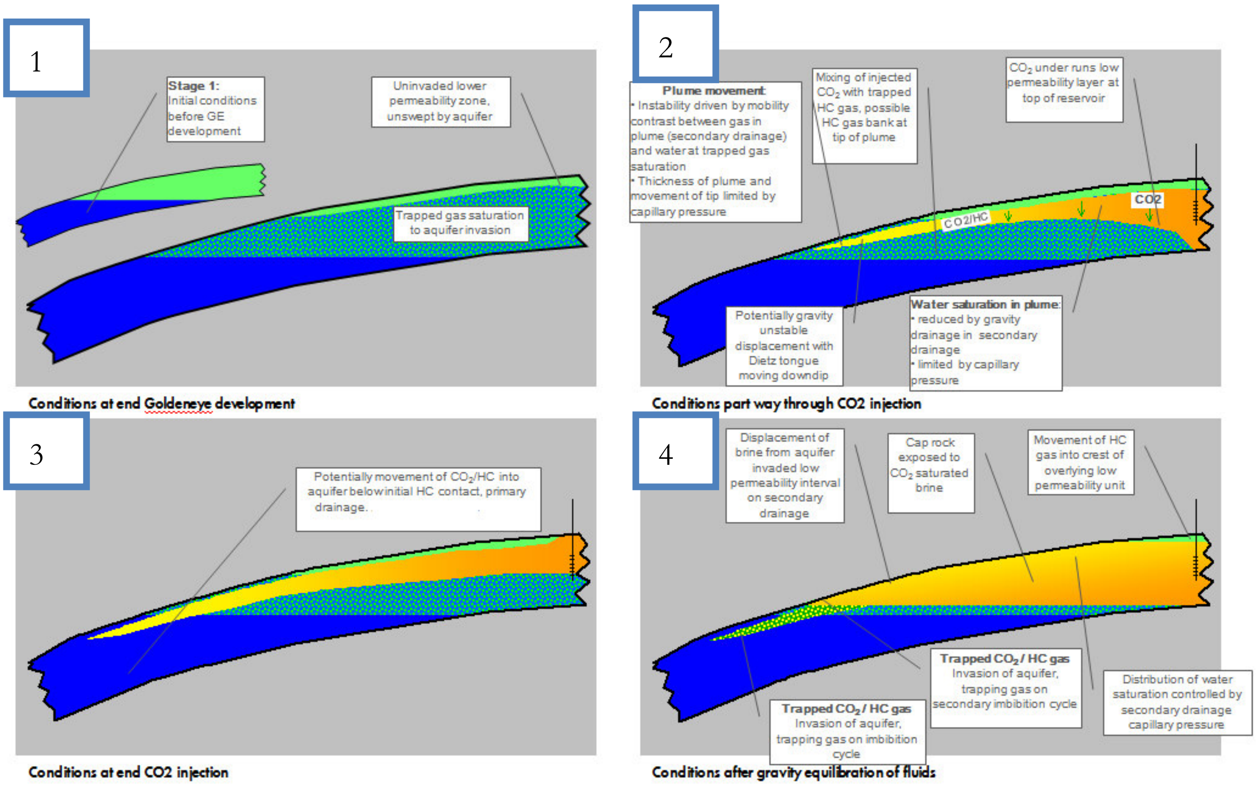


Figure 2-4 Cartoon to show the development of a 'Dietz tongue'

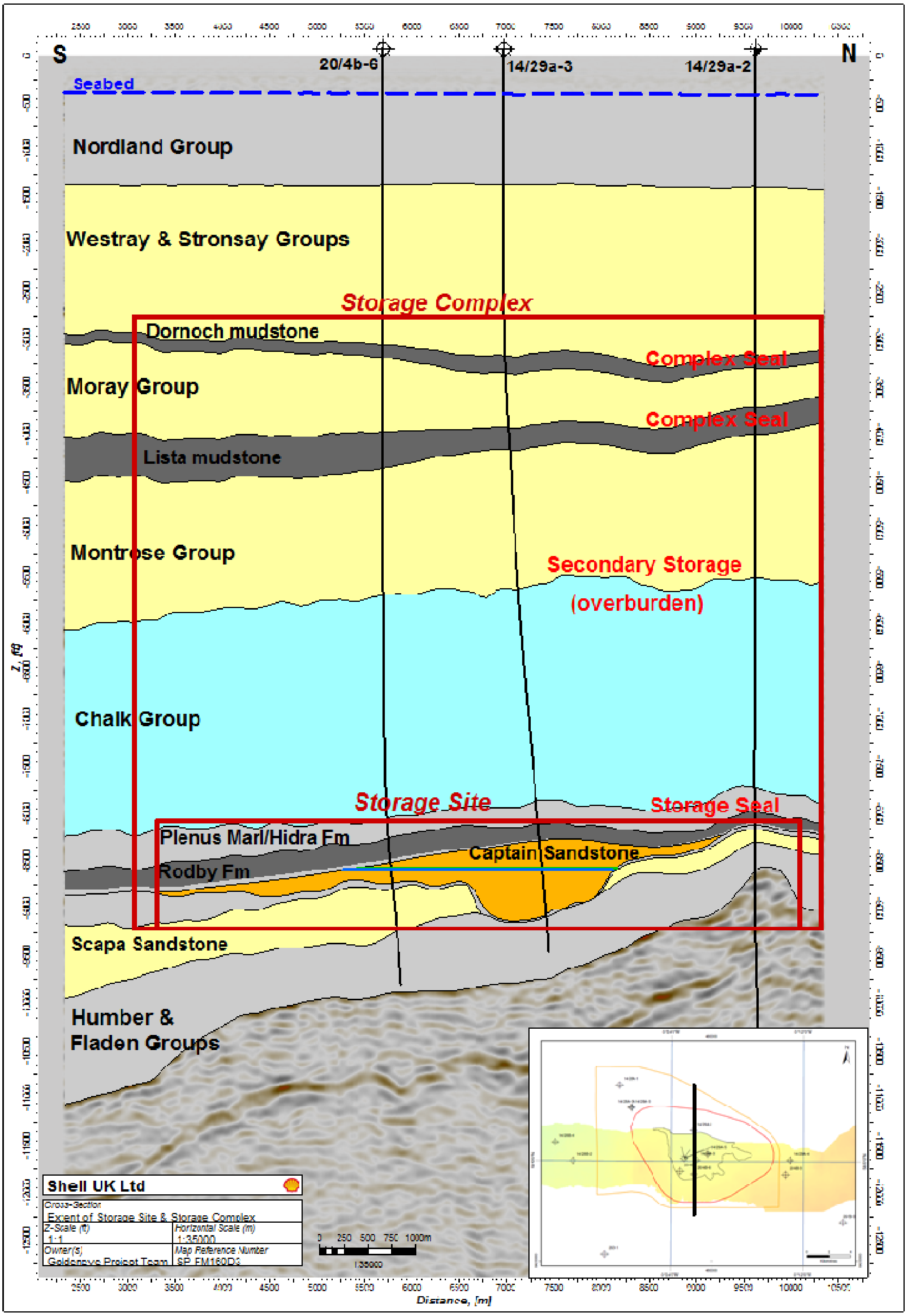


Figure 2-5 **Cross sections to indicate the vertical (subsurface) extent of the storage site and storage complex**

2.6. CO_2 injection plan

The Goldeneye field is penetrated by five existing development wells (where one development well has been sidetracked) and four abandoned exploration and appraisal wells. CO_2 will be injected using the former Goldeneye gas production wells that will be converted into CO_2 injectors. One of these wells will serve as monitoring well. The injection target is the upper part of the Captain 'D' subunit where the CO_2 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 gravity forces and there is potential for a tongue of CO_2 to move below the original hydrocarbon water contact Figure 2-6). When injection ceases, gravity (buoyancy) forces will dominate and any mobile down dip CO_2 will re-equilibrate and flow up structure (Figure 2-7).

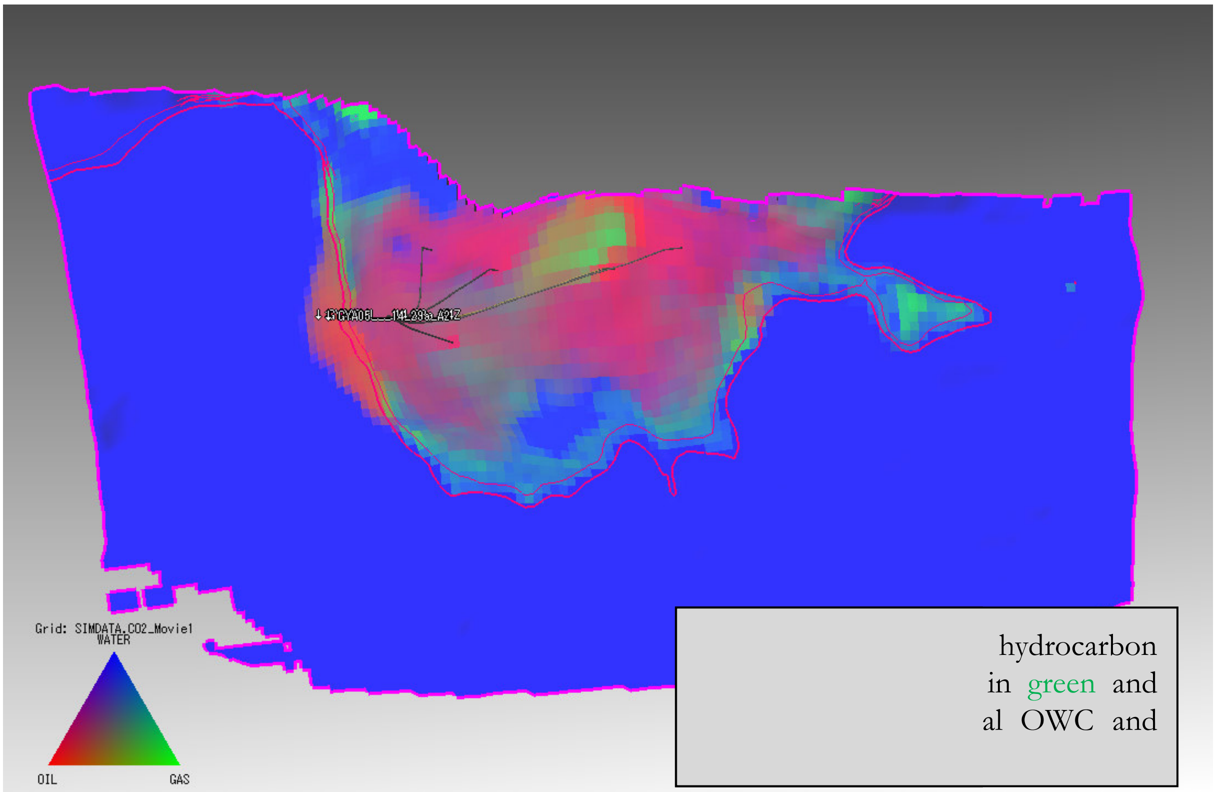


Figure 2-6 Example CO_2 injection realisation while injecting in wells 5, 4 and 1. Red colour shows CO_2 plume and Green colour shows original-fluids-in-place

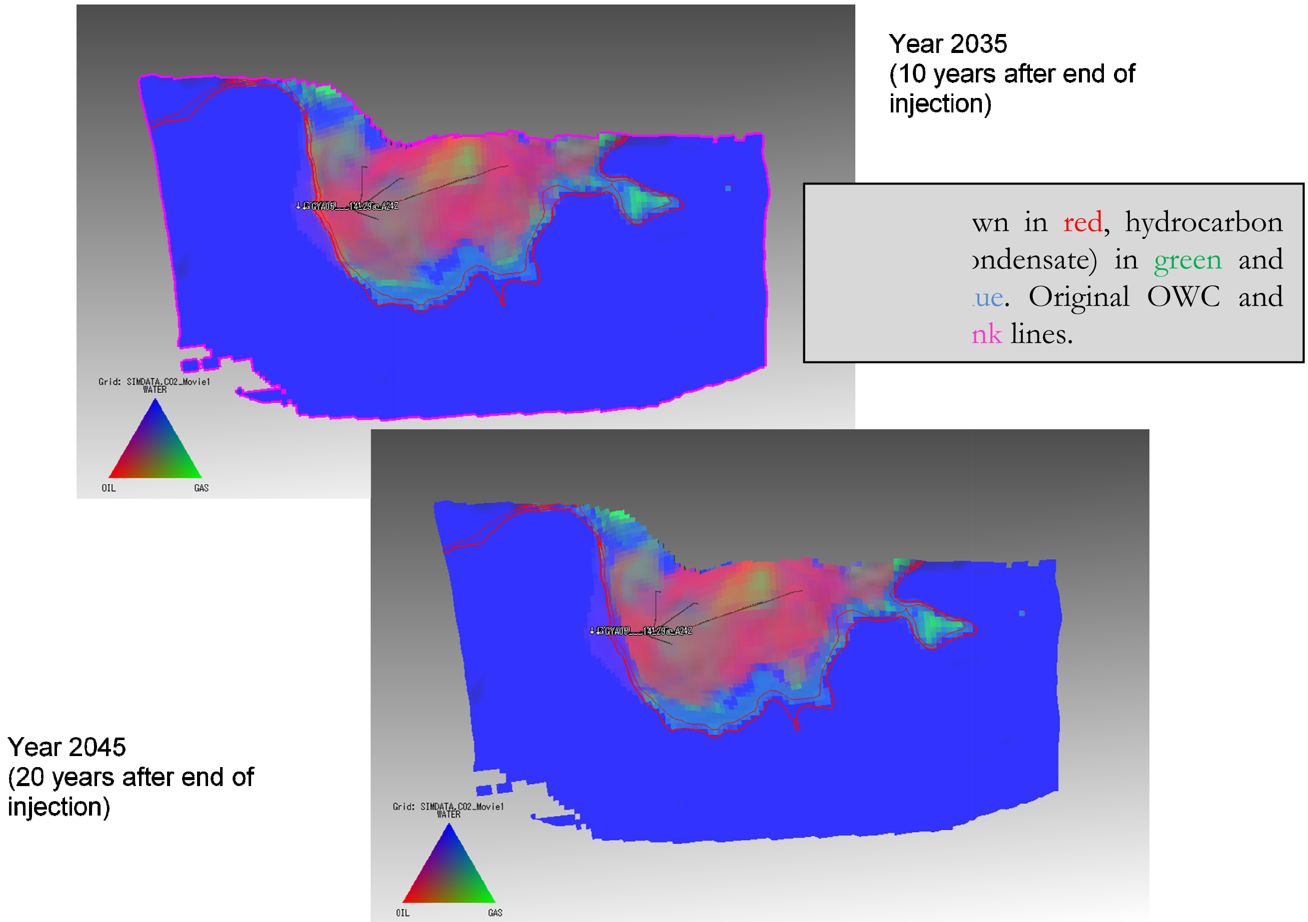


Figure 2-7 **CO_2 plume, 10 and 20 years after end injection showing CO_2 flowing back into the original hydrocarbon zone.**

3. Risks

The following section outlines the risks or threats that could cause migration that might lead to a significant irregularity.

3.1. Risk assessment

The containment risks are described using the standard bowtie risk assessment methodology.

3.1.1. Bowtie risk assessment method

Bowtie analysis has been used for risk management world-wide across a variety of business sectors and the method has been in widespread use since the mid-1990s. It provides a readily understandable visualisation of the relationships between the causes of unwanted events, the escalation of such events to a range of possible outcomes, the controls preventing the event from occurring and the mitigation measures in place to limit the consequences.

Illustrating the preventive and mitigation controls against their respective causes and consequences in such a structured way demonstrates that risks are understood, and can highlight gaps in risk control which should be a focus for remedial action. The bowtie diagram provides a simple visual demonstration of the way in which risks are managed.

The bowtie method entails building a bowtie diagram (Figure 3-1), step-by-step, to produce a qualitative risk assessment of the hazard under consideration.

A **hazard** is defined as something which has the potential to cause injury, damage or loss.

For the Goldeneye CO_2 store, the hazard is the release of carbon dioxide (CO_2). It has the potential to cause harm (e.g. by asphyxiating people who are engulfed by a cloud of CO_2, from acidic corrosion when CO_2 is dissolved in water or by contributing to greenhouse gas environmental damage).

Hazards normally do not cause harm because they are kept under control. However, if control of the hazard is lost, an initial incident will occur – this is the **top event** and is shown at the centre of the bowtie diagram. The top event in this project is loss of containment from Goldeneye storage complex by vertical egression past the complex seal or lateral migration from the secondary storage containers (either the hydraulically connected Captain sandstone aquifer or overburden aquifer formations (*i.e.*, Mey and Dornoch Sandstone Members).

The **causes** (sometimes called "**threats**") illustrate the various ways in which the hazard could be released (possible pathways that can lead to the top event) i.e. what could cause loss of control of the hazard. Examples of causes which could result in movement of CO_2 outside the Goldeneye storage complex include existing faults or fractures which cross the primary and secondary seal, the stress of injection causing new faults or fractures or re-opening existing faults or fractures, and flow of CO_2 up abandoned wellbores.

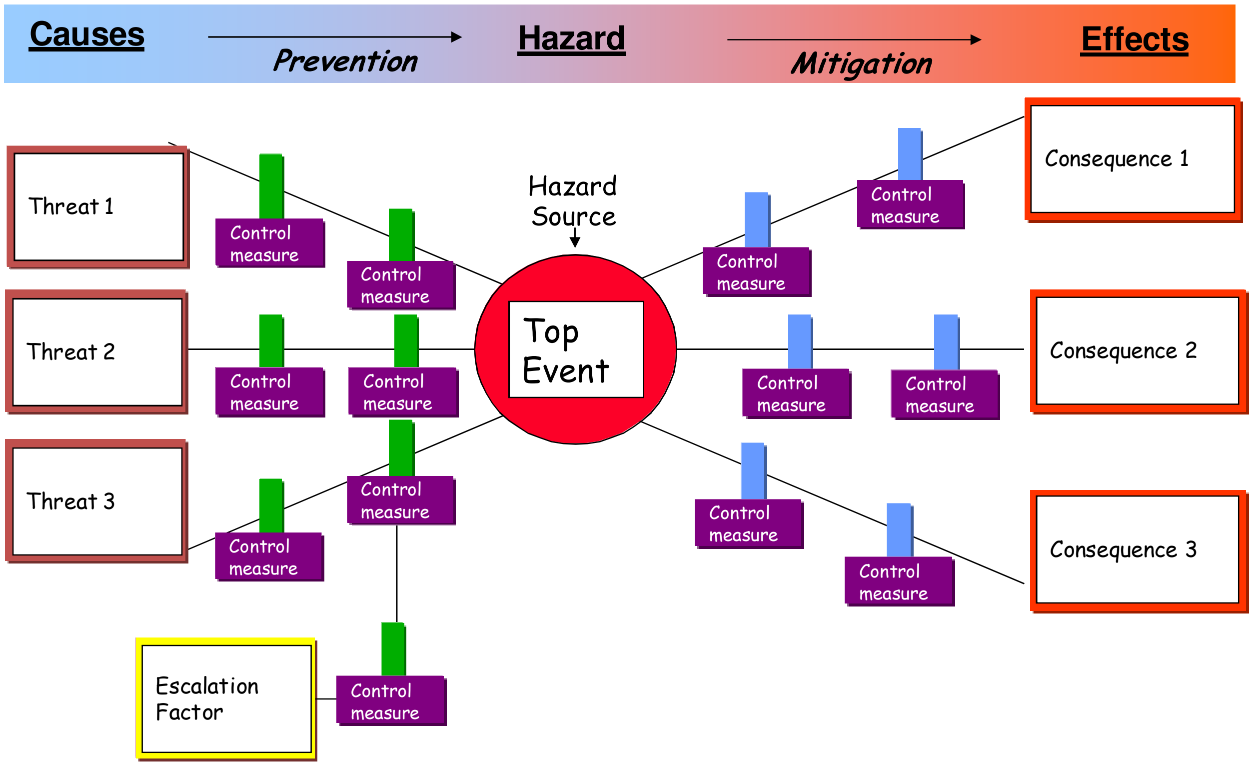


Figure 3-1 **Illustration of the bowtie diagram**

Once control is lost and the top event occurs, there may be a number of ways in which the event can develop to the ultimate **consequence**. Each consequence will result in a specific extent of harm i.e. severity of impact. The impact might be to people, the environment, physical assets or the reputation of the company, or all of these. Examples of potential consequences relevant to the Goldeneye project are release of CO_2 at the seabed, release into the shallow subsurface, or deep release just above the complex seal.

There are **preventive controls** (or **barriers**) in place to prevent the release of the hazard (i.e. prevent the threat leading to the top event). These controls are shown on the left side of the bowtie diagram and can be items of equipment or actions taken in accordance with training and procedures. The safeguards/barriers are present in three forms:

- **Geological barriers** identified during containment risk analysis[8],
- **Engineered barriers** identified during engineering concept selections.
- **Monitoring barriers:** MMV activities complemented by a preventative or corrective measure

Geological and *engineered* barriers are 'passive' barriers as both are either already present or will be installed prior to start of injection. *During injection*, the Goldeneye infrastructure will use existing facilities converted to handle CO_2 operations and process to support transport and injection domain. *Monitoring* barriers are the only 'active' barriers, which will function as preventative measures.

No control can be 100% effective, so if the barriers and preventive measures fail to maintain control and the top event occurs, further **mitigation measures or corrective measures** are in place to interrupt development of the event and limit, or recover from, the consequences.

[8] Shell 2010, Storage Development Plan

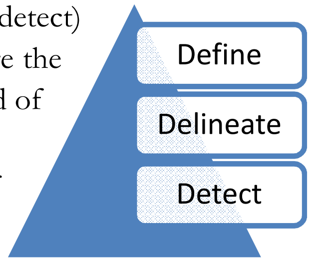
Circumstances may arise which undermine a preventive or mitigation control and reduce its effectiveness; these are recorded on the diagram as **escalation factors** (i.e. they allow the event to escalate). Escalation factors are, in turn, managed by further controls.

Mapping the hazard in this manner promotes a structured review of the hazard, each threat and each consequence, identifying not only what is planned to be in place, but also how control efficacy can be improved or further controls can be added to provide more effective management of the risk.

3.1.2. Goldeneye bowtie

Both Goldeneye threats and consequences are shown in a simplified bowtie in Figure 3-4 and Figure 3-3, whilst full list of threats is tabulated in Table 1. The identification of threats is particularly important for the MMV plan as they will be used to identify migration/leakage causes and path-ways and are the basis of MMV plan selection.

MMV activities, which will be described in detail in the next sections, consist of two plans:



- Base case plan: to provide prevention by identifying migration (detect) within storage complex and enable further action to be taken to ensure the integrity of storage. Activities in this plan are lined up on the left hand of the bowtie to address specific threats.
- Contingency plan: to locate the source in the event of leakage/migration (delineate) and enable further action to be taken as part of corrective measures (including quantification or define). Activities in this plan are lined up on the right hand of the bowtie which link to consequences.

Threats have been ranked for likelihood of occurrence according to the Shell risk assessment matrix (Figure 3-2). Four threats were classified as likelihood A (never heard of in the industry or in analogous situations e.g. gas injection wells) and three were rated likelihood B (heard of in the industry or analogous situations, but has not happened within Shell and occurs less than once per year in the industry).

Passive diffusion of CO_2 through the primary seal was identified as the most likely threat, as it is an ongoing, background process which occurs continuously throughout the CCS life cycle. However, it is an extremely slow process that takes place over geological timescales (many thousands of years).

The most likely threats to storage complex integrity with a relatively rapid effect are:

- **injection induced stress** re-opens faults / fractures or creates new faults / fractures;
- the **presence of existing faults, fractures or features** which cross both the primary and secondary seals;
- **flow up abandoned well bores** (either exploration and appraisal wells, or old injection wells); and
- **injection well tubing leak** to annuli.

These threats were judged by the assessment team to have a likelihood of C (has happened within Shell or happens more than once per year in the industry or analogous industries).

This likelihood rating is based on the experience of the team and their understanding of previous events in the industry or analogous industries, and thus reflects the inherent risk with 'average' preventive controls in place rather than the Goldeneye-specific controls. The rating is intended to indicate the relative likelihood value for each of the threats.

SEVERITY	CONSEQUENCES				INCREASING LIKELIHOOD				
	People	Assets	Environment	Reputation	A	B	C	D	E
					Never heard of in the Industry	Heard of in the Industry	Has happened in the Organisation or more than once per year in the Industry	Has happened at the Location or more than once per year in the Organisation	Has happened more than once per year at the Location
0	No injury or health effect	No damage	No effect	No impact					
1	Slight injury or health effect	Slight damage	Slight effect	Slight impact					
2	Minor injury or health effect	Minor damage	Minor effect	Minor impact					
3	Major injury or health effect	Moderate damage	Moderate effect	Moderate impact					
4	PTD or up to 3 fatalities	Major damage	Major effect	Major impact					
5	More than 3 fatalities	Massive damage	Massive effect	Massive impact					

Figure 3-2 Shell risk assessment matrix (RAM)

Table 1 Summary of threats to CO_2 containment

Threats		Likelihood (Figure 3-2)	Relevant CCS Stage
AF	**Acid fluids**		
AF-01	Acid fluids perforate primary seal (Rodby)	A	Post-closure at hydrostatic
AF-02	Acid fluids react with minerals in existing fault / fracture cement making them conductive / open	A	Injection, post-closure below hydrostatic and post-closure at hydrostatic
AF-03	Acid fluids react with minerals in the reservoir weakening the formation and causing failure (geomechanical failure).	B	Injection, post-closure below hydrostatic and post-closure at hydrostatic
AF-04	Acid fluids react with minerals in the fault / fracture cement allowing fault to reactivate (reactive transport)	A	Injection, post-closure below hydrostatic and post-closure at hydrostatic
DD	**Diffusion**		
DD-01	Pure diffusion of CO_2 through primary seal (Rodby) (without permeability)	E (happens continuously but at extremely slow rates)	Injection, post-closure below hydrostatic and post-closure at hydrostatic
SI	**Stress of Injection**		
SI-01	Stress of injection / refilling causes fault opening or formation of new open fault in seal	C	Injection
SI-02	Stress of injection / refilling causes tensile / shear fracture opening or formation of new open fractures in primary seal / cap rock	C	Injection
FF	**Faults, fractures and features**		
FF-01	Existing faults, mapped / unmapped crossing primary seal (not secondary seal)	B	Injection (local effects) and post-closure at hydrostatic
FF-02	Existing faults / features that cross primary and secondary seal	C	Injection and post-closure at hydrostatic
LM	**Lateral Migration**		
LM-01	Lateral migration beyond the storage complex.	A	Injection
AW	**Abandoned wells**		
AW-01	low up abandoned exploration and appraisal wellbores to near surface	C	Injection, post-closure below hydrostatic and (particularly) post-closure at hydrostatic
AW-02	Abandoned injection wells create leak path	C	Post-closure below hydrostatic and (particularly) post-closure at hydrostatic
IW	**Injection wells**		
IW-01	Injection well tubing leak to annuli	C	Injection
IW-02	Behind production casing cross flow	B	Injection, post-closure below hydrostatic and post-closure at hydrostatic

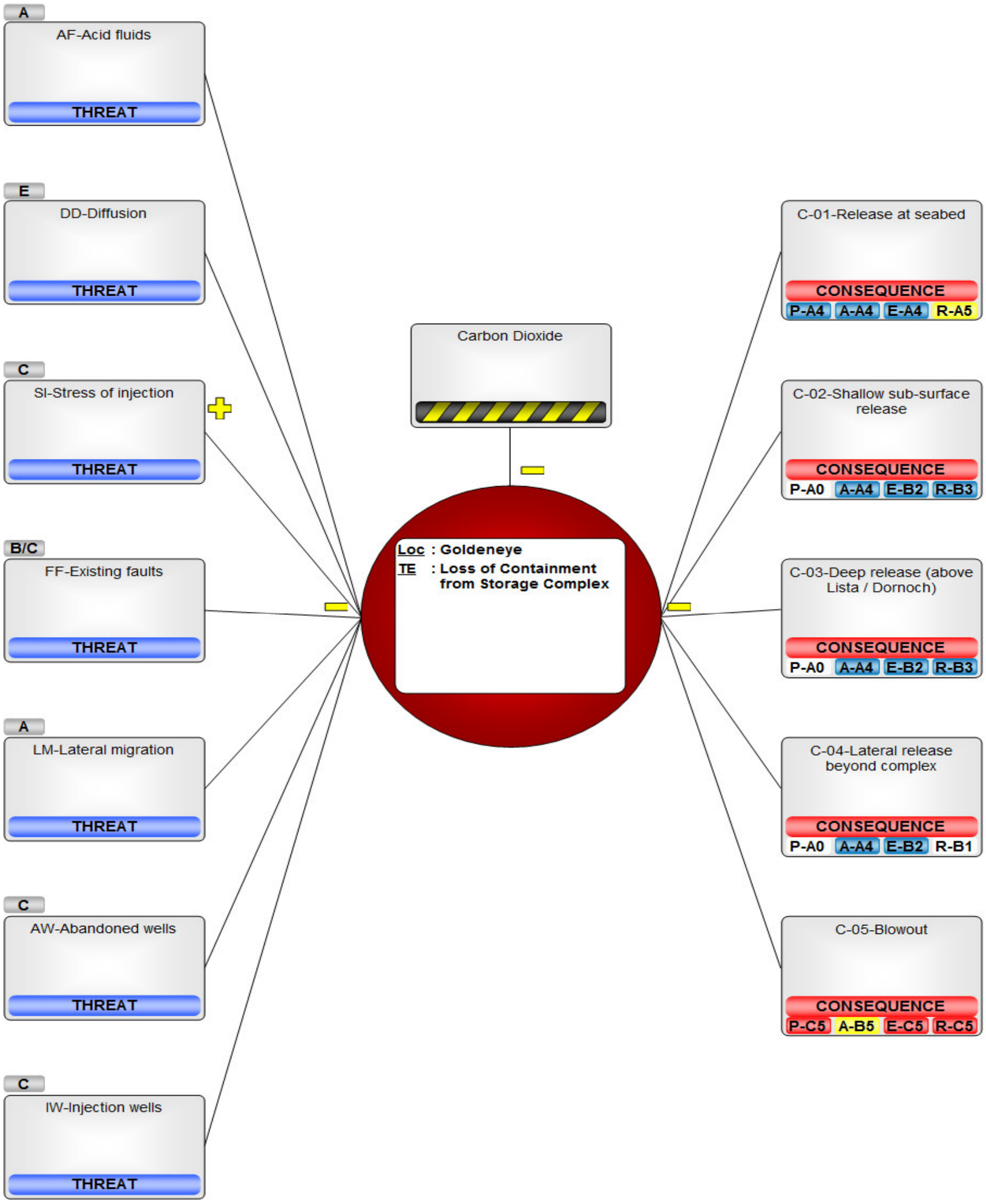


Figure 3-3 **Goldeneye simplified bowtie describes loss of containment as the main event with associated threats (left hand-blue nodes) and consequences (right hand-red nodes)**

The residual risk is determined in relation to the site specific characteristics of the Goldeneye store and also the engineered barriers (e.g. multiple casting strings, CO_2 resistant tubing). This is shown in Figure 3-4 lower section. This residual risk is assessed as low for all risks/threats except diffusion where the residual risk level is negligible (more details are to be found in the SDP[9]).

[9] Shell 2010, Storage Development Plan

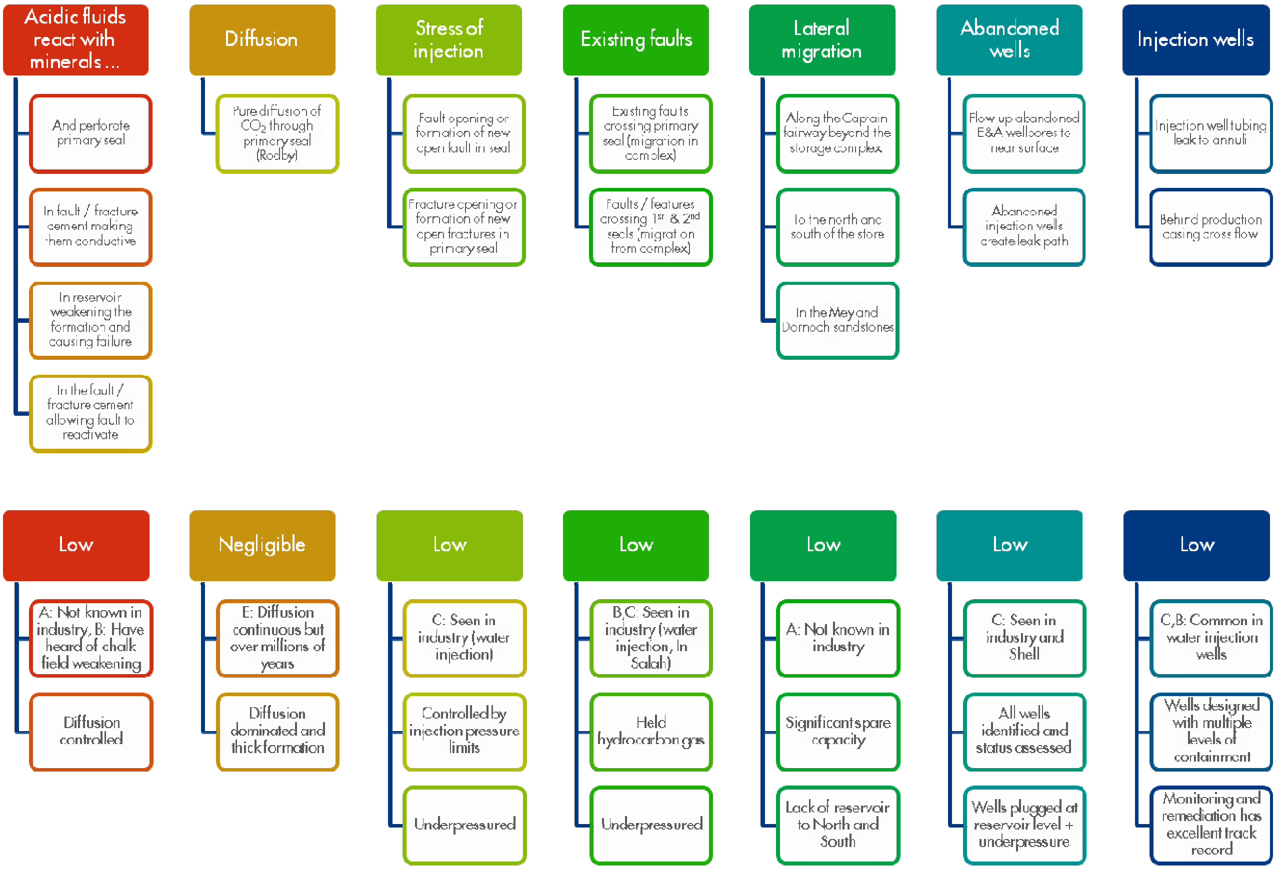


Figure 3-4 **Tabulation of Bowtie risks (top), with risk ranking/assessment after site specific mitigations are taken into account (bottom). See risk assessment section of the SDP for a full description.**

3.2. Leak-path mechanisms

Migration from the primary storage volume can take place laterally and/or vertically. For vertical migration to take place there must be a migration or leak path 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. As described in section 2.5, the storage complex has more than one seal: a storage seal (Rødby Fm) and a complex seal (Dornoch/Lista Mudstone Unit). If vertical migration occurs, in most cases it would pool in aquifers underneath the Dornoch or Lista mudstones and then migrate laterally. Only if migration takes place along a well conduit, fault or continuous fracture could it bypass the complex seal.

Lateral migration can potentially take place at Captain Sandstone Member level. If the injected CO_2 migrates to and then beyond a local spill point (one of the contingency scenarios), 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). In this event, the plume also has the potential to interact with other potential migration and 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 section of the Storage Development Plan) and are summarised in Table 3.

Table 2 Leakage/migration mechanisms for Goldeneye CO_2 storage complex. See Figure 3-4 for risk ranking.

Threat (potential path)	Destination	Cause
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
Injection wells (*during injection* and *post-injection/closure*)	Well annuli, within storage complex, above storage complex and surface	Lack of cement bond, casing/tubing integrity issue
Existing faults/fractures	Within storage complex (faults/fractures in Rødby), above storage complex and surface (faults/fractures in Dornoch/Lista)	Fluid conducting fault or fracture network
Stress of injection (reactivated fault/fracture)	Within storage complex (faults/fractures in Rødby), above storage complex and surface (faults/fractures in Dornoch/Lista)	Stress induced movement/opening of fault/fracture
Acidic fluids (Caprock integrity failure)	Within storage complex (faults/fractures in Rødby), above storage complex and surface (faults/fractures in Dornoch/Lista)	Chemical reactivity with acidic fluid
Lateral migration (past spill point)	Captain aquifer – still below primary seal, but potentially lateral complex boundary	Dietz tonguing causing lateral migration from the primary storage (reservoir)

Effective monitoring will compliment the passive barriers by identifying irregularities, which may lead to leak or migration confirmation and could be utilised as a trigger to preventative or corrective measures. It will also support validation of the CO_2 plume movement within the reservoir (storage site) *during-* and *post-injection/closure* (conformance). The data acquired through monitoring will be used as input to and calibration of reservoir modelling tools and should increase confidence in the simulation of where the plume will migrate both vertically and laterally.

3.3. MMV leakage scenarios

In order to develop effective MMV base case and contingency plans, it is crucial to identify properly the likeliest leakage event scenarios based on the residual risk after natural and engineered barriers for each threat and leakage mechanism and then implement a monitoring technique that is able to detect the start of migration as well as delineate the source – thereby providing a reactive/monitoring barrier in combination with a preventative or corrective measure. Many threats lead to a similar consequence or leakage scenario. It is this scenario that the monitoring needs to be able to detect.

The leakage scenarios are grouped by categorising the threats and considering the combination of leakage pathway mechanisms as shown in Table 3. These leakage scenarios are used as a basis for data acquisition and technology selection for MMV base case and contingency plans.

In a scenario, leakage mechanisms are combined because CO_2 can start to migrate from one mechanism and then continue through another. Therefore, not all leakage mechanisms are suitable for standalone scenarios, *e.g.*, caprock integrity failure. Migration that starts due to a failure in caprock integrity could continue through a well or fault, which would increase its potential to become a leak. Another scenario that also considers multiple leakage mechanisms would be lateral migration in reservoir quality overburden formation below complex seal after the CO_2 has migrated through a well or fault. Both of these scenarios involve a combination of vertical and lateral migration.

Table 3 Goldeneye MMV leakage scenario identification from threats and leakage pathway mechanisms

Threats (detailed)	Leakage actor	Leakage scenarios
Flow up abandoned E&A wellbore near surface	Plugged and Abandoned wells	Leakage through plugged and abandoned wells
Abandoned injection wells create leak path	Plugged and Abandoned wells	
Acid fluids react with minerals in wellbore cement plugs, cement, casing and create leak path	Caprock integrity failure	
Behind production casing cross flow	Development wells	Leakage through injection wells
Injection well tubing leak – to annuli caused by wrong CO_2 spec leading to corrosion, poor connection, make up, mandrel seal failure, thermal cycling, etc.	Development wells	
Acid fluid react with minerals in wellbore cement plugs, cement, casing , creating a leak path	Caprock integrity issue	
Existing faults/fracture that cross primary and secondary seal	Conductive faults/fractures	Leakage through (conducting and reactive) fault/fracture
Existing faults, mapped/unmapped crossing primary seal	Conductive faults/fractures	
Acid fluids react with minerals in fault/fracture cement allowing fault to reactive	Caprock integrity failure	
Acid fluids react with minerals in fault/fracture cement making them conductive/open	Caprock integrity failure	
Stress of injection causes tensile fault opening or formation of new open fault in seal	Reactivated fault/fracture	
Stress of injection causes shear fracturing increasing permeability or formation of new permeable fracture/fault in seal	Reactivated fault/fracture	
Stress of injection causes opening/formation of new open fractures in seal/cap rock	Reactivated fault/fracture	
Acid fluids react with minerals in the reservoir weakening the formation and causing failure	Caprock integrity failure	
Lateral migration along captain Fairway passing the spill point or to North and South	Lateral migration past spill point	Lateral migration in permeable Captain sandstone
Lateral migration along permeable formation at overburden	Wells, fault/fracture, lateral migration	Combination of wells/fault and lateral migration in Mey/Dornoch sandstone

4. Summary of feasible MMV techniques

Forty-five monitoring techniques from ongoing CCS projects, hydrocarbon maturation projects and research and development projects have been examined and twenty-seven have proven to be suitable to monitor CO_2 movement within the Goldeneye storage site, storage complex and beyond. The screening used following elements to determine feasibility:

- **Risk relevance:** How well the measurements provided by these techniques address/identify the subsurface risks associated with CO_2 containment within the storage complex.
- **Measurability:** The ability to identify property contrast *during injection* and in *post–injection/closure* phases compared to background condition (*pre-injection*) and whether the property contrast exceeds the detection limit for the technique.
- **Operational constraints:** The ability to apply the technique in the Goldeneye environment based on its compatibility with 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 favours the technology having the least operational risk, the least cost and that which gains optimal information.
- **Proven technology:** Technologies are either proven for CCS/EOR application, proven 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 during the project execution timeline. The detail of the evaluation will be described separately in report no. SP-MN010D3 Technology maturation.

The list was then narrowed to select the most effective techniques using a value of information exercise, which compares benefit to cost in cost/benefit plot as shown in Figure 4-1. The lower boxes, 'just do it' and 'focussed application' represent the highest benefit. These techniques are the main candidates for the base case plan, although focussed application techniques require further justification due to the costs they potentially incur. Some techniques in the 'consider' box are relatively new for CCS project application. These techniques require further study to establish their feasibility in the Goldeneye environment. Once this is complete, their position on the benefit scale could be redefined.

Low and High definition in the cost is directly linked to the amount of investment required to obtain data acquisition using these techniques. The variation in benefit is best explained by comparing geochemical probe and seismic time–lapse techniques. The geochemical probe detects CO_2 concentration (as well as change in pressure, temperature, pH and salinity), typically in the seabed domain, whilst the seismic time-lapse surveying technique is able to detect/delineate multiple sources of migration/leakage, covers overburden (geosphere) and aquifer domains and is able to quantify (due to detection limit) the migration if it is in low gas/oil saturation.

Applications in the 'park' area are currently disregarded and will not be investigated further. The only exception is the use of a chemical tracer, which is being strongly considered for a move to the base case. The use of tracer for continuous injection in a CCS context is relatively new and, therefore, the selection and the cost are still flexible and will only be decided in next phase. Currently it is positioned in 'park'. However, upon maturation of tracer technology it may be reclassified.

The short-listed techniques are listed in Table 4 which also includes the type of data acquisition, domain and risk addressed. The list focuses on the injection wells and subsurface. The surface and transport domains are described in Figure 5.1 and the details in the surface discipline documents.

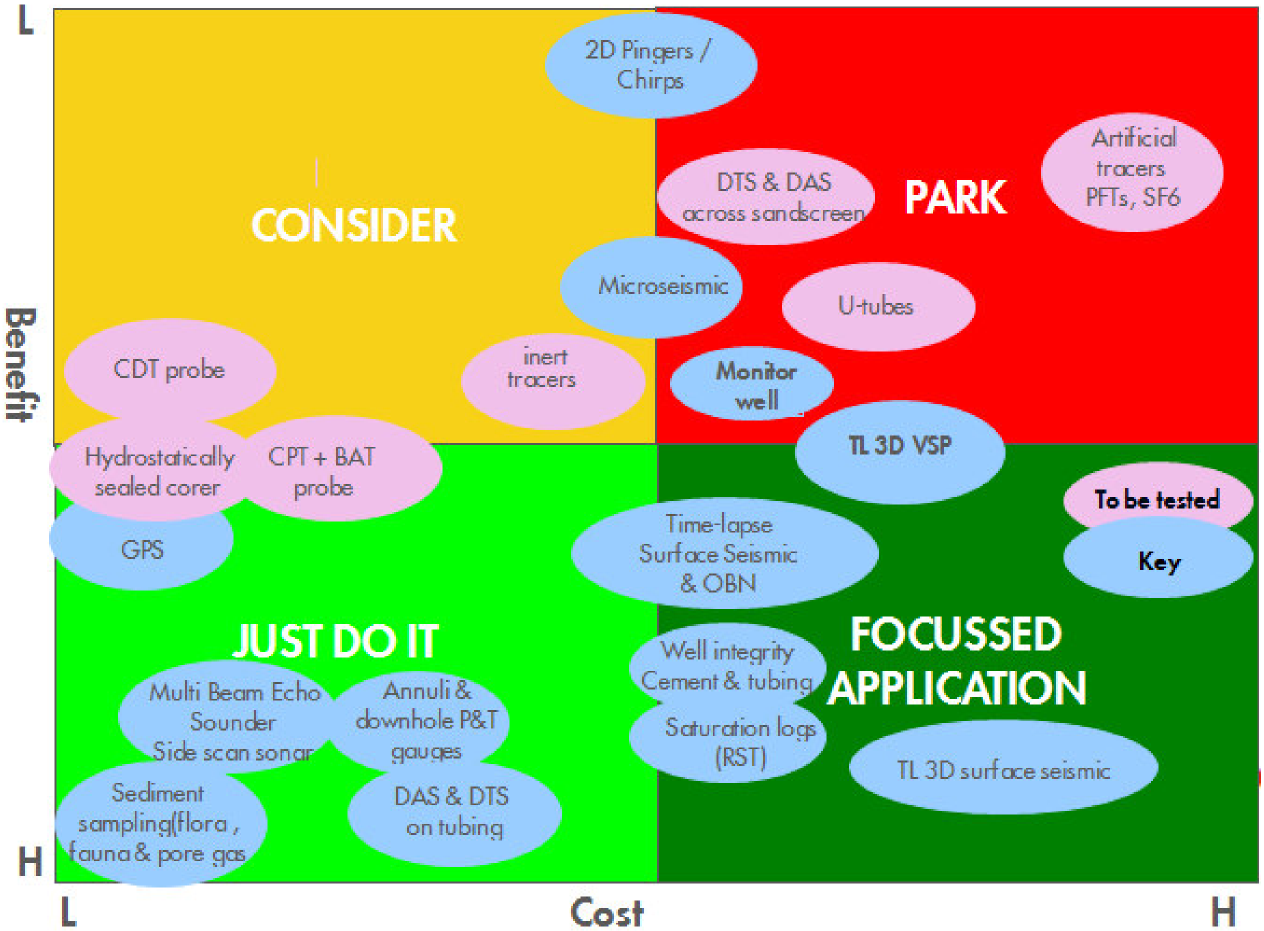


Figure 4-1 **Cost/benefit plot of Goldeneye MMV technologies. The technologies in the blue and pink boxes are part of the MMV base plan. The technologies in the pink boxes need additional development. Note that use of inert tracers (indicated by a red circle) for continuous injection in a CCS context is new and requires further development before a final decision on application can be taken which will only be decided in the next phase of the project.**

Table 4 List of feasible techniques to monitor potential CO_2 migration/leakage from Goldeneye storage

Domain	Data acquisition	Technologies/techniques	**Proposed in MMV Plan**
Seabed and shallow overburden	Water column profiling near seabed	CDT	Yes
	Seabed sampling (seabed sediment, flora & fauna and pore gas sampling)	Van Veen Grab Vibro Corer CPT rig fitted with BAT probe Hydrostatically sealed corer	Yes (One/two options)
	Pockmarks	MBES	Yes
	Subsidence and uplift	GPS	Yes
	Shallow overburden seismic	Chirps/Pingers 2D lines/3D swath	Yes (Contingency Plan)
Overburden and aquifer	Time-lapse seismic	Repeat 3D streamer OBN 3D swath/2D lines Borehole VSP	Yes Yes No No
	Microseismic	Microseismic	No
Well and reservoir	Well integrity	Cement bond logging Casing integrity logging Tubing integrity logging DTS DAS	Yes Yes Yes No (Potentially – New technology)*
	A1.1.1.1. CO_2 Detection	U-tube Downhole sampling	No Yes
	CO_2 Conformance	Sigma logging Neutron porosity logging	Yes Yes
	Pressure conformance	PDG Long term gauge Cased-hole pressure and temperature	Yes Yes (PDG replacement) Yes (in Sigma and neutron measurement tool)
	Fingerprint	Inert Chemical tracer	Considered (subject to further evaluation)

Note: * DAS is currently in R&D maturation programme which is excluding from this document. Further information of the progress and plan for execution will be discussed in monitoring plan update.

5. Base case monitoring design

The base case or day-to-day monitoring scheme was designed by examining the overlap between the risk assessment for each monitoring domain, the modelled behaviour and the nature and scope of the responses of the candidate monitoring technologies – the aim being to reduce the possibility of an undetected migration occurring to as low as reasonable practicable. The process followed for this exercise was:

1. List monitoring technologies based on domains covered and data acquired to determine if there are alternative technologies that cover the same area. Where alternatives exist, rank these according to detection limit, benefit and cost.
2. Develop monitoring themes that are composed of groupings of monitoring technologies, frequencies of application, and also combinations of base case and contingency monitoring. These themes cover each project phase: *pre-injection (baseline)*, *during injection* and *post-injection/closure*.
3. Plot the theme elements based on domains against project monitoring goals in order to construct base case by selecting the most suitable element at each domain that satisfy the monitoring goals and value drivers. The MMV monitoring objectives are listed in Section 2.1. The MMV value drivers are listed in Table 5.

After this analysis it is apparent that a number of choices/philosophies exist. It is possible to develop a monitoring plan that monitors everything in minute detail all the time. In so doing there are significant consequences – environmental (emissions from survey shipping movements, on local fauna from repeated shooting of seismic surveys and potentially on the sea bed if drilling operations are performed); safety (multiple helicopter flights, boat movements in rough seas and other offshore hazards); and cost escalation. On the other hand, it is possible to develop a plan that detects potential leaks, and then triggers a contingency monitoring plan if and when needed. This has the benefit of lower base case environmental, safety and cost implications, offset against variable – and unknown – costs plus an increased time before any suspected irregularity is confirmed.

In the Goldeneye site specific case, reflection seismic surveys have been assessed as an efficient technique both for detection and delineation. Therefore, some of the differentiation between monitoring philosophies has been removed. Other key choices involved the drilling of a dedicated monitoring well, with the concomitant environmental and cost impacts of drilling and operating a new well, plus the additional risk resulting from an additional penetration of the complex and site seals. In this case it was determined that the well would not deliver sufficient additional information to outweigh the demerits as much of the information was already being collected by other means.

Table 5 MMV Value Drivers

MMV monitoring goals	Definition
Environmental	Emphasis on zero leakage to seabed and shallow overburden area closely in contact with biological habitat
Storage certainty	Reservoir conformance data acquisition and detection/delineation of CO_2 plume within or away from storage complex
Operating cost	Cost of selected monitoring plan
Exposure to corrective measures	Cost of contingency plan and associated corrective measures if irregularities are detected by monitoring, which indicate potential or actual leakage.

Table 6 MMV base case plan

Domains	Data acquisition	Techniques	Location	Timing	Reasoning
Baseline (*pre-injection* and *post-injection/closure*)					
Seabed & shallow monitoring	Seabed mapping (pockmarks)	MBES	Storage complex	Pre-injection Yr 1 post-injection/closure	Baseline for seabed leakage identification & quantification (no alternatives)
	Seabed sampling (seabed sediment, flora & fauna and pore gas sampling)	Options: Van Veen Grab Vibro Corer CPT +BAT probe Hydrostatically sealed corer	Sampling points within storage complex- emphasis on high risk area (wells, seismic anomalies, platform)	Pre-injection Yr 1 post-injection/closure	Baseline for seabed leakage on seabed identification & quantification Technologies need maturation, will be selected in next phase
Field overburden & aquifer	Time-lapse seismic	3D streamer (full-field)	Storage complex	Pre-injection Yr 1 post injection/closure	Baseline large area of field overburden and aquifer (the alternatives cover smaller area range)
		OBN	Surrounding	Pre-injection	Provide best resolution for baseline on surrounding and

Domains	Data acquisition	Techniques	Location	Timing	Reasoning
			platform area	Yr 1 post-injection/closure	underneath platform (compared to undershoot)
Wells & reservoir	Well integrity	Cement bond logging	Five wells	Pre-injection	Baseline condition of cement bond between casing and formation
		Casing integrity logging	Five wells	Pre-injection	Baseline condition of casing thickness
	CO_2 conformance	Sigma & neutron logging	Monitoring well	Feed or Pre-injection	Baseline the fluid contacts
	Pressure conformance	PDG	Five wells	Pre-injection (installation)	Identify pressure conformance in Captain reservoir, identify when system will re-pressurise and have energy to drive fluids out of the store
During & Post injection					
Seabed & shallow	Water column & seabed profiling	Geochemical probe	Seabed under platform	Continuous	Indication of increased CO_2 flux and change of environment properties
	Seabed sampling (seabed sediment, flora & fauna and pore	Options: Van Veen Grab Vibro Corer CPT +BAT probe	P&A wells surface location	Yr 5(±)	Indication of increased CO_2 flux and change of environment properties

Domains	Data acquisition	Techniques	Location	Timing	Reasoning
	gas sampling)	Hydrostatically sealed corer			
Field overburden & aquifer	Time-lapse seismic	3D streamer (full-field)	Storage complex	Yr 5(±) Post injection as dictate by pressure profile	Indication of CO_2 migration in overburden and aquifer – similar to baseline (alternatives covers less area)
		OBN	Surrounding platform area	Yr 5(±)	Indication of CO_2 migration surrounding and underneath platform – similar method to baseline
Wells & reservoir	Well integrity	Annular pressure and DTS	Assume 5 wells	Continuous	Indicate leakage at casing by pressure profile and along tubing by temperature profile
		Tubing integrity logging	Active injectors (assume 5 wells)	Periodically every 3 yrs	Indicate leakage in the tubing using direct measurement
	CO_2 Detection	Downhole sampling	Monitoring well	Yr 5-10, periodically every year	Identify CO_2 concentration profile for saturation performance (the alternative is restricted due to well & completion constraints for installation)
	CO_2 Conformance	Sigma & neutron logging	Monitoring well	Yr 5-10, periodically	Identify breakthrough CO_2 interval profile for saturation conformance

Domains	Data acquisition	Techniques	Location	Timing	Reasoning
				every year	
	Pressure conformance	PDG	Assume 5 wells	Continuous+ potentially 3 years post injection/closure	Identify pressure conformance in Captain reservoir
		Long term gauge	Assume 5 wells	Replacement for PDG	Identify pressure conformance in Captain reservoir

5.1. Surface monitoring

Active surface monitoring takes place in the form of:

- gas detection in and around the facilities (for the protection of staff and the environment)
- flow metering, which quantifies in-flow of CO_2 – in absolute terms and also giving well allocation.
- in-flow composition monitoring - this is important in terms of injection and maintenance of the facilities but is performed prior to the CO_2 reaching the Shell pipelines and facilities.
- Pipeline monitoring – ensure the inlet specification and condition are monitored regularly
- Operating envelope in pressure and temperature.

The above are explained in more detail below.

5.1.1. Gas detection

Various typical detection scenarios and the technologies to be used, in order of descending preference:

- Boundaries/Areas Monitoring. The first preference for gas detection is the application of Line-Of-Sight (LOS) techniques, due to its reliable and cost effective coverage of large areas. This technology is especially useful for detecting the migration of significant gas clouds between process modules and the accumulation of gas clouds within process modules.
- Significant Potential Leak Sources. In areas where there is a significant risk of leak (e.g. concentration of flanged joints, screwed joints, valve spindles, complex instrumentation piping and pump glands) point detectors using the IR absorption technique shall be employed.
- Congested Plant Modules. In congested areas within process modules where LOS detection is unsuitable due to the absence of any substantial sight lines or where there is increased risk of accumulation due to confinement, then additional IR point gas detection shall be employed.
- Building Interiors. The first preference for protecting building interiors from gas build-up is the detection of gases much closer to their release in the field. Where gas could be ingested into a structure by HVAC systems, then the intakes shall be monitored. Where gas release is possible inside the building (compressor enclosure for example) then detection within the building shall also be employed. A cost effective alternative to monitoring multiple points inside a structure is monitoring the outlet vent.
- Ducting and Air Intakes. Due to the potential difficulty of high air flows and maintenance access associated with gas detection inside ventilation ducts, it is preferable to protect an air inlet/duct from gas ingestion using Point Detection in the vicinity of the intake, rather than inside the duct itself. If it is possible that concentrated gas might flow into the duct undetected using point detection at its opening, then Line-Of-Sight detection across the duct cross-section shall be employed, with consideration given to how these detectors may be tested by maintenance in the future.
- Non-Methane Hydrocarbon Gases. Generally hydrocarbon gas detectors are sensitive and primarily calibrated to detect Methane gas. Often a sensor's capacity to detect Ethane, Propane and Butane gas clouds is poorly defined. It is highly unlikely that any potential hydrocarbon gas releases on the Goldeneye platform or St Fergus Terminal will not contain significant concentrations of Methane in the release, hence there is no special consideration needed to accommodate Non-Methane Hydrocarbon Releases on this project.

There are two survivability criteria for CO_2 gas concentration alarm limits as defined by Shell standard, they are listed as following:

Table 7 Exposure Limit and CO2 Concentration for gas detection alarm

Exposure Limit	CO2 Concentration
Short Term Exposure Limit (15 minutes)	3.0% CO2 Concentration In Air
Long Term Exposure Limit (30 minutes)	1.5% CO_2 Concentration In Air

There is some variation in the current workplace exposures limits for CO_2, hence the above limits may be either modified or employed unchanged for this project. However the above tabulated figures provide an excellent basis of the order of magnitude of sensitivity required for an effective CO_2 gas detection system.

CO_2 gas detector selection is made based on its distinctive absorption line character in the Infra-Red (IR) light spectrum. By shining an IR light through a sample of gas under test, and checking for absorption of this specific frequency of light, it is possible to determine if CO_2 is present in the gas sample. This principle can be applied to a Line-Of-Sight (LOS) detector spanning hundreds of metres or a point detector only a few centimetres across. The technology for CO_2 detection by IR absorption is developing rapidly, and there are a large number of suitable CO_2 gas point detectors currently in the market. Hence the detailed design shall evaluate the current market offerings and field experience to select the best device at the time.

The market offering for CO_2 Line Of Sight Detectors (LOS) is less well developed, however commercial products exist:

- An example of a commercially available CO_2 LOS detection product is the Gas Finder range by Boreal Laser Inc.
- A number of companies are able to modify their standard LOS gas detection product to detect CO_2.

Where LOS CO_2 detectors without proven field experience are deployed, they must be field testing prior to being relied upon for safety critical purposes. An alternative is to use the CO_2 LOS detector for wide area coverage to provide early warning of CO_2 leaks.

5.1.2. Flowmeter

The metering of CO_2 throughout the installation will vary with regard to operational pressure, temperature and phase. Mass flow will be the standard flow measurement unit for CO_2 throughout the installation. The meter, function and its location are as following:

- Contract (fiscal) meter at the inlet to onshore pipeline at the Longannet site or at the Valleyfield AGI. It is owned and operated by National Grid and is specified for custody transfer duty. The metering system will comprise of a volumetric gas flow meter with temperature and pressure correction, a gas analyser and a flow computer. The system will record a totalised mass flow of CO_2 with an uncertainty of less than 2.5%, to meet the EU ETS requirements. The equipment will operate with the required uncertainty over the normal pipeline operating pressure and temperature ranges, coincident with the normal pipeline mass flow range. The CO_2 recorded by the contract meter will be taken to represent the CO_2 in storage minus the allowance for leakage and venting in the downstream system, as quantified by the EU ETS monitoring requirements

- CO_2 mass flow meter at the outlet from each of the two capture trains at Longannet. These are used to assess individual capture train performance.
- CO_2 mass flow meter at the inlet to the St Fergus compressor(M1). This meter will provide insight in the location of CO2 losses, whether this is occurring on the NG feeder 10 or on the Offshore pipeline section.
- CO_2 mass flow meter at each injection well line on the Goldeneye platform. This is used to record the CO_2 injected to each well for well and reservoir management. As part of the validation of the fugitive, vented and leaked CO_2 from the transportation system and allocation of CO_2 in the reservoir. The topside meter (M2) will be an orifice meter. This meter type can achieve an uncertainty of ±1% in single phase flow regimes but given the platform layout constraints the target uncertainty for the metering system is based on <±2%. Individual Injection Well Metering will be designed with a target uncertainty of <±5%.

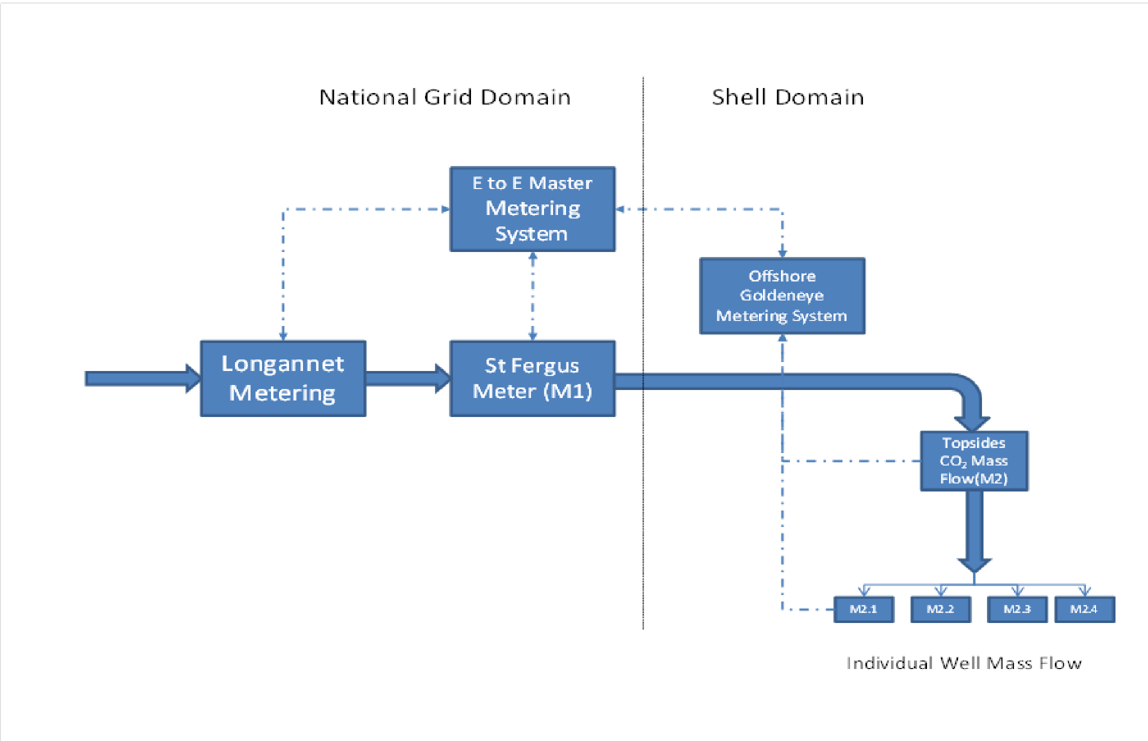


Figure 5-1. Metering Diagram from Longannet to Shell interface

The Offshore Goldeneye Metering System will use the adjusted M1 meter mass flow as a baseline for comparing actual flow to the Goldeneye Platform through the data collected by the Goldeneye topsides meter M2. In a continuous stable operating environment it is expected that these meters would provide data that would confirm that what entered the pipeline has arrived on the platform or potentially leaked through pipeline transport. Goldeneye individual well mass flow data would be available on the end to end metering system but its primary use is to meter individual well flow for formation management purposes. These meters must also collectively provide information to the Offshore Goldeneye Metering system for comparison to the Topsides Meter M2 e.g. Topsides Mass Flow M2 = Individual Well Mass Flow M2.1+M2.2+M2.3+M2.4.

5.1.3. In-flow composition monitoring

Compositional data is available from multiple points between the source at Longannet and the proposed Blackhill Compressor Station adjacent to the St Fergus gas terminal. The data is accessible through the end-to-end telemetry system. At this point in time it is expected that full spectrum analysis using gas chromatographs will be installed at: ScottishPower Longannet; National Grid Longannet (x2); and National Grid Blackhill (x2). Analysis will be carried out on a continuous basis but the sample processing time is in the order of 15 minutes. The current product "out of specification" interface between Blackhill and St Fergus defines water and oxygen content as being the only critical contaminants because of the main concerns : Moisture in CO_2 will create unacceptable corrosion in the pipelines and inert gases in dense phase CO_2 increase the risk of running ductile fracture mechanisms in dense phase pipeline..

The corrosion management strategy will have to consider the gas "wet" if the analysers are offline. Consequently this triggers a higher frequency of intelligent pigging (IP). The gas spec is critical to the offshore pipeline mechanical integrity. The operating conditions for the offshore pipeline are set to meet arrest of running ductile fracture. The limits of the operating condition require a confirmation of the maximum level of contaminants in combination with not succeeding the related inlet temperature. If the contaminant level is not known the pipeline cannot be confirmed operating within the design condition. Therefore no gas should be fed into the offshore pipeline if the contaminants levels are not known.

5.1.4. Pipeline monitoring

In high pressure, dense phase CO_2 systems, the environment is normally dry. Therefore the base case is "no corrosion", but excursions to wet operation give very high corrosion rates which only occur when operation is "out of spec" and where water separates from the $CO_{2.}$ Control of CO_2 corrosion is then by specifying a high degree of dry operation and monitoring the occurrence of free water. The latter would be indicated by a higher than specified water content of the CO_2, which therefore needs to be monitored (semi-)continuously. Based on a predicted corrosion rate of 10 mm/y and 2 mm remaining corrosion allowance of the pipeline, wet operation should not occur for more than 1% of time if the design life of 20 years is to be achieved.

If excursions in CO_2 water content are observed, the associated corrosion loss needs to be assessed, which may require wall thickness measurements. For subsea and buried sections this implies Intelligent Pinging. For accessible sections Ultrasonic based spot checks can be used. In either case, measurements need to be performed where the water is expected to separate and wet the pipe wall, which would typically occur in low spots and at the 6 o'clock position. It is likely that in view of the uncertainties in quantifying corrosion in CO_2 service, the due date will fall probably well within 5 years after commencing CO_2 service. The actual date for IP depends on further detailed work, including the integrity verification, the base line IP run results before CO_2 service starts and the operational dehydration performance.

5.1.5. Operating envelope monitoring

- Pressure
  Base case pipeline design pressure is 132barg, the compressor discharge will be controlled by NG(HIPPS system) to protect the pipeline from incidental pressures in excess of 145barg. Once compressor details are provided by NG this base case can be re-evaluated.
- Temperature
  Both the onshore and offshore pipelines have high temperature and low temperature operating limits. The temperature of the CO_2 at the each pipeline inlet is continuously

measured and recorded within the control system for each pipeline. Alarms are signalled to the operator to advise if measured temperature is nearing or exceeding the permissible limit.

5.2. Baseline monitoring

Base line surveys are required to establish pre-injection conditions of all the domains. This requirement is in addition to compliance with the usual industry environmental impact assessment requirements. The range of base level measurements prior to CO_2 injection will include:

- **Marine biosphere:** macrofaunal, physiochemical, gas flux rates, concentrations, geochemical compositions and fingerprints (isotopes).
- **Geosphere:** (remaining gas indication and gas within water bearing formations within the overburden or aquifers) in the proposed storage complex.
- **Reservoir conformance:** pressure and saturation data within primary site.

5.2.1. Seabed (marine biosphere) baseline survey strategy

The purpose of the Seabed baseline survey is to establish a baseline for the Goldeneye storage complex against which impacts of a potential CO_2 leak could be assessed. Marine biosphere monitoring is not intended to be used as a CO_2 leak detection methodology but as a means of assessing any significant adverse effects on the surrounding environment as required under the Storage of Carbon Dioxide (Licensing *etc.*) Regulations, 2010.

Should a leak from the storage complex reach the seabed, it is expected to travel rapidly through the water column to the atmosphere. This expectation, coupled with the relative tolerance of water column organisms to elevated levels of CO_2[10] and the sediment type over the Goldeneye storage complex, has resulted in the baseline survey effort being focused towards benthic communities.

Potential CO_2 migration pathways over the storage complex are described in Leak-path mechanisms and indicate that the development and abandoned exploration and appraisal wells are potential leakage pathways [11]from the storage complex for the CO_2. The seabed locations of all wells in relation to the Goldeneye storage complex are shown in Figure 5-2.

The OSPAR Guidelines for Risk Assessment and Management of Storage of CO_2 Streams in Geological Formations[12] suggests considerations for the characterisation of the marine environment. The following sections explain the sampling strategies and methodologies associated with establishing a seabed baseline at the development, P&A[13] wells and over the storage complex as a whole taking in to account the OSPAR considerations.

[10] SP-F_HS010-Environmental Impact Assessment (EIA)

[11] Shell 2010, Well Abandonment Report.

[12] OSPAR Guidelines for Risk Assessment and Management of Storage of CO_2 Streams in Geological Formations. Reference No. 2007-12.

[13] Plugged and Abandoned

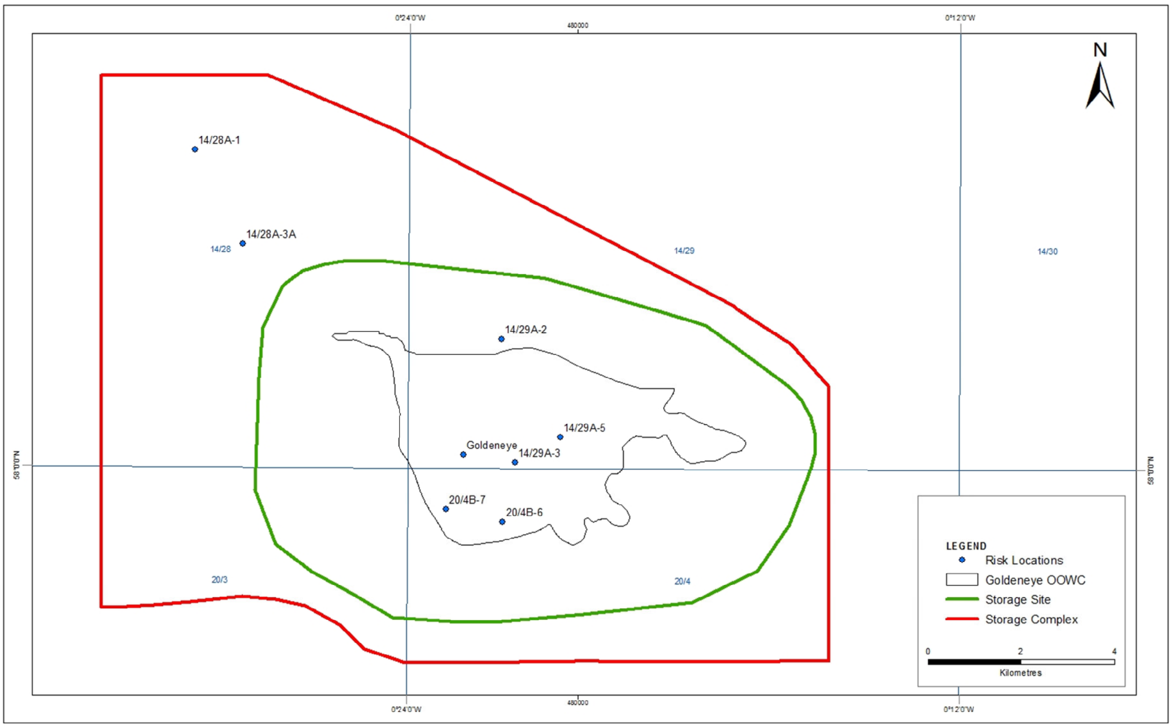


Figure 5-2 Seabed location of the development and P&A wells in relation to the Goldeneye storage complex

5.2.1.1. Development wells

There are five injection wells rising from the seabed on the east side of the Goldeneye platform in 30" conductors.

5.2.1.1.1. Geochemical probe (CDT)

In order to detect leakage occurring behind the development well casing a geochemical probe, such as a conductivity, density and temperature (CDT) probe, will be used to detect CO_2 and changes in seawater pH due to seawater acidification. The probe could measure conductivity, temperature, pH, redox (reduction potential), salinity and, potentially, partial pressure of CO_2 (pCO_2). The probe will be connected to the Goldeneye platform for power and data transfer to allow for continuous data to be streamed back to the onshore facilities at St. Fergus. The probe's seabed location will be optimised using CO_2 dispersion modelling and should be deployed at the earliest practical time following cessation of gas production to ensure a baseline data set is collected pre-injection. The exact type of geochemical probe to be installed and its exact deployment location will be matured in the Technology Maturation Plan.

5.2.1.1.2. Sediment sampling

Sediment sampling for macrofaunal, physiochemical and pore gas/water compositions is not applicable for leakage detection and will therefore be used to characterise the effects of a CO_2 leakage event of the benthic environment. An Environmental baseline survey was undertaken around the Goldeneye platform in November 2009[14] following the OSPAR guidelines for monitoring the impact of oil and gas activities[15]. A total of nineteen environmental sampling stations were positioned in a

[14] Fugro Survey Ltd., 2009, Environmental Survey, UKCS Block 14/29 & 20/4, Goldeneye Field, Ref. 0076.8

[15] OSPAR guidelines for monitoring the impact of oil and gas activities. Reference No. 2004-11

cruciform centred on the Goldeneye platform, with two reference stations located 10km upstream of the installation.

The Goldeneye CCS baseline sampling strategy for the development wells is, wherever possible, to revisit sampling stations from the environmental survey. A CO_2 leak on the outside of the well conductors would reach the seabed in close proximity to the wells themselves therefore for the purposes of the baseline survey, a 500m radius sampling area around the development wells will be surveyed. This 500m radius is considered sufficient for assessing the impact of any CO_2 leakage behind the development well casing on the benthic environment, any leakage beyond this area will be detected via the seismic survey. This 500m survey radius at the Goldeneye development wells is shown in Figure 5-3. The potential for oil and gas activity contamination has already been assessed (Fugro 2009) however an existing sampling station 1km to the south (downstream of the prevailing current) will also be surveyed in order to verify the 2009 environmental surveys results.

In order to provide reference conditions three sampling stations will be established outside of the storage complex in areas perpendicular to the direction of the modelled CO_2 plume.

For each sampling station a detailed survey program will collect benthic macrofaunal, physiochemical, and pore gas/water samples as described in Section 5.2.2.

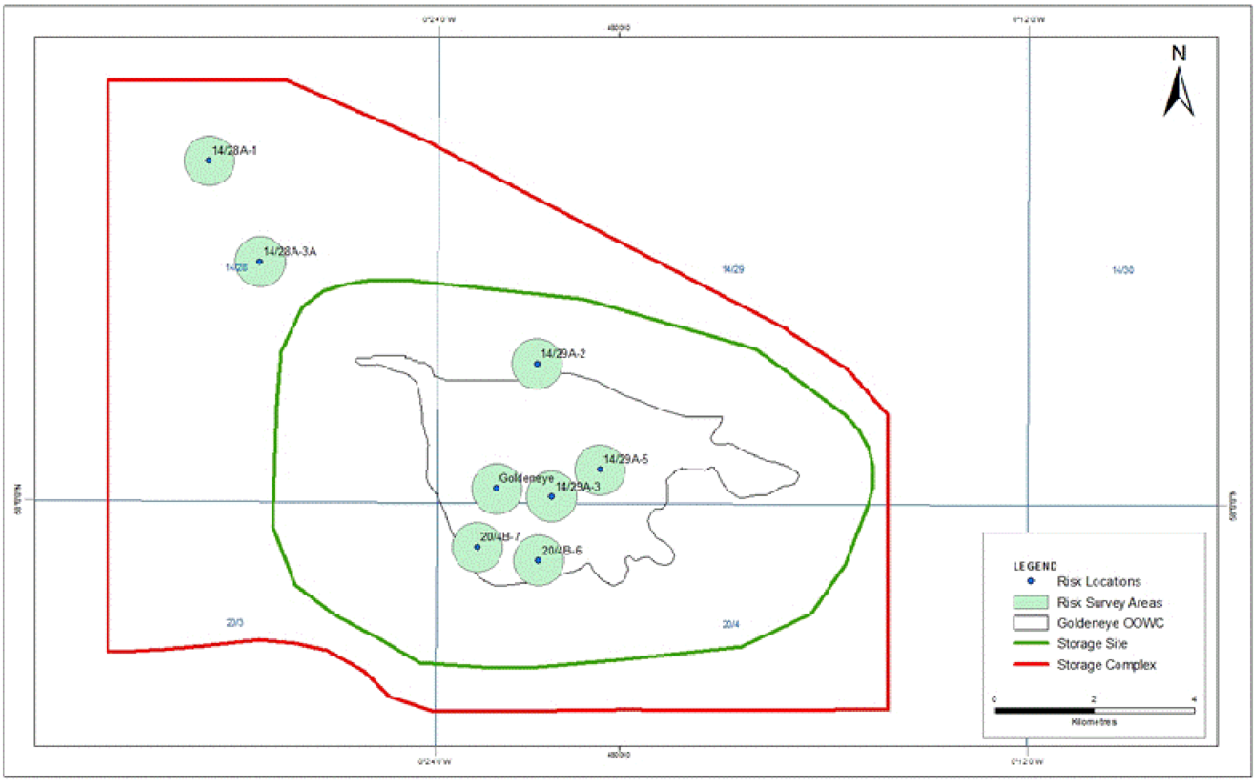


Figure 5-3 **Development platform (Goldeneye) and seven P&A wells with 500m radius survey areas**

5.2.1.2. Plugged & abandoned wells

There are seven plugged and abandoned (P&A) wells located within the storage complex (Figure 5-3). These P&A wells potentially provide a migration pathway direct to the seabed. The casing strings of the 7 P&A wells were cut 3-5m below the seabed, therefore CO_2 travelling straight up the well would exit just below the seabed preventing significant lateral movement therefore, for the purposes of the baseline survey, a 500m radius sampling area around each P&A well will be surveyed. This 500m radius is considered sufficient for assessing the impact of any CO_2 leakage via the P&A well on the benthic environment, any leakage beyond this area will be detected via the seismic survey. As there are no existing sampling stations at any of the P&A wells a cruciform sampling pattern will be established. It is likely that sampling stations will be set up at 250m and 500m in all four cardinal directions away from the P&A well location. An additional station will be established 1km to the south (downstream of the prevailing current) in order to identify any historical drilling activity contamination. The 500m sampling area radius around each of the seven P&A wells are shown in Figure 5-3.

In order to provide reference conditions three sampling stations will be established outside of the storage complex in areas perpendicular to the direction of the modelled CO_2 plume.

For each of the seven P&A wells a detailed survey program will collect benthic macrofaunal, physiochemical and pore gas/water samples as described in Section 5.2.2, Seabed (marine biosphere) survey methodology and analysis.

5.2.1.3. Storage complex

The storage complex area covers approximately 163km^2 of seabed. Shell geotechnical surveys over the Goldeneye storage complex are listed in Table 8. Seabed horizon and multi-beam echo sounder (MBES) data was available from the 1997 East Ettrick 3D seismic survey dataset. The survey coverage over the Goldeneye storage complex is shown in Figure 5-4.

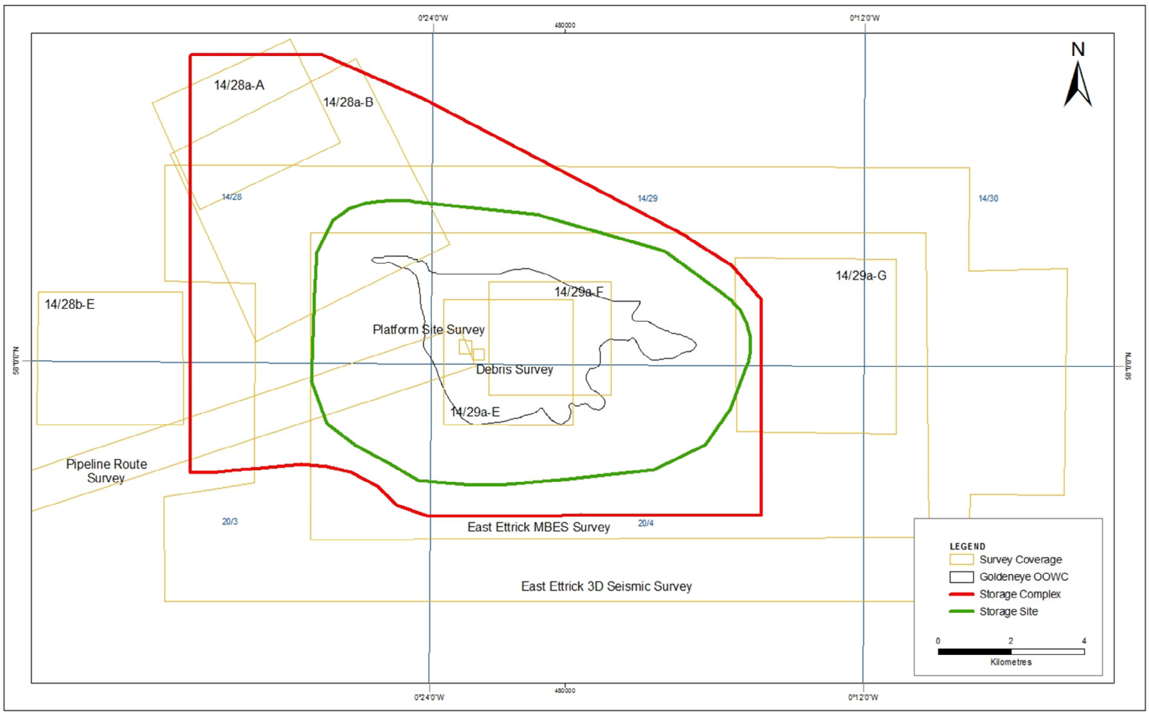


Figure 5-4 Shell geotechnical and seismic survey areas over the Goldeneye storage complex

Table 8 Seabed surveys within or proximal to Goldeneye Field (survey area within 14/29a-E Rig Site Survey area, near to field platform)**

Item	Surveyor	Survey Title	Date
1	Gardline Geosurvey	Debris Detection Survey, Goldeneye Platform UKCS Block 14/29a **	April 2004
2	Fugro Survey Ltd.	Debris Detection Survey, Goldeneye Platform East Face UKCS Block 14/29a **	July 2003
3	Fugro Survey Ltd.	Pipeline Route Survey, Goldeneye to St. Fergus	July 2001
4	Fugro Survey Ltd.	Platform Site Survey, Goldeneye UKCS Block 14/29a **	June 2001
5	Fugro Survey Ltd.	14/28a-B Rig Site Survey	October 1997
6	Fugro Survey Ltd.	14/28b-E Rig Site Survey	August 1997
7	Fugro Survey Ltd.	14/29a-G Rig Site Survey	July 1997
8	Fugro Survey Ltd.	14/29a-F Rig Site Survey	July 1997
9	Fugro Survey Ltd.	14/29a-E Rig Site Survey	March 1996
10	Britsurvey	14/28a-A Rig Site Survey	August 1988

The geotechnical surveys in Table 8 indicate that the seabed environment over the storage complex is homogeneous with respect to sediment type, depths and currents with sediment type ranging from poorly sorted, silty sand to poorly sorted, sandy silt.

Due to the large areal extent of the storage complex and the relative homogeneity of the seabed a judgement or targeted sampling design will be adopted[16]. As described in Section 2.6, the CO_2 is expected to remain predominantly within the boundaries of the Goldeneye OOWC with the 'Dietz tongue' extending further into the storage site. Therefore, the baseline survey effort will focus on the Goldeneye OOWC and storage site with reduced effort in the wider storage complex reflecting the reduction in leakage risk.

A 13km by 17km grid was placed over the storage complex in order to provide a basis for selecting targeted sampling locations. Taking in to account the areal extent of the survey activities around the development and P&A wells, twenty-one 1km^2 sampling locations are considered adequate to provide a proportionate sampling effort for such a large homogenous area. Sampling locations will be selected in order to provide a wide spread of sampling locations over the whole storage complex. At each 1km^2 sampling location a single sampling station will be established. An example survey pattern is shown in Figure 5-5.

[16] JNCC - Davies, J., Baxter, J., Bradley, M., Connor, D., Khan, J., Murray, E., Sanderson, W., Turnbull, C. & Vincent, M., (2001), Marine Monitoring Handbook, 405 pp, ISBN 1 85716 550 0

If irregularities from the expected sediment type are identified during the MBES/side scan sonar survey (Section 5.2.2.1), these will be targeted for baseline sampling. The number of sampling stations within any irregularity will be dependent on the irregularity's areal extent.

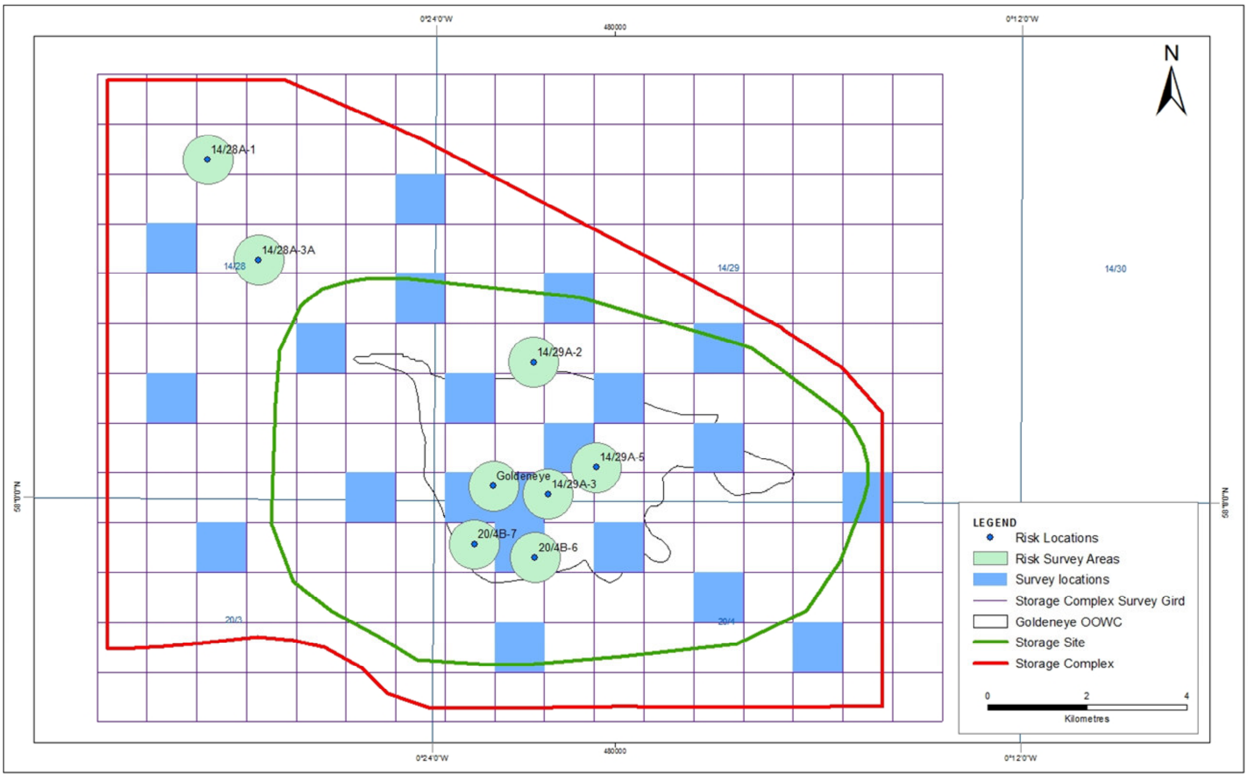


Figure 5-5 Storage complex survey locations and risk locations map

In order to provide reference conditions, three sampling stations will be established outside of the storage complex in areas perpendicular to the direction of the modelled CO_2 plume.

The benthic macrofaunal, physiochemical, and pore gas/water sampling methodologies to be undertaken at each sampling station are described in Section 5.2.2.

5.2.1.4. Pockmarks

Under Annex I of the Habitats Directive submarine structures made by leaking gases can be designated as Special Areas of Conservation (SAC). The Goldeneye storage complex is located on the edge of an area of seabed from which gas seeps are known to occur and therefore there is the potential for submarine structures made by leaking gases to occur. These gas seeps are associated with sediments of the Witch Ground Formation and result in the creation of pockmarks on the seabed surface. However, the vast majority of pockmarks in the Goldeneye vicinity are thought to be relict gas seepage structures that formed during the last 8,000 years since sea level stabilised after the most recent glaciation event, resulting in the seabed in the Witch Ground Basin remaining relatively unchanged during this time[17].

Geotechnical surveys (Table 8) and MBES and 3D seismic survey datasets identified numerous pockmarks over the storage complex. These are shown in Figure 5-6. The data suggests that there is no indication of the presence of any active gas seeps or submarine structures.

[17] Long, D. (1992) Devensian Late-glacial gas escape in the central North Sea. Continental Shelf Research 12:1097–1110.

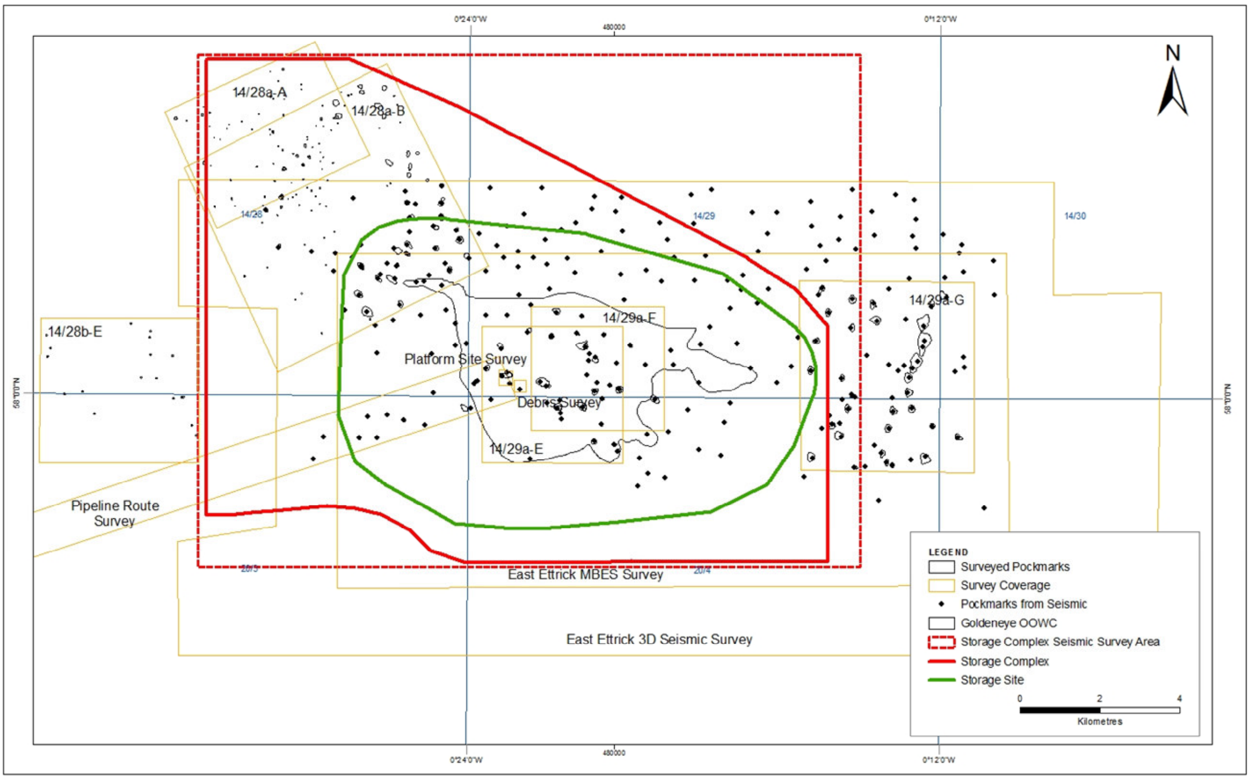


Figure 5-6 Surveyed pockmark locations and proposed seismic survey area

The MBES/side scan sonar survey (Section 5.2.2.1) frequency will be calibrated to detect active gas seeps and submarine structures. The survey area is shown in Figure 5-6. Due to the relic nature of the pockmarks in the storage complex vicinity, it is not expected that any such seeps or structures will be identified. However, if they are, additional survey effort will be undertaken. The type of additional survey effort employed will depend on the nature and extent of the identified gas seep or submarine structure. Any additional survey is likely to include benthic macrofaunal, physiochemical, and pore gas/water sampling and potentially ROV investigation for video and still photography.

5.2.2. Seabed (marine biosphere) survey methodology and analysis

5.2.2.1. MBES/side scan sonar survey

A high resolution (1x1m) regional 3D bathymetry MBES baseline survey will be acquired over the storage complex area. The survey will provide a detailed image of the seafloor structure and provide a baseline to monitor risks associated with the development wells, P&A wells and near surface faults/fractures. Interpretation of the MBES map, in combination with the planned seismic baseline surveys and geological data may identify active present day fluid expulsions (pockmarks and bubbles) and possible (subsurface) conduits for fluid expulsion. A survey over the whole storage complex area is recommended because localised surveys may not identify regional features and trends.

MBES is part of a standard site survey package that includes side scan sonar image for each sail line. The side scan sonar will provide a 2D acoustic ‘photograph’ of the seabed sediments. The side scan sonar imaging instrument may aid the interpretation of the MBES data.

5.2.2.2. GPS

A high precision Global Navigation Satellite System (GNSS) monitoring system will be installed on the Goldeneye platform prior to injection to detect any change in elevation (uplift) of the structure caused by gas injection. 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 with an accuracy of 1 to 2 centimetres. Regarding the accuracy of displacement rates (assuming no significant changes in production 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).

Continuous monitoring ensures that all events (include short duration events) are recorded. Besides the vertical displacement, also horizontal movements are monitored using GNSS, which can be utilized for the calibration of subsurface parameters. This technique has been successfully employed across the North Sea to monitor platform subsidence.

The model predicted uplift by geomechanical modelling is several centimetres over the 10-year injection period. The data will help to gain further confidence and or update the existing models.

5.2.2.3. Macrofaunal sampling methodology

In order to baseline the benthic communities over the storage complex triplicate macrofaunal samples will be acquired at each sampling station using a 0.1 m^2 Day grab. Macrofaunal analysis of $0.1m^2$ samples sieved on a 1mm and 0.5mm mesh shall identify the:

- Total number of species;
- Number of individuals of each species per m^2;
- Total number of individuals per m^2;
- Complete name and lists of species found;
- Diversity (Shannon-Wiener index);
- Evenness as Pileous "J";
- Expected number of species per 100 individuals after Hurlbert;
- Top ten dominant species per site.

In addition, a video/still camera should be used prior to sampling to survey the sampling area and provide digital stills of each sampling station.

5.2.2.4. Physiochemical sampling methodology

Oil and gas activities within the Goldeneye storage complex and in the North Sea as a whole have the potential to have contaminated the seabed above the Goldeneye storage complex. Therefore, the physiochemical sampling and analysis methodologies will follow the OSPAR guidelines for monitoring the impact of oil and gas activities[18] and the OSPAR JAMP Guidelines for Monitoring Contaminants in Sediments[19].

Single physiochemical samples will be taken at each sampling station using a $0.1m^2$ Day grab. In addition, triplicate physiochemical samples should be acquired at selected stations to measure in-station variability.

OSPAR Guidelines for Monitoring the Environmental Impact of Offshore Oil and Gas Activities (OSPAR 2004-11) suggest the following physiochemical parameters be assessed:

- Particle Size Analysis (PSA);
- Total Organic Carbon (TOC);
- Total Hydrocarbons (nC12-35) (THC);
- PAHs (16 US EPA) – only sampled where THC levels are above background levels;
- NPDs - only sampled where THC levels are above background levels;

[12] OSPAR guidelines for monitoring the impact of oil and gas activities. Reference No. 2004-11

[19] OSPAR JAMP Guidelines for Monitoring Contaminants in Sediments. Reference number 2002-16

- Trace and heavy metals - Al (or Li), As, Cd, Cr, Cu, Fe, Ni, Pb, Zn, Ba and Hg.

These parameters will be analysed following OSPAR JAMP Guidelines for Monitoring Contaminants in Sediments[20].

5.2.2.5. Pore gas sampling

Under the European Union Emission Trading Scheme (EU ETS) there is a requirement for the quantification of any CO_2 leakage. As the Goldeneye storage complex sits in a gas seepage area it is essential that the background or baseline gas compositions in the seabed sediment be established in order to differentiate any potential CO_2 leakage. Therefore, pore gas sampling will be undertaken at each sampling station.

Single pore gas samples will be acquired from the marine biosphere at each station. In addition, triplicate pore gas samples will be acquired at selected stations to measure in-station variability. Free and dissolved gases will be analysed using gas chromatography to identify:

- C1-C5 hydrocarbons;
- Isotopes δ13C , δ18O and δD;
- Gas composition (i.e. CO_2, O_2, N_2, etc…);
- Tracer

The sampling methodology for acquiring pore gas samples will be matured in the Technology Maturation Plan.

5.2.2.6. Pore water sampling

In order to identify and quantify background gas composition in the seabed sediment above the Goldeneye storage complex pore water samples will be taken and analysed for dissolved gases. Pore water analysis will also allow for background water chemistry composition to be quantified.

As with the pore gas sampling, single pore water samples will be acquired from the marine biosphere at each station. In addition, triplicate pore gas samples will be acquired at selected stations to measure in-station variability. Pore water samples will be analysed for:

- pH;
- conductivity;
- HCO_3^- (bio carbonates);
- Trace / heavy metals (Pb, As – as they can be mobiilised with a change in pH);
- Total Dissolved Solids (TDS) (e.g. major ions Na^+, K^+, Ca^{2+}, Mg^{2+}, Mn^{2+}, Cl^-, Si^{4+}, HCO_3^-, SO_4^{2-});
- Organic acids;
- Isotopic compositions (δ13C TDIC = total dissolved inorganic carbon).

5.2.3. Seismic surveying

4D seismic imaging will be used to monitor risks related to wells, faults/fractures, and vertical and lateral migration in the storage complex.

The seismic baseline surveys planned are: a new streamer baseline over the Goldeneye field covering the storage complex surface area, including both the primary and secondary containment formations plus the remainder of the overburden; and, an Ocean Bottom Node (OBN) survey covering the

[20] OSPAR JAMP Guidelines for Monitoring Contaminants in Sediments. Reference number 2002-16

platform undershoot area and development wells. An OBN seismic survey is preferred because streamers vessel surveys struggle to obtain a good coverage right under the platform which is an important area to monitor in case of a shallow leak in the injection wells.

4D seismic surveying with streamer and Ocean Bottom Nodes is a proven but rapidly developing technology. The best possible technical solution available to acquire 4D data will be considered for each individual seismic survey planned as part of this MMV monitoring plan or if required to monitor the success of potential corrective measures. This will include a decision on the type of Ocean Bottom System (individual nodes or a permanent cabled system) that will be used for acquisition.

The streamer survey will repeat the East Ettrick '97 survey, which was acquired before gas and condensate production from Goldeneye started. The aim of repeating this survey is to map the changes in Oil Water Contact changes related to the gas production to further calibrate the dynamic model. For this purpose, the East Ettrick '97 legacy survey will act as the pre-gas production baseline and the new streamer survey as the monitor survey as well as a pre-injection baseline.

The OBN survey will be acquired to obtain a high resolution pre-injection baseline for the platform undershoot area. Streamer vessels must sail around the platform, which causes an illumination gap in the seismic image. The Ocean Bottom Nodes do not suffer from this problem because they can be positioned with an ROV under the platform. The OBN survey removes the need for a dedicated 4D streamer platform undershoot and hi-res shallow seismic with site-survey vessels to monitor the development wells.

In addition nodes have several additional advantages over a streamer survey including:

- Better 3D and 4D seismic signal resolution because of better location repeatability and lower noise. Nodes can be placed accurately and do not suffer from streamer tow and wave noise.
- Nodes allow for the acquisition of wide azimuth and long offset data that may produce higher quality images benefiting from advanced and emerging geophysical processing algorithms (multi-azimuth, full wave form inversion and reverse time migration). This data is more difficult to acquire with streamers.

Figure 5-7 shows the areas planned for coverage by the streamer and OBN surveys. The output survey areas in the figure describe the target imaging areas. The input survey area is this area plus the migration rim which is required to obtain a proper image of the target area. The streamer survey input area includes a small rim to ensure proper 4D seismic imaging of the fringes of the secondary storage container. The OBN includes a larger, 2km migration rim to allow for proper imaging of the areas around the development wells. The size of the surveys is chosen such that the storage complex itself is fully covered. There are two P&A wells further away from the container complex which are not covered by the streamer baseline. However since a potential leak from the container complex would take years to reach these P&A wells A CO_2 plume travelling outside the primary container will be visible on the planned 4D seismic monitor surveys and allows for sufficient time to acquire further baselines if a CO_2 plume would appear travelling near these wells.

Hi-res 3D shallow seismic is currently planned in the case that vertical CO_2 plume migration is detected in shallow formations above the Dornoch/Lista complex seal and beyond the area covered by the OBN survey. No hi-res 3D shallow seismic baseline is planned because such a migration scenario is only possible after a few years of injection as it takes time for the injected CO_2 plume to migrate outside the area covered by the high-resolution OBN survey.

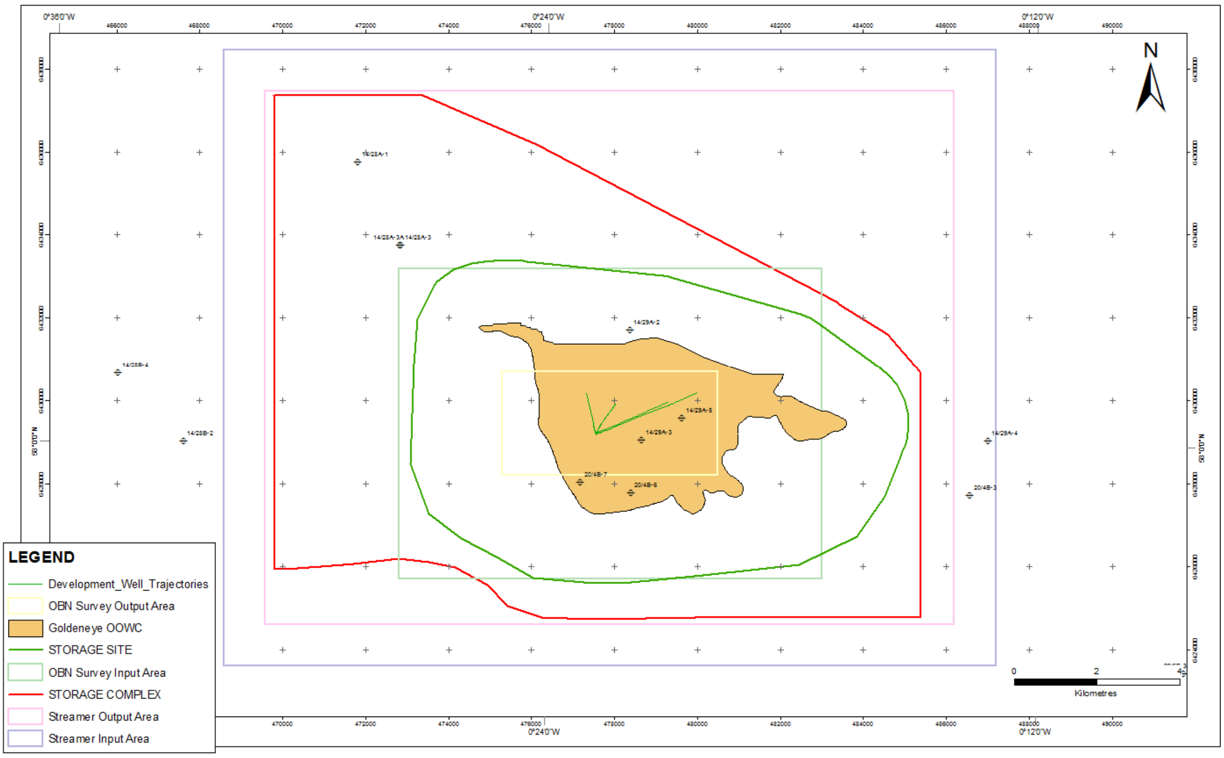


Figure 5-7 Outlines of areas for seismic surveying

5.2.4. Well integrity logging

Well integrity logging covers cement and casing evaluation and will be performed one time only, when the upper completion is replaced. The logging interval starts from the top of 9 5/8" casing (single casing) down to the top of lower completion (typically set in lower chalk group) and will evaluate cement bond quality and casing integrity prior to injection. During recompletion tubing is pulled out, allowing access for the logging tool. That also means that only recompleted wells can be evaluated. The current base case states that 5 wells will be recompleted to to injector wells, one of these will initially function as a monitor well and can be used as back up injector when the monitoring function has ceased. Therefore all wells will be checked and the one(s) with serious integrity issue should be excluded whenever possible.

5.2.5. Saturation logging and sampling

Saturation logging and sampling requires a baseline to provide background for subsequent comparison during injection in the monitoring well. This logging is very likely to detect the presence of CO_2 through a reduction of the water saturation. Under ideal measurement conditions the logging can give an estimate of the CO_2 saturation as described inthe Monitoring Feasibility Study Report No MN010D3A (RT077). The baseline can be performed pre injection when the recompletion takes place.

5.2.5.1. Saturation logging

For saturation logging, the baseline is a test run, to see if sigma and neutron porosity logging precondition requirements are met. Sigma and neutron porosity are applicable if the monitoring well contains water over the reservoir interval. In addition, both logs have to indicate remaining hydrocarbon gas in order to differentiate and quantify CO_2 breakthrough *during injection* phase. The logging requires a repeat run and quick log interpretation to determine fluid contact between remaining hydrocarbon gas (if any) and water column before the tool is pulled out, to allow for an additional run if log interpretation is of low confidence. An example of a saturation logging suite is combination of Pulse Neutron Capture (PNC) tool (to measure sigma and neutron) with gradiometer and standard pressure-temperature measurement in a wireline string, to determine fluid contacts in the formation and borehole, as well as saturation under ideal condition.

5.2.5.2. Downhole sampling

Downhole sampling will be run after fluid profiling interpretation from RST (complemented by gradiometer) is obtained. At least three samples are required for each run, two from the interpreted hydrocarbon gas column and one from the water column. The final number of samples will be determined by the quality of fluid profiling interpretation. The samples in the gas column provide an analysis of concentration of remaining light hydrocarbon (*pre-injection*) and the sample in the water column provides analysis of the amount of dissolution of gas in the water. The downhole sampling is run with wireline.

5.3. During injection acquisition

5.3.1. Geochemical tracer

If geochemical tracers are proven to be an effective technique then it is envisaged that they could be added to the Goldeneye CO_2 stream. The primary aim of adding a tracer is to uniquely tag the Goldeneye CO_2 stream, which will help with the identification of sources of any CO_2 detected outside the Goldeneye complex – this is useful in areas such as Goldeneye where there is:

- Potential for additional CO_2 storage projects.
- The possibility that natural CO_2 is leaking to the seabed.

The tracer is expected to be added using a continuous injection method. This is a novel application of tracer technology. Typically, tracers are used in EOR studies to understand the movement of the flood front between wells or across a reservoir and no previous commercial or pilot CCS projects have used tracers in the way Goldeneye intends. It suggests that further maturation of the process is required to properly select a suitable geochemical tracer for this application, as well as identify the location of tracer injection. For the point of tracer injection, there are two feasible options where the pro and cons are described below:

- **St Fergus onshore facilities:** Lower cost due to ease of transportation and handling but requires leakage monitoring along pipeline and on platform. There is a possibility that it would increase the risk of running ductile fractures on the pipeline because it acts as an impurity in the CO_2 flow and alters the thermodynamic behaviour of the CO_2 mixture.
- **Platform:** Higher cost due to more complex transportation and handling, however it eliminates the potential hazard to the subsea pipeline.

At the time of writing, candidates for tracer selection are as described below:

1. **Commercial Perfluorocarbon (PFC):** PFC has benefit of being a non-reactive substance, shows minimum partitioning, has a low detection limit and can be obtained at a reasonable cost. The downside is that it has some greenhouse gas warming potential which, in continuous injection method, could add approximately 0.008% to the global warming potential of the sequestered CO_2 on the basis that 20 kg/year tracer is equivalent to 100 tonnes of CO_2. Any migration to the biosphere and ultimately the atmosphere would therefore have a marginally higher warming potential that that of pure CO_2.

2. **Noble Gas (Xe, Kr, He, Ar, Ne):** Noble gases are non-reactive, have medium level of partitioning and low environmental effect. Some, such as Xe and Kr have low detection thresholds. The application procedure and behaviour are still undergoing research. Procurement is possible but limited, to date. As there are still four years before injection execution there is time to mature this option in terms of both a research project and procurement exercise.
3. **Non-Tracer based:** This option is in the early stages of research. It offers a potential way forward but may not meet the project timeline.

Selection of tracer will require further study on dispersion, a reduction of tracer concentration when the CO_2 migrates toward shallower depth and changes its phase from dense liquid to gas due to in-situ pressure and temperature.

Owing to the immaturity of the area the costs are highly speculative.

5.3.2. Geochemical probe and seabed (marine biosphere) surveys

Of the risks to be monitored early on *during injection* the most likely to allow CO_2 to reach seabed quickly are leaks and behind casing flow in the development wells. *During injection*, continuous annular pressure tubing temperature monitoring with DTS will be used to detect potential injection well leaks. The CDT probe connected to the platform will monitor CO_2 flux below the platform and at the seabed.

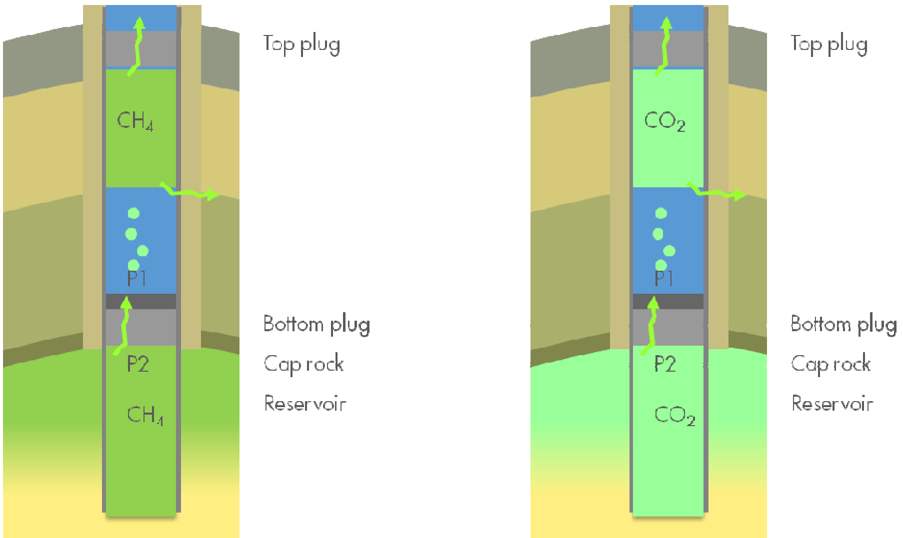


Figure 5-8 Potential leak path in plugged and abandoned well

Another risk is in the P&A wells. This is a low likelihood leak as it relies on a number of conditions occurring simultaneously[21] (see Figure 5-8):

- The well needs to have a lower plug with a leak path that was below the detection limit of the integrity tests when the plug was set.
- If the upper plug also has a tiny leak path that leaks slower than the lower path then, before the reservoir was depleted, it would have been possible for a head of gas to form below the top plug.

[21] Shell 2010, Well Abandonment Report.

- The head of gas needs to be long enough to create a *gas column head* that is sufficient to counteract the depletion in the reservoir.
- When the store is repressurised with CO_2 the well foot needs to be in communication with either CO_2 or carbonic acid. This will then be pushed into the well and will bubble up following the leak path previously used by hydrocarbon gas.
- If the head of CO_2 is sufficient to overcome the pressure depletion from the reservoir then there is a potential leak path to just below the sea bed.

To mitigate against this case, the seabed surveys (MBES and sampling) will be acquired surrounding the surface locations of the P&A wells within the Goldeneye field OOWC (14/29a-3, 14/29a-5, 20/4b-6 and 20/4b-7) at approximately Year 5 (between Year 4 - 8). It is expected that, after a few years of injection, the 'Dietz tongue' at the top of the reservoir, will have reached these well locations and filled the well column and so will require monitoring. These wells are a priority over other wells within the storage complex as they penetrate the Goldeneye Captain reservoir and are exposed to this threat. The other, lower priority wells will be monitored if there is any indication of lateral movement further into Captain aquifer (e.g. from time-lapse seismic monitoring) or within the shallower formations of the storage complex (e.g., Mey sandstone). Both cases are covered by the contingency plan.

Subsequent seabed surveys will be acquired at Year 1 *post-injection/closure*, which will function as a new baseline for the *post-injection/closure* period. The detail of this survey is identical to *pre-injection* baseline described in section 5.2.2.

5.3.3. Seismic survey plan

Time lapse seismic has been shown to be a suitable and feasible technique and has been selected because it covers CO_2 migration along:

- P&A wells,
- injector wells,
- faults/fracture
- and lateral movement to the aquifer
- or in the water bearing formations in the overburden.

It is also suitable for multiple time periods:

- In the early years it will be more focused on the injectors owing to the limited extent of the plume.
- After a few years of injection the 'Dietz tongue' at the top of the reservoir, will require monitoring when it reaches the Original Oil Water Contact (OOWC) and is expected to be visible on 4D seismic.
- Over time, when the pressure rises closer to hydrostatic, it provides the monitoring of potential leaks through the P&A wells and vertical or lateral migration through faults, fractures or caprock failure may be required.

Note that the risk of leakage via flow paths through the caprock is low in the early years of injection away from the injection wells, because the reservoir will be under-pressured after gas and condensate production. In addition it has been shown that the time lapse seismic technique is unable to discriminate the plume where it is within the depleted reservoir. However, once a sufficiently thick Dietz tongue moves beyond the original OWC, it can be readily detected with time lapse seismic.

The above points taken together mean that it is logical to plan the timing of seismic surveys using a trigger-based approach. The continuous data from wells and the CDT probes and dynamic modelling provide the information inputs. The triggers are

- Release of CO_2 at seabed detected by the CDT probes
- Suspected leak to formation of CO_2, derived from the well integrity monitoring
- Lack of conformance in the dynamic modelling response
- Dynamic modelling indicates that the 'Dietz tongue' should have migrated under the OOWC

Current modelling of the tongue indicates that a first seismic monitor survey over the storage site should be acquired at approximately Year 5 (between Year 4 - 8) to confirm that the 'Dietz tongue' is behaving as predicted by the dynamic models. The Seismic survey will be performed in the same year as the seabed surveying around the abandoned wells.

The configuration of any seismic survey (OBN below the platform and/or streamer) and optimal area will be determined by the target. The lateral migration of a CO_2 plume through the spill point or other vertical/lateral migration away from the platform can be effectively monitored with the proposed seismic streamer survey as no dedicated observation wells are planned because of their high drilling costs . A streamer survey is the most cost effective solution to monitor these risks given the current state of technology. Risks related to the developments wells, or vertical containment (faults, fractures and caprock) below the platform are best monitored by a repeat OBN survey.

As with the timing of the mid-term survey, further contingency seismic monitoring (additional repeat OBN and streamer surveys) in the injection phase will only be pursued if a trigger occurs:

- Release of CO_2 at seabed detected by the CDT probes
- Suspected leak to formation of CO_2, derived from the well integrity monitoring
- Lack of conformance in the dynamic modelling response
- Mid-term seismic survey shows suspected irregularity

A contingency seismic survey may consist of a full 3D, 3D swath or OBN repeat surveys depending on the suspected location of observed anomalies, and could subsequently trigger further hi-res shallow seismic if required in case of a seismic or well related anomaly above the container complex Lista/Dornoch seal. Further details on contingency monitoring are outlined in MMV contingency plan.

Pressure build-up is not expected to reach sufficient levels for fault reactivation or caprock failure during injection. A second seismic streamer and/or additional OBN repeat survey will be acquired Year 1 post-injection. The trigger for this post injection survey will be a pressure trigger unless there has been unexpected CO_2 migration up the Captain Fairway.

The use of 2D seismic monitoring will not be pursued. Only 3D surveys over the full complex or a 3D-swath (mini-3D) will be performed. The quality of 3D seismic processed data is superior to the quality of 2D seismic data because 2D cannot image cross-line dips, has limited options for multiple suppression and many other deficits when compared to 3D surveying.

5.3.4. Saturation logging and sampling

This logging is targeted at conformance rather than containment, its aim being to confirm and constrain the dynamic simulation modelling by providing information on the movement of the CO_2 front within the store. Dynamic simulation prediction drives the start and duration of the programme. It suggests the timing when the CO_2 plume will reach the monitoring well and the number of saturation data points required to characterise the model. Current realisations in Figure 5-9 suggest the programme should start between Year 5 and Year 10, with a frequency of one per year – assuming all four injectors (GYA-01, 02, 04 and 05) inject at the same rate. Year 5 is the time when the CO_2 plume is predicted to reach GYA-03, whilst yearly frequency is deemed sufficient to capture the CO_2 concentration and column increment. If there is variation in injection capacity among wells, the injection pattern will be developed later, which would provide better prediction for the start and duration of saturation logging and sampling.

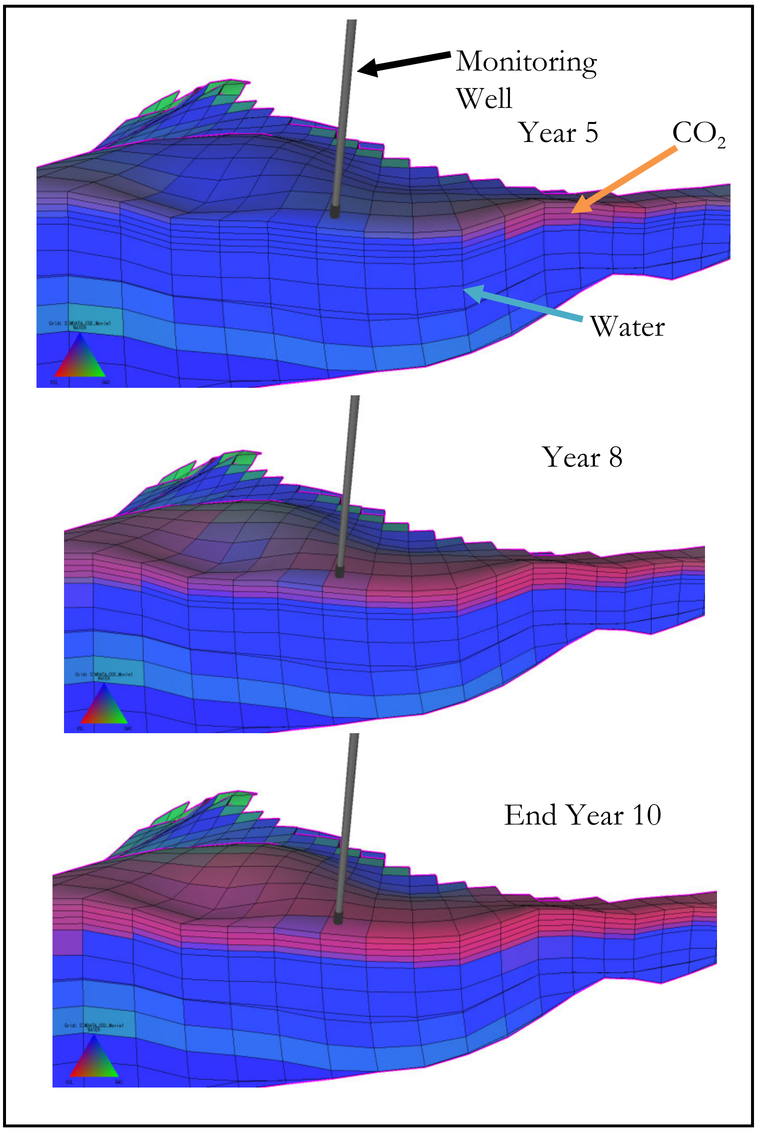


Figure 5-9 **CO_2 movement near monitoring well as predicted by base case realisations between Year 5 to end of Year 10**

If a monitoring well has significant water in the wellbore (post recompletion) this will be displaced to CH_4 or CO_2 or a mixture of both once a flux of these fluids/gasses starts to pass through the well completion (sand screens). This displacement is accompanied by a pronounced change in the wellbore pressures as the gradient of the well fluids alters. This pressure change is an additional indication that the front has impacted the wells and can act as a trigger for saturation logging and sampling.

It is essential to keep the logging suite similar to the baseline and consistent throughout the periodical logging runs in order to provide consistent background for the interpretation. PNC tool and gradiometer derived fluid profiling will be used for reference for deciding sampling locations. Fluid samples will be taken in the water column (below the gas-water interface) to examine CO_2 dissolution in water, gas column just above gas-water interface to examine CO_2 concentration and top of gas column to examine remaining light hydrocarbon concentration. In both samples of the gas column, the ratio of the light hydrocarbon mixture to CO_2 will be investigated and more than one sample may be required at one location.

5.3.5. Tubing integrity logging

Tubing integrity logging serves an operational as well as a monitoring purpose. The critical timing is during early injection when it is necessary to check the impact of pressure arising from CO_2 injection on the tubulars. Assuming current base case realisation, tubing integrity logging will start at Year 3 and will be repeated every five years until the end of injection. The second survey in Year 8 is planned to coincide with saturation logging and sampling to simplify the mobilisation and demobilisation of logging crews and equipment in that year. For the efficiency of the evaluation, only the wells that have been actively injecting would undergo tubing integrity checks.

5.3.6. Wells gauges post re-completion (PDG and DTS)

Accurate and stable pressure measurements are essential for long-term reservoir monitoring. Although it is possible to multi-drop up to four PDGs (Permanent Downhole Gauges) onto a single encapsulated electrical cable, it is likely that only two PDG will be installed into each of the four Goldeneye wells that are to be recompleted for CCS operations – this gives accurate gradient information allowing better estimation of the reservoir pressure.

Inclusion of up to four gauges in the monitoring well (GYA03) is being evaluated in order to give better discrimination of the multiple fluids contacts that could occur (as described in 5.2.5.1). This will be pursued during the detailed design phase.

Gauges are currently qualified for a 10-year life cycle and have drift stability better than +/- 7kPa at 82,740 kPa and 150 °C (+/- 1°C at 12,000psi and 302°C). Standard NPQG pressure gauges are routinely calibrated for temperatures in the range 25°C-150°C (65°F-302°F). Therefore, the selected PDG will require to be specially calibrated for the lower BHT (20°C-35°C (68-95°F)) expected when injecting CO_2. Full details of the NPQG pressure and temperature gauge can be found in the Completion Component Selection document.

The selected Neon opto-electric monitoring cable expands the capability of the conventional well watcher PDG system by adding a fibre-optic, distributed-temperature-sensing (DTS) line to the permanent downhole cable (PDC), enabling simultaneous acquisition of pressure gauge data and distributed temperature data. The permanent well watcher system NPQG or NHQG gauges operate on an electrical conductor as normal. The fibre-optic line operates independently of and does not affect the reliability of the electric conductor. The Neon cable is externally identical to the PDC, and no modification to the Well Watcher NPQG system is required. A special hybrid wellhead outlet for splitting the electric and fibre-optic lines is the only nonstandard equipment requirement for using the Neon cable.

The Neon cable provides DTS temperature measurements at approximately 1.0m [3.3ft] intervals along the length of the fibre optic cable producing a profile of temperature effects along the injection tubing and across the mud line. The fibre optic line can be interrogated on a continuous or intermittent basis, providing well site diagnostics without interfering with production or injection operations. Once the data is received at surface, it can be transmitted to multiple remote locations for real time identification of time, depth, and reasons for changes in flow or injection inferred from the temperature profile. One of the primary functions of DTS on Goldeneye is to quickly identify if tubing integrity has been compromised and identify the source of a leak by observing differences in the temperature profile along the length of the tubing. Given that the Neon Opto-Electric cable has an operating temperature range between –20°C-175°C (4.0°F-347°F) and can operate at pressures up to 103,420kPa (15,000 psi) no further qualification of this equipment is required.

5.3.6.1. Data monitoring plan for continuous type measurements (geochemical probe and well gauges)

Geochemical probe, DTS and the PDG acquisition are managed in the control room which houses robust databases that store all acquired data on site with local backup. In addition, various technologies are available to integrate the data into any IT environment. Industry-standard technologies such as the Modbus communication protocol, OPC open connectivity, well site information transfer, standard markup language (WITSML), and SQL database replication can be used to deliver the data in real time to SCADA systems, data historians, a real-time monitoring and data delivery secure Web service, or simply to Microsoft Excel® software on a personal computer.

5.3.7. Wireline intervention

Although no well intervention work has yet been carried out on Goldeneye wells, several studies had been undertaken prior to hydrocarbon production to investigate a number of well intervention scenarios that could potentially take place on Goldeneye platform. The objective of these studies was to identify and list the main items of equipment that will be required and to produce representative equipment layout drawings to demonstrate that intervention activities can safely be carried out on Goldeneye platform. Among the operations studied were slick line and electric wireline operations.

Required intervention equipment has been identified, the respective dimensions and weights have been listed and it has been confirmed that the equipment can be lifted on board the platform (Goldeneye crane has a maximum lift capacity of 17 tonnes) and can be accommodated on the Goldeneye platform weather deck. The most significant aspect of wireline activities is the requirement for a 60ft or 90ft high wireline mast to be erected directly above the well being worked on. The mast needs to be stabilized by guy wires tied down to the platform structure at points on all four sides of the mast and at a minimum distance of 7 or 13m in order to withstand a maximum wind speed of 80mph. Since the Goldeneye weather deck is only 16m wide, the use of the taller mast is not considered feasible. In all cases, tool string length is a major consideration when preparing each run in intervention programs. Since no intervention work has yet been carried out on Goldeneye platform, it is unlikely that the required pad eyes or cantilever to secure mast and wireline units are in place. Therefore, a full site survey will be required prior to intervention operations.

5.4. Post-injection/closure acquisition

5.4.1. Aim of post-injection/closure monitoring

The aim of post-injection/closure monitoring is to show that all available evidence indicates that the stored CO_2 will be completely and permanently contained. Once this has been shown the site can be transferred to the UK Competent Authority.

In Goldeneye this translates into the following performance criteria:

- The CO_2 is contained within the licensed storage site.
- The CO_2 within the structural containment storage site evolves toward an equilibrium post injection. Any CO_2 in aquifer storage containment is conforming to dynamic modelling assumptions – i.e. its size and rate of motion match the modelling results.

The above are proven by two separate post closure surveys – with a minimum separation of five years - described in more detail in section 5.4.3 below.

5.4.2. Goldeneye specific conditions and risks

Goldeneye is a structural store in a depleted hydrocarbon field. Depletion means that the field is at a lower pressure than the fluids in the surrounding rock formations. Where the rocks are permeable (as in the adjacent Captain Aquifer) the fluids flow into the field. Where the rock is impermeable (the caprock) the pressure differential is maintained. This means that if a leak path was to develop though the caprock or in a water filled well that is in hydraulic communication with the overburden (or even the sea), fluids will flow into the store. CO_2 will not flow out until the store has reached a pressure that is near its original pressure.

This leads us, for risk assessment purposes, to separate the post-injection/closure period into *post –injection/closure at hydrostatic* and *post-injection/closure below hydrostatic.*

The post-injection/closure monitoring will therefore be driven by the following considerations:

1. Determine the rate of average reservoir pressure recovery
2. Forecast when this will near hydrostatic and therefore when the reservoir has the potential to drive CO_2 into the overlying formations
3. Shoot a seismic survey 2-5 years after the pressure has recovered: when there is sufficient time to establish a concentration above the detection limit
4. Survey the abandoned well locations to look for surface leaks

If the recovery is projected to take more than 20 years then hand over will need to take place before the pressure *at hydrostatic* condition has been achieved.

How the pressure monitoring will be achieved depends on technology innovation.

- At the current time it would be necessary to leave the platform in place and the wells open in order to collect pressure data – at the cost of >£2m p.a.
- Technology to allow the wells to be abandoned and platform removed while still giving pressure monitoring is conceivable (similar applications but of shorter duration have been achieved for isolated sub-sea wells).

5.4.3. Monitoring plan

At Year 1 *post-injection/closure*, seabed and seismic surveys will be acquired for the purpose of baselining *post-injection/closure* period. The timing is set to allow the injection wells to come to equilibrium with the formation (warm up) to minimise spurious temperature effects that might lead to a false positive.

Other decisions with regards to additional monitoring (pressure/additional seismic surveys) will be taken toward the end of the *during injection* phase to include consideration of reservoir performance evaluation during injection. The evaluation provides better projection to which of the following options will be selected:

1. **Combination of pressure monitoring and seismic surveying:** This plan relies on pressure monitoring for a certain number of years after injection in order to capture the aquifer strength during recharging of the Captain reservoir pressure. Pressure monitoring duration will be determined by early *post-injection/closure* behaviour to further characterise reservoir performance. Currently, the PDGs that will be installed in wells during recompletion have a limited lifetime and will need to be replaced by wireline-retrievable LTMG or a new version of PDG available commercially during the *post-injection/closure* phase. A second seismic streamer and/or additional OBN repeat survey will be acquired one year after cessation of injection. To enable pressure monitoring the wells and platform will need to be kept operational for the monitoring period duration as it is required to retain well accessibility and wireline operation capability. To accommodate pressure monitoring some of the platform facilities are maintained, such as operational support (power, structural and lifting facilities), data flow support (control system and telecom) and life system support (living accommodation, transport, safety system). This raises a significant cost that needs to be

considered and therefore a decision on the duration of this monitoring has to undergo a value of information process in order to maximise its value.

2. **Repeat seismic surveying, no additional pressures:** This plan relies on time-lapse seismic monitor surveys covering the storage complex. At this time a first 4D survey monitor survey has already been collected during the injection period. The timing of this survey is planned around the time the Dietz tongue reaches the initial oil water contact after about Year 5 *during injection*. A second survey is planned at Year 1 *post-injection/closure*. The timing of a further survey depends on the rate of pressure buildup. For leaks to occur the field first has to regain the energy to drive fluid up a leak path and reach hydrostatic pressure. If the pressure is building up rapidly then hydrostatic may be reached within 20 years and a seismic survey may confirm that the field is behaving as expected, implicating low further risk of leakage. If the build up is slow then the risk profile will not change for many decades. A further survey is then recommended for five years after the initial post closure survey to check for unknown effects. If the store is behaving as expected relative to the initial post closure survey then handover can be recommended. Further work is required to confirm the exact timing and need for these post closure surveys. The timing for hydrostatic pressure prediction is less accurate in comparison to the first option. The downside of this option is that, with the absence of early *post-injection/closure* pressure measurements, the dynamic simulation is only characterised during the injection phase. However, the upside is that, by performing seismic survey more frequently, it will enable more accurate identification of leakage pathways and observation of CO_2 migration away from storage site. This enables early and selective corrective measure planning compared to option one.

6. MMV contingency plan

6.1. Action plan for each scenario

The aim of the MMV contingency plan is to respond to suspected irregularities. The contingency plan is trigger-based and will be executed when significant irregularities are suspected. The base plan acts to detect suspected irregularities. These early indications of CO_2 migration away from the primary container (storage site) will be provided by seismic surveying, plus environmental sampling at the plugged and abandoned well sites.

The contingency plan is site-specific and based on the leakage path risks defined in section 3.2. The various monitoring techniques in the base plan act as active barriers that detect potential CO_2 migration along suspected leakage paths. Interpretation of the monitoring data from the contingency plan will delineate the plume in terms of location and areal extent, followed by physical or modelled quantification of the expected irregularity which potentially leads to leakage events or leakage event itself and implementation of the appropriate corrective action. It is then employed to ascertain the efficacy of any corrective measures deployed.

Note that all action plans below are indicative. The exact detail of any plan will depend on the combination of site specific conditions and the suspected risk at the time of detection.

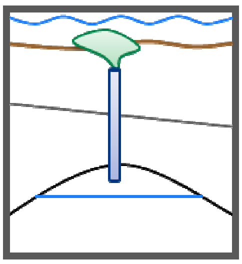
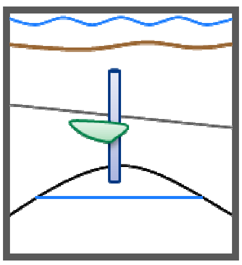
6.1.1. Action plan for leakage pathway through plugged and abandoned (P&A) wells

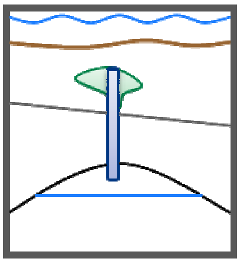
P&A wells located within the Goldeneye structure are 14/29a-3, 14/29a-5, 20/4b-6 and 20/4b-7, of which the first two are located on the crest of the structure and the latter are close to the original hydrocarbon-water contact in the south of the field, as shown in Figure 5-2.

If CO_2 was to migrate past plugs within an abandoned wellbore, CO_2 could move into a number of strata – dependent upon

- The placement of well plugs
- The development of flow paths through the casing and cementations below any plugs

These are shown schematically below:

	Migration sketch	Description
1		All well plugs leak or CO_2 flows into well above lower plugs. CO_2 released a few feet below seabed. Point source release at seabed.
2		Well with Dornoch or Lista plugs still sealing, and leak path into strata below these seals. CO_2 will form a plume in the Dornoch or Mey sandstones, originating from point source.

3		Leak past the complex seal and release into shallower formations.

When the pressure is sub-hydrostatic, during the early injection phase, CO_2 migration/leakage is considered to be unlikely[22]. The planned streamer and OBN seismic baseline surveys and the *injection phase* monitor at approximately Year 5 during injection will indicate potential leak paths that could accommodate CO_2 migration away from the P&A wells, provided the path is already filled with remaining hydrocarbon gas and provided the areal plume volume and concentrations are sufficient to be detected on seismic. The risk increases in the *post injection/closure* phase when the pressure climbs toward hydrostatic due to aquifer recharging.

Potential leaks may initially be detected on 4D seismic, by seabed sensors, or by seabed sampling near the abandoned well heads (of course subject to the detection limits of each technique). Anomalies in the observed data will trigger the following action plan:

1. Interpret the location of the leak from the available seismic, seabed geochemical probe and sample point data. If a tracer was added to the injected CO_2 stream then check the probe or sample for presence of the tracer before taking further action.
2. In case the probe or sample data indicates an anomaly then the leak is possibly close to the seafloor. Subsequently seismic or MBES surveys should be considered to delineate the plume, and additional equipment or surveying at the seabed may be planned.
3. If the seismic data shows anomalies then the next step is to determine the leak location. If the CO_2 plume appears to be shallow then consider the requirements for increased seabed sampling, or seafloor geochemical probe placement. When the plume is observed below the Dornoch/Lista complex seal determine the appropriate repeat seismic survey frequency by forward modelling and plan further monitoring to delineate the plume.
4. Quantification of the CO_2 flux is required when the plume reaches the seabed. The quantification procedure is outlined at a high level in section 6.2.

6.1.2. Action plan for leakage pathway through injectors

There are five wells in Goldeneye with access to Captain Reservoir. Four, or all five, wells will be converted into injector wells for CO_2 injection (one well will be retained as a monitoring well during the early phases of the injection, but will also act as a contingency injector should it be required). The injection pattern defines the injection well sequence and the rates, which impacts the risk distribution. Late in the *during injection* phase, well injection pressures at the sand face could exceed hydrostatic pressure and a combination of temperature and pressure may induce local fractures. The risk assessment shows that there is also a possibility of fault reactivation. In addition, potential pathways for migration up to surface are available along the casing in the case of a failure of the cement bond.

All injection wells tie back to the Goldeneye platform. One well is vertical. The others wells have deviation between 30 and 60 degrees. Baseline datasets will include cement bond/casing integrity logs acquired during recompletion, seafloor sampling, geochemical probe data, plus the seismic

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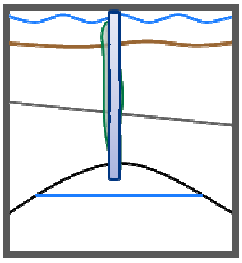
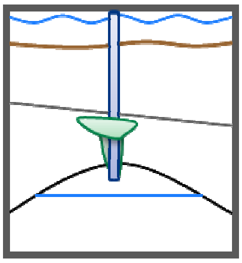
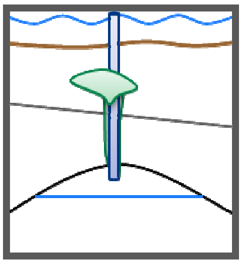
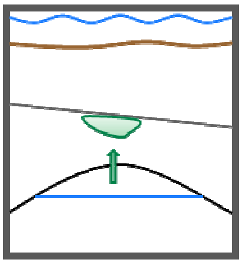
[22] Site Characterization and Risk Assessment Section in SDP

streamer and OBN baseline surveys. DTS, annular pressure and downhole pressure data will be used to monitor potential leaks in the wells or riser during injection. The seafloor geochemical probe is expected to detect anomalies in gas (hydrocarbon gas/CO_2) released in seabed or water column. Geochemical samples should be checked for the presence of possibly CO_2 tracers added in the injection stream. Insufficient detection may be possible due to minimal release of CO_2 or the leakage point is located away from probe location. The planned seismic monitor surveys may *detect* fracture induced or fault reactivation related leak path ways. DTS will be installed down to top of packer, just above the Captain reservoir. This makes it less sensitive to deeper leakage but still more sensitive than annular pressure. Potential leakage paths between casing and formation are will be detected (subject to detection limits) by the seismic surveys if the CO_2 accumulated underneath the seal

	Migration sketch	Description
1		Migration behind casing to surface below the platform
2		Migration behind casing to deep formations
3		Migration behind casing to shallower formations
4		Leak through caprock, contained by complex seal

Anomalies in the monitoring data will trigger the following action plan:

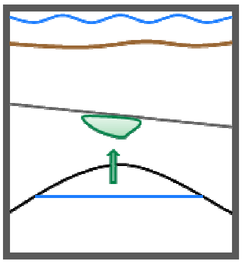
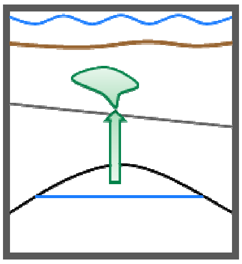
1. **DTS/pressure gauge anomalies:** check for potential leaks and their location using the data. In case of a suspected leak check the geochemical probe data for anomalies. If a leak is established then determine if a seismic or MBES survey plus other seabed or sea surface monitoring may be used to further delineate. Followed by quantification of the leakage if it reaches the seabed.

2. **Seafloor probe or sample anomalies:** consider a leak close to seafloor. Establish if additional seismic, MBES surveys, or seabed sampling is required for delineation in combination with forward modelling.
3. **Seismic data anomalies:** first determine the leak location. If the CO_2 plume is detected in the shallow sections then consider additional seabed sample locations and geochemical seafloor probe placement. At some point a seismic or MBES survey may be required to further delineate the plume. Combining the monitoring data and forward models may delineate and quantify the extent of the plume when it reaches the seabed. If the plume is deep and below the Dornoch/Lista complex seal then determine the appropriate repeat seismic survey frequency by forward modelling and plan further monitoring to delineate extent of the plume.

6.1.3. Action plan for leakage pathway through fault/fractures

Faults and connected fractures appear as a major risk in the bowtie analysis, although very few faults have been interpreted on the existing 3D seismic dataset. Faults and fractures can be activated in both the *during injection* phase pressurisation and the *post-injection/closure* phase due to repressurisation related to aquifer recharge. In sub-hydrostatic conditions, potential open faults and connected fractures are not expected to be able conduct CO_2 upwards because of the negative pressure differential; instead water from brine saturated formations in the overburden may flow downward. However, any indications of fluid conducting pathways appearing on the seismic surveys have to be mapped and closely monitored by subsequent monitoring, especially when the pressure reaches hydrostatic conditions. Since pressure monitoring is of limited use away from the injection wells, the planned injection and post injection seismic surveys are required to cover potential existing fault/connected fracture pathways and caprock integrity problems across the Goldeneye field. Seafloor geochemical probe or sampling data will be initially of limited use since these events will originate at significant depth.

The migration schematic is shown below:

	Migration sketch	Description
1		Through caprock fault or fracture to deep formations
2		Through caprock and overburden fault or fracture to above complex seal (no faults have been mapped that cross all seals)

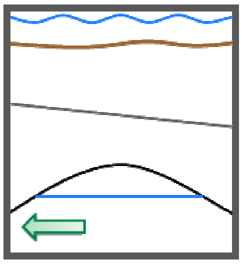
Seismic anomalies *detecting* a possible plume migration trigger the following action plan:

1. Interpret potential leakage pathways from 4D seismic interpretation.
2. If the plume is in deeper depth below the Dornoch/Lista complex seal then proceed with the appropriate repeat seismic survey frequency by forward modelling and plan further monitoring to

delineate the plume. When the CO_2 plume migrates vertically to the shallower formations above then Lista/Dornoch seal then seabed sampling or additional geochemical probes at the seafloor are required for quantification of the flux.

In the specific case when fault or connected fracture have been identified and confirmed to cause leakage from storage site but the action plan cannot determine the source of the leakage to a certain level of confidence, then drilling a new monitoring well through the fault to obtain data to select appropriate corrective measure could be considered. It is extremely unlikely that this data collection technique would be used as drilling into a fault zone has a high degree of risk, drilling into a depleted and gas (CO_2) filled fault zone has an even greater risk of major losses leading, potentially to a blow out, loss of life and significant environmental damage.

6.1.4. Action plan for leakage laterally to Captain aquifer



The Dietz tongue of CO_2 is propelled through the field by viscous forces and is expected to migrate significantly beyond the original oil water contact (OOWC). A risk of leakage develops if it passes the Goldeneye Captain reservoir spill point, in the northwest of the field. There is also a lower probability risk that the CO_2 plume reaches below the OOWC within the field structure, but in this case the CO_2 will be trapped and stored in place by a capillary pressure trapping mechanisms. The permeable formations of the Captain Sandstone are not present to the North and South of the field – nor is connection into other formations expected. Therefore, the highest risk is lateral mobility mentioned earlier, CO_2 migrating along Captain Sandstone reservoir into the Fairway to the East and West in the *during injection* phase. The absence of injection pressure in the *post-injection/closure* phase allows dynamic stabilisation when the tongue retracts and stabilizes the CO_2 column at the crest of the Goldeneye reservoir structure away from spill point (see Figure 2-7).

As the Captain D reservoir is homogeneous, the possibility of a CO_2 spill will depends upon the injection pressure and rate and the location of the injectors relative to the spill point. GYA-03, the closest well to the spill point, is allocated as a monitoring well (base case) until CO_2 breakthrough is observed. Observation in the monitoring well focuses on saturation logging and downhole fluid sampling, complemented by PDG pressure data from all re-completed wells (injectors and potentially monitoring well). The data will be used to calibrate the Full Field Model (FFM) dynamic simulation in modelling CO_2 plume movement within Captain reservoir. The model will predict the timing and amount of CO_2 potentially escaping though the spill point. Deviations from predicted behaviour will trigger the following action plan:

1. A seismic survey (3D-swath/mini-3D) will be acquired to cover the spill point and west areas of the structure (including wells and other geological risks that may provide potential leakage pathways) to detect if CO_2 plume is migrating towards the Captain fairway.
2. If a plume is detected then the plume will be interpreted to update the FFM simulation. This will project the plume growth and direction. Seismic forward modelling can subsequently determine the timing of another seismic monitoring survey.

In the event of migration of CO_2 beyond the spill point, leakage risk will increase significantly if the CO_2 plume would reach well 14/28b-4, to the west of the Goldeneye structure. This well has a poor completion history, and there is some risk that the well may act as pathway to shallow formations and, eventually, to the surface. Indications of the CO_2 plume moving towards this well will be obtained from FFM projections or from plumes observed in the planned injection or post-injection seismic surveys. If this occurrence is indicated from FFM projection or a seismic anomaly, the following steps will be taken:

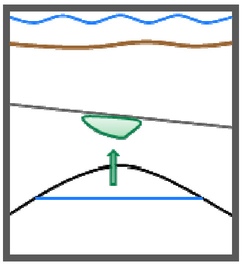
A. FFM projection trigger:

1. Seismic survey (3D swath/mini 3D) to cover west area of Goldeneye structure including the 14/28b-4 well to detect and if present delineate the CO_2 plume towards the well or geological risk feature. Seismic forward and FFM modelling can be used to plan subsequent follow-up surveys or other monitoring activities if required.
2. If the plume is migrating vertically through strata then seismic and FFM should be used to estimate the progression of the plume towards surface for further seismic monitoring activity planning. If the plume is close to surface then shallow 3D seismic may be considered if the streamer survey would be unable to deliver a high-resolution image.
3. When the plume is progressing through the shallow strata then geochemical probe installation and an appropriately timed repeat MBES surveys may be necessary to delineate the plume further, followed by leak quantification.
4. Seabed sampling if the leakage is confirmed to obtain fluid composition (tracer detection if any injected in the system)

B. Seismic trigger:

Use seismic and FFM forward modelling to project when the next seismic survey is required. Continue with step 2 of the FFM trigger plan described above.

6.1.5. Action plan for leakage laterally in Mey Sandstone Member



If CO_2 migrates through the storage seal due to activation of a vertical leakage mechanism (i.e., caprock integrity failure, wells, faults), it will likely accumulate in the Mey sandstone (reservoir quality formation) beneath the Lista mudstone. Since the Mey sandstone does not have a structural closure over the Goldeneye field, the CO_2 plume could migrate towards shallower structures to the west or northwest until it becomes capillary trapped or mineralised. The Mey sandstone sits below the Lista mudstone and above the latter is the Dornoch sandstone and Dornoch mudstone – the seal complex.

The CO_2 accumulation is expected to be insignificant volume-wise in sub-hydrostatic conditions (if the leak occurs during injection). The potential hazard is elevated when hydrostatic pressure is reached or the deep plume is passing vertical pathways (i.e., wells or fault). In this case the seismic survey will be the most effective method to monitor this risk as the CO_2 plume in high porosity brine saturated sandstone is expected to develop a strong acoustic response, visible to 4D seismic.

A detection of the CO_2 plume on seismic in the aquifers of the Montrose Group or the overlying Mey Sandstone Member. will trigger the following action plan:

1. Seismic survey (3D swath/mini 3D) to cover the storage complex (including potential pathways from wells and geological features) on west to northwest direction to delineate and define the migration in the overburden and through the Mey sandstone. Appropriate timing of the surveys is to be confirmed by forward modelling.
2. Shallow seismic to be considered if the plume were to break through the Lista/Dornoch complex seal.
3. Seabed Mapping (MBES) if the leakage appears to reach seabed to identify location proximity.
4. Geochemical probe installation at leakage point on seabed.
5. Seabed sampling if the leakage were confirmed to obtain fluid composition (tracer detection if any injected in the system).

CO_2 flux quantification is again necessary when the plume reaches the shallower formations.

6.2. CO_2 leakage/migration quantification

ETS regulations require the calculation of CO_2 volume at the seabed (marine biosphere) in the event of leakage. To achieve such compliance, a fit-for-purpose monitoring plan should be designed in close cooperation with the regulator as preparation in case of suspected leaks and the leakage event itself.

A workflow that can be used to quantify leak volumes at seabed is outlined below:

1. Establish the suspected leak source and quantify the possible leaked volume. Direct and indirect measurements from monitoring program should be used to calculate indicative leak volume. Leakage can be estimated either from source or storage peripheral (lateral extent of storage complex and seabed). Quantification on the source can be achieved by using synergy interpretation of direct measurements like reservoir pressure, injection rates and in-flow composition for migration/leakage from injectors. Quantification at storage peripheral can be achieved by a combination of the following direct measurements: seismic (storage peripheral and near seabed) and MBES/visual observations (at seabed) for volume/area/rates and sediment samples for concentration. It should be recognised that these direct measurements have variation in detection limits and uncertainty ranges. Indirect measurements can be obtained from modelling prediction such as quantitative seismic interpretation, reservoir models, and regional geological models, or extrapolation of direct measurements, *e.g.*, reservoir pressure between wells. These methods are applicable for migration/leakage with the exception of at surface leakage where direct measurements mentioned earlier are the only suitable methods.
2. Build a reservoir model in the area where the irregular CO_2 plume migration is observed. The size of the model is driven by source of plume, plume migration and the potential pathways to the surface. This model is then used to obtain a range of estimates (low-medium-high) of migrated volumes. 4D seismic, MBES and visual data acquisition are used to constrain the modelled volume range by minimising the uncertainty.

Quantification is a requirement for a leakage event. However, should a major irregularity (migration) that could potentially lead to CO_2 leakage be detected, then the course of action is to inform the regulatory authorities and determine the most appropriate procedure using the methodology outlined above to establish the size of the leak and the flux rates for possible ETS credit payments and corrective measures, especially at the seabed where it interact with marine biosphere. A summary of quantification techniques is shown in Table 9.

Table 9 Leakage/migration quantification techniques summary

Techniques	Information gained	Event
Reservoir pressure, injector rates and in-flow composition	Volume & concentration	Migration/leakage from source (injectors)
Quantitative seismic interpretation and inversion using reservoir dynamic model	Volume & concentration prediction	Migration under seabed
Shallow seismic	Volume interpretation Delineation of area for sampling	Leakage near seabed
MBES	Flux rate (high flux rate) Delineation of area for sampling	Leakage at seabed
Sediment sampling (including pore gas)	Concentration	

A CO_2 migration event within storage complex does not require quantification from legislative perspective, however this event should be detectable during injection to enable preventive actions. Detection limits of several techniques that are utilised for this purpose are listed in Table 10

Table 10 Monitoring technique detection limit for CO_2 migration (in weight/time) based on minimum resolution/accuracy

Technique	Scenario/ Placement	Detection limit
Seismic [1]	In near surface (shallow depth) In Mey Sandstone Member In Captain aquifer	15-500 tonnes [1] 500-12,000 tonnes [1] 3,000-30,000 tonnes [1]
Pressure	Annular pressure PDG	38.7 kg/day* 9.5 kg/day**

Note:

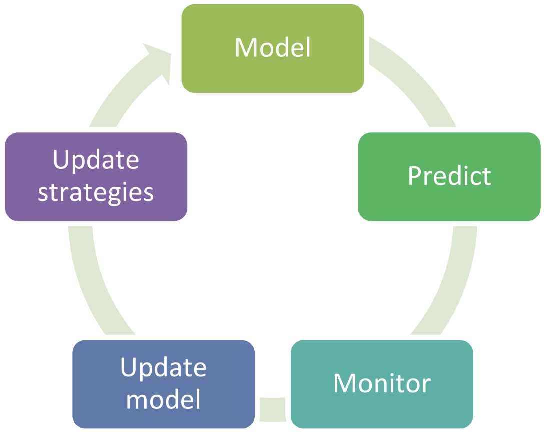
[1] The seismic detection limits are expressed as a range reflecting geological uncertainties in porosity, sand vs shale distribution etc at near surface, Mey and Captain levels..

*38.7 kg/day is based on calculation of typical annular pressure resolution at 1.6% and 20 Million Tonnes CO_2/10 injection years rate at 2000-3200 psi (average).

**9.5 kg/day is based on calculation of NPQG resolution at 0.07 kPa/s and 20 Million Tonnes CO_2/10 injection years rate. The condition is applied when there is no influence from reservoir pressure.

7. Updating Plan

The Goldeneye monitoring plan will be reviewed by DECC on a minimum of a five year interval. Updates will be on the basis of revised static and dynamic models that incorporate the results from monitoring and verification surveys. Even with the most rigorously designed static and dynamic geological earth models, deviations from predicted injection behaviour may be expected. As such, it is important to adopt an adaptive learning process based upon the following iterations:



Updated strategies should address shortcomings in history matching and options for new/updated technologies or technology improvements. History matching is the comparison of observed behaviour of the injected CO_2 in the storage complex with the behaviour predicted in the dynamic modeling approach. The monitoring methodology should be changed if the updated strategy improves the accuracy of the reported data, unless this is technically not feasible or a cost/benefit analysis rules out a technique.

There are three types of circumstances that would initiate a revision to the original monitoring plan.

- Unexpected plume migration behaviour (*i.e.*, leakage up a well, plume shape or migration velocity) during injection.
- Migration of CO_2 out of the primary containment formation but within the storage complex.
- Changes in the cost and detection limits of monitoring technologies. This can be expected to occur as monitoring technologies for CCS are in their infancy, especially in the offshore environment.

If deviations are found between the two, the dynamic model(s) and/or the monitoring plan will be updated. Mismatches between dynamic models and monitoring data may also lead to corrective measures, including acquisition of new subsurface data and/or a change of the originally intended injection plan.

The first two circumstances identified above impact the storage complex risk assessment, which is tightly linked to the monitoring plan. In these circumstances the following steps in Figure 7-1 will be used to update the monitoring plan.

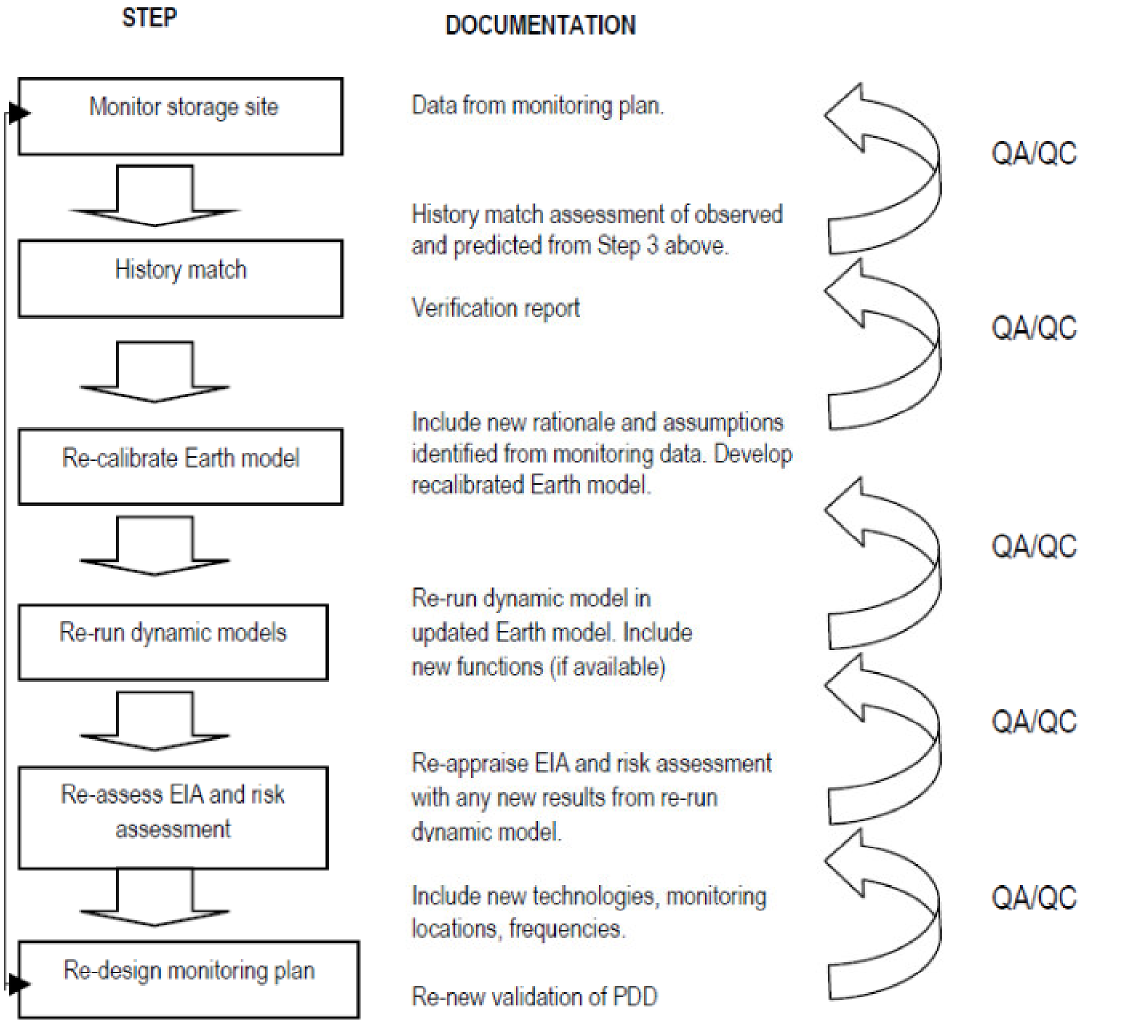


Figure 7-1 Iterative process of updating MMV Plan[23]

[23] Key steps in updating a CO2 storage complex monitoring plan. Source: IEA Greenhouse Gas R&D Programme (IEA GHG), "ERM – Carbon Dioxide Capture and Storage in the Clean Development Mechanism", 2007/TR2, April 2007

8. Abbreviations

BHT	Bottom Hole Temperature
CBL	Cement Bond Logging
CCS	Carbon, Capture and Storage
CDT	Conductivity, Depth and Temperature
CO_2	Carbon Dioxide
CPS	Compact Production Sampler
DECC	Department of Energy and Climate Change
DTS	Distributed Temperature Sensing
EOR	Enhance Oil Recovery
ETS	Emissions Trading Scheme
FFM	Full Field Model
GD	Guidance Document 2
GHG	Green House Gas
GR	Gamma Ray
LOS	Line of Sight
LTMG	Long Term Memory Gauge
MBES	Multi Beam Echo Sounder
MMV	Monitoring, Measurement and Verification
NHQG	Net Hyper Quartz Gauge
NPQG	Net Pressure Quartz Gauge
OBN	Ocean Bottom Node
OOWC	Original Oil Water Contact
P&A	Plugged and Abandoned
PBMS	Platform Basic Measurement Sonde
PDC	Permanent Downhole Cable
PDG	Permanent Downhole Gauge
PFC	Perfluorocarbon
ROV	Remotely Operated Vehicle
RST	Reservoir Saturation Tool
SAC	Special Area of Conservation

TDS	Total Dissolved Solid
TDIC	Total Dissolved Inorganic Carbon
USIT	Ultrasonic Imaging Tool
VOI	Value of Information

In the text well names have been abbreviated to their operational form. The full well names are given in Table 11 below.

Table 11 Well name abbreviations

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. MMV precedents in the North Sea

To date there are three MMV precedents in the North Sea: Sleipner, KB-12 and Miller. The Sleipner project is the only commercial CCS project in the North Sea, injecting into a saline aquifer setting, the Miller project did not become commercial, while K12-B is a pilot project in the Dutch sector, injecting CO_2 from the gas field back into the original reservoir. Due to the different intentions (commercial vs. pilot), geological/field settings (aquifer vs. depleted fields and shale vs. salt caprocks) all three projects have different risk and monitoring aims. Hence the MMV technologies deployed are different, despite the three projects being located in the same region. Table 12 provides an overview of the range of monitoring techniques deployed/proposed at the three projects.

A.1. Sleipner – commercial scale project (taken text directly from Quest MMV report)

The Sleipner project began in 1996 when Norway's Statoil began injecting more than 1 million tonnes a year of CO_2 under the North Sea. This CO_2 was extracted with natural gas from the offshore Sleipner gas field. In order to avoid a government-imposed carbon tax equivalent to about US$55/tonne, Statoil built a special offshore platform to separate CO_2 from other gases. The CO_2 is re-injected about 1,000 metres below the sea floor into the Utsira saline formation, located near the natural gas field. The formation is estimated to have a capacity for about 600 billion tonnes of CO_2, and is expected to continue receiving CO_2 long after natural gas extraction at Sleipner has ended.

The focus of monitoring in this application has been the repeat use of 3D/4D surveys. So far six time-lapse surveys have been acquired which show regular expansion of the CO_2 plume. The plume revealed the importance of thin shale layers in creating a multiple-stack storage system.

A.2. K12-B – pilot project

The first CO_2 storage test site in the Netherlands is at the K12-B natural gas field, in the Dutch sector of the southern North Sea (100 km from the coast NW Den Helder). The K12-B gas field has been producing natural gas with relatively high CO_2 content, since 1987. The pilot project has been investigating the feasibility of injecting and storing CO_2 in a depleted gas field. The first injection tests took place in 2004, and injection now continues at about 20kilotonnes per year into a depleted reservoir. Over 60,000 tonnes of CO_2 (January 2009) has been re-injected back into the same reservoir. The storage depth was 3800m. Until recently, the CO_2 produced from the field has been separated and released into the air. The monitoring and verification part of the project is being carried out by CO2REMOVE. The field is a Clastic reservoir with a salt seal and is geologically different to Sleipner.

A.3. Miller

The Miller Oilfield lies in the UK sector of the North Sea about 240km north east of Peterhead and was proposed as a storage site, with the injected CO_2 providing a drive for enhanced oil recovery (CO_2–EOR) from a depleted reservoir. The proposed storage depth was 4000m.

Table 12 Monitoring techniques utilisation in Sleipner, Miller and K12-B

	Sleipner	Miller	K12-B
Deep-focussed			
3D surface seismic	✓		
2D surface seismic	✓	✓	
Seabed gravimetry	✓		
Seabed CSEM	✓		
Wellhead P,T	✓	✓	✓
Downhole P,T		✓	✓
Geophysical logs		✓	✓
Crosshole seismics		✓	
Downhole fluid chemistry		✓	✓
Passive seismics			
Shallow-focussed			
Multibeam echosounding	✓	✓	
Sidescan sonar	✓	✓	
Sparker/boomer/hires acoustic		✓	
Bubble-stream detection		✓	
Bubble-stream chemistry		✓	
Ecosystem		✓	
Infrastructure			
Well integrity			✓