Peterhead CCS Project

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Executive summary

The purpose of this document is to demonstrate that the depleted Goldeneye geological complex has sufficient capacity to demonstrably contain for a period exceeding 1000 years a cumulative volume of 15Mt supercritical CO_2 plus specified contaminants, injected at a rate of 1Mt p.a for an injection period of up to 15 years.

The structure of the monitoring report is as follows:

- Site description, including a brief history of the site and structural configuration.
- Risks and uncertainties, including a discussion on the consent process.
- Site capacity, giving an overview on well functional requirements, injectivity and operability.
- Transportation and injection facilities, including engineering challenges faced with these aspects.
- Site containment, addressing factors which could potentially impact on primary containment.
- Monitoring Plan, including corrective measures and contingency arrangements.
- Closure and Post-closure plan.
- Decommissioning.

The analysis discussed within this document shows that the field and water-leg of the Goldeneye reservoir have sufficient capacity to store over 30 million tonnes of CO_2, above the capacity required by the Peterhead CCS Project. The risk of leakage through any identified natural or engineered barrier has been assessed as low or negligible. To mitigate any leakage a corrective measures plan has been prepared outlining actions to be taken in the event of an irregularity. This is tied to the contingency plan. Provisional closure and post-closure plans have been prepared in-line with the U.K. Regulator guidelines.

1. Introduction

The Peterhead CCS Project aims to capture approximately one million tonnes of CO_2 per annum, over a period of up to 15 years, from an existing combined cycle gas turbine (CCGT) located at SSE's Peterhead Power Station in Aberdeenshire, Scotland. This would be the world's first commercial scale demonstration of CO_2 capture, transport and offshore geological storage from a (post combustion) gas-fired power station.

Post cessation of production, the Goldeneye gas-condensate production facility will be modified to allow the injection of dense phase CO_2 captured from the post-combustion gases of Peterhead Power Station into the depleted Goldeneye reservoir.

The CO_2 will be captured from the flue gas produced by one of the gas turbines at Peterhead Power Station (GT-13) using amine based technology provided by CanSolv (a wholly owned subsidiary of Shell). After capture the CO_2 will be routed to a compression facility, where it will be compressed, cooled and conditioned for water and oxygen removal to meet suitable transportation and storage specifications. The resulting dense phase CO_2 stream will be transported direct offshore to the wellhead platform via a new offshore pipeline which will tie-in subsea to the existing Goldeneye pipeline.

Once at the platform the CO_2 will be injected into the Goldeneye CO_2 Store (a depleted hydrocarbon gas reservoir), more than 2 km under the seabed of the North Sea. The project layout is depicted in Figure 1-1 below:

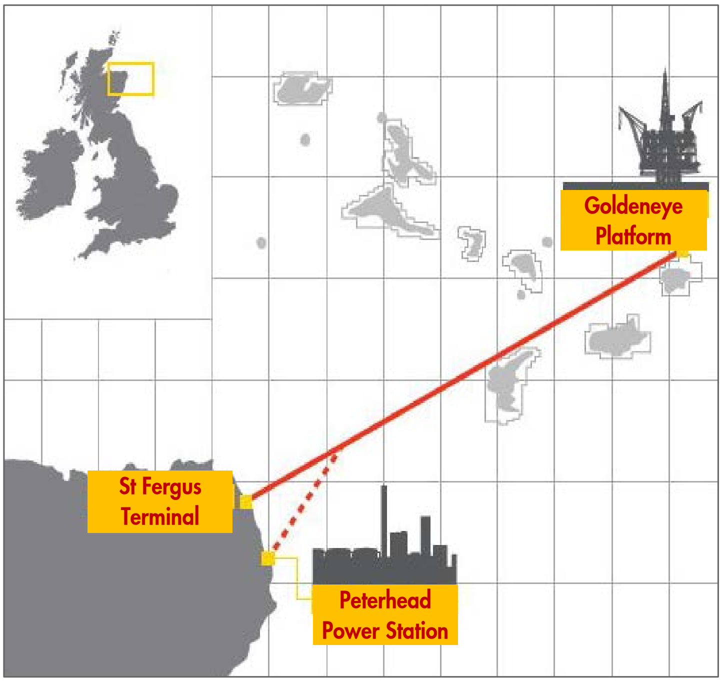


Figure 1-1: Project Location.

2. Report Overview

This section aims to give an overview by condensing the Storage Development Plan report into six pages – highlighting the key points from each section.

One aim of the project is to re-use as much existing infrastructure as possible. The existing undersea pipelines will have front end filtration equipment installed and will be cleaned for injection operations. The platform will be modified with the addition of filtration and the replacement of much of the pipework. The vent system and all safety systems will be upgraded for CO_2 operation.

A key operational task will be managing CO_2 as it flows into the depleted field. If it is allowed to flow freely into the reservoir the *Joule-Thompson effect* will cool the CO_2 to a low of -30°C which is outside well design specification. The cooling will be managed by working over the wells and installing slim tubing – constricting the flow and maintaining the CO_2 in the dense phase for the whole length of the well – and by placing operational constrains on the rate of bean up/bean down and cycle frequency of the facility.

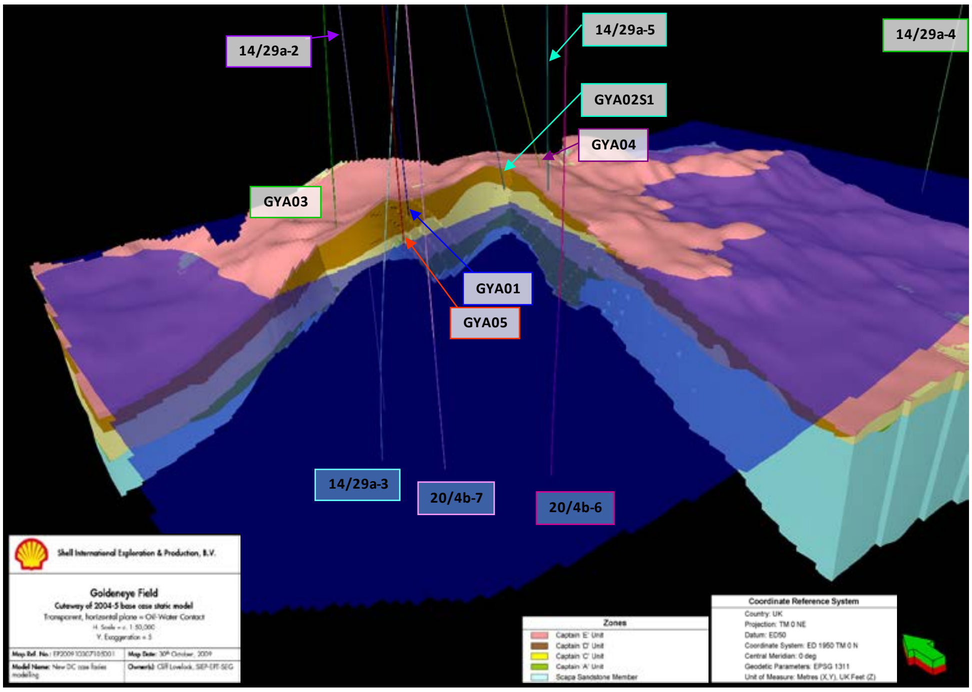


Figure 2-1: Goldeneye reservoir cross-section.

The topside facilities will also be exposed to low temperatures in the event of an emergency depressurisation. The temperature requirement necessitates the replacement of existing pipework and wellheads. As the CO_2 will be de-hydrated at Peterhead, internal corrosion of the pipeline and facilities is not a concern – as long as the system remains within specification. This is being assured by the implementation of quality monitoring systems at the compression stations.

The system has to handle varying CO_2 rates from the capture plant – ranging from 89.9 to 138.3 tonnes per hour. At any specific flow rate, one or two out of a selection of three wells will be called upon to provide the desired surface and subsurface pressures. The fourth well will be used for monitoring. Late in injection life, as the CO_2 plume grows the value of information from well monitoring will reduce – to be replaced by seismic techniques – allowing the recompleted well to be used as a spare late-life injector. The fifth well will be a subsurface abandonment with downhole cement plugs at the primary seal level. Monitoring of this partially abandoned well would be performed during the project injection period. Information will be gained for assessing the final abandonment of this well and the rest of the injectors at the end of the life of the project.

The wells each have a non-cemented completion with gravel pack and sand screens. These are to be re-used. The risk of plugging posed to these completions from fines in the offshore pipeline (residual after cleaning or from potential de-lamination of an internal coating) is being mitigated by the installation of a filtration package on the platform.

The CO_2 will be injected into the storage site at a depth >2516m [8255ft] below sea level into the previously gas bearing portion of the high quality Captain Sandstone Member – in total a 130km long and <10km wide ribbon of Lower Cretaceous turbiditic sandstone fringing the southern margin of the South Halibut Shelf, from UKCS block 13/23 to block 21/2. At the Goldeneye field, this sandstone has permeability of between 700 and 1500mD.

Since 2004, the field has produced 568 Bscf of gas and 23 MMbbl of condensate. During production, the field experienced moderate to strong aquifer support – which also served to end the gas production from the wells as each well sequentially cut water.

The primary CO_2 storage mechanism will be accommodation in the pore space previously occupied by the produced gas and condensate from the Goldeneye field. A secondary mechanism will be immobile capillary trapping in the water-leg below the original hydrocarbon accumulation. When CO_2 is injected into the field it will displace the invaded aquifer back into the aquifer. The CO_2 will form a layer due to gravity and unstable displacement effects and some of the injected CO_2 will be displaced below the original oil-water contact. Once CO_2 injection has stopped the CO_2 is predicted to flow back into the originally gas bearing structure. Between 20% and 30% of the CO_2 that was displaced into the water-leg remains trapped in place due to capillary forces.

Analysis and modelling have shown that the field and water-leg have sufficient capacity to store over 30 million tonnes of CO_2 – more than sufficient for the 15 million tonnes proposed in the UK competition.

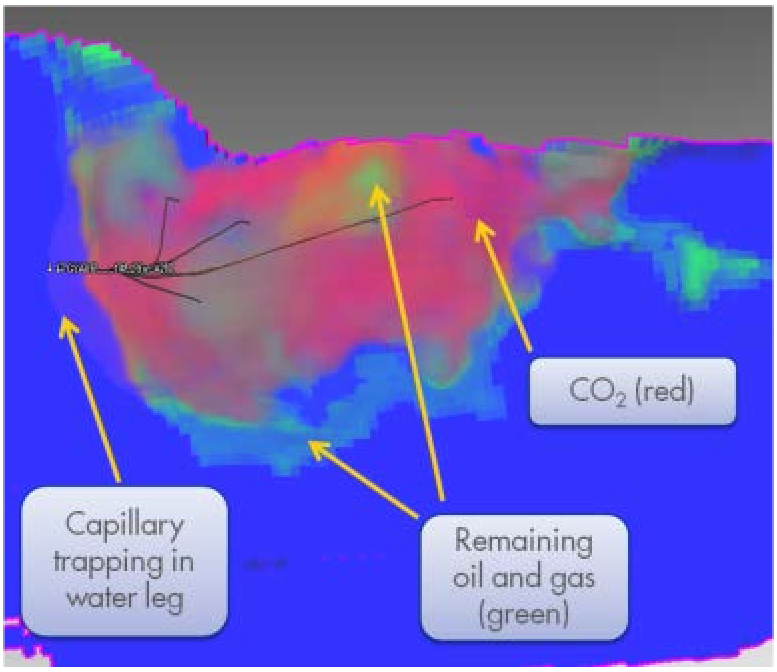


Figure 2-2: CO_2 plume after injection.

Note: Green: hydrocarbon, Red: CO_2, Blue: water.

The Goldeneye field is hydraulically connected through the Captain Aquifer water-leg to the neighbouring fields in the east (Hannay, 14/29a-4 discovery – named Hoylake by Shell – and Rochelle) and in the west (the no longer producing Atlantic & Cromarty fields and, potentially the still producing Blake field). The pressure support from the Captain Aquifer has limited the decline in Goldeneye pressure, from an original of 262 bara to a little under 145 bara (at datum level of 2560 m [8400 ft.] TVDSS). Injection of 15 million tonnes of CO_2 will raise the pressure in the main interval, the Captain D to between 228 bara and 260 bara at the end of injection. The pressure will then drop to between 222 bara and 250 bara as it dissipates into the aquifer. Over time the fall off rate will decline and change to slow (or no) recharge as pressure becomes controlled by the Captain Aquifer and the fields connected to the same aquifer.

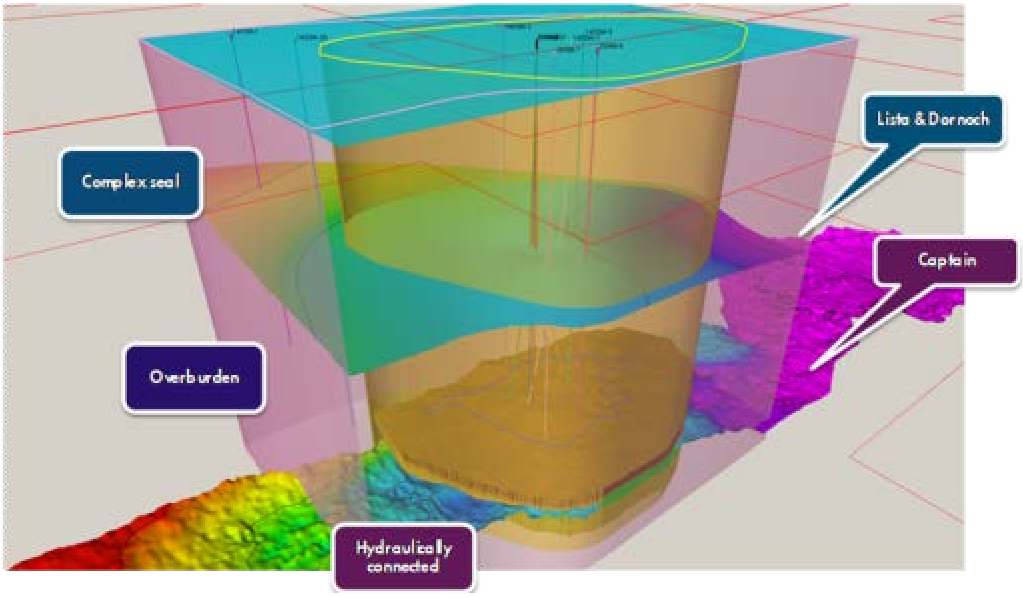


Figure 2-3: Storage Complex.

Other nearby fields (Ettrick – 20km from Goldeneye; Tweedsmuir at 30km; Buzzard at 40km; Ross at 60km) have Upper Jurassic or older reservoirs, Buchan at 25km distance has a Devonian reservoir. Pressure and compositional data from these fields show that they are not in communication with the Captain Fairway fields. Vertical containment is provided by the 470-700 ft. [143-202 m] thick *storage seal*, a package including part of the Upper Valhall Formation, Rødby Formation, Hidra Formation and the Plenus Marl Bed. No gas chimneys are observed above the Goldeneye complex. The sealing capacity of the Rødby Formation acts as the primary seal for all hydrocarbon fields in the Captain Fairway.

Further containment is provided by the *complex seal,* made up of two mudstone units that can be reliably correlated across the area of the Goldeneye Field. These are the mudstone at the top of the Lista Formation (Lista mudstone) and the Dornoch mudstone. They are found at depths greater than 800 m TVDSS across the entire area under investigation meaning that any CO_2 that is stored beneath them will remain in the dense phase. They dip upwards to the northwest at 1-1.5° and crop out at the seabed at least 150 km away from the *storage site*. The Lista mudstone is also a proven seal to hydrocarbons elsewhere in the Outer Moray Firth Basin.

Secondary storage is provided by the formations between the storage and complex seals (Upper Chalk Group, Mey Sandstone Member and lower Dornoch sandstone). There is little or no chance of CO_2 escaping the storage site laterally under the spill point, owing to the significant spare capacity within the store. However, if the injection plume were to pass the structural spill point of the Goldeneye field this CO_2 would then be contained under the same cap rocks within the much larger Captain Fairway. The Captain Fairway has the potential to be a giant (predominantly aquifer) CO_2 store.

The site contains four exploration and appraisal (E&A) wells within the Captain reservoir and one immediately to the north. All of the E&A wells have good quality abandonment plugs at reservoir seal level.

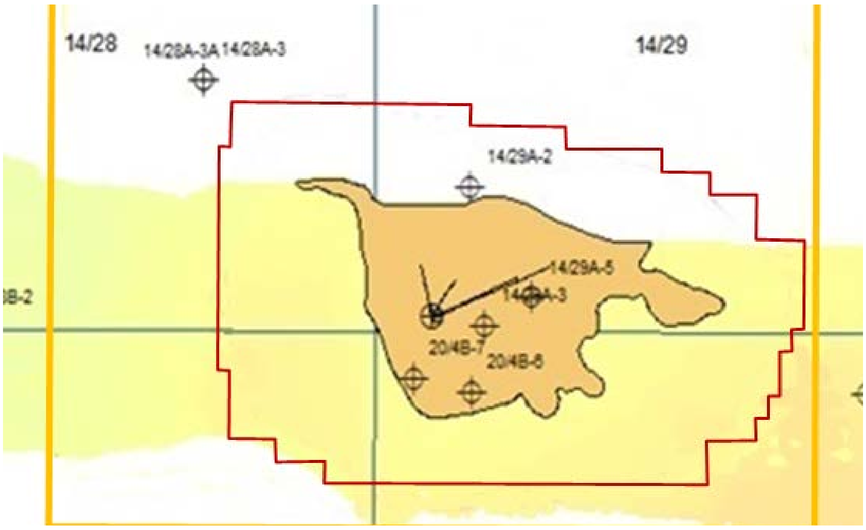
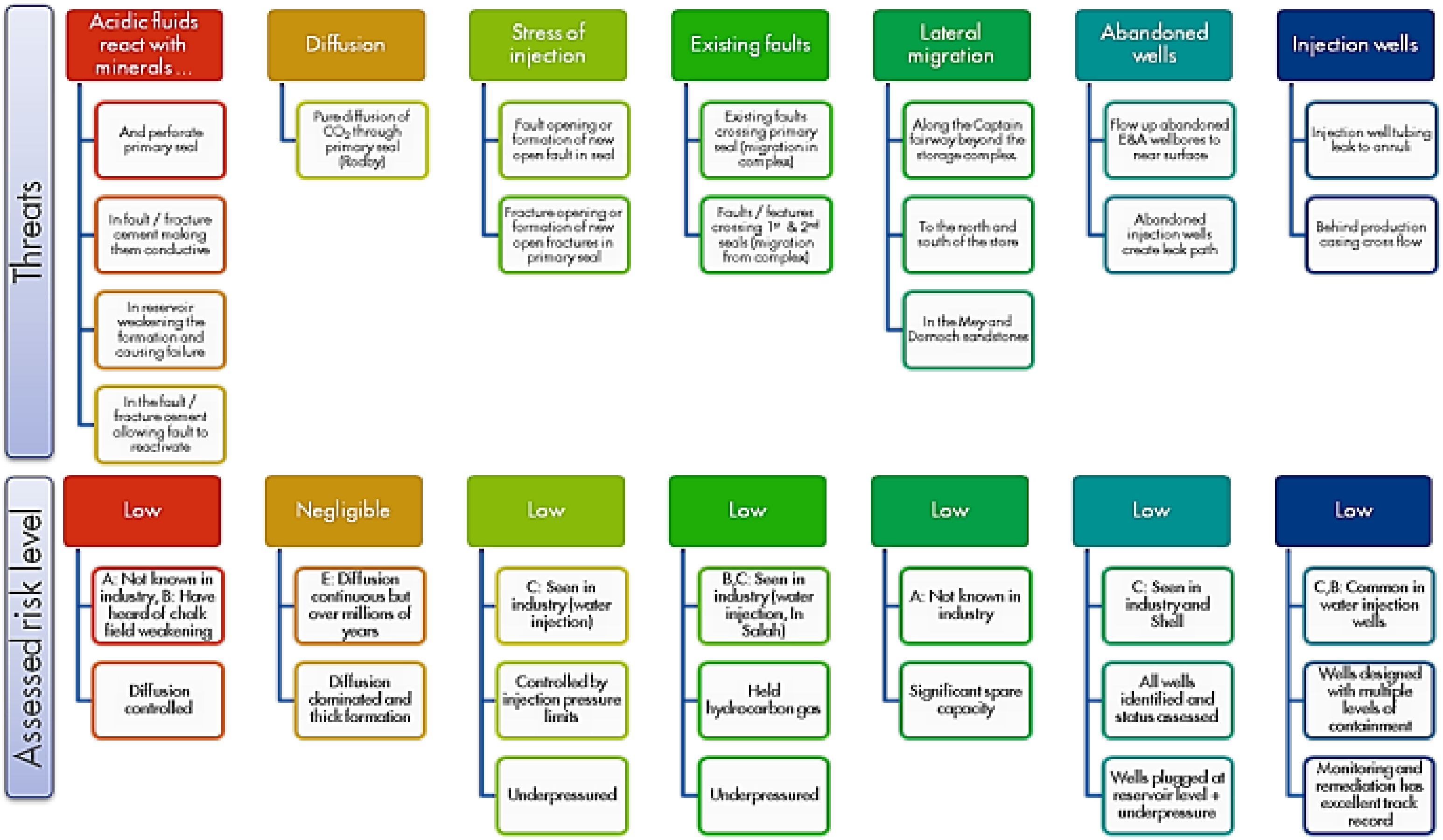


Figure 2-4: Wells in the site.

Existing faults have been mapped and fractures have been analysed and none have been identified to be completely pervasive throughout the seal systems. The key advantage of using a depleted hydrocarbon field is that the caprock integrity has been tested and proven by the very presence of a gas field containing highly mobile gas that is under pressure compared to the surrounding formations. Even though no faults or fractures are observed that currently allow the migration of CO_2, two mechanisms exist that potentially allow for the formation of flow paths. The first is through geochemical interaction between the carbonic acid formed when CO_2 dissolves in water and the host rocks. These interactions have been studied and found to be of a low magnitude and speed and so will not perforate the caprock or dissolve any cementation in the faults. The second is rock failure as a result of the pressure cycling coupled with thermal weakening. Pressure cycling has been studied and the reservoir and seals are indicated to be competent. Fault remobilisation during earlier hydrocarbon depletion and proposed CO_2 injection re-pressuring has also been examined and results indicate that the conditions are such as to inhibit this. The injection of cold CO_2 can cause limited local thermal weakening of caprock. This can potentially lead to tensile fracture propagation into the caprock. Studies indicate that this will not penetrate the whole thickness of the seal complex and does not create a leak path. The *complex seal* is penetrated by seven exploration and appraisal wells. Only two of these wells have plugs at the secondary seal, meaning that the other wells have the potential to provide migration paths should CO_2 migrate out of the primary containment and travel through the secondary storage and overburden buffers and create a migration plume that intersects one of the wells. This risk is mitigated through monitoring for which corrective measures have been identified should migration ever be observed.

All the containment risks have been assessed using the bow-tie analysis technique. This identifies the barriers to, escalation factors for, controls of and consequences of, CO_2 breaching the complex seal and (possibly) reaching the biosphere. This is summarised below:



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

Figure 2-5: Bow-tie diagram for containment risks.

There are seven categories of risk/threat illustrated in the figure above. Each category has, after the consideration of natural and engineered barriers (already in place or planned), been assessed as low or negligible.

The key barriers in the Goldeneye system are the primary and complex seals, the well abandonment plugs and injection well design, and the fact that the system operates at a lower average pressure than that in the surrounding formations. This means that – were a leak path to form – formation brine would prefer to flow into the store rather than CO_2 flow out: at least until the system re-pressurises over a period of tens to hundreds of years. By that time, the injected CO_2 will have evolved into pressure equilibrium with the aquifer, so there will be no further movement of fluids into or out of the store.

A comprehensive monitoring programme has been designed tailored around the risk assessment. It consists of two plans:

- *Base case plan*: is driven by the risk assessment and monitors the conformance of the injection and identifies unexpected CO_2 migration (*detect*) within the storage complex, allowing action to be taken (if required) to ensure the integrity of storage before leakage occurs.
- *Contingency plan*: in the event of CO_2 leakage outside the storage complex, the *contingency plan* is mobilised to locate the source of migration (*delineate*) and enable mitigation plans to be implemented (including quantification or *define*).

The monitoring *base case plan* includes environmental baselines before and after injection, injection well monitoring and monitoring of the seawater under the platform for traces of CO_2. The key detection mechanism for non-injection well related leaks is 4D (time-lapse) seismic. A baseline survey is planned before injection. A second, monitor survey will be acquired during injection to check conformance and identify the CO_2 plume movement. Another monitor survey will be acquired one year post injection, to be used as the new baseline. The final surveys will be acquired at least six years after injection ceases, timing thereof dependent on the pressure performance of the field. The seismic surveys are complemented by seabed surveying around exploration and appraisal wells to check for elevated levels of CO_2.

The *contingency plan* ties closely to the corrective measures and includes focused application of the techniques/technologies used in the *base case plan* plus additional options.

Once the required volume of CO_2 has been injected it is currently planned to monitor the reservoir pressure build-up for three years while leaving the platform in place. After this the platform and wells will be decommissioned. Handover to the *UK Competent Authority* is proposed to take place between six and twenty years post-closure. Exact timing will depend on the rate of pressure recharge, the dynamic performance of the reservoir and the acquisition of two time-lapse surveys.

A *corrective measures plan* has been prepared outlining the actions that will be performed should a significant irregularity occur. The underlying principle is to identify the source/cause of the irregularity, assess its likely evolution and then plan remediation in consultation with the regulatory authorities. The response must always be proportional and the risk and impact associated with any corrective measure activity should be offset against the risk and impact of the irregularity being targeted.

3. Structure and background

This document outlines the storage development plan for offshore transport and storage of CO_2 in the depleted Goldeneye hydrocarbon field.

3.1. Structure of the SDP

The storage development plan is structured around demonstrating that the following can be achieved:

The store (and complex) as defined must have sufficient capacity to demonstrably contain for a period exceeding 1000 years a cumulative volume of 15Mt supercritical CO_2 plus specified contaminants, injected at a rate of 1Mt p.a for an injection period of up to 15 years.

Four main pillars support the demonstration of the main question – the subordinate questions must each be satisfied – these are: *capacity, injectivity, containment, monitoring & corrective measures*:

In a hydrocarbon development the subsurface evaluation work focuses on understanding the *most likely* ranges for the reserves (capacity) and production rates (injectivity) and then designing a transport and processing system – with some monitoring and metering – that optimises the profitability of the development.

CO_2 storage aims to establish parameters *with high certainty (deterministic approach)*, rather than looking for the most likely case. A large portion of the work is performed on assessing the containment of the system – something that is proven *a priori* for hydrocarbon development because the presence of hydrocarbon implies that is has been contained over geological time.

A key element required for project execution is monitoring, or more simply, the ability to show that the site is containing the CO_2. The monitoring plan is built around the containment risk assessment, is site specific, and depends on the injection profile and parameters. However, monitoring is of little value if there is not an effective plan in place to correct a significant irregularity should one be observed, hence the corrective measures plan.

The structure of the monitoring report is as follows:

- First to describe where it is planned to store the CO_2. The surface location of the storage site is described, along with information on other users of the area.
- The subsurface store is then outlined along with the history of the hydrocarbon field that is being reused.
- The major risks assessed as relating to the project are summarised.

The four pillars of CCS are then addressed:

- Capacity.
- Injection and injectivity plus transport and injection facilities.
- Containment and the related subsurface risk assessment.
- The proposed monitoring plan and the proposed corrective measures plans are outlined.

It is also necessary to describe the conditions required for and manner in which the site will be closed and handed over to the *UK Competent Authority* after the end of injection. The plan finishes by describing components in common with a field development plan:

- HSE plan.
- Facilities, pipeline and wells decommissioning plan.

3.2. CO_2 profile for storage

The detail of the CO_2 profile depends on the mode of operation of the power plant and on the reliability and availability of all the components.

The exact details of the profile will be determined during detailed design and the project contract negotiations. An initial RAM (reliability and availability model) has been constructed.

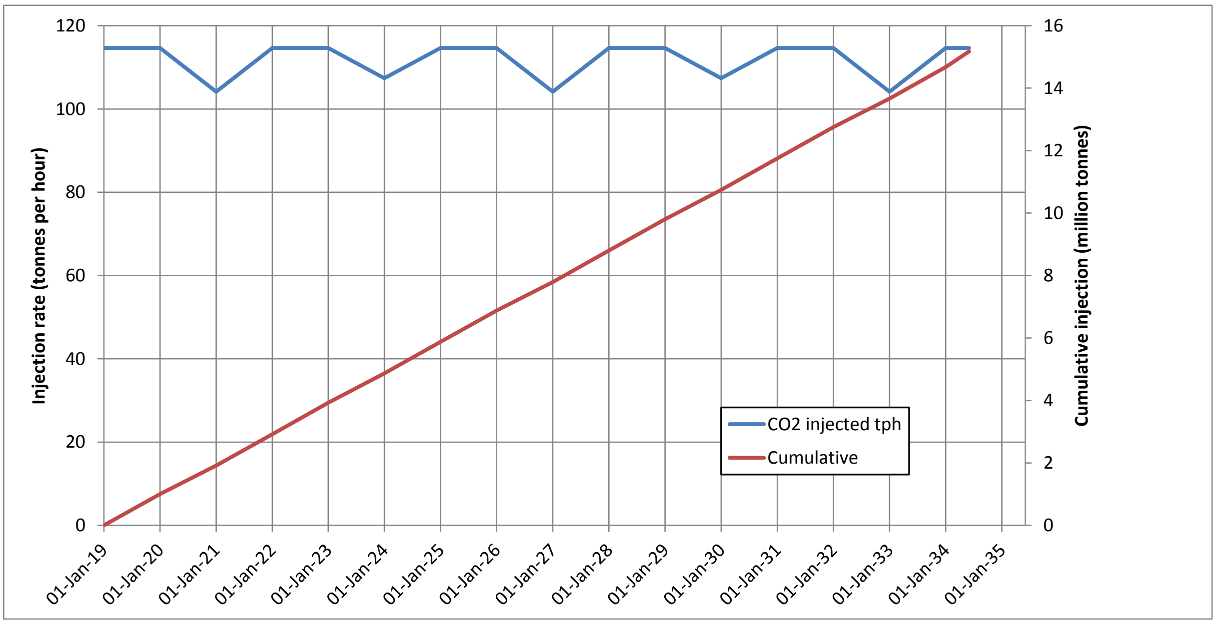


Figure 3-1: Indicative CO_2 injection profile.

The reliability of the full project chain (gas turbine to wells) is expected to be 86% on average. The design rate of the CO_2 capture plant is 138.3 tonnes/h, with normal operating conditions expected to be 130 tonnes/hr. (1.139 Mt p.a.). With the end to end uptime from the RAM calculation, 15 Mt CO_2 will be stored in just over 15 years (roughly 180 months). The average rate (after (after commissioning) is 1 Mt p.a.

4. Site description

This chapter sets out the basic data for the storage solution, including a description of the surrounding environment, identification of other users who may be affected by the change of use of the Goldeneye gas condensate field, description of the geology of the complex and the fluids contained within it. Succeeding chapters will set out the individual assessments of Capacity, Injectivity, Containment and Monitoring which use assumptions based on the understanding of the Goldeneye storage complex presented here.

4.1. Definition of the proposed site

The *storage site* is based upon the use of the Goldeneye gas condensate field as the primary container for the CO_2 planned to be stored from the Peterhead Power Station. The Goldeneye field is located in the Outer Moray Firth, circa 100km north-east of the St Fergus gas plant, mainly in UKCS blocks 14/29a (Offshore Hydrocarbon Production License P257) and 20/4b (License P592) but is mapped to also straddle blocks 14/28b (License P732) and 20/3b (License P739). In detail, it is defined as the pore volume between the mapped top of the Kimmeridge

Clay Formation and the mapped top of the Captain Sandstone Member (Figure 4-1:) that exists within an area bounded by a polygon that lies a short distance beyond the original oil-water-contact (OOWC) of the Goldeneye field (Figure 4-2:). Porous and permeable lithologies exist within the Scapa Sandstone, Yawl Sandstone and Captain Sandstone Members. The last named of these acts as the hydrocarbon reservoir of the Goldeneye field.

The *storage complex* includes the *storage site*, defined above, and the following additional elements (Figure 4-3:):

- Storage seal – The *storage seal* comprises all of the stratigraphic units between the top of the Captain Sandstone Member and the top of the Plenus Marl Bed (including the Upper Valhall Member & Rødby Formation – both part of the Cromer Knoll Group – and the Hidra Formation and Plenus Marl Bed – both part of the Chalk Group - Figure 4-1:).
- Secondary containment (hydraulically connected) – The hydraulically connected secondary storage is intended to accommodate migration of CO_2 within the reservoir formation but beyond the licensed boundary of the *storage site*. As such, it is represented by the lateral extension of the permeable formations that make up the *storage site*.
- Secondary containment (overburden) – The purpose of *secondary storage (overburden)* is to accommodate any migration of CO_2 that escapes vertically beyond the *storage seal*. To contain this migrated volume, the secondary containment requires the presence of a *secondary (or complex) seal*. The *secondary storage (overburden)* for the Goldeneye field includes the Chalk Group above the top of the Plenus Marl Bed, the Montrose Group (particularly the Mey Sandstone Member) and the lower Dornoch sandstone, within the Moray Group (Figure 4-1:).
- Complex seal – The mudstone at the top of the Lista Formation (which is referred to in this report as the Lista mudstone and is of Palaeocene age) within the Montrose Group, and the Dornoch mudstone, part of the Palaeocene to Eocene-aged Dornoch Formation in the Moray Group, were chosen as the *complex seal*.

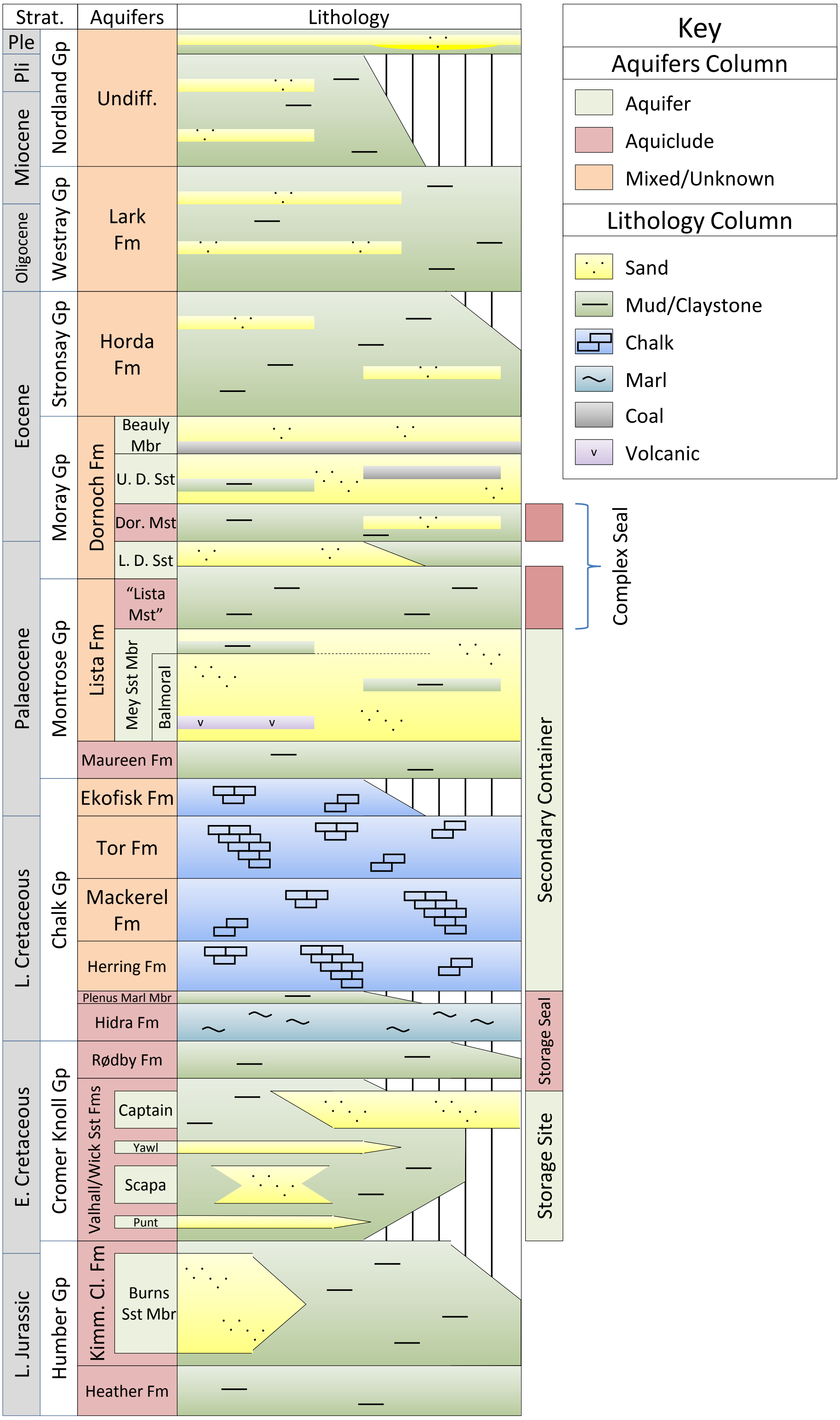


Figure 4-1: Generalised stratigraphy of the Goldeneye storage complex.

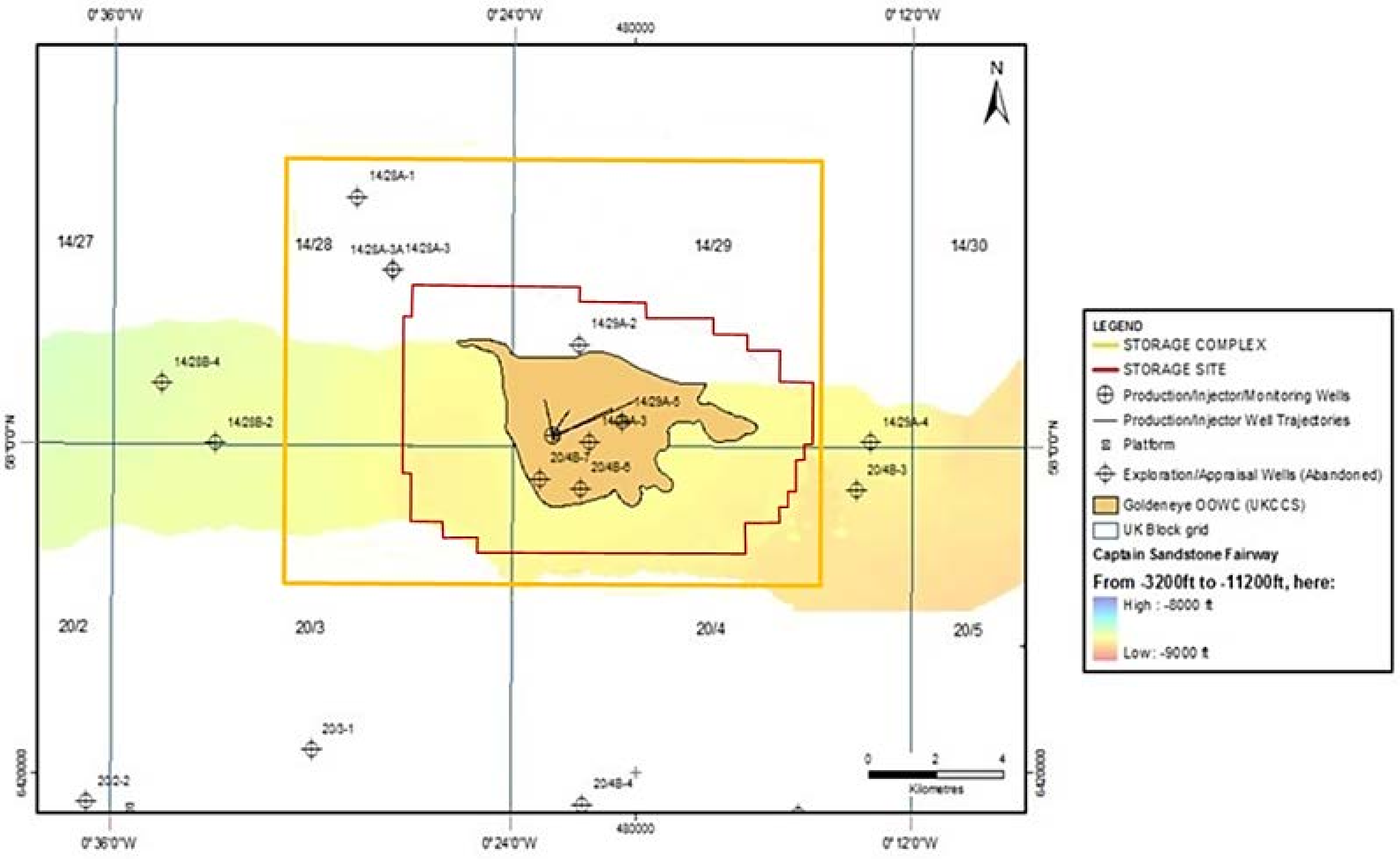


Figure 4-2: **Map to show the geographical extent of the storage site and storage complex with extent of Captain Sandstone Member aquifer indicated**

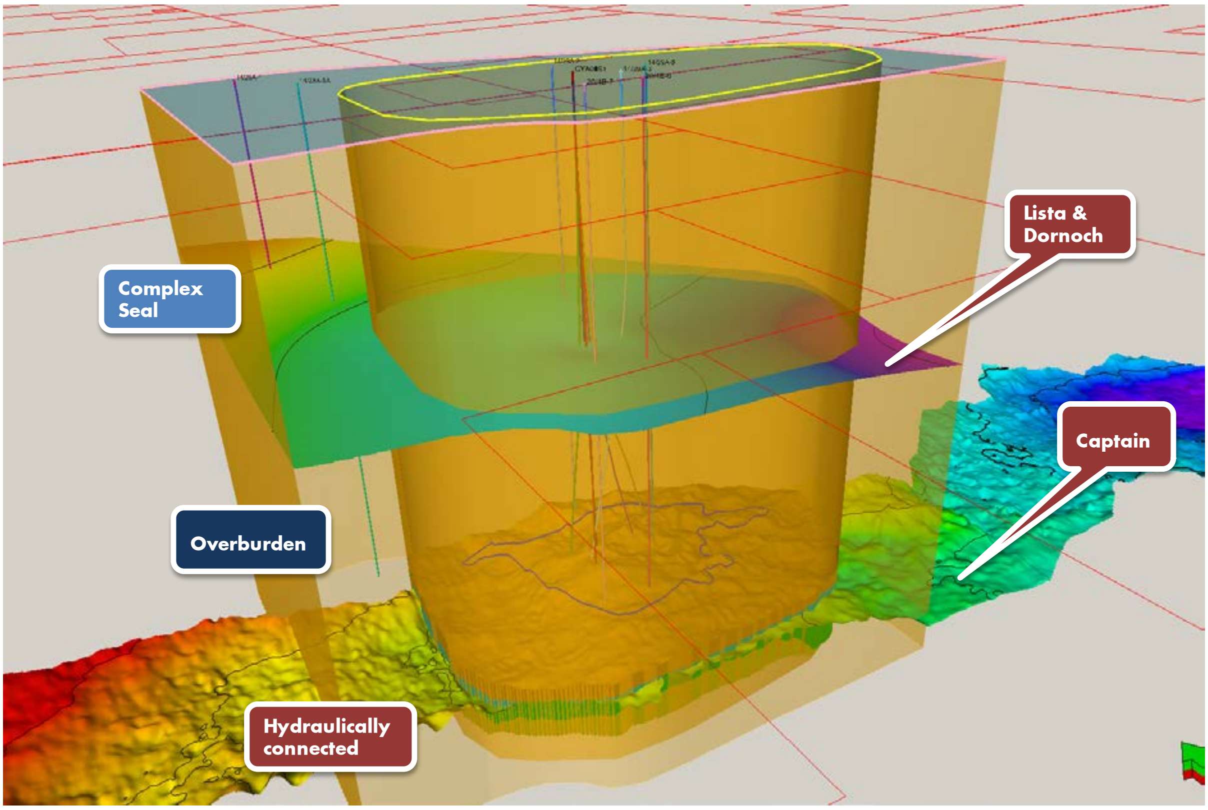


Figure 4-3: Schematic representation of the Goldeneye *storage site* and *storage complex* – not to scale.

4.2. Seabed and surrounding ecosystems

A draft environmental site description is reported in the Environmental Impact Assessment report and the following conclusions have been drawn:

- Sea currents are southerly and maximum surface speed (over 10 years of observation) is 0.8m/s.
- Average sea surface temperature in the area of the development range from 6.0°C at the surface in winter to 14.5°C at the surface in summer. The water temperature at the sea bed ranges between 6.0-7.0°C.
- Wind direction and velocity is variable throughout the year, with the wind originating predominantly from the south to northwest. Annual wind velocities in the area range from 0 - 26m/s with the calmest months being June to August and the windiest months being December to March.
- The composition of benthic and planktonic communities that inhabit or use the development area is known and documented.
- Marine birds are present in the area year round but occur in highest numbers during the months of August or September.
- Cetaceans occur in low numbers throughout the year, though sightings increase slightly in the summer months.
- The nearest candidate Special Areas of Conservation (SACs) are the 'Scanner Pockmarks' and 'Braemar Pockmarks' (located ~83 km and ~149 km to the northeast of the Goldeneye platform respectively).

- The site surveys and pipeline route surveys undertaken in the vicinity of the development found no species or habitats of conservation significance under the UK's Offshore Petroleum Activities (Conservation of Habitats) Regulations 2001. Due to this, and the relatively large distance from the Goldeneye platform to both the 'Scanner' and 'Braemar Pockmarks', the development is not considered to pose any risk to these habitats.

4.3. Natural Seismicity

Information about the location and magnitude of all earthquakes recorded from the UK continental shelf has been plotted and reviewed (Figure 4-4:). The closest recorded seismic event to the location of the Goldeneye development site is at a distance of approximately 55 km. There are no recorded instances of seismicity related to hydrocarbon production in Goldeneye.

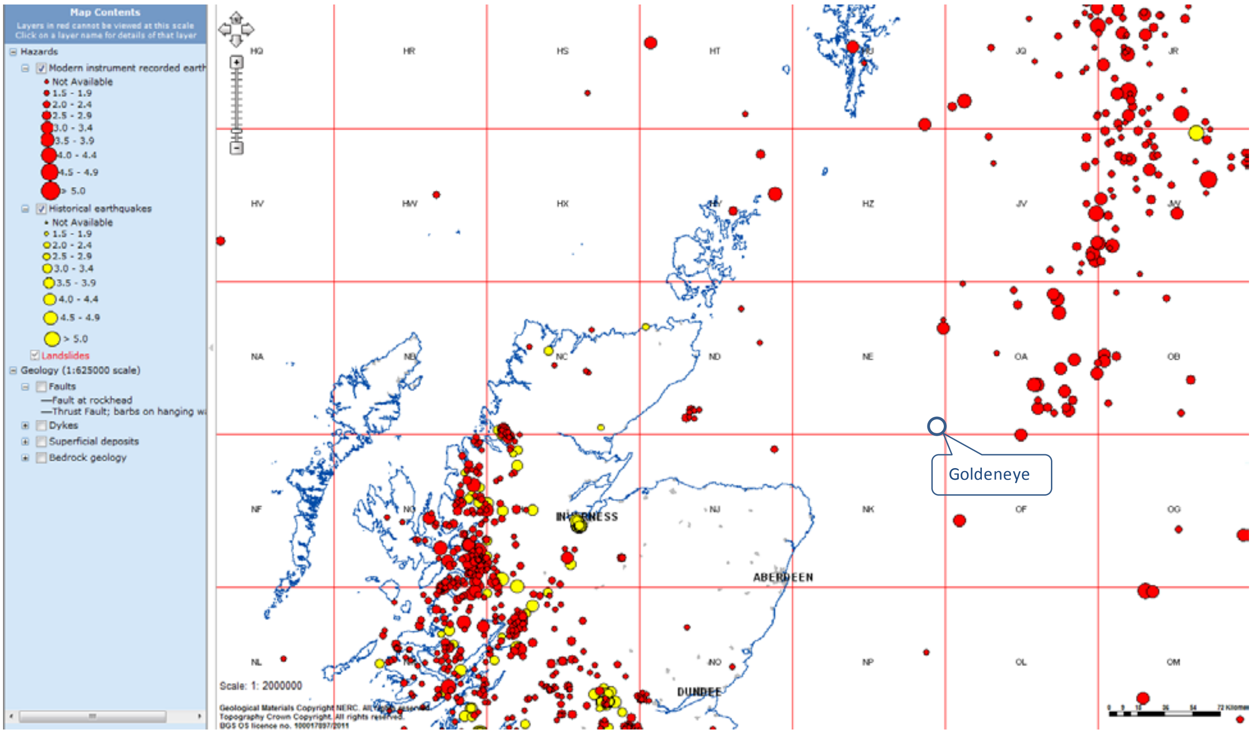


Figure 4-4: Map of all earthquakes recorded from northern Scotland and the central and northern North Sea [1].

[1] Figure obtained from , from historical times until 20th January, 2011 (BGS Online Geoindex http://mapapps2.bgs.ac.uk/geoindex/home.html?theme=hazards)

4.4. Other users of the environment

A number of other users of the surface, water column and subsurface environments within and in the vicinity of the development area have been identified. These are as follows:

- **Fisheries**: Fishing intensity within the development area is low. Fishing effort expended in the development area ranged between 0.25% and 1.2% of that expended in UK waters while the catch (predominantly demersal species and crustaceans, using bottom trawl gear) from within the vicinity of the Goldeneye development represents at most 0.78% of that from UK waters.
- **Shipping**: a traffic study for the central and northern North Sea indicates moderate shipping, with between 1 and 10 vessels per day passing through the area.
- **Telecommunications and oil & gas pipelines**: There is one telecommunication cable (CNS Fibre Optic) and four hydrocarbon export pipelines (Beryl to St Fergus, Miller to St Fergus, Britannia to St Fergus and Goldeneye to St Fergus) in use in the vicinity of the development. The Goldeneye to St Fergus pipeline route crosses a number of other hydrocarbon export pipelines (Brent Alpha to St Fergus, Frigg to St Fergus, Miller to St Fergus and Britannia to St Fergus).
- **Oil & gas exploration & production**: The Goldeneye CCS storage complex covers numerous licensed oil and gas blocks as shown in Figure 4-5: The relevant equity holders and operators are shown in Table 4-1: The nearest platform is Ettrick FPSO (16km) and the next nearest is Buchan Alpha (27km).
  The Goldeneye reservoir is in pressure communication with a number of other hydrocarbon fields in the vicinity of the outer Moray Firth. The Blake oil field (operated by BG Group) is currently in production as is Rochelle (operated by Endeavour). At the Atlantic gas condensate (BG), Cromarty gas condensate (Hess) and Hannay (Talisman) oil fields production is currently suspended. There is no evidence that Goldeneye is in pressure communication with any other producing oil or gas field. Other hydrocarbon accumulations in the area (e.g., Ettrick, Buchan and Buzzard) have reservoirs of different ages and on different pressure trends.
- **Wind farms and aggregate extraction**: There are no offshore wind farms proposed and no areas licensed for aggregate extraction in the vicinity of the development.
- **Wrecks and hazards to shipping**: No shipwrecks were identified by any of the surveys undertaken in the immediate vicinity of the development area.

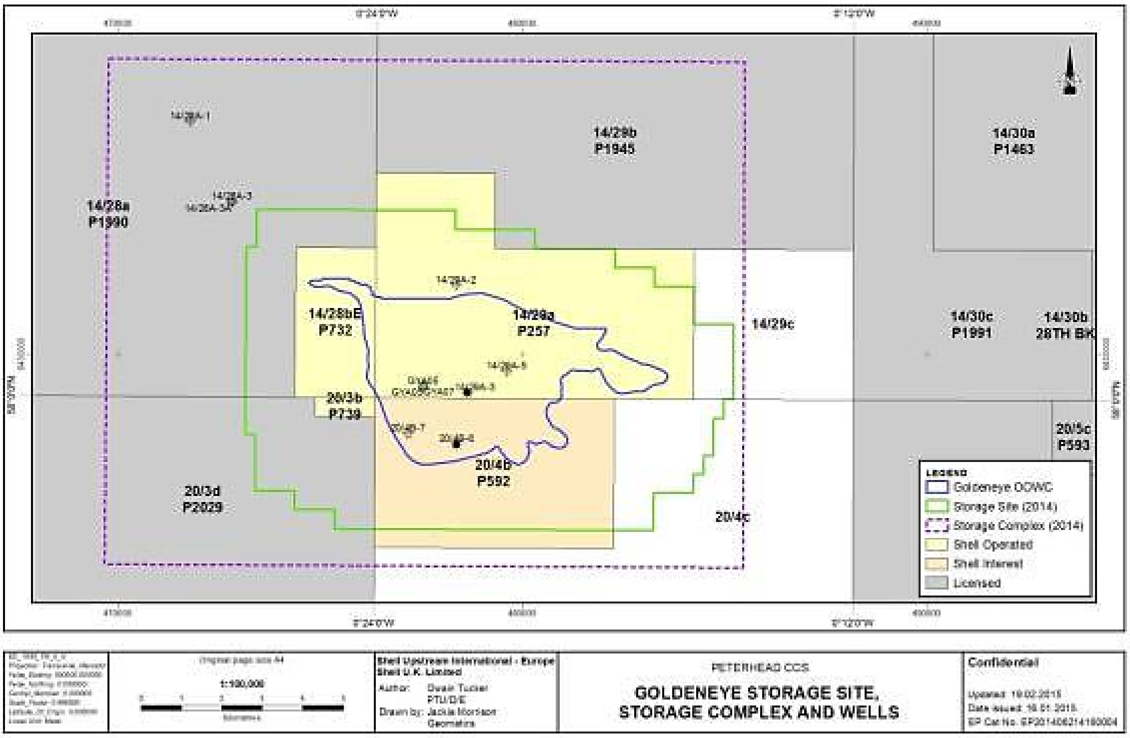


Figure 4-5: Oil and gas licence blocks in the vicinity of the Goldeneye CCS storage complex.

Table 4-1: Licence block owners and operators.

Block	Equity holders
14/28b (E)	Centrica (25%), ExxonMobil (25%), Shell* (50%)
14/28c	Black Sapphire Resources Ltd. (100%)
14/29a	ExxonMobil (50%), Shell* (50%)
14/29e**	Encore Petroleum Ltd. (100%)
14/29c	Black Sapphire Resources Ltd. (100%)
14/29d	Encore Petroleum Ltd. (100%)
20/3b	ExxonMobil (50%), Shell* (50%)
20/4a	Apache North Sea Ltd. (50%) Nexen Petroleum U.K. Ltd.* (50%)
20/4b	Centrica (17.5%), Endeavour Energy Ltd.* (37.5%), Shell* (45%)
20/4c**	Encore Petroleum Ltd. (100%)
20/5f**	Encore Petroleum Ltd. (100%)

Note: * denotes Operator, ** potential Seaward Production Licence awards in the 26th Seaward Round.

This table was correct at the time of creation, but licence owners change. For up-to-date date please refer to the DECC EDU website.

4.5. Structural configuration and geological history

The Goldeneye field is situated in the Outer Moray Firth on the northern margin of the South Halibut Basin (Figure 4-6:) and has a combined structural and stratigraphic trap of Lower Cretaceous Captain Sandstone Member. Structural dip closure is provided to the east and south and is interpreted also to the west, whilst pinchout of the Captain reservoir sands to the north provides an additional stratigraphic trapping element.

The structural configuration in Goldeneye is the result of two major extensional phases during the Late Jurassic and the Cretaceous with periods of north-south directed compression. Further minor compression, combined with a period of regional eastward tilting took place in the early Tertiary.

4.5.1. Storage site

As well as the Goldeneye field, which has a reservoir within the Captain Sandstone Member, the *storage site* also includes all of the rocks down to the base of the Cromer Knoll Group (equivalent to the top of the Kimmeridge Clay Formation). This interval is predominantly mud-prone but contains two other porous and permeable formations – the Yawl Sandstone Member and the Scapa Sandstone Member. All of the sandstone units were deposited in a deep marine, sand-rich turbidite slope/base of slope system. Additionally, the Captain Sandstone Member includes contribution from mass-wasting of locally exposed fault scarps. The Captain Sandstones occur in a continuous ribbon of sand that fringes the southern boundary of the South Halibut Horst (Figure 4-6:), whilst the others have a more localised distribution. The subdivision of the Captain Sandstone Member and the reservoir properties for each unit are shown in Table 4-2: The existing development wells have been completed within the Captain 'E' and Captain 'D' Units.

Table 4-2: Subdivision, description and average reservoir properties of the Captain Sandstone Member in the vicinity of the Goldeneye field.

Unit	Description	N/G (v/v)	Tot. Φ (v/v)	Net Φ (v/v)	Tot. K (mD)
Captain 'E' Unit	Laterally variable thin heterogeneous unit	0.61	0.13	0.21	7
Captain 'D' Unit	Laterally extensive massive sand unit	0.94	0.23	0.25	790
Captain 'C' Unit	Laterally extensive, mudstone-rich heterogeneous unit	0.33	0.07	0.22	10
Captain 'A' Unit	Laterally restricted sand-rich unit	0.84	0.19	0.23	134

Note: (Tot. Φ & Tot. K are averages for gross interval; Net Φ is an average for the net sand interval)

Apart from the gas condensate and oil rim of the Goldeneye field, all porous formations within the storage site have been found to contain brine only. Gas condensate shows were recorded from a thin Upper Jurassic interval (Burns Sandstone Formation) to the north of the field but a pressure measurement taken from this unit indicates that it is not on the same pressure trend as Goldeneye.

4.5.2. Storage seal

The *storage seal* includes the Upper Valhall Member & Rødby Formation – both part of the Cromer Knoll Group – and the Hidra Formation and Plenus Marl Bed – both part of the Chalk Group. Over the storage site, the Rødby alone is at least 100 ft. [30 m] in thickness and has an average thickness of 200 ft. [60 m]. The Upper Valhall Shale provides additional thickness in the southern two thirds of the field. The storage seal as a whole varies from 470 ft. [143 m] in the north to 697 ft. [201 m] in the south. The lower parts of the storage seal consist of mudstones with sporadic thin beds of argillaceous limestone, the Hidra Formation consists of bioturbated limestones with interbedded mudstones and the Plenus Marl Bed is a relatively thin unit of black mudstone.

4.5.3. Secondary containment (hydraulically connected)

The Captain Sandstone Member is interpreted to maintain its presence all the way along the Captain Fairway. The Yawl and Scapa Sandstone Members (Figure 4-1:) are more locally distributed. Data from wells to the west of the Goldeneye field shows that both sands are absent in this direction, though an older sandstone unit – the Punt Sandstone Member, is penetrated. To the east of the *storage site*, well data shows that the Scapa Sandstone Member shales out in this direction. The Yawl sandstone continues to be seen in wells over several tens of kilometres east of Goldeneye.

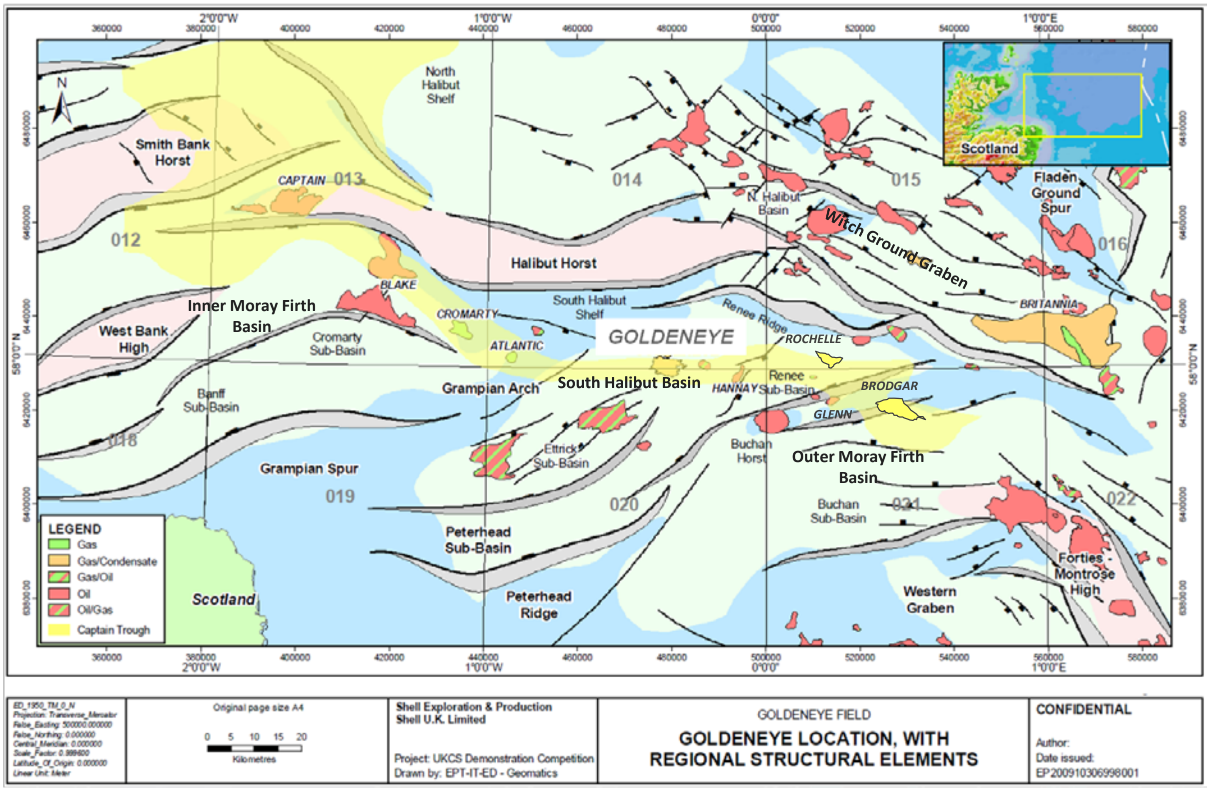


Figure 4-6: Distribution of Captain Sandstone across the outer Moray Firth: Captain Fairway highlighted in yellow; basinal areas in pale green

4.5.4. Secondary containment (overburden)

The *secondary storage (overburden)* for the Goldeneye field includes the Chalk Group above the top of the Plenus Marl Bed, the Montrose Group (particularly the Mey Sandstone Member) and the lower Dornoch sandstone, within the Moray Group (Figure 4-1:).

The Chalk Group formations are of Late Cretaceous to Early Palaeocene age and are composed of almost pure chalk. Fractures are seen on borehole image but these are not vertically extensive and do not interconnect. The Montrose Group (Palaeocene) contains the Lista Formation which is characterised by the presence of interbedded sandstones and mudstones. Within the Lista Formation the Mey Sandstone Member (equivalent to the Andrew Formation of the Witch Ground and Central Grabens, where it is a major hydrocarbon reservoir) includes the Balmoral Sandstone Units and the Balmoral Tuffite Unit. These rocks represent a range of environments from outer shelf to slope to basin, with shelf sands being redistributed to form slope aprons of superimposed and laterally coalescing fans. The tuffite is derived from air fall deposits associated with Hebridean province volcanism. At the top of the Lista Formation, is an un-named mudstone facies dominated unit which is one of two regionally continuous mudstones that are identified as acting as the *complex seal* (see description below). Only the lowest part of the Moray Group (Palaeocene to Early Eocene age) is included in the *storage complex* – the lower Dornoch sandstone, part of the Dornoch Formation. The lower Dornoch sandstone was deposited in a shelfal setting and consists of single or multiple sandstones interbedded with silty mudstones. Its immediate successor unit – the Dornoch mudstone, which forms part of the *complex seal* (see description below) – represents a prograding delta front.

All of the formations in the *secondary containment (overburden)* are brine bearing.

4.5.5. Complex seal

The 'Lista mudstone' and Dornoch mudstone were selected as the *complex seal* because:

- they can be reliably correlated in all wells within the *storage complex*;
- they are found at depths greater than 2,620 ft. [800 m] across the entire area under investigation;
- any outcrop of these units is interpreted to be >150km away from the *storage site*, and;
- two of the abandoned exploration wells have plugs set at either Lista or Dornoch mudstone level.

The lateral equivalent of the Lista mudstone is a seal to hydrocarbon reservoirs in the Central Graben area – specifically Rubie (which is 40 km from the *storage site*), the MacCulloch cluster fields (at approximately 50 km: MacCulloch, Donan, Nicol, Lochranza, Blenheim, Blair, Beauly, Burghley and Andrew fields) and Cyrus.

4.5.6. Fluids

The hydrocarbons of the Goldeneye field are gas condensate with a thin (7 m) oil rim. Geochemical analyses have established that the condensates in all Goldeneye wells are geochemically identical indicating full pressure communication in the gas. Oils (particularly the heavy fraction) in different wells are significantly different and, therefore, the part of the reservoir below the gas-oil contact (GOC) is not fully connected.

Brine samples available from the reservoir show little variation between the samples. Salinity is measured at 54,000 mg/l. From informal discussion with other operators in the Captain Fairway, salinity is of a similar value from all fields in the area.

Although no samples have been collected, all of the overburden formations are interpreted to be water (brine)-bearing, based on the evidence from wireline logs and are interpreted to be of higher salinity, in the main, than the Captain Sandstone Member.

4.5.7. Faults

Fault patterns at the *storage site* and *storage seal* levels are highly interpretive due to the poor resolution of the available seismic data. This does, however, indicate that the fault throws are around or less than the seismic resolution. The mapped faults at top Captain are of limited vertical and lateral extent with small throws (20m) parallel to the observed regional structural trends orientated WNW-ESE to E-W. There has been little evidence seen during the production phase of the Goldeneye field for intra-reservoir fault compartmentalisation and so faults have been omitted from structural models of the reservoir.

In the *secondary containment (overburden)* faults trend NW to SE and are mainly developed over the eastern and south-eastern flank of the field. These faults are decoupled from the WNW-ESE to E-W trending reservoir level faults and intersect the Chalk Group and the lower part of the overlying Montrose Group. Again, difficulties with the image quality at these levels of the available seismic data (this time caused by the topography on the top of the Chalk Group, which has been karstified due to sub-aerial exposure after deposition) makes definitive fault interpretation difficult.

Above the Chalk Group, there is little evidence of significant faulting. The seismic imaging is again hindered in the Montrose Group by the presence above of a thick, laterally variable coal package and large sub-glacial channels buried close to the sea-bed. Some vertical discontinuities in the seismic data were initially interpreted as faults. However, subsequent reprocessing of the seismic data using a proprietary high-resolution algorithm has shown these to be an effect of the seismic wave front being distorted due to its transit through the sub-glacial channel lithologies.

4.5.8. Stress regime

The formation pore pressure is hydrostatic in the reservoir and overburden (with a hydrostatic pore pressure gradient of 10 kPa/m – 0.442 psi/ft. – used outside the reservoir). The recent stress regime in the Goldeneye area is Normal. The direction of maximum horizontal stress is NNW-SSE as inferred from image log, calliper and world stress map data. In the wider Goldeneye area a normal-stress regime (S_v>SH>S_h) is seen.

4.6. Brief history of the hydrocarbon field

4.6.1. Exploration

The Captain Sandstone discovery well, 14/29a-3, drilled in 1996, found a significant (303 ft. [92m]) gas condensate column with a thin (24 ft. [7m]) oil leg in well-developed Lower Cretaceous Captain Sands. These lie within the Upper Valhall Formation of the Lower Cretaceous Cromer Knoll Group directly above the Kimmeridge Clay Formation (Figure 4-1:). Three appraisal wells were subsequently drilled - 20/4b-6 (1998), 14/29a-5 (1999) and 20/4b-7 (2000). All of these encountered varying thicknesses of hydrocarbon column but confirmed common gas / oil and oil / water contacts of 8568 ft. [2,611 m] TVDSS and 8592 ft. [2,618 m] TVDSS respectively.

An earlier well – 14/29a-2 drilled in 1981, did not encounter Captain Sandstone reservoir, but did see gas condensate shows in the Upper Jurassic Burns Sandstone Member of the Kimmeridge Clay Formation. This is not part of the Goldeneye field and is not in communication with it.

4.6.2. Surface facilities and pipelines

The Goldeneye field was developed as a full wellstream tieback (FWT) to shore for onshore gas and condensate processing in new facilities at Shell/Esso’s St Fergus terminal. This approach was possible due to Goldeneye's proximity to shore (105 km) and relatively lean gas condensate composition. Offshore, a normally unattended wellhead platform was installed for field/well control, metering and water detection. Fluids were transported through a new build multiphase, wet gas pipeline to shore under field pressure. A Mono Ethylene Glycol (MEG) system (with corrosion inhibitor) was installed to prevent the formation of (methane) hydrates and corrosion.

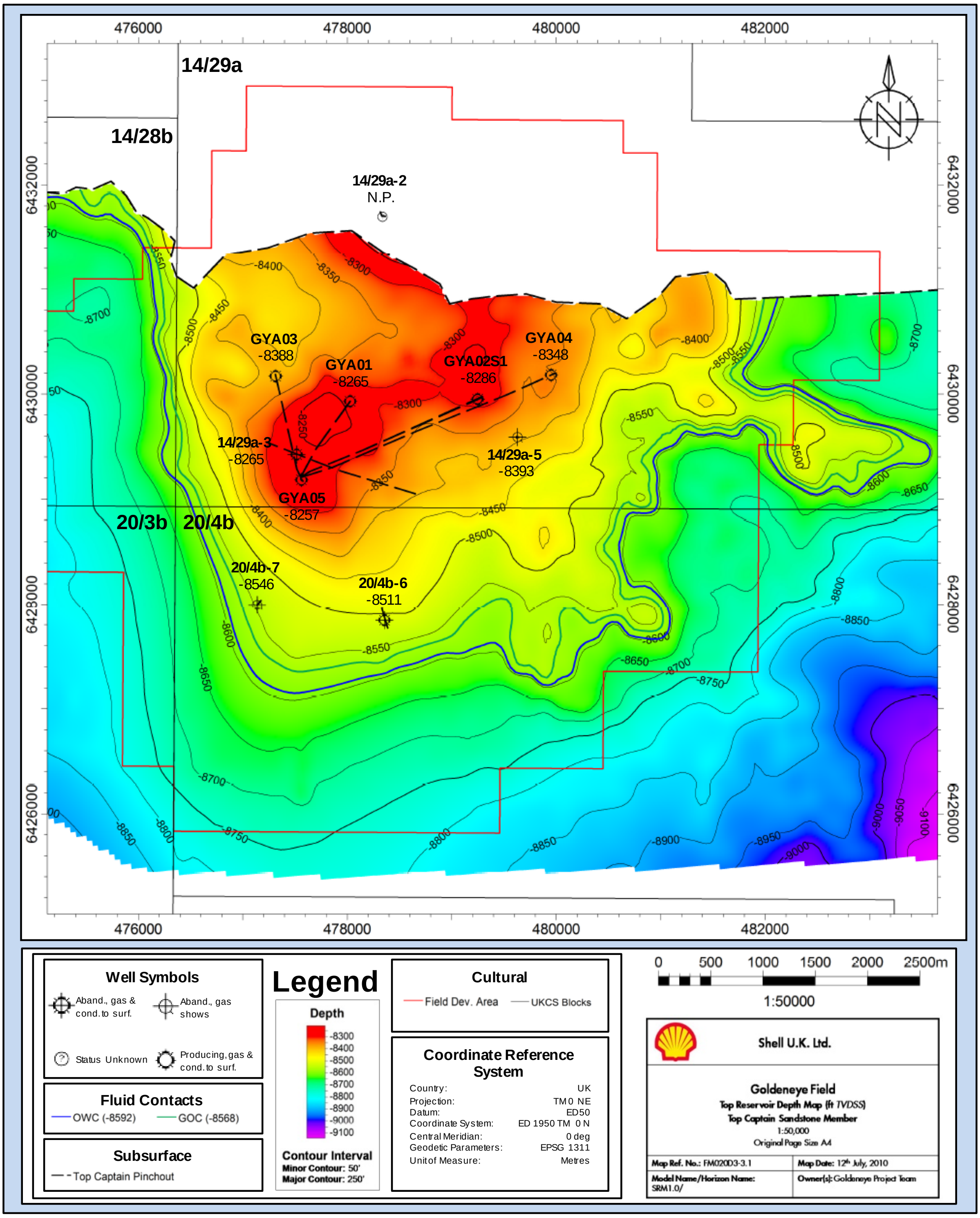


Figure 4-7: **Goldeneye field top structure map – reference case.**

Note: Absence of Captain Sandstone Member in well 14/29a-2

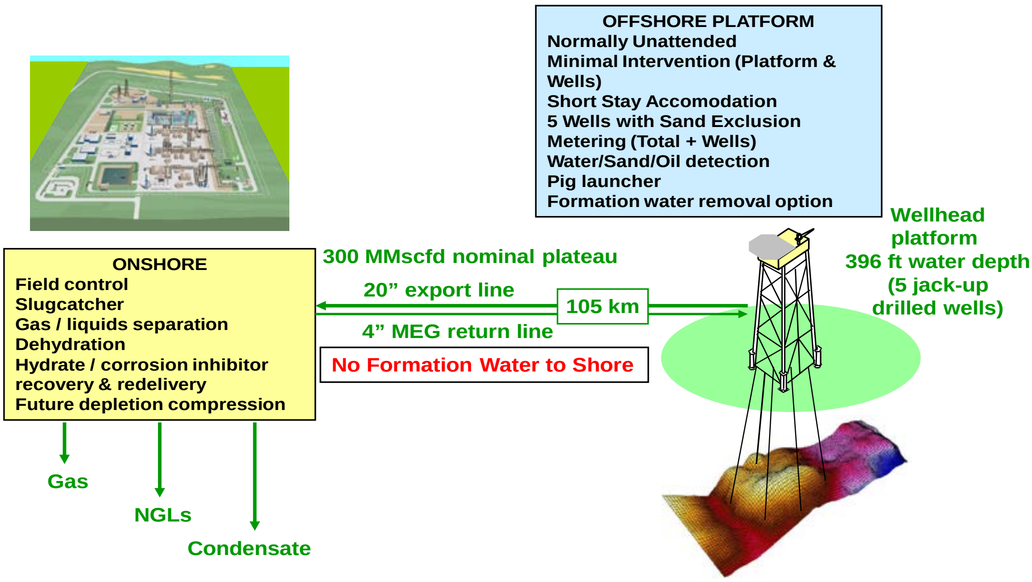


Figure 4-8: Goldeneye field hydrocarbon development plan.

4.6.2.1. Offshore Platform

The offshore facility comprises a Normally Unattended Installation (NUI) located in 121 m of water. The installation is a simple 4-leg piled steel jacket platform with 8 slots for the wells and a small topside providing metering, water/oil detection and well/field management facilities. The platform is controlled from shore (St Fergus control room) and accessed by helicopter when required. The platform is fitted with short-stay accommodation (SSA), enabling up to twelve technicians to visit as necessary.

Each well was equipped with Venturi meters for reservoir/well management purposes, with the capability for fluids sampling. A production separator enabled field allocation metering using ultrasonic and coriolis meters.

The platform separator and the piping are designed for the maximum well CITHP (Closed in Tubing Head Pressure) up to the entry to the export system. This is protected by a High Integrity Pipeline Protection System (HIPPS), rated for 214bara. The header, riser, and export pipeline and system are designed for 133bara.

4.6.2.2. Pipelines

The export of multiphase fluids is via a 20" [508 mm] export pipeline, 105 km in length, operated with the continuous injection of hydrate and corrosion inhibitors. MEG, along with a corrosion inhibitor, is transported to the platform using 4" [10mm] service line from St Fergus, laid parallel to the main line and injected directly into the export system on the Goldeneye platform to suppress the hydrate formation temperature within the export pipeline. External corrosion of the pipelines was controlled by cathodic protection and anti-corrosion coatings.

Due to the diameter of the main line, a concrete weight coating was required. The service line was trenched and buried.

The evacuation and service lines were brought together 1.5 km offshore and the service line piggybacked onto the main line with both lines then trenched and buried. Onshore the lines were laid together across the dunes. The multiphase flow from the pipeline was received into a slug catcher. Compression was installed after the primary separation later in field life in order to maintain production and maximise recovery.

4.6.3. Development wells

The five development wells drilled on the Goldeneye structure are listed in Table 4-3. The abbreviated well names are used in this document.

Table 4-3: Well name abbreviations.

Full well name	Abbreviated well name	Spudded (batch operations)
DTI 14/29a-A3	GYA01	8/12/2003
DTI 14/29a-A4Z	GYA02S1	13/12/2003
DTI 14/29a-A4	GYA02	13/12/2003
DTI 14/29a-A5	GYA03	19/12/2003
DTI 14/29a-A1	GYA04	5/10/2003
DTI 14/29a-A2	GYA05	2/12/2003

The production wells were designed with the following design and life cycle philosophy:

- Simple with minimal intervention requirements.
- Maximum well deliverability with sand exclusion.
    - Optimal well deliverability required a producing interval of about 60 ft. [18 m] TVT (True Vertical Thickness).
    - 7" [178 mm] production tubing maximised well deliverability whilst maintaining liquid lift to depleted reservoir pressures.
    - Sand exclusion was required since sand failure was anticipated at the start of Goldeneye production.
    - External gravel packs provided proven mechanical reliability and excellent productivity.
- Completed high in the column to maximise recovery.

4.7. Expected state of the field at cessation of production

4.7.1. Remaining hydrocarbons

At formal cessation of production, the ultimate volume of hydrocarbons recovered (UR) from the field was 568 Bscf gas and 23 MMbbl condensate. The full field simulation model (FFSM) predicts that a small hydrocarbon gas cap will remain in the middle of the field in units 'D' and 'C'. By-passed gas is more widely spread in the tighter 'E' unit, which is only partially flooded by the aquifer. The aquifer connected to Goldeneye in the FFSM has been modelled and is continuing to encroach. It has begun to repressurise the field.

4.7.2. Pressure

During production the field has been depleted from the initial pressure of approximately 262 bara at a datum level of 8400 ft. [2560 m] TVDSS to 145 bara in December 2010 when Goldeneye production was halted. In February 2011 the pressure was 146 bara and in the process of recovering. This will continue to do so until start of injection. The magnitude of the pressure recovery depends on the balance between:

- the effect of fluid extraction operations in neighbouring fields, primarily in Rochelle West and East
- the *fast* influx of the neighbouring aquifers and depressurisation of tighter formations in the field area,
- the *slow* influx of the regional trough wide aquifer.

Various forecast of pressure recovery have been made (detailed in the Dynamic Modelling report). These are illustrated in Figure 4-9: and show an expected rise to between 186 bara and 206 bara by start of CO_2 injection.

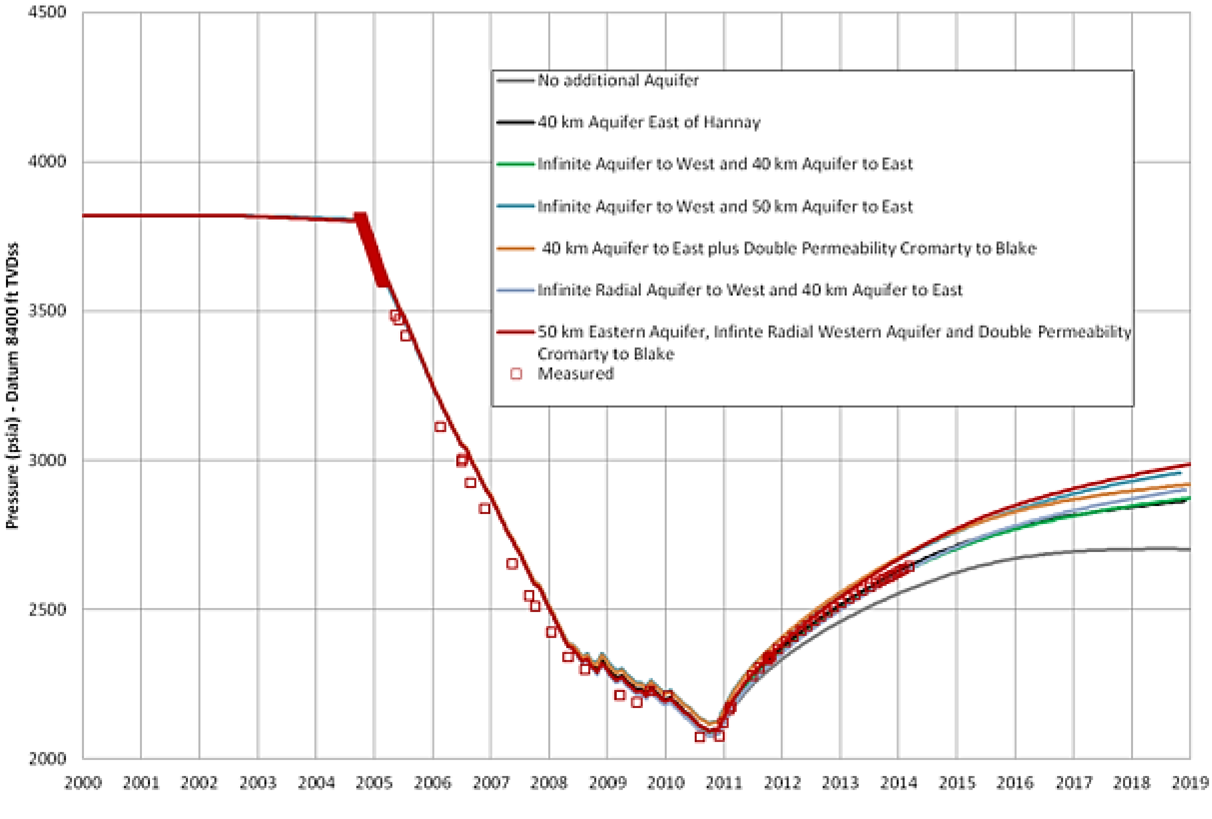


Figure 4-9: Predictions of Goldeneye pressure from field shut-in at end 2010 to 2019

4.7.3. Hydraulically connected units

The performance of the Goldeneye reservoir has been significantly influenced by the surrounding aquifer and offtake at the other fields in the Captain Fairway. This can be seen in the early pressure drop before production started (due to production at Hannay) and also in the longer term pressure history of the field which indicates significant aquifer support. As well as the Hannay field, three other fields (Atlantic, Cromarty and Blake) have produced from the Captain Sandstone. In addition, the Rochelle West field which is approximately 35 km east of Goldeneye and inside the aquifer model, started production in October 2013 followed by Rochelle East in January 2014, which is just outside the aquifer model. All six fields are interpreted to be in communication with Goldeneye and might have the potential to influence its pressure, if not at present then in the future. In addition the Hoylake gas field, 5 km east of Goldeneye, has been included in the aquifer model to address pressure interference effects with Goldeneye. Buffalo, a prospect mapped by Premier Oil further to the east was also tested in the model to address pressure interference effects with Goldeneye. The model does not cover the whole aquifer and so does not explicitly include the Rochelle East field which lies one km outside the eastern edge of the model. The Rochelle East field was modelled as part of the Rochelle West field, which lies inside the aquifer model. This model also enables the aquifer representation and history match of the FFM to be evaluated which improves confidence in the storage capacity estimate. These have been taken into account in the design.

The Brodgar gas field, which is located at the eastern edge of the Captain Fairway and outside of the aquifer model, 30 km east of Rochelle, is not thought to be in communication with the other fields in the Captain Fairway. The field is located south of a major fault, the Glenn fault, and there is evidence to suggest that the field, which started producing in August 2008, is not under influence by the Captain Fairway aquifer. The pressure depletion seen in Rochelle East (December 2008) and Rochelle West (October 2010) also does not reflect Brodgar production.

5. Risks and uncertainties

The risks and uncertainties associated with the storage and offshore transportation of CO_2 can be divided into:

- Regulatory, permitting, legal and commercial.
- Political and public perception.
- Technical.
- Schedule.

5.1. Regulatory, permitting, legal and commercial risks

5.1.1. Storage license and permit

The regulatory and legal terms which apply to this project are in place however they remain untested in the U.K. This stems from the fact that the project will be a first of a kind therefore there are no precedents and there is no performance history in the U.K.

Key risks are summarised below.

First of a Kind Project Risks: The Peterhead to Goldeneye CCS project looks set to be one of the first in the UK to be permitted under the EU CCS Directive. The ROAD project in the Netherlands is the only other project with a storage permit. There are, therefore, few precedents or other means of guiding either the developers or the regulator on how to interpret the often broad terms of the regulatory framework. As a result, the project is exposed to a number of important ‘first of a kind’ risks on the conditions applied to the permit and potential delays in the process of agreeing the permit with the regulators.

CCS Directive: Article 38 of the CCS Directive provides for a review of the Directive by March 2015. From the draft recommendations published by the consultants undertaking the review of the CCS Directive on behalf of DG Clima, we understand that the Directive is likely to remain largely unchanged. The final recommendation of the EU Commission on what the changes to the CCS Directive will be has been delayed and therefore not yet published.

EU Scientific Panel: The CCS Directive provides for up to four months for the EU Commission to offer a non-binding opinion on Member State decisions to award a Storage Permit (Art.10). We understand that the opinion will be based on scrutiny by an independent Scientific Panel. As one of the first projects to be taken through this process we expect a lengthy process and a significant degree of scrutiny. The lack of directly comparable precedent, and lack of a deep pool of expertise, is likely to create considerable uncertainty over the outcome of the Panel's deliberations.

5.1.2. Goldeneye Regulatory Timeline

The Peterhead CCS project has already received an Agreement for Lease (July 2012) (see further detail below) and a Carbon Storage Licence (December 2013) and has submitted the Offshore Environmental Statement (January 2015) and the Storage Permit to the appropriate regulator. The Storage Permit was submitted to the EU Commission for their Review on 27 April 2015.

Three key plans are submitted along with the storage permit, all three must be agreed with the regulator prior to award of the permits. These plans are:

- MMV plan.
- Corrective measures plan.
- Provisional post closure plan.

5.1.3. Crown Estate Lease

In the 2008 Energy Act the UK Government created one of the first bespoke legal regimes anywhere in the world specifically designed to permit the safe storage of carbon dioxide (CO_2) underground. It provides for the UK (consistent with the terms of the United Nations Convention on the Law of the Sea) to assert certain rights to make use of the offshore area beyond the territorial sea, through the designation of a Gas Importation and Storage Zone (GISZ). The GISZ was designated on 6th April 2009 by SI 2009/223.

The exclusive right to store CO_2 offshore has been vested in the Crown within an area extending from the seaward limits of the territorial sea to the boundaries of the GISZ. The Crown Estate already has the right to grant leases for any purpose within the area of the territorial sea. The vesting provisions of the Act allow The Crown Estate to grant similar authorisations in respect of carbon storage activities beyond the territorial sea but within the area of the GISZ. The new licensing scheme will operate in parallel to the leases and authorisations granted by The Crown Estate.

Shell received an "agreement for lease" from the Crown Estate in 2013.

5.2. Other permits

As is the case with the storage permit the "first of a kind" nature of the project increases the uncertainty in the obtaining of all permits and licenses. These include

- Offshore environmental statement.
- Onshore environmental impact assessment.
- Updated COMAH safety report.
- Planning consent for construction.
- Combined operations notification (for use of mobile drilling rig alongside Goldeneye during workovers ops, drilling and platform modifications).

5.3. Commercial risks

The commercial project risks can be divided into

- Expense recovery: Capital, abandonment costs, operating expenses
- Return on investment
- Liability protection/transfer
- Purchase/transfer of assets to the Storage Joint Venture

Detailed commercial negotiations are taking place in order to establish all of the above. There are a number of parties involved in various sets of negotiations:

- UK Government
- Shell UK
- Production Joint Venture (Shell, Exxon, Centrica, Endeavour)

Failure to reach agreement in all negotiations has the potential to delay or derail the project. Some of the key points will be outlined below.

5.4. Political and public perception risks

The project is exposed to political and public perception risk. The importance of both political and public perception is highlighted in the fact that political and public perception issues have resulted in cancelling some CCS projects throughout the world. What has been learned from early CCS activities is that both political and public support for CCS projects is essential for them to succeed.

Industry, governments and public must join together to further understanding and acceptance. To succeed, we believe that the public needs to be comfortable with the technology of CCS and the role it has to play.

A project Communications Plan is reviewed at regular intervals to ensure it remains relevant. The plan includes stakeholder identification and analysis, messaging and engagement plan, including government and the wider public as well.

5.5. Technology maturation

In a relatively new field of work it is to be expected that some technologies required to deliver the project are yet to be developed. The offshore transport and storage of CO_2 is no exception. The project has a technology maturation plan and a number of key technologies are required to be mature before injection (for example seabed CO_2 flux measurement) while others have the potential to reduce costs later in the project (for example the installation of permanent gauges in abandoned wells). A summary is show in Table 5-1:.

Table 5-1: Technologies to be matured for project execution – including required timeline, probability of success and impact on project success.

	Description	Technical readiness level [Discovery 1-5, Develop 6-8, Deploy 9-10]	Cost Impact	Schedule Impact	Purpose
1	**Pipeline/well operating envelope**	8 – field trials & Beta tests	High	Medium	Operation
2	**CO_2 vapour/liquid equilibrium behaviour**	5 – prove concept	Medium	High	Operation
3	**Pipeline running ductile fracture prevention.**	9 – early deployment	Low	Very High	Operation
4	**Testing of Goldeneye pipeline internal epoxy coating.**	8 – field trials & Beta tests	N/A	N/A	Operation
5	**Assessment of effect of dense phase CO_2 on non-metallic (elastomer) materials used for seals in valves, etc.**	9 – early deployment	High	High	Operation
6	**Assessment of cement stability in downhole CO_2 environments.**	8 – field trials & Beta tests	Very High	Very High	Operation
7	**Manage extreme cooling of wellhead material during transient conditions.**	10 – study	High	N/A	Operation
8	**CO_2 friendly subsurface safety valve (SSSV) testing procedure.**	10 – study	High	N/A	Operation
9	**Hydrate inhibitor selection.**	10 – study	N/A	N/A	Operation

10	**Multiple CO_2 gas detector technology (Vapour/Dense phase)**	Acoustic detection – 6/7 Thermal imaging camera – 8 Mist detection – 6 Fibre optic temperature detection – 6/7 Existing CO_2 Laser type detectors – 6/7	N/A	N/A	Safety, impact to environment
11	**Dense phase CO_2 release modelling validation**	Pure CO_2 release models validation – 8/9 CO_2 with contaminants release model validation – 3/4	N/A	N/A	Safety, impact to environment
12	**Seabed Leakage identification and quantification – (method & technologies to measure volume & concentration at seabed & shallow depth)**	6-8	N/A	N/A	Regulation, impact on license or environment
13	**Tracer selection and addition/CO_2 fingerprinting**	3-4	N/A	Very High	Reputation
14	**4D streamer in combination with ocean bottom nodes (OBN) application**	9-10	N/A	N/A	Monitoring
15	**Pitting of 13% Cr tubing material**	8	Very High	Very High	To confirm corrosion limits and set onshore Oxygen

					specification range
16	**Design for blowdown of supercritical CO_2.**	6	High	N/A	Operation
17	**Geochemical probe (conductivity, depth and temperature – CDT – & CO_2 `saturation).**	6-8	N/A	N/A	Monitoring
18	**Sediment and pore gas sampling method**	6-8	N/A	N/A	Monitoring
19	**CO_2 uncontrolled release measures analysis**	N/A – Study	N/A	N/A	Contingency
20	**Extended downhole pressure measurements (>10-15 years) for use in post-injection/closure phase**	Proposed	N/A - High	N/A – Very High	Optional
21	**Distributed acoustic sensing (DAS)**	6-8	Very High	N/A	Optional
22	**Wells materials fatigue testing**	3-5	Very High	Very High	Operations
23	**Opportunity – pipeline mechanical connectors**	5	Low	N/A	HSSE Cost Saving
24	**Intelligent inspection pigging tools**	9	High	Very High	Monitoring
25	**Large size booster fan in flue gas duty.**	9	High	Very High	Operations
26	**Use of large size Cansolv pre-scrubber and absorber; constructability and performance**	8	High	Very High	Construction & Operations
27	**Use of a rotary type gas/gas heat exchanger for flue gas service**	7	N/A	N/A	Operations
28	**Use of liner in large size pre-scrubber and absorber units for flue gas services with new**	8	High	Very High	Construction

	DC-201 solvent				
29	**Application of novel Cansolv DC 201 solvent; General and performance aspects**	8	N/A	N/A	Operations / Reputation / Economics
30	**Use of large Welded Plate Block Heat Exchangers and/or Plate & Frame Heat Exchanger in flue gas cleaning services**	9	N/A	N/A	Economics / Operations
31	**Catalytic removal of oxygen from CO_2**	6	Low	Low	Operations
32	**Use of mol sieve for dehydration in CO_2 service**	7	Low	Low	Economics / Operations
33	**Use of integral geared compressor with integrated cooler knock out vessels for CO_2 compression**	9	N/A	N/A	Operations
34	**Use of reclaiming techniques for new DC-201 solvent service**	7	N/A	N/A	Economics / Operations
35	**Biological treatment of pre-scrubber and acid wash effluent stream from Cansolv plant containing DC-201 amines and degradation products**	6	N/A	N/A	Reputation / Operations
36	**Utility system; Large 3.5 bara saturated LPS system, large closed cooling loop system and quality of sea water from SSE**	9	High	Very High	Economics / Operations
37	**Fibre Optics based CO_2 Sensor for monitoring well**	Develop	Low	Low	Operations

38	**Subsurface Safety Valve for CO_2 Injection**	5	Medium	Medium	Operations
39	**Pressure Control Equipment for Well Intervention**	4	Very High	Very High	Operations
40	**Rig Qualification for CO_2 intervention**	2-4	High / Very High	Very High	Operations

Note: The **Discovery** phase starts with opportunity identification and analysis followed by solution concept generation. The most promising approach is selected. Subsequently critical risks are reduced and the feasibility of the selected solution is demonstrated. The discovery phase ends with a proof of concept.

The **Development** phase brings the technology from concept to applied technology by prototyping, field trials, and/or beta tests.

The **Deployment** phase is where the transition from the Research Organisation responsible for the first applications for learning takes place to a broad application by the Delivering Organisation in most or all relevant assets and projects. This phase ends with accepting the technology for all other projects.

5.6. Technical risks and uncertainties

A storage development plan is based round the assessment of the risks and uncertainties inherent in Capacity, Transport & Injection, Containment, and Monitoring. It is also important to show that migration leading to leakage that can affect humans or the environment can be managed via a corrective measures plan. All risks have been assessed as low (or negligible) after taking account of natural barriers and introducing engineered barriers, plus monitoring plans complemented by the corrective measures plan.

The technical uncertainties depend strongly on the rate and injection pressure of storage and the volume to be stored. Fundamentally the faster you inject and the more you inject the more likely you are to find the limits of the container injectivity and volume.

Any change in the scope of the current plan would require a re-assessment of the technical risks and uncertainties – and potentially significant modelling and/or appraisal work.

At this stage in the project the uncertainty has been assessed and the Goldeneye store has been shown to have: the capacity to store more than 15 Mt CO_2; and the injectivity to accept 1 Mt p.a. Containment risks have been assessed and are discussed below, while monitoring and corrective measures plans have been developed.

It is important to note that the risk assessment is a *live* document. The risk assessment draws upon all available information from sources such as:

- Additional study work.
- New research results.
- Collection additional data.

The risk assessment will be updated when key sources of additional data become available. These are:

- Pressures recorded during the period of aquifer recharge between cessation of hydrocarbon production and commencement of CO_2 injection.
- The collection of the environmental and seismic baselines – including the isotopic analysis of any CO_2 at seabed.
- The recompletion of the wells for injection.
- The pigging of the offshore pipeline.
- The potential receipt of additional data from other operators in the Captain trough.
- The start-up of injection.
- The operational phase and concomitant monitoring activities.
- When the system is re-pressurised to original hydrostatic pressure.

The risks have been broken down into the four main categories. Each category has an execution/operational risk element and all but one also have HSE risks.

Table 5-2: Residual Technical Risks

CCS dimension	Description	Execution/ operational risk	HSE risk	Domain
Capacity	Can the reservoir store the required volume?	☑		Subsurface
Containment	Can we show that sequestration will be effective?	☑	☑	Subsurface
Injectivity & transport	Can we inject the required rates? Can we transport the CO_2 in a safe manner?	☑	☑	Subsurface & facilities
Monitorability & Corrective measures	Can we show that containment is being achieved, the volume is being injected, and that it is being done in a safe manner? Can we manage a CO_2 blowout during well intervention after injection has commenced?	☑	☑	Subsurface & facilities
	Can an effective corrective measures plan be developed that satisfies regulators?	☑	☑	Subsurface

The main residual technical risks within the project stem from the fact that the project is a demonstration. It is to be noted that the injection of CO_2 into a depleted gas field has not been tested or performed on an industrial scale in an offshore setting before. This lack of prior experience leads to some risks relating to:

- Thermal effects and pressure cycling on the caprock.
- The injection of cold dense phase CO_2 into a low pressure reservoir.
- And the quantification of any leak to surface were it to take place.
- If well intervention is required after CO_2 injection has started.

The main results of the technical risk assessment and the techniques used to assess the risks in each CCS theme are summarised in the table below:

Table 5-3: Results of technical risk assessment

CCS theme	Technique employed	Description
Capacity	Subsurface modelling study using scenarios to span the uncertainty range	Very low risk that the capacity is not available.
Containment	Bowtie risk assessment supported by: geomechanical, geochemical, fluid dynamic and geological modelling; plus detailed assessments of current state and historical well engineering experience; and monitoring & corrective measures plan.	Some aspects have higher risks and therefore require additional active/reactive barriers to be put in place to reduce to ALARP – this is done in through a combination of monitoring and corrective measures. The higher risk areas are: • Well injection tubing leaks • Well penetrations in the secondary and tertiary seals
	Studies performed (indicates that thermal fractures are not a high risk), but further modelling required.	Risks that require further detailed study are: • Fractures in the caprock caused by cold CO_2 injection
Injectivity & transport	Numerical modelling of: the injection of CO_2 into the well tubing (temperature and pressure); the stresses and strains imposed on the wells; assessment of risk of plugging (including geochemical and thermal fluid dynamic modelling)	A moderate risk of completion sand screen plugging was identified and mitigated by installation of surface filtration equipment. There is an increased risk of failure in the injection wells (leading to down time to ensure containment is preserved) if the whole chain delivery (rates, quality, variability in rates) is not to specification. The technique for impedance matching of the surface and subsurface conditions has not been tested on an industrial scale before.
	Numerical modelling of the whole surface pipeline system. Numerical modelling of CO_2 releases. Analysis of the condition of the surface materials and pipelines (complemented by planned intelligent pigging of the pipeline). Design: replacing materials	Risks do not differ significantly from conventional pipeline and plant activities, with the exception of the behaviour of CO_2 when released (sinks rather than rising). The release modelling is being improved by physical release testing experimental work[2].

[2] CO_2 release testing has been performed. The results are being analysed and the modelling updated during detailed design.

CCS theme	Technique employed	Description
	and systems in offshore facilities. HAZID, HAZOP.	
Monitorability	Feasibility study to identify and assess available techniques (including detailed geophysical property modelling), combined with the bowtie risk assessment to identify the critical areas for monitoring. Surface facilities and pipeline monitoring follows standard practice as detection equipment exists.	Flows can be metered (volume and quality). Significant irregularities can be detected once they leave the reservoir; however, monitoring of the movement of CO_2 within the store is limited to point measurements. Monitoring does not identify leak paths, only leaks. The store is under pressure and unlikely to leak until the pressure increases to above normal original levels. Quantification of a leak to seabed is currently untested within the industry.
Corrective measures	Feasibility study identifying and assessing available techniques to address migration along the leak paths identified in the containment risk assessment.	Some geological leak paths are effectively impossible to fix, however, these are low flux and have low to negligible impact on the environment. Although the EU guidance document acknowledges this fact, it has yet to be subject to regulatory test.

5.7. Execution delay risk

Execution delay can impact the project in two main areas. (i) The current hydrocarbon infrastructure (platform and pipeline) will need to be preserved and maintained, incurring significant additional cost. In addition the condition of the pipeline could deteriorate. (ii) The reservoir pressure will continue to increase due to the aquifer re-pressurisation altering the behaviour of the injection wells. The rise in pressure is partly offset by fluid extraction operations in neighbouring fields (mainly Rochelle). The pressure increase is described below.

Alternative injection scenarios were run to look at the impact on pre-injection and post-injection reservoir pressure if the start of CO_2 injection is delayed for some reason.

Delay to the planned date of injection start-up does not significantly alter the project. As recompletion of the existing wells, and conversion to injectors, will take place within a year of start-up, it will be possible to tune the completions to the observed pressure.

5.8. Risks to capacity

The risk to Goldeneye CO_2 storage capacity resides in the accuracy of the factors considered as elements that increase or decrease the capacity. The error bars in each of the elements of Figure 6-4: represent the risk observed.

- **Heterogeneities:** reservoir heterogeneities were highlighted in Goldeneye by the permeability contrast with Captain D sand and the assumption that most if not all of the CO_2

will be injected in Unit D. This sand contained ~78% of the original hydrocarbon, however, this has a range among all the geologic realisations available for Goldeneye, that goes from 70% to 82% and this error bar represents that span.

- **Residual water saturation:** how large the effective "residual water saturation" (S_{wr}) left behind the CO_2 flood front could be, was estimated by Buckley-Leverett displacement theory and fractional flow equations. S_{wr} ranged from 15% to 25% and this error bar represents that span.
- **Mixing with hydrocarbon gas:** the reduction in capacity was estimated to be as much as 6%. This is assuming 100% mixing between CO_2 and the remaining hydrocarbon gas, however, simulation has shown that instead of a perfect mix, a hydrocarbon gas bank is formed at the tip of the plume, meaning that mixing is not perfect and the reduction will be smaller than 6%, making it a small reduction factor. 4% was taken as a lower end for this element, which is pretty small over all.
- **CO_2 dissolution in brine:** the increment of storage capacity was estimated in 2.2%, taking into account a CO_2 solubility of 4.6% (weight) and that CO_2 will contact approximately 25% of the brine due to the water saturation left behind the CO_2 injection front. Of course a full description of the part played by dissolution is more complicated than the instantaneous dissolution described before. There will be diffusion of the carbon dioxide dissolved in the water, allowing more CO_2 from the gas phase to dissolve in the aqueous phase. There will also be a convective mixing effect because the density of water saturated with CO_2 is greater than that of undersaturated water, so density instability is created and eventually plumes of CO_2 laden water flow downwards through the formation. Assuming this, a maximum dissolution reduction was estimated to be 11.2% if not only the height of the CO_2 plume (residual water saturation) is contacted but the whole reservoir thickness in the long term.
- **Buoyancy filling of Unit E:** after injection, buoyancy forces dominate, and the CO_2 contracts back into the original gas cap and it also starts to fill the overlying Captain E sand. It was seen in simulation that Captain E will be finally flooded with CO_2 but mainly the bottom part only. A refilling efficiency for Unit E was assumed to be between 33% and 66% to create the span for this error bar.
- **Water leg extra capacity:** error bar shows an uncertainty margin in this case dominated by the static uncertainties regarding the structural west flank of the field. Alternative realisation SRM3.05 (shallower west flank) allowed only 2 3Mt stored in the water leg, while SRM3.15 (pinch-out sensitivity) allowed 7Mt and the reference case (SRM3.1) 4 Mt.

The summation of all the positive and negative uncertainty bars gives the total uncertainty range for the storage capacity at the end of injection. The extremes represent the unlikely scenarios where all the elements decreasing or increasing the storage capacity happen all in the downside or upside cases.

The final capacity and the extremes are for the specific injection pattern using the current Goldeneye well penetrations and currently proposed store rock volume. If for example, more CO_2 were to be injected, an alternative pattern with new penetrations could yield a higher post injection capacity by forcing more CO_2 to be stored in the water leg.

Nevertheless, this approach still resulted in a storage capacity that sits well above the 15 Mt planned by the Peterhead CCS Project, with a lower end scenario of about 25 Mt.

5.9. Injection Risks

5.9.1. Well plugging

The fundamental reservoir properties of the Goldeneye field (average 790mD permeability 25% porosity); together with its hydrocarbon production history, all point to excellent properties for CO_2 injection. However the operating conditions and CO_2 composition present a risk of this injectivity declining over time as a result of two mechanisms: (i) plugging of the completion screens, gravel pack or near-well bore formation; (ii) hydrate/halite precipitation.

The screens and the gravel pack require an estimated maximum particle size of 17 microns to avoid plugging the lower completion; a size of 5 microns is required to avoid plugging the formation. The most probable cause of low injectivity is thought to the failure of offshore filtration, designed to remove debris.

Hydrates might a problem during initial injection conditions due to the presence of formation water and hydrocarbon gas at the wellbore. During later stages the risk of hydrates decreases due to the lower presence of water and increasing CO_2 content around the wellbore. Batch injection of methanol is currently planned to reduce this risk.

5.9.2. Friction dominated concept

The concept for the well design is to use a friction-dominated scenario by high velocities. This concept is used to restrict production from wells. The concept has been discussed in the industry (1) to overcome the CO_2 Joule Thomson effect in depleted reservoirs but has not been implemented to date.

Friction is a well-known effect in fluid thermodynamics. The extension to management CO_2 phase behaviour by the use of friction is a logical step.

The bottom hole pressure depends mainly on CO_2 density and tubing friction (back pressure). The CO_2 density / properties remain similar along the tubing length during injection conditions. Once the tubing size is defined, the main factor affecting the friction is then tubing roughness. Different values for steel roughness have been used to derive the frictional losses in the well. The wells will be required to maintain a wellhead pressure of minimum 50 bara to keep the CO_2 in the dense phase.

The other mitigation factor is the overlapping of the different well envelopes. A maximum velocity in the tubing of 12m/s has been used in restricting the wells envelope. This value includes a safety factor of 0.75 over the equivalent experience in water injection and gas producing maximum velocities in wells as follows below.

The CO_2 in the well will have a high density 900-970kg/m^3 depending on pressure and temperature and it is liquid. The maximum velocity suggested for liquid guidelines APIRP14E or ISO13703 is 4.6 or 5m/s respectively for continuous service. These guidelines are mainly used in the design and installation of offshore production platform piping systems. Sudden changes in flow directions are included in the guidelines. However, the trajectory of Goldeneye wells is smooth enough not to cause changes to flow directions. Well experience across the world has shown that the guidelines are conservative and higher values in velocity are normally used in the industry.

Operators have reported using 10m/s in water injectors wells completed with carbon steel; the velocity is increased to 17 m/s for a duplex stainless steel or higher alloy.

Similarly 50m/s under gas hydrocarbon conditions has been used on a continuous basis. This is equivalent to around 16 m/s under CO_2 injection using the C-factor for the ISO 13703 or APIRP14E (see Figure 5-1).

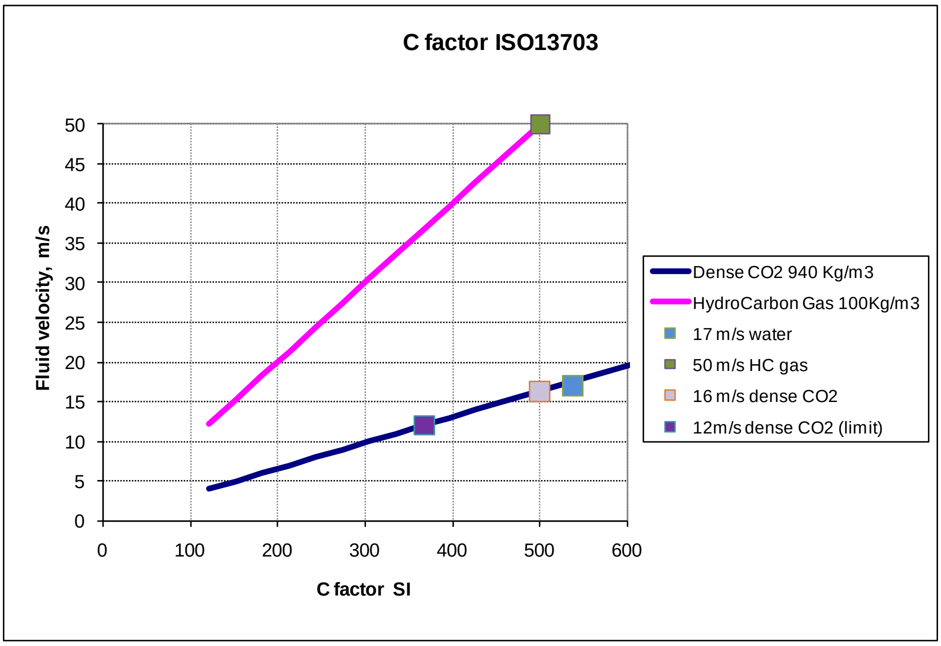


Figure 5-1: C factor comparison (from ISO13703) for CO_2 and hydrocarbon gas.

Erosion of the metal is not considered to be an issue. Erosion is not generally a result of surface shear, but is usually a result of repeated, micro- (1) metal deformation or (2) fracture damage as a result of a mass (solid in liquid or gas, liquid in gas) changing direction at a metal surface. No "mass" changing direction equals no erosion.

Flow induced vibration /pulsation are currently being investigated by a formal study with TNO Delft. Vibration problems are not expected to develop, based on experience in water injection wells.

5.9.3. Well integrity

The well materials are suited to the CO_2 injection characteristics if Oxygen is controlled. However, there is always long term performance uncertainty.

The well components are suited to the low temperatures in the steady state and for short term very low temperatures during the transient operations. However, the number of transient cycles are not well characterised. From the wells perspective, the number of cycles needs to be minimised. Experience in cold CO_2 injection wells is not available.

Although the casing hanger is not in direct contact with the CO_2, it will be subjected to cooling, especially during transient conditions. During transient conditions, the temperature of CO_2 inside the top of the tubing reaches a minimum of -20°C. As a result, the average tubing temperature at the top of the well reduces to -15°C. The casing hanger is rated to a minimum temperature of -18°C and even though it is difficult to model the temperature interaction that is taking place inside the wellhead, the casing hanger is not expected to get exposed to temperatures that exceed the casing hanger's temperature limitations.

The current wells were designed for producing hydrocarbons. As such they were not designed to withstand the potentially very low temperatures that would be experienced during a CO_2 blowout (theoretical sublimation temperature of -78.5 °C at atmospheric conditions).

One important factor is the ability of the SSSV to limit the amount of CO_2 to be released. Temperatures around the SSSV require to be assessed during a release scenario to verify the sealing capabilities of the valve.

Most of the well components are not qualified down to these low temperatures.

Tubing leak identification needs to consider all available information. It is proposed to have standard platform annular monitoring. Potential leak identification is augmented by the installation of DTS and PDGs.

The periodic SSSV inflow test will be a lengthy process (20-40hr) to avoid low temperature during the bleed off operation especially at the gas-dense phase interface.

Pulsed Eddy Current (PEC) corrosion surveys were run on both the conductor and the surface casing.

5.10. Risks to Containment

There are two areas where there are potential risks to containment barriers:

- There is the theoretical potential for thermally induced fracturing of the primary caprock during injection. This has been evaluated for the situations of thermal changes near injection wells and thermal changes where a CO_2 plume encounters the caprock. In the former case, very low probabilities of failure were concluded and mitigation strategies were recommended; in the latter case, it was concluded that hydraulic fracture from the Captain reservoir into the Rødby caprock will not occur, but instead that slip along the reservoir-caprock interface is most likely.
- While all wells in the storage complex are plugged at the primary caprock level they are not plugged at the secondary and tertiary containment levels. This means that were CO_2 to migrate from the store and were the plume to flow past these well penetrations there is a possibility that they could provide a leak path. If this were to take place then the corrective measures plan would be called upon.

6. Site capacity

The objective of this chapter is to show that the Goldeneye store has sufficient capacity to receive 15Mt CO_2 (with contingency for 20MT to allow for possible future expansion) while accounting for the effects of geological heterogeneity and refill efficiency. The stored CO_2 is split between two primary trapping mechanisms: (i) structural trapping in the original Goldeneye hydrocarbon field; and (ii) capillary trapping in the aquifer immediately below and adjacent to the field. Other trapping mechanisms exist but are minor on the injection time scale.

6.1. Summary of capacity

The space voided from hydrocarbon production is equivalent to 47 million tonnes of CO_2. This represents a theoretical maximum volume of CO_2 that can be structurally trapped within the storage site. To arrive at a final estimate for the volume of CO_2 that it is possible to store, a number of other factors that either act to reduce or to increase storage capacity must be taken into account. A major increasing factor is the realisation that a significant volume of CO_2 will be capillary trapped in the aquifer rocks immediately below the original oil-water-contact, after the expansion and contraction of a 'Dietz Tongue' (at Goldeneye pressures and temperatures, the CO_2 dense phase is less dense than water and so, under equilibrium conditions it will overlay the brine filled part of the reservoir. During injection, the CO_2 displaces water under segregated flow conditions and can tongue and override the water). Together, estimates for the discounted structurally trapped and the capillary trapped volumes of CO_2, show that 34Mt of CO_2 can be geologically stored in the Goldeneye storage site.

An uncertainty analysis was carried out, oriented towards the impact of CO_2 injection, aiming to deliver a set of parameter ranges and subsurface realisations that need to be modelled (static and dynamic). The study showed that three major static elements could impact the storage capacity of Goldeneye:

(a) extension of the stratigraphic pinch-out;

(b) structural dip on the western flank of the field; and

(c) internal Captain Sand stratigraphy (thickness).

In addition, dynamic elements were also considered within the uncertainties that will potentially have an impact on the CO_2 storage capacity of the field, mainly related to the displacement mechanism and the unfavourable mobility ratio of the process. These elements are:

(a) relative permeability end points (both water and gas/CO_2), and

(b) residual gas saturation (S_{gr}).

The entire suite of static reservoir model realisations have been simulated and a range of injection scenarios have been tested. Much of the simulation work referred to here was performed during the early stages of preparation of this report, and was done for a scenario requiring storage of 20 Mt of CO_2 with an injection rate of 1 Mt p.a. Results from such cases are valid to support storage of 15 Mt, and are identified where appropriate. With regard to the uncertainties evaluated, all the scenarios have sufficient capacity to hold 10, 15 or 20 million tonnes of CO_2.

In order to determine the maximum geologic carbon storage capacity for the Goldeneye reservoir, a theoretical scenario of 50 years continuous CO_2 injection at 1 Mt p.a. Revealed that over 30 Mt CO_2 had to be injected to reach the structural spill point and create an egression, i.e. there is a substantial storage buffer within the hydrocarbon bearing structure before sequestration expands into aquifer storage.

6.2. Capacity assessment

For storage in a depleted hydrocarbon field the major factor influencing storage capacity is the voidage created – i.e. the volume of hydrocarbon and water extracted from the subsurface less anything injected. Aquifers can flow into fields, however, in so doing they lose pressure – i.e. voidage is created in the aquifer too.

This initial voidage cannot be completely refilled – there are factors that reduce the volume available and other factors that increase it. The following diagram summarizes the factors impacting the CO_2 storage capacity in a depleted hydrocarbon fields – with some specific *localisations* for the details of the Goldeneye field.

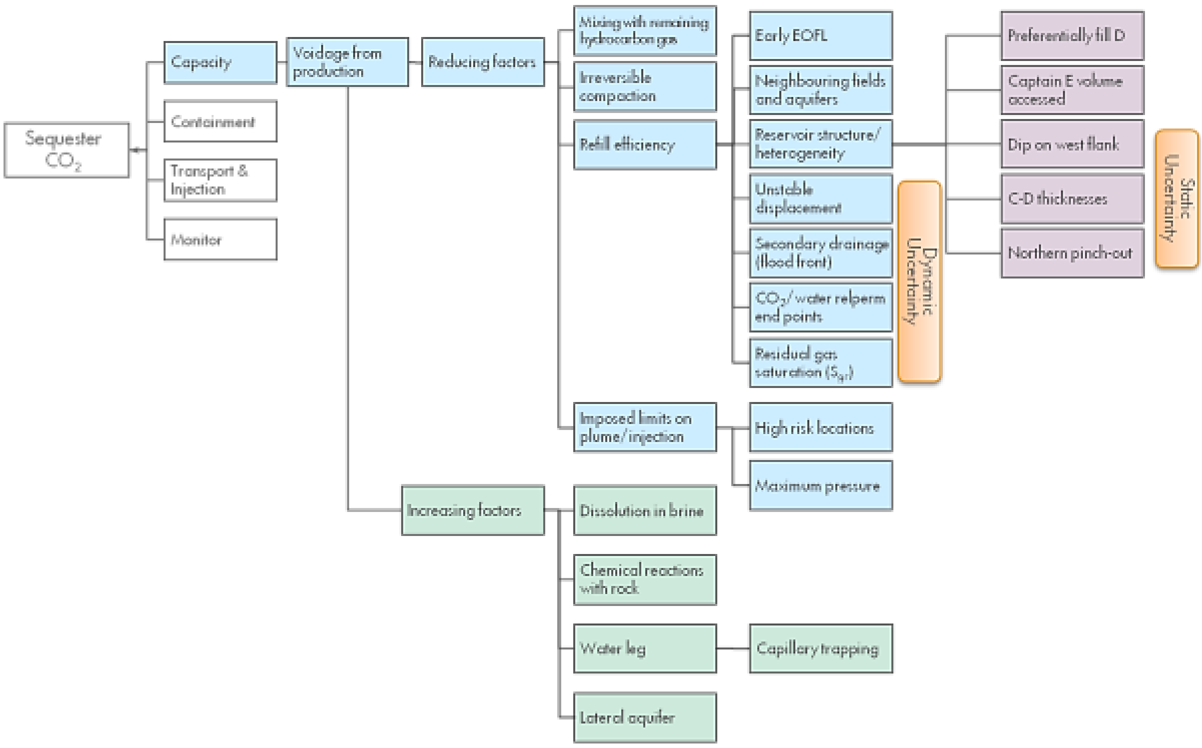


Figure 6-1: Factors impacting CO_2 Storage Capacity.

6.3. Total pore volume available: voidage from production

The total pore volume available for CO_2 was determined by making the assumption that all the pore volume vacated by produced hydrocarbons is replaced with CO_2 using the following factors:

- reservoir temperature of 83°C.
- the characterised Pressure, Volume, Temperature (PVT) properties of the Goldeneye fluids.
- recharge to initial pressure at datum of 266 bara at datum level of 2610 m true vertical depth subsea (TVDSS).

This gives a storage capacity of 47 million tonnes of CO_2 using the total cumulative hydrocarbon production till cessation of production. However, this would be a maximum theoretical storage capacity assuming a perfect refill of the Goldeneye container and in reality there will be a series of additional factors, some that will increase the capacity, and some that will decrease this maximum storage capacity. The following section will analyse and describe these elements in order to estimate an effective storage capacity.

6.4. Possible increases in the sequestration capacity

Permanent sequestration ("immobilisation") of CO_2 is achieved in time through various factors such as: structural and stratigraphic trapping, dissolution of CO_2 into the formation brine, residual CO_2 trapping, and chemical reactions of CO_2 with minerals present in the formation. The latter three processes increase the sequestration capacity; their significance grows with time.

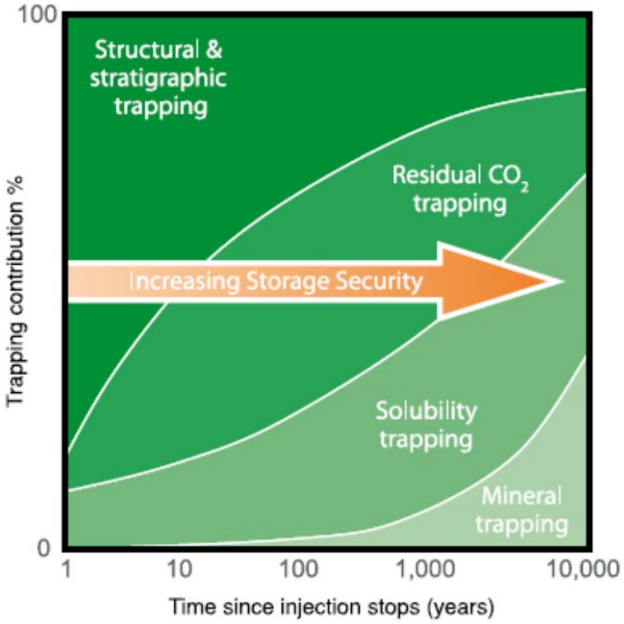


Figure 6-2: Storage security depends on a combination of different trapping mechanism[3].

Mineralisation is strongly dependent on the geochemical composition of reservoir rock and happens over very long timescales. Over time, reactions with clay minerals will also lead to a removal of CO_2 from the continuous phase. This effect has been modelled for this system and found to work over longer time scales than the injection period and therefore will not be taken into account for the storage capacity. Nevertheless, it will work in favour of the project reliability within large period of time.

6.4.1. CO_2 dissolution in brine

CO_2 solubility in water is higher than that of hydrocarbon gases such as methane, and is a function of pressure, temperature and water salinity. In general, CO_2 solubility increases with pressure and decreases with temperature. An increase in salinity of the reservoir water decreases CO_2 solubility significantly. Dissolution of CO_2 is an important immobilisation mechanism.

Several correlations are available in the literature regarding CO_2 solubility. One of them was published by Chang, Coats and Nolen in 1996[4].

[3] Special Report on Carbon Dioxide Capture and Storage, 2005. Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp, 2005.

[4] Chang, Coats and Nolen 1996 "A Compositional Model for CO2 Floods Including CO2 Solubility in Water" SPE35164.

Applying this methodology to estimate an average CO_2 solubility for the Goldeneye reservoir conditions of approximately 262bara, 83°C and 53,000ppm of salinity; results in dissolution of 145scf/bbl. [7.7kg/bbl., 4.6% on weight]. Goldeneye conditions are relatively favourable for CO_2 dissolution due to the low formation brine salinity.

The increment of storage capacity has been estimated at 2.2%, taking into account a CO_2 solubility of 4.6% (weight) and that CO_2 will contact approximately 25% of the brine due to the nature of the displacement process (water saturation left behind the CO_2 injection front is about 25%, estimated by fractional flow and Buckley-Leverett solution).

6.4.2. Water leg and Lateral Regional Aquifer

Additional factors that could increase the storage capacity are related to the aquifer.

The lateral regional aquifer surrounding Goldeneye is not part of the current analysis; nevertheless it represents a significant opportunity for CO_2 aquifer storage. To the east of Goldeneye, the Captain Sandstone extends approximately another 40-60 km and continues to deepen. To the west of the Blake field the formation starts to widen and eventually outcrops at the seabed about 50 km to the west of Blake. This could be considered for further developments in the fairway and is under study by the Scottish Centre for Carbon Storage.

The aquifer immediately below and adjacent to the Goldeneye hydrocarbon accumulation (termed the water leg) increases the capacity as when CO_2 is pushed into the water leg as a result of viscous forces and subsequently flows back up dip into the Goldeneye structure, 20-25% of the CO_2 is left behind residually trapped (often termed capillary trapping) in the water pore spaces.

6.5. Possible reductions in the pore volume available to the CO_2

Three effects were identified that reduce the vacated hydrocarbon pore volume available to CO_2:

- Mixing of the CO_2 and Goldeneye gas.
- Irreversible compaction of the reservoir sands.
- Efficiency of refilling:
    - Reservoir heterogeneities (Volumetric Sweep).
    - Unstable displacement (Dietz efficiency).
    - Water from the aquifer ingress that has become effectively immovable to CO_2 injection within the pores (Secondary drainage relative permeability effects – Water displacement).
    - CO_2/water relative permeability end points.

In addition, other elements can alter the capacity that can be accessed. These are:

- Operations in neighbouring fields that alter the pressure in the Captain Aquifer and ultimately change the rate of pressure change in Goldeneye.
- Injection in high risk locations (for example at the spill point) – this is not planned for the current project.
- Restriction on maximum injection pressures.
- Plugging or loss of injection wells.

If current conditions and plans are maintained, no major impact is foreseen in relation to the above.

6.5.1. Mixing of the CO_2 and Goldeneye gas

Mixing of CO_2 and the remaining hydrocarbon gas present in Goldeneye will have an impact on the CO_2 storage capacity estimation. CO_2 will be injected in a depleted predominantly methane gas reservoir. The reduction in capacity has been estimated to be as much as 6%. This is assuming 100% mixing between CO_2 and the remaining hydrocarbon gas, however, simulation has shown that instead of a perfect mix, a hydrocarbon gas bank is formed at the tip of the plume, meaning that mixing is not perfect and the reduction will be smaller than 6%, making it a small reduction factor.

6.5.2. Irreversible compaction of the reservoir sands

The reservoir is currently grain supported, therefore compaction is minimal. Additionally, the depletion during hydrocarbon production is forecast to be from approximately 260 bara to 140 bara. Irreversible compaction is expected to be minimal. When CO_2 is injected in the Captain Sandstone the small amount of calcite in/around the pores will be dissolved. However, there is not much carbonate cement in the reservoir parts that will be used for the CO_2 injection. So, the pore space will increase a small amount (so more volume to inject will be available) and the matrix will become a slightly weaker but without risk of pore collapse.

Compaction experiments carried out in 1998-1999 showed that the compaction of cores from Goldeneye sands is partly elastic (reversible) and partly plastic (irreversible). There was minimal compaction and the porosity change was about 0.3%, as a result this effect has negligible impact.

6.5.3. Efficiency of refilling

Refill efficiency has been divided into macroscopic and microscopic fill efficiency. The microscopic efficiency has been partially discussed under the last point above, but macroscopic efficiency also includes the impacts of permeability variations in the subterranean formation and dynamic stability of the flood fronts due to mobility ratio (viscosity and relative permeability).

6.5.3.1. Reservoir heterogeneities

Reservoir heterogeneities are best illustrated in Goldeneye by the permeability contrasts of the various units (Figure 6-3). The best unit is the Captain D sand which accounted for ~78% of the original hydrocarbon. Injected CO_2 will tend to follow the path of least resistance. Full field simulation has confirmed that, during the injection phase, the CO_2 preferentially fills and follows the D sand. If the D sand were the only sand available for filling, the capacity would be reduced by 10 million tonnes CO_2.

After injection, buoyancy forces dominate, and the CO_2 contracts back into the original gas cap and it also starts to fill the overlying Captain E sand. It was seen in simulation that Captain E will be finally flooded with CO_2 but mainly the bottom part only. A refilling efficiency for Unit E between 33% and 66% was assumed Numerical simulation results for a 20Mt case show that only 1.3Mt of CO_2 makes its way into Captain E, twenty years after injection stops.

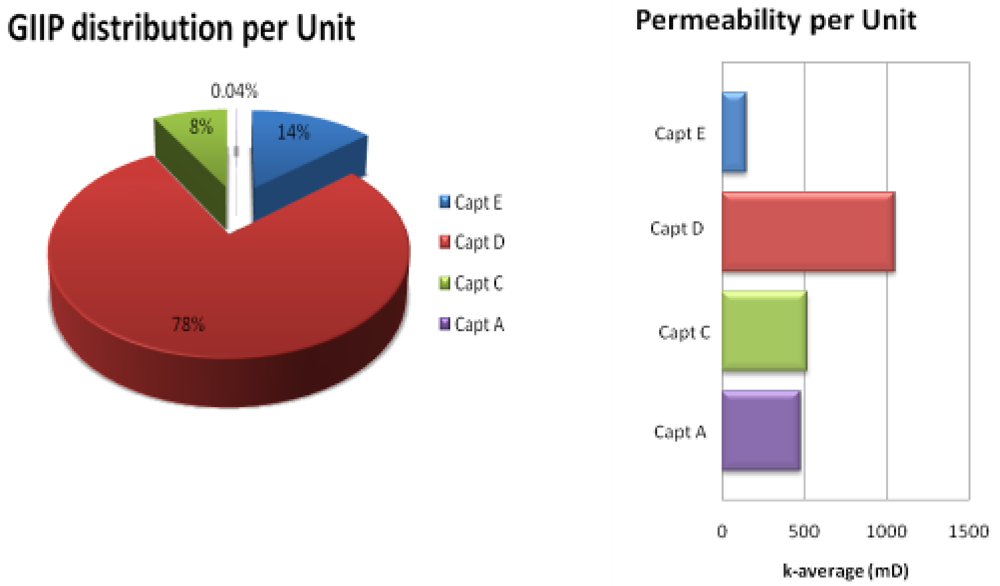


Figure 6-3: Goldeneye Gas Initially In Place (GIIP) distribution and average permeability per geological unit.

6.5.3.2. Unstable displacement

The effects of unstable displacement during CO_2 injection process in Goldeneye could potentially reduce the short term (i.e. during injection) storage capacity.

A simulacrum simulation model was constructed to investigate these effects – this consisted of a dipping box model representing roughly one quarter of Goldeneye in volume, with similar rock properties (permeability and porosity) and dip angle to the main full field model. The model was conditioned with a 10 year depletion period, further 10 years of recharge from the aquifer and finally, a 10 year CO_2 injection period.

Sensitivities were done on a range of values of effective water relative permeability at residual gas saturation (S_{gr} = 30%) within the observed data, varying between 0.1, 0.25 and 0.6.

Results from the model confirmed that a strong override of water by CO_2 will occur in the reservoir, producing a CO_2 tongue moving downwards due to the unstable displacement (a consequence of the unfavourable mobility ratio). As expected, the tonguing effect is enhanced relative to how low the water relative permeability end point can be, creating a Dietz tongue that could be almost parallel to the top of the interval. This means that, during injection, the mobile CO_2 dense phase can extend below the original hydrocarbon water contact.

Finally, the refill efficiency is highly impacted. Based on the simulation results less than 50% of Captain D will be flooded with CO_2 (in the vertical sense) before the CO_2 has moved under the original OWC. However, this is a short term effect that will happen only during injection. The Dietz tonguing behaviour means that the tip of the CO_2 plume will reach the original OWC after injecting just the first 10 to 12 million tonnes of CO_2, but the structure will continue to fill if more were to be injected.

6.5.3.3. Secondary Drainage Relative Permeability

The secondary drainage relative permeability curve is expected to follow the primary drainage curve, however, the time required to bring back initial water saturation will be much longer than the injection period because there is not sufficient time for gravity drainage to bring saturations into capillary equilibrium.

In order to estimate how large the effective "residual water saturation" (S_{wr}) left behind the CO_2 flood front could be, both analytical and numerical estimations were done. Buckley-Leverett displacement theory and fractional flow equations were applied for a process where gas (CO_2) is displacing water and sensitivity analysis was done within the water relative permeability Corey Exponent.

Fractional flow analysis allows calculation of the average saturation of the displacing front (CO_2) and hence, the complemented displaced phase (in this case brine).

A set of relative permeability curves as well as rock properties were used taking into account Goldeneye basic data from logs and Special Core Analysis Laboratory (SCAL) such as: S_{wi}, porosity, Net-to-Gross (NTG), vertical permeability and thickness, among others. Corey exponents were used as sensitivity and CO_2 and brine properties were taken at Goldeneye reservoir conditions.

The results showed that for a range of Corey exponents of 2, 3 and 5, Sw_{avg} can vary from 0.15 to 0.25, depending on how easy it is to displace the water during CO_2 injection. Based on literature and the unfavourable mobility ratio foreseen for the reservoir, a Corey exponent of 5 could be the more appropriate which yields the higher water saturation left behind, considerably higher than the connate water saturation observed in Goldeneye ($S_{wi} \sim 0.07$), meaning that this factor represents an important storage capacity reduction element for Goldeneye, because it, in conjunction with S_{gr}, will reduce the pore space available.

6.5.3.4. CO_2/water relative permeability end points

The injection rate can vary significantly for different relative permeability values and injectivity could be sensitive also to variables that define the relative permeability curves. In addition, the end point of the relative permeability curves is conditioned to the mobility ratio (M) of the fluids, having a large impact on the CO_2 plume shape. As mentioned before, water will be by-passed and gas tongues will develop, leading to an unfavourable displacement. In such conditions, the CO_2 plume will travel further away from the injection point, diminishing the average CO_2 storage density and requiring a bigger area to store[5]. As a consequence, a proper assessment of the relative permeability variables is important for the refill efficiency of the system.

The main impact of the CO_2/water relative permeability end points on the storage capacity is related to the displacement mechanism, affecting the behaviour of the Dietz tongue and potentially generating scenarios where the CO_2 can move to levels below the original OWC. From there it could eventually migrate under the spill point. As a result, it is difficult to assign a specific reduction factor to it. Addressing the direct impact of end point relative permeability on the refilling efficiency (based on how unstable the displacement is, i.e. extent of the Dietz tongue) will give an approximation of the storage capacity reduction.

Sensitivities were done, in the dipping box model, for a range of values of effective gas (CO_2) relative permeability (k_{rg}) at residual water saturation, of 0.8, 0.5 and 0.25.

The results showed that the relative permeability end points have a minor impact on the displacement, making the plume go slightly further in the case where $k_{rg} = 0.80$ meaning that it will move easily, and the other way round when k_{rg} is restricted (as mentioned above by different publications) to lower values such as 0.25. However, a bigger effect will be seen in injectivity, where the overpressure needed could be higher than expected.

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[5] L.P. Dake, 1978: "Fundamentals of Reservoir Engineering", Elsevier 1978

6.6. CO_2 storage capacity result

The effective storage capacity can be estimated as a function of available volume (production-based) and refill efficiencies based upon the most important reducing and increasing factors mentioned above:

- Available volume: total pore volume available, production-based.
- Volumetric sweep: considering where the CO_2 will preferentially go in, based on reservoir quality (heterogeneities).
- Dietz efficiency: related to the unstable displacement of CO_2 displacing water under an unfavourable mobility ratio.
- Water displacement: "residual water saturation" (S_{wr}) left behind the CO_2 flood front.
- Mixing: of CO_2 with remaining hydrocarbon gas saturation (undeveloped + trapped).
- Dissolution: of the CO_2 in both the pore water and the underlying aquifer.

Mineralisation has been identified as a potential increasing factor, but makes significant contributions over timescales long after the injection period has finished. It is therefore not considered further here. Other factors, such as irreversible compaction, are considered negligible.

Additionally, processes such as the possible filling of Captain E sand when buoyancy forces dominate after cessation of injection, may be added at the end of the capacity estimation.

It is important to highlight that the unstable displacement factor (Dietz efficiency) will be in play only during injection, and will determine the point in time when the tip of the CO_2 plume reaches the boundary of the OOWC. Thereafter, CO_2 will continue to spread inside the CO_2 storage complex. Nevertheless, it must be stressed that this discount factor could have an important role depending on the reservoir structure. In addition to the storage capacity defined by the structural trap of Goldeneye, the water leg beneath the reservoir that lies within the storage site, could potentially add some extra capacity, based on numerical simulation results. This could potentially increase the storage capacity by 6 million tonnes, leading to a post injection combined storage capacity of 34 million tonnes of CO_2.

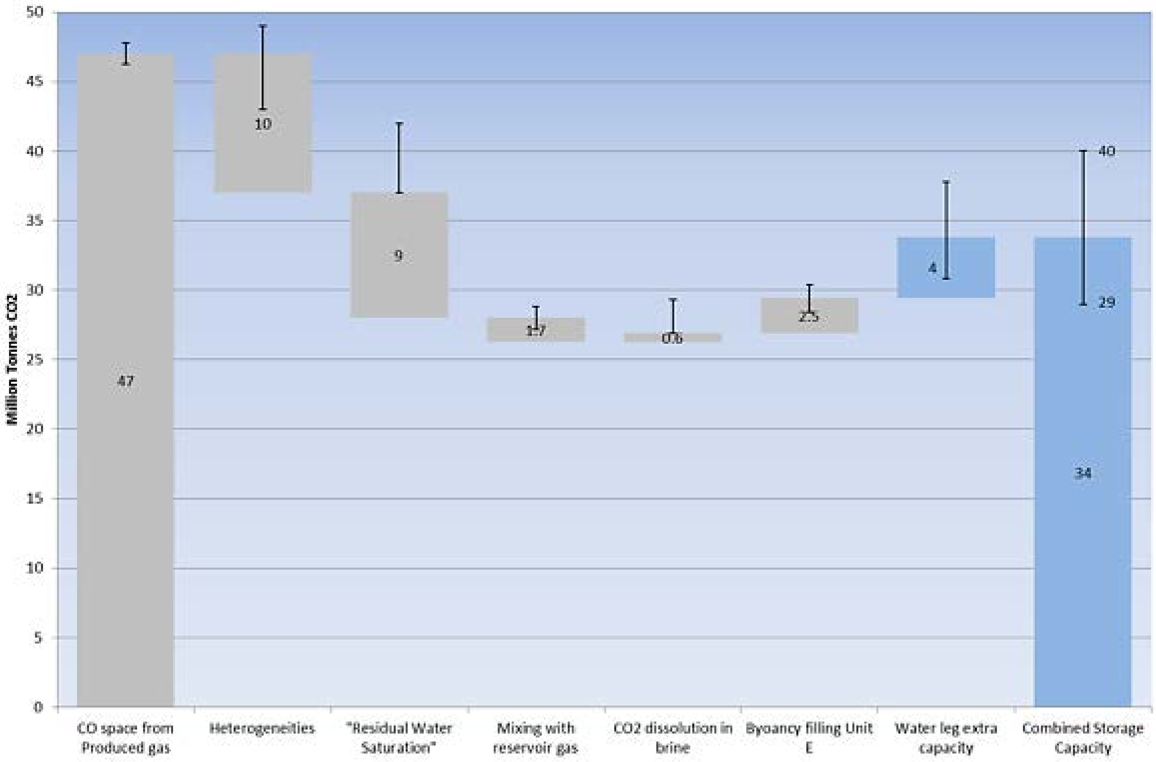


Figure 6-4: Post injection effective storage capacity of Goldeneye (bars 6 and 7 are derived from simulation of 20 Mt injection).

7. Injection Wells and Injectivity

After establishing that the store has sufficient capacity, the next question is *can the capacity be accessed and can the injection be sustained for the duration of the project?* The objective of this chapter is to analyse the expected injectivity in Goldeneye during the 15 Mt of CO_2 injection. In addition, it will define the key elements of well requirements in order to achieve and sustain injectivity within the field.

7.1. Summary of Injection wells and Injectivity

The injection wells will consist of 13Cr and Super 13 chrome (S13Cr corrosion resistant tubing strings (and sand screens), and carbon steel liners and casings.

Analyses have shown that injecting dense phase CO_2 into a depleted reservoir has the risk of producing low temperatures in the top part of the well. These low temperatures cause problems with the materials and fluids in the wells. In order to avoid this, small injection tubing is being installed. This will introduce enough friction to maintain the injection column in dense phase from the well head to the sand face. However, low temperatures at the top of the well can be encountered for a short period of time during transient operations (start up and shut down).

The current upper completion was designed for hydrocarbon production. Changing to CO_2 injection will require a workover to install a single tapered tubing string in order to manage the CO_2 phase behaviour and to maintain well integrity.

There are only a limited number jack-up rigs that have the capability of working at the Goldeneye platform owing to the significant water depth.

Limitations of the different well components were investigated for the expected well conditions under CO_2 injection. The Christmas tree and the tubing hanger will be replaced in the workover with units having a lower minimum temperature rating as per API-6A classification. All completion equipment (i.e. attached to the tubing string) will have 13Cr or S13Cr equivalent metallurgy and will have working pressures in excess of the expected final well pressures.

The oxygen level shall be controlled below 1 ppm to avoid corrosion issues in the 13Cr well components (upper and lower completion). A high level of corrosion could occur in the casings made of carbon steel and when both CO_2 and free water are present. The design takes this into account.

Based on the hydrocarbon production and the reservoir characteristics there is expected to be good initial injectivity in the Captain D. Filters will be installed on the platform to avoid the presence of particulates in the injected fluid and hence reduction of injectivity by plugging/erosion of the lower completion. Batch hydrate inhibitor is planned before well start-ups during the initial stage of injection to avoid hydrate formation in the tubing.

The installation of small bore tubing in the wells mainly defines the operating envelope of each well. In order to accommodate the range of injection rates at the different reservoir pressures during the injection life, each well will be completed with a different tubing size/configuration tailored to a specific rate range. The wells will then have overlapping operating envelopes, and minimum and maximum rates from the capture plant can be injected through the choice of a specific combination of wells.

Three wells are going to be recompleted as injectors, although mostly one well will be required for the injection at any one time. This provides a degree of redundancy within the wells. The fourth well (GYA03) acts both as a monitoring well and as a backup in the case of a significant loss of integrity in other wells. The fifth well will feature a subsurface abandonment.

In the completions, there will be permanent temperature and pressure monitoring gauges. There will also be a distributed temperature gauge - a fibre optic system taking temperatures every one metre in the well, and distributed acoustic sensing (DAS).

7.2. Well functional requirements

The general requirements for the wells under Goldeneye CO_2 injection are:

7.2.1. Hydraulic Requirements

Management of the CO_2 properties (Joule Thomson, JT expansion) and the resultant temperatures in the existing platform wells.

Flexible injection. The injector wells need to be able to cope with a range of CO_2 arrival rates within the limits of the capture plant and surface equipment. Facilities and their modus operandi should be operated to have minimum impact in the wells.

CO_2 will be injected in a single phase with wellhead pressure kept above the saturation line.

7.2.2. Well Integrity

Avoid any leak path through the well.

All well completion materials should be compatible with the injected fluid and expected pressures and temperatures.

Completion design should consider the presence of CO_2, water and hydrocarbon. The proportion will change depending on the well position and during the life of the project.

Expected remaining well life (after start of injection): 15 years.

7.2.3. Well Modifications

Deepwater jack-up rig is required for Goldeneye platform due to the water depth.

Minimise complexity and cost of any well work. Uncomplicated well design.

7.2.4. Operational aspects

Normally unattended platform.

Maintain injectivity during the life cycle of the well.

Optimise life cycle well cost.

7.2.5. Well Monitoring

Able to monitor wells/reservoir. Facilitate intervention.

In-well monitoring to be installed in the wells: Permanent Downhole Gauges (PDG) and Distributed Temperature Sensing (DTS). Distributed Acoustic Sensing (DAS) is being considered.

7.2.6. Life Cycle Cost

The five existing wells will be handed over to the storage license from the production license. As such, the cost associated to all the wells should be considered by the project (e.g. abandonment costs should be included in the cost estimates in case of selecting the options of drilling new wells).

Reduce (or eliminate) the requirement to bring a rig in the middle of the project.

Minimise complexity and cost of any well work. Uncomplicated well design.

Facilitate final well abandonment.

7.3. CO_2 phase behaviour management in the wells

CO_2 will arrive at the Goldeneye infrastructure in liquid state between 2.3 and 10.1 °C depending on the season of the year and at approximately 120 bara. CO_2 will be injected in a single phase with wellhead pressures maintained between 50 to 120 bara: it will be maintained in dense phase by the introduction of friction to avoid extremely low temperatures in the well caused by the Joule Thomson effect (Figure 7-1:).

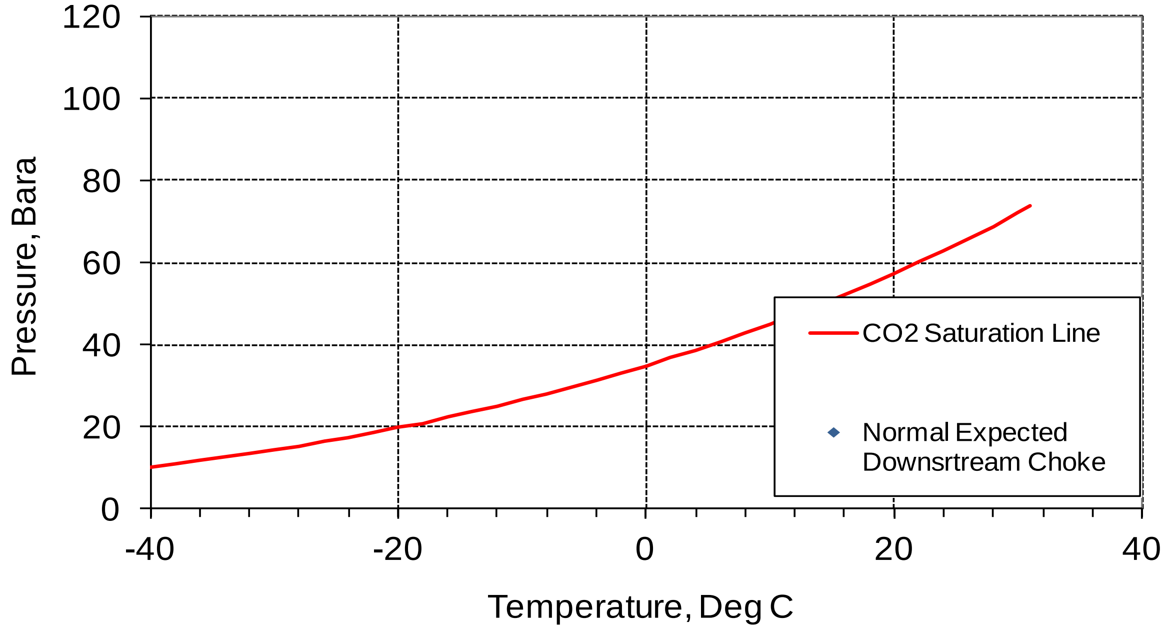


Figure 7-1: Expected CO_2 choke performance.

In the case that the wellhead is operated in two phases (liquid-vapour) the resulting temperature in the top of the well can be extremely low (with a minimum of -25°C and below 0°C above 1000 m TVD) during the entire injection period. This is due to the flashing of the CO_2 to gas caused by relatively low reservoir pressure and practically no pressure drop in the well when using the existing 7in completion tubing. These extremely low temperatures will create serious implications in terms of well design and operability. For this case, there will be requirements to change the materials and shallow well equipment (SSSV, Christmas tree, wellhead equipment, casing hangers) which will need to be qualified or replaced for extremely low temperatures and integrity issues in the well caused by freezing of annuli fluid.

In order to avoid the extremely low temperatures at the top of the well under normal injection conditions, the CO_2 stream should be kept in liquid phase at the wellhead by increasing the required injection wellhead pressure above the saturation line. The required wellhead pressure will be achieved by extra pressure drop in the well by means of friction (small tubing). The minimum wellhead pressure to maintain the CO_2 in single phase has been determined at 50 bara considering the arrival temperature of the CO_2 to the platform.

7.4. Pressure and Temperature Profiles

7.4.1. Closed in conditions

Different CO_2 phases exist in a static well at geothermal conditions depending on reservoir pressure. With different reservoir pressures, the transition depth between gas and dense phase inside tubing will vary. Higher reservoir pressure will tend to have a smaller gas phase, moving the transition point shallower. For Goldeneye reservoir pressure, less than around 207 bara, CITHP remains about the same at approximately 37 bara. At reservoir pressures above 207 bara the CITHP increases with pressure. See pressure profile below under closed-in conditions:

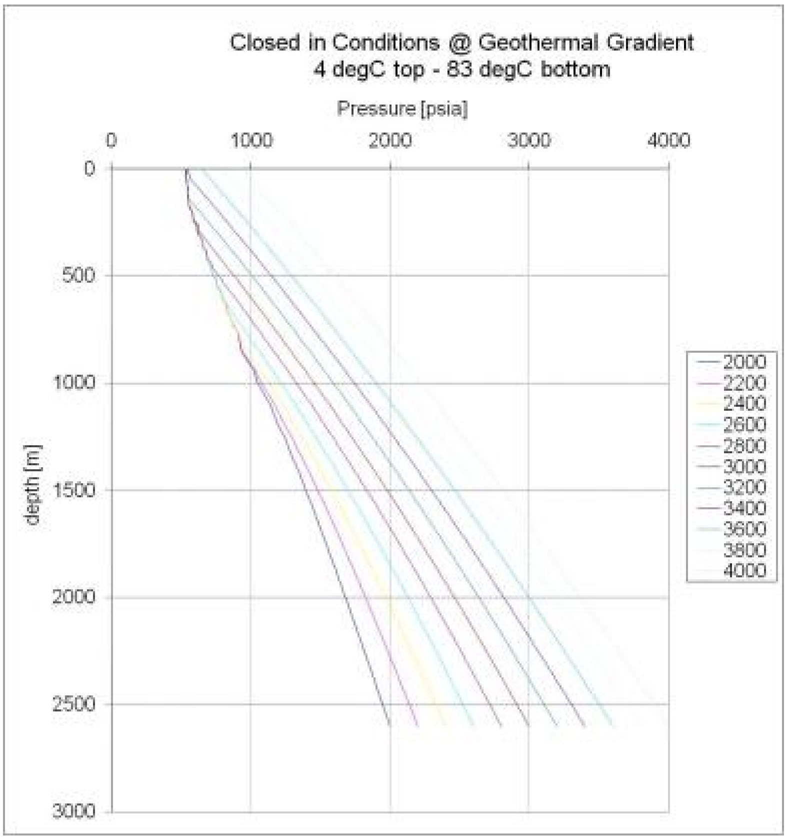


Figure 7-2: Pressure profile in a closed-in well (at geothermal conditions).

7.4.2. Steady State Conditions

The concept of outflow and inflow calculations is presented in Figure 7-3:. The outflow curves are for a given tubing size and represent the bottom hole injection pressure at different wellhead pressures. The general inflow curve is given mainly by the reservoir characteristics. The operating envelope is defined with the injectivity curve at a given reservoir pressure. Under steady state injection the well should not inject below 50 bara due to the JT characteristics of the CO_2 leading to extremely low temperatures. The maximum injection rate per well is given at the maximum injection pressure around 115 bara and it will be changing with changes in reservoir pressure.

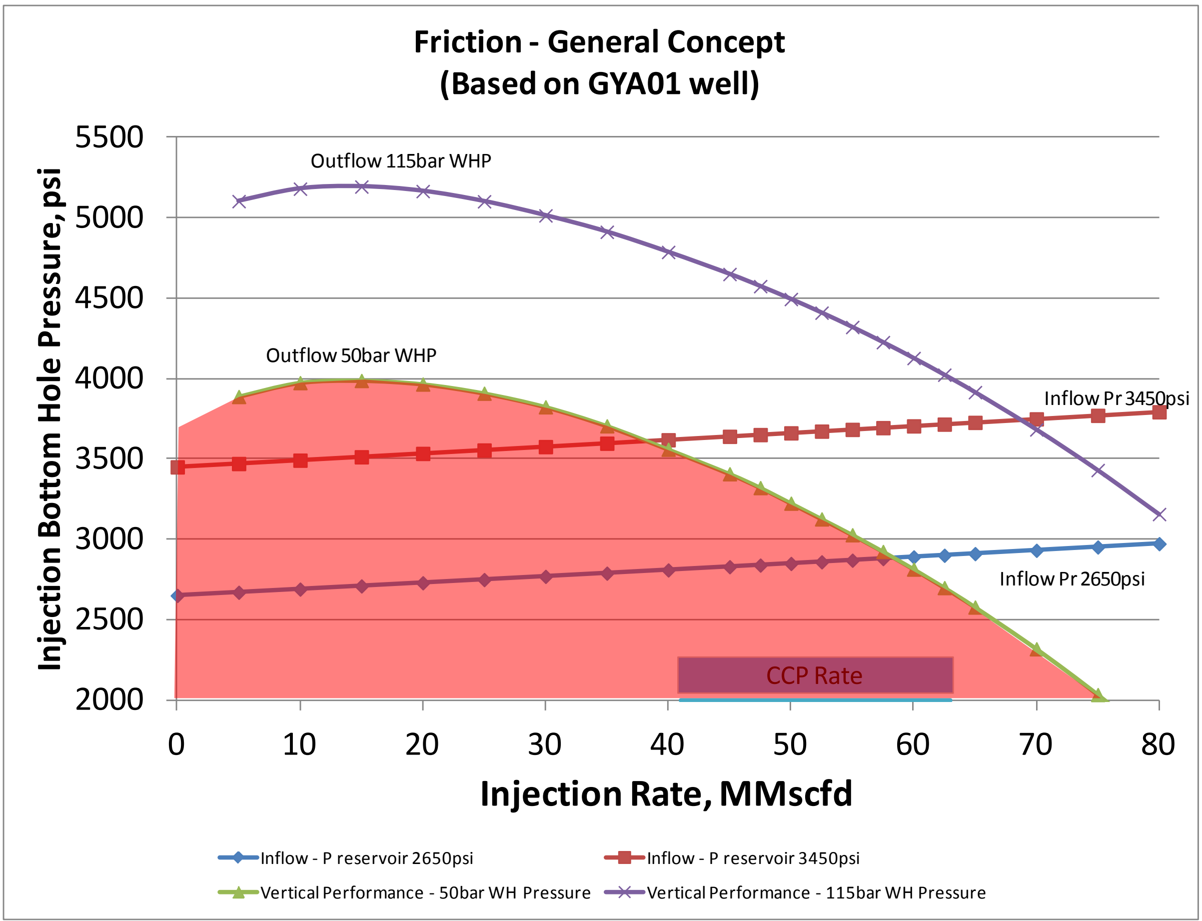
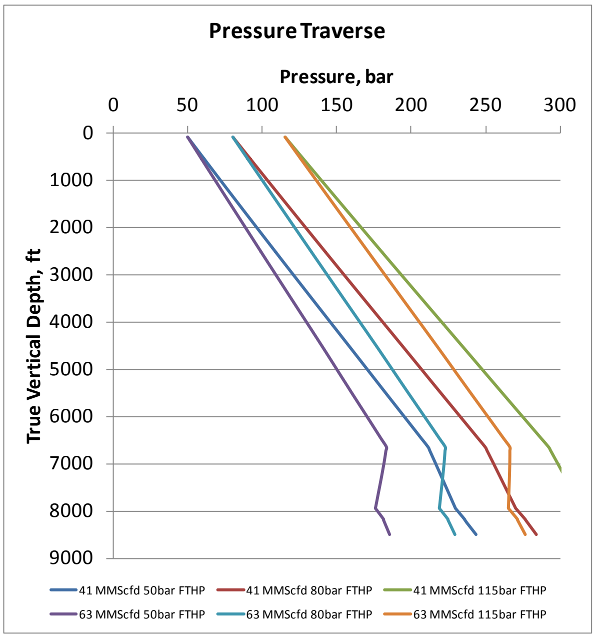


Figure 7-3: Outflow curves for the friction concept.

The CO_2 arrival temperature range at the platform is 2.3 to 10°C depending mainly on seabed temperature, reference case being 5°C. Reservoir temperature is 83°C at mid Captain D depth.

The expected pressure and temperature profile of the CO_2 in the wells under steady state injection are presented in Figure 7-4. The bottom hole CO_2 temperature is in the range of 20 to 35°C. The lowest temperature observed from modelling is 20°C



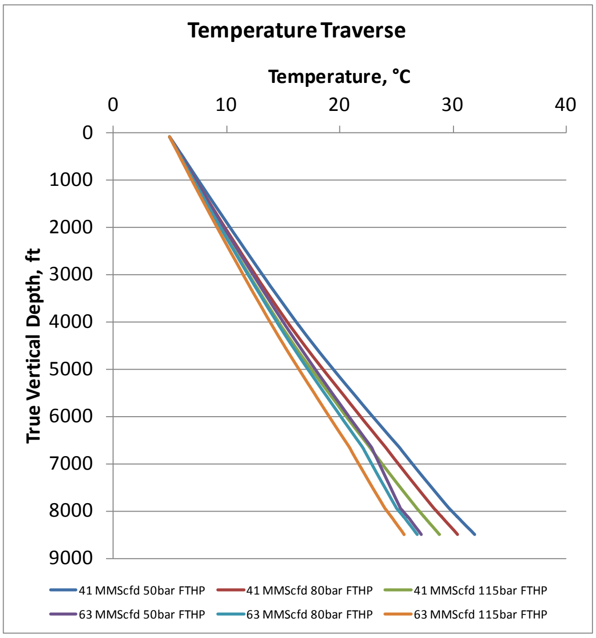


Figure 7-4: Pressure and Temperature predictions under steady state

The CO_2 will be injected in the tubing of the well in single phase (dense phase). The PVT properties of the CO_2 are well defined in this region as observed in the Figure 7-5 where the CO_2 density is relatively stable travelling down the well. This will minimise the calculation error in terms of the operating envelope of the wells and pressure traverses.

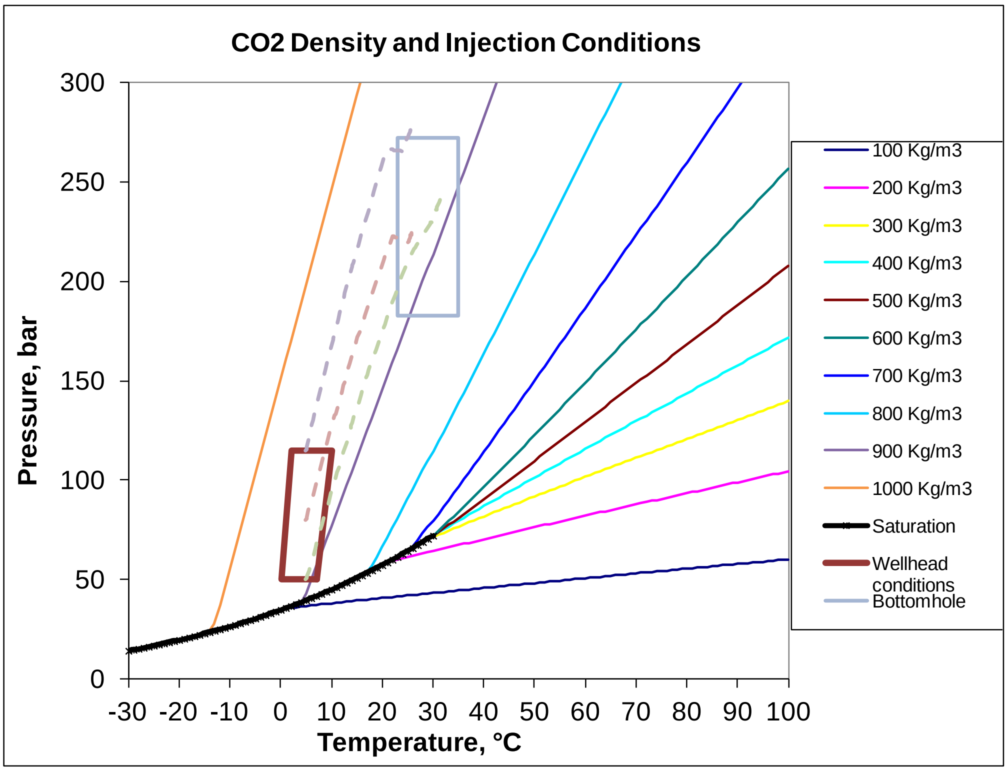


Figure 7-5: Pressure and Temperature prediction with respect to CO_2 phase envelope and density

The well components are well within the range of pressure and temperature expected during the injection period.

7.4.3. Transient conditions

During transient operations (well close-in and well start-up), temperature drop is observed at the top of the well. The faster the shut-in or faster the well opening, the less the resultant temperature drop. The cooling effect diminishes deeper into the well due to limited CO_2 flashing and heat transfer from the surrounding wellbore.

The reservoir pressure affects the temperature calculation during the transient calculations. The lower the reservoir pressure, the lower is the surface temperature expected during transient operation and hence the higher the stresses/impact in terms on well design.

The recommended procedure is to bring the well to the minimum rate (rate required to keep CO_2 in liquid phase at the wellhead, i.e. injection at 45 bara WH Pressure) and then close the well at the wellhead in 30 minutes. For bringing on a well on CO_2 injection, the recommended procedure is also to do it quickly. It is recommended to attain the minimum rate in 1 hour. Temperature as low as -15°C can be reached inside the tubing in the top of the well. Due to heat capacity/storage, this low temperature in the CO_2 is not observed in the other well components (tubing, annulus fluid, etc.), which will see less severe temperature drops. Calculated temperatures in the well for the recommended case at 172 bara reservoir pressure are given in the figure below.

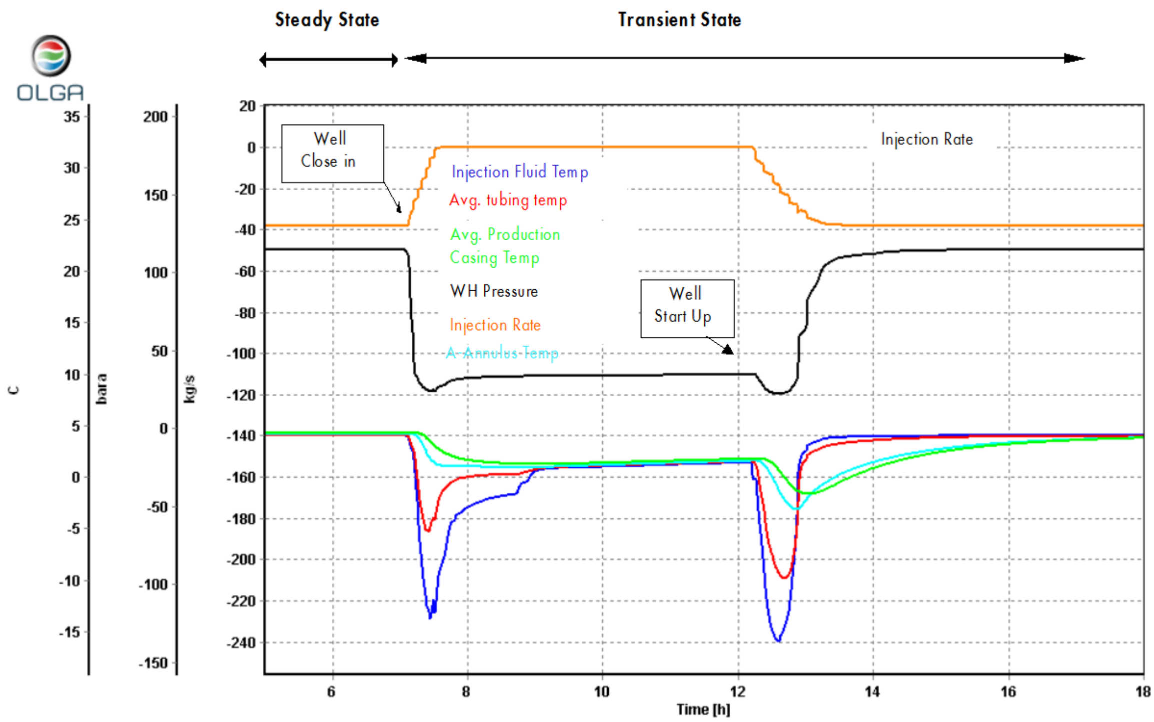


Figure 7-6: Recommended operations case. 4°C IWHT (2500psi P reservoir).

At ~450m depth CO_2 temperature in the tubing is 0°C. At reservoir depth, during CO_2 injection steady-state conditions, the temperature is constant around 17-20°C for an injection fluid temperature of 4°C. When shut-in, this bottom hole temperature rises slowly (~2 weeks) towards initial reservoir temperature. In summary, the expected transient conditions are as follows (Table 7-1:).

Table 7-1: Results of transient calculations - design case (Base Oil in the annulus).

	Design Case	Operating case
Steady State CO_2 manifold T, °C	3	-
Steady State manifold P, bara	120.2	-
Reservoir Pressure, psi	2500	2500
Steady State Conditions		
WHP, bara	45	115
WH temperature, °C	1	4
BH temperature, °C	17	20
Transient conditions		
Close in operation, h	2	0.5
Start Up operation, h	2	1
Coldest temperature (wellhead)		
Fluid CO_2, °C	-20	-17
Average tubing, °C	-15	-10
A annulus, °C	-11	-4
Production casing, °C	-10	-1

Strict operational procedures need to be implemented and adopted by the Goldeneye Well Operations Group during transient operations to avoid extreme cooling of the well components due to temperature limitations of the well components.

7.4.4. Well Design

The Goldeneye production wells targeted the Captain Sandstone gas reservoir and have been produced to a single NUI platform. The well design consists of 30", 20" x 13 3/8" and 10 ¾" x 9 5/8" casing design. A pre-perforated liner has been run in all wells across the reservoir in 8½" hole. This liner in turn has been covered with 4" sand screens and gravel packed. Hole angles vary up to 68 degrees - in Well GYA04.

The five existing wells were evaluated as suitable for use in CO_2 injection. However, due to integrity issues and CO_2 phase behaviour management it is not possible to use the wells without any modification. A rig is required to carry out a workover of the upper completion by installing small tubing in order to manage the CO_2 expansion.

There is no intention of drilling new wells or sidetrack wells, nor is there the intention of performing further workovers a later date.

Limitations of the different well components have been investigated for the expected well conditions under CO_2 injection. The change of use of Goldeneye wells from hydrocarbon production to CO_2 injection has been checked against the existing well design in the following areas: materials (metallurgy and elastomers), casing design, cement and pressure management.

The lower completion installed in the Goldeneye wells (screen + gravel pack) is considered fit for purpose for CO_2 injection.

The initial installation of the single tapered completion option is the simplest and most robust. The other evaluated systems - insert string, dual completion, concentric completion and downhole choke - present extra design /operation challenges and additional cost in comparison to the selected single tapered completion. As such, the proposal for the upper completion is to use single wells with slim tubing sizes.

Re-completion of the wells will incorporate changing out of the 7" tubing to a smaller size. It is proposed to standardise the top (from surface Xmas tree down to the SSSV) and the bottom (tail pipe up to the Permanent Downhole Gauge (PDG) mandrel) of the upper completion for the CO_2 injection.

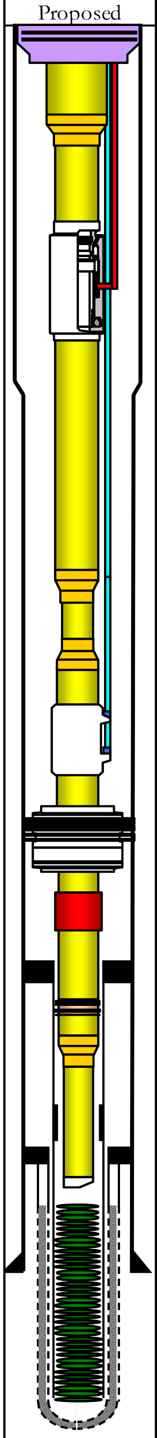
Distributed Temperature System (DTS) will be installed in the wells for monitoring purposes.

All completion equipment (i.e. attached to the tubing string) will have 13 percent Chrome metallurgy (13Cr) or super 13 percent Chrome metallurgy (S13Cr) equivalent metallurgy and will have working pressures in excess of the expected final well pressures.

The Xmas tree and the tubing hanger will be replaced in the workover with units having a lower minimum temperature rating than the currently installed.

For normal well operating conditions (injection and transient conditions) the wellhead system is compatible with the expected low temperatures. To validate the suitability of the wellhead system for CO_2 operation, detailed thermal simulations of the wellhead/Xmas tree system under uncontrolled CO_2 leaks will be done in the next phase to evaluate the extension of the low temperature during leak scenarios.

The planned completion for CCS is shown in Figure 7-7.



GYA 01 Proposed	Depth MD (ft)	Description of Item	ID (Inches)	Drift (Inches)
	79	Tubing Hanger	6.169	
		7.00 29# Tubing 13Cr/S13Cr	6.184	6.059
	139	XO 7.00" 29# x 4 1/2" 12.6#	3.958	3.833
		4 1/2" 12.6# Tubing 13Cr/S13Cr	3.958	3.833
	2500	SCTRSSSV 4 1/2" 13cr	3.813	
	3130	Casing XO 10 3/4" x 9 5/8"		
	6800	XO 4 1/2" 12.6# x 3 1/2"	2.922	
		3 1/2" Tubing	2.922	
	8430	X/O/Wire Finder Trip Sub 3 1/2" x 4 1/2" 12.6#	2.992	2.787
	8536	4 1/2" PDGM for PDG + DTS	3.958	3.833
		4 1/2" 12.6 # Tubing	3.958	3.833
	8596	9 5/8" x 4 1/2" Packer	3.818	
		4 1/2" Circulating/Pressure Relief Device	3.958	3.833
		4 1/2" Tubing		
	8696	Baker SC-2R packer/screen hanger 13Cr (existing)		
		G22 Seal Assembly	3.958	3.833
	8650	XO 4 1/2" 12.6# x 2 7/8" 6.4# FJ Tubing	2.441	2.347
	8755	Schlumberger FIV (existing)	2.94"	
	8850	2 7/8" Mule Shoe		
	8952	Top of 4.00" Screens (existing)	3.548	

Figure 7-7: Proposed general completion.

7.5. Workover Operations

A heavy-duty jack up is required in Goldeneye due to the 400 ft. [122 m] water depth. There are only a small number of jackups worldwide that can work in the water depth at Goldeneye.

Wells will be worked over by isolating the formation either with plugs or polymer fluids. In the case of using polymer plugs, an enzyme action will break down the polymers to a clean non damaging fluid, at a time after the workovers have been completed. In the case of using mechanical plugs then they need to be retrieved before injecting CO_2.

The existing production packer will be removed. A new packer will be installed along with the tubing, with a tail pipe seal assembly stung into the top of the sand screen hanger. An outline programme is presented below:

- Rig to location.
- Kill Well / set downhole barriers.
- Remove Xmas tree.
- Rig up & test BOPs (Blow Out Preventers).
- Recover downhole barriers.
- Recover existing completion tubing.
- Recover packer.
- Clean scrape 9⅝" casing.
- Carry out cement logging.
- Run new completion tubing.
- Set packer.
- Test tubing, annulus and TRSSSV (Tubing Retrievable Sub Surface Safety Valve).
- Install and test Xmas tree.

7.6. Injectivity

7.6.1. Initial Injectivity

The initial CO_2 injectivity in Goldeneye is expected to be on line with the excellent reservoir properties in the Captain D, injection pressure above the reservoir pressure for the expected injection rates is in the order of 14 to 28 bara. This conclusion is based on the rock properties and the hydrocarbon productivity. Corrections are made to the hydrocarbon productivity to obtain the expected CO_2 injectivity.

The best information available to estimate the future CO_2 injectivity is the current hydrocarbon wells productivity. The hydrocarbon productivity has been excellent and had confirmed the reservoir characteristics (see Figure 7-8: below).

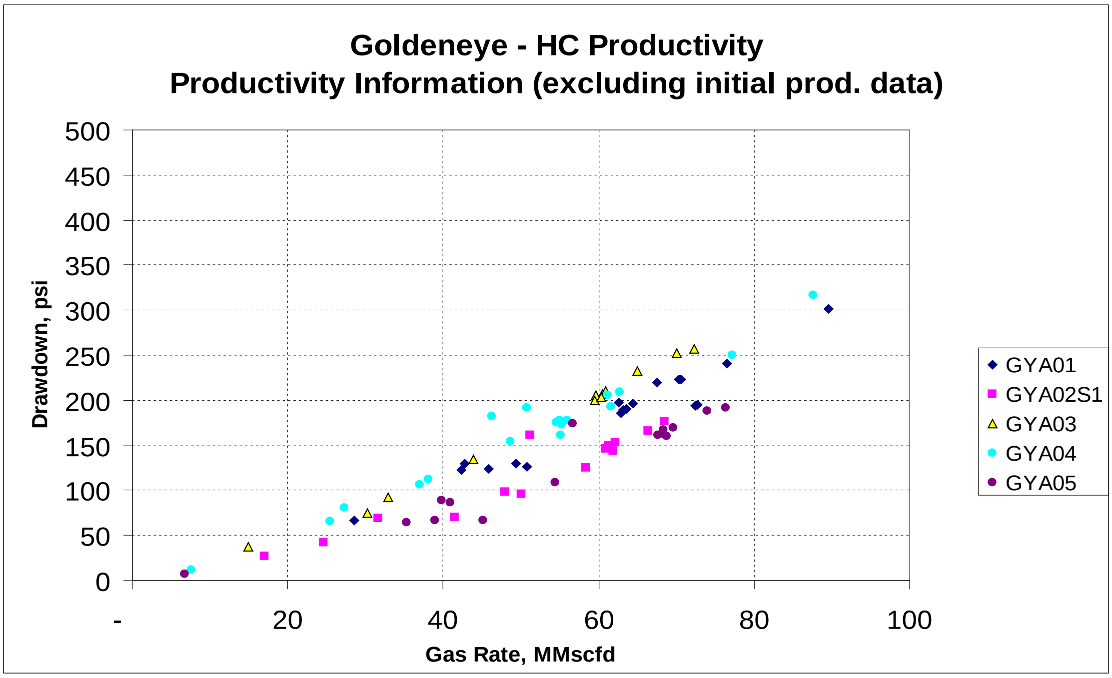


Figure 7-8: Productivity per well during long term production phase.

The CO_2 injectivity under matrix conditions can be estimated from the hydrocarbon productivity considering the different PVT between the hydrocarbon and the CO_2 PVTs. The impact of the PVT correction is small on injectivity as the high viscosity of the CO_2 is compensated by the low expansion factor of CO_2 with respect to the hydrocarbon gas. The differences in relative permeability between the hydrocarbon gas and the CO_2 have been estimated and also have a small impact.

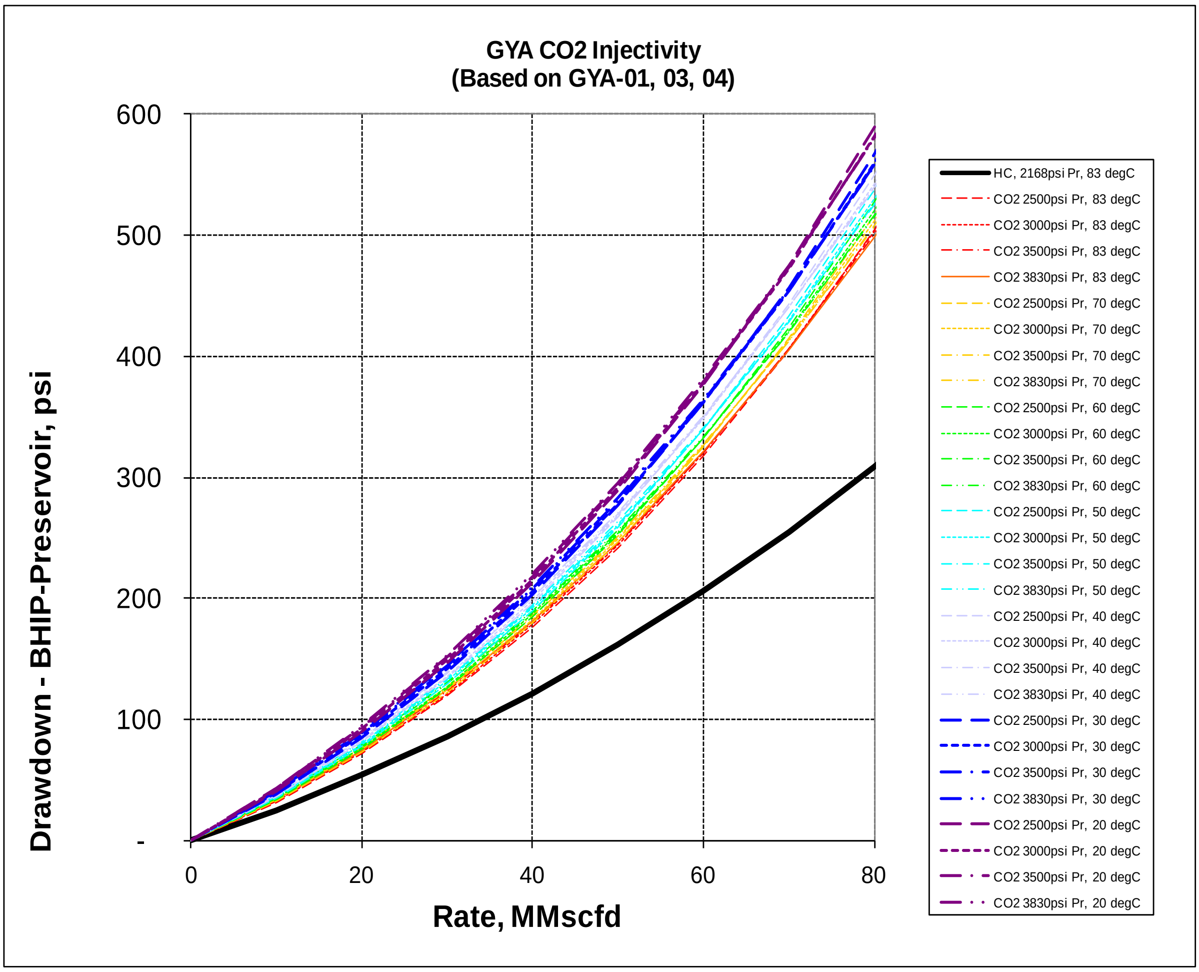


Figure 7-9: CO_2 injectivity vs hydrocarbon productivity (GYA01, GYA03 and GYA04).

7.6.2. Injectivity declining over time

7.6.2.1. Gravel pack and formation plugging

A threat to injectivity comes from the likelihood that debris (corrosion products, sand, dis-bonded pipeline coating etc.) resides in the pipeline today, after 6 years of operation. Displacement of these products into the well without any mitigation measures will plug the lower completion (screen-gravel pack) and the formation. Plugging may reduce the injectivity through the lower completion (screens / gravel) and formation with time. Mitigation options related to pipeline commissioning and filtration are required to ensure long term injectivity.

The offshore pipeline will then be cleaned during the commissioning phase of the CCS project. Removal of the solids and liquids during this phase is very important to ensure the long term integrity of the pipeline and the lower completion / formation.

Filtration of the injection fluid is required to avoid plugging at the screens / gravel pack and formation. The recommended values are filtration to 17 micron to avoid plugging of the lower completion and 5 microns to avoid formation plugging.

7.6.2.2. Hydrates

The formation of hydrates is only possible when water is present in significant enough quantities and the temperature and pressure of the fluids are within the hydrate formation window. Hydrate curves for CO_2 and Goldeneye hydrocarbon and their mixtures in the presence of a free water phase are shown below (the hydrate region is to the left of the curve). The hydrate deposition curve depends on the composition. Hydrocarbon hydrates are formed more easily compared to CO_2 hydrates according to temperature. For instance, at 200 bara pressure and in the presence of water, hydrocarbon hydrates can be formed at temperatures below 22°C whereas CO_2 hydrates only form below 11°C. Steady-state injection conditions are expected to be between 20 to 35°, as such hydrates are not expected at the reservoir level.

Free water is not expected in an injection scenario. However, it is possible that water will enter back the wellbore in case of an injection trip when not enough CO_2 is injected to displace the water from the wellbore.

During production, water has encroached into the Goldeneye gas cap and at least part of the well gravel pack will be surrounded by water at the time injection starts. The trapped gas saturation is estimated to be 25% so some methane will remain near the well. This is miscible with CO_2 so will eventually be displaced by the injected CO_2. The initial injection of CO_2 will drive water away from the well and cool the reservoir. If the well is then shut in this water may well return into the cooled part of the reservoir where hydrates could potentially form.

In order to reduce the initial risk of hydrate formation during the first years of injection (once water is displaced from the wellbore) it is considered prudent to introduce batch hydrate inhibition prior to operational opening of a well for injection purposes. If water is subsequently introduced into a well and/or it is suspected that water is present in a wellbore, then batch injection should continue. Methanol is currently preferred as an inhibitor and this will be supplied to the platform via the 4" piggybacked supply pipeline. Batch hydrate inhibition will feature as an instruction in the well operational procedures that will be developed for the injection system.

The hydrate curve for CO_2 and Goldeneye hydrocarbon and their mixtures in the presence of a free water phase are shown below (Hydrate region is to the left of the curve). The hydrate deposition curve depends on the composition. Hydrocarbon hydrates are formed more easily compared to CO_2 hydrates in terms of temperature. For instance, at 200 bar pressure and in presence of water, hydrocarbon hydrates can be formed at temperatures below 22°C whereas CO_2 hydrates only form below 11°C. The Steady State Injection conditions are expected to be between 20 and 35°C).

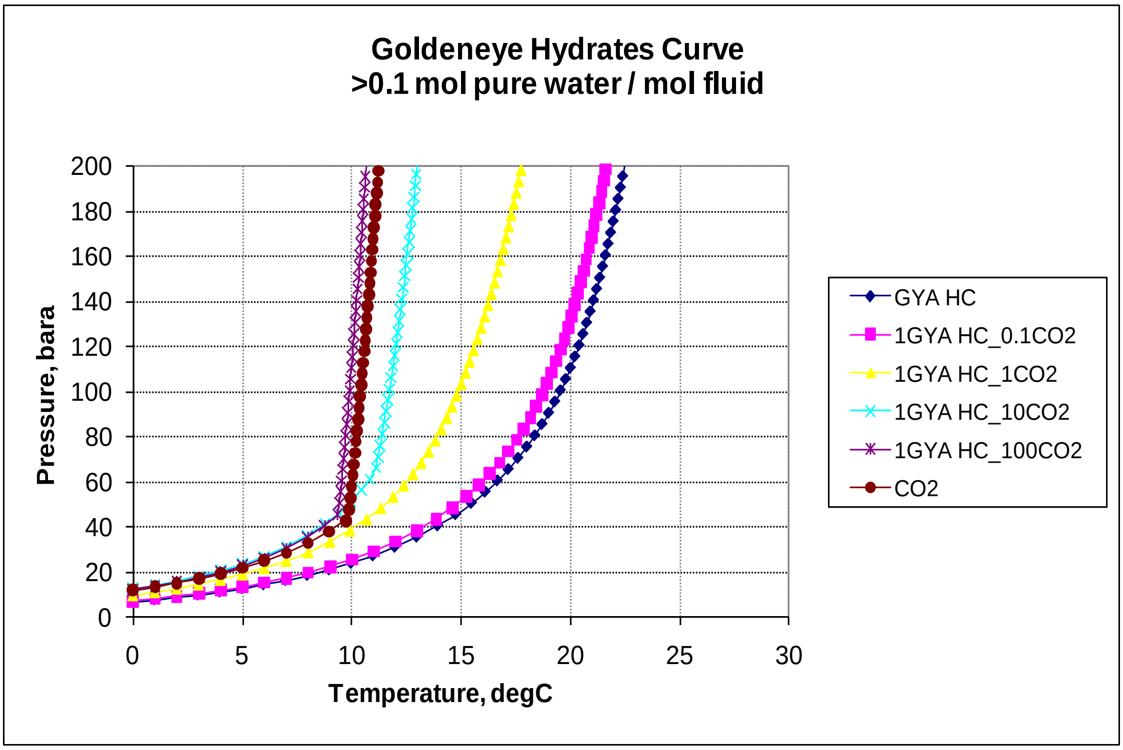


Figure 7-10: Hydrate deposition curve.

At reservoir temperatures there will not be an issue regarding hydrates. The cooling of the injection well and the surrounding reservoir matrix induced by the injection of CO_2 have the potential to create conditions favourable for the formation of hydrates. This assessment is based on the assumption that both formation water and hydrocarbon gas will be present initially in the well and the surrounding reservoir matrix.

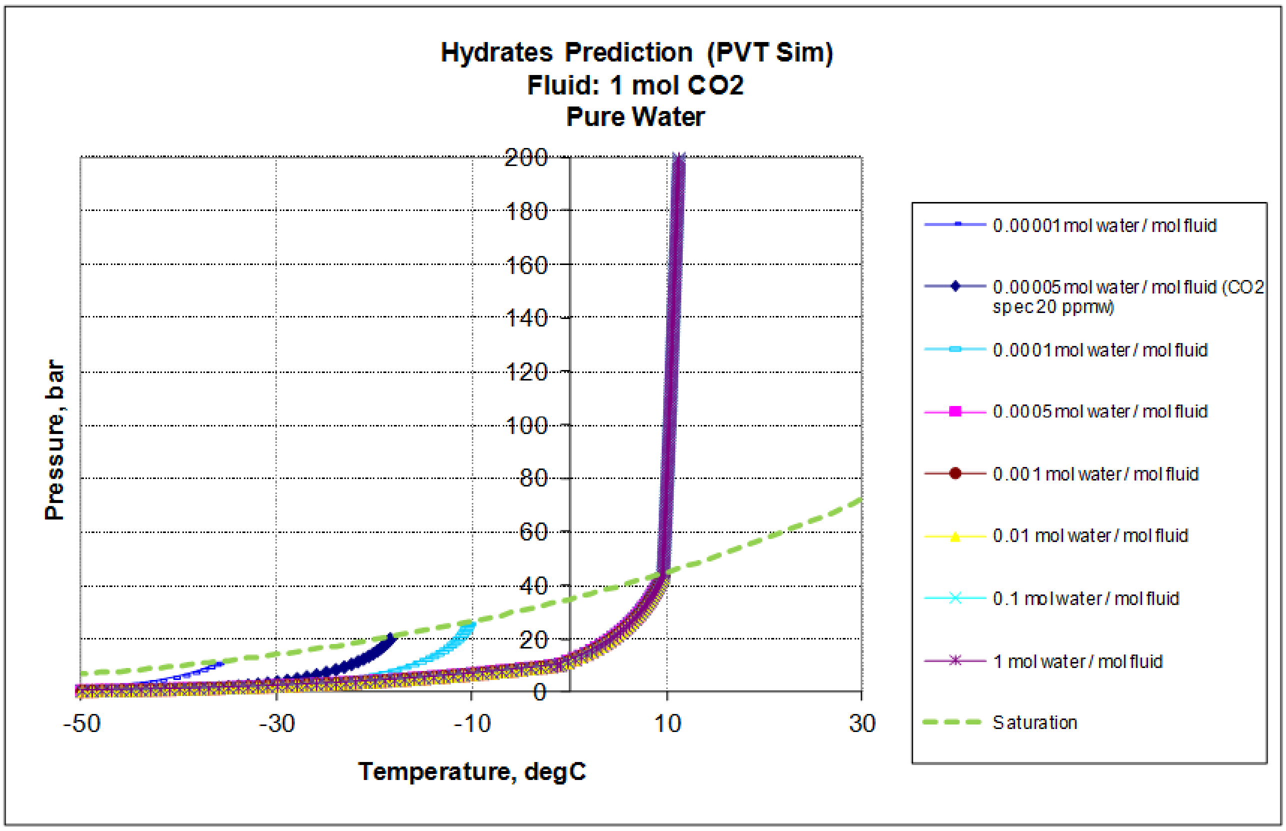


Figure 7-11: Hydrate deposition curve for CO_2 at different water concentrations

During steady injection conditions there are no hydrate issues as the dehydration of the injected fluid effectively inhibits any hydrate formation.

To reduce the risk of hydrate formation, it is considered prudent to introduce batch hydrate inhibition prior to well start-ups during the first year of injection. If water is re-introduced in the well and/or it is suspected that formation water is present in the wellbore then the batch injection should continue. Methanol is the preferred inhibitor.

The existing MEG system will be converted to a Methanol wellhead injection system. Modifications will involve the decommissioning of the MEG regeneration system and the two injection points on the topsides associated with ESDV equalisation and pipeline inhibition. The MEG drainage system will be modified to isolate redundant feeds and remove the nitrogen blanket discharges and relief valves from the existing flare. The MEG pumps, pipeline and lean MEG storage facilities will be retained and converted for methanol use.

It is expected that the requirement for methanol injection will decrease over time as light hydrocarbons and water are flushed from the well by the dry CO_2 and formation around the injection point and the reservoir pressure rises.

7.6.2.3. Disbondment of pipeline coating

This risk will be mitigated by the operation of tight control of the quality of the injection gas, and the installation of an appropriate filtration system on the platform upstream of the wells. Again, injection gas quality management will feature in operational procedures that will be developed for the installation.

The offshore pipeline was installed with an internal epoxy coating. The internal coating is a solvent based cured epoxy. The coating is not installed to protect against operational corrosion, it was installed to provide short-term corrosion protection during the pipeline storage and transportation. The thickness of the cured epoxy is between 30-80 microns.

Decompression testing was performed on the section of stock/spare pipe in the warehouse with CO_2 content during Longannet FEED. This provided confidence that the coating is not going to disbond even under very aggressive decompression rates with dense phase CO_2 (worse than will be seen in operation) and that we do not expect the coating to come off but this should not remove the need for filtration.

Although coating disbondment is not expected, there is still some degree of uncertainty of the coating response under CO_2 exposure.

Should disbondment occur during operation then particles ranging from small solids to relatively large fractions of coating may be formed, which could subsequently clog or completely block the gravel pack / formation, thereby reducing injectivity. The mitigation for this case is to have a tight control on the CO_2 quality being injected into the wells using a filtration system on the platform.

7.6.2.4. Flow reversal

By reversing the flow, from the production hydrocarbon production phase to the CO_2 injection phase, there might be some re-accommodation of fines currently embedded in the gravel pack under hydrocarbon production.

The effect of the flow reversing is considered because wells' productivities have been stable with time. Captain D is a well-sorted sandstone and gravel pack was designed considering the general criteria in the oil industry and industry experience in underground storage with sand control.

7.6.2.5. Joule Thomson cooling upon CO_2 injection into the reservoir

A Joule Thompson cooling effect can be expected when CO_2 undergoes adiabatic expansion upon entering the formation. The likelihood of encountering CO_2 expansion problems in Goldeneye is very low due to the low JT coefficient based on the injection pressure and temperature. Cooling effects of less than 3°C are anticipated.

7.6.2.6. Halite Precipitation

This problem has been observed in salt-saturated formation water reservoirs, and is caused by water evaporation around the wellbore due to CO_2 injection. The formation water in Goldeneye has a relatively low salinity (56,000 ppm TDS) that which will minimise the effect of any potential salt precipitation.

7.6.2.7. Injection under fracturing conditions

The reservoir has experienced a depletion process during the hydrocarbon production phase, from the original pressure of around 3830 psi to 2100 psi at the end of the hydrocarbon production phase. The minimum stress is affected by this process. The reservoir will undergo inflation during CO_2 injection and aquifer support. The minimum stress development is uncertain during an inflation process. The minimum stress development is also uncertain during a re-pressurisation process where it might not recover from the absolutely minimum in an inelastic process to the original minimum stress in a full elastic process.

The CO_2 will be injected cold with an average difference of 60°C between the formation temperature and the injection temperature; the minimum stress will also be affected by this cooling effect.

Considering the minimum stress range in the formation and the injection pressure, the most likely scenario during the initial injection period, when the reservoir pressure is relatively low, is to have injection under matrix conditions. However, as the reservoir pressure increases, it is possible that the formation is fractured during the injection process.

These fractures in the reservoir or Captain Formation are not detrimental to the containment capacity of the seal (Rødby/Hidra): they only penetrate a small distance (the distance depends on the interplay of thermal cooling and injection pressure).

In the case of injecting under fracturing conditions the CO_2 quality specification can be relaxed; however, there are limitations related to the erosion of the lower completions (screens / gravel) currently installed in the well.

The other potential issue is the displacement of gravel into the propagating fracture. The drag forces of the injected CO_2 might displace the gravel into the fracture leaving the space between the hole and the screens without gravel. Even under this event, the amount of solids from the formation passing the screens and depositing/filling the wellbore will be limited. The premium screens have an aperture of 208 microns, which is similar to the average particle diameter (d50) of the formation sand in the Captain D (d50=230 microns). In addition, the uniformity coefficient of the formation sand was estimated at 2.5. In summary, the screens were also purpose designed for the formation sand and in the event that the gravel is displaced into the propagating fracture, then the lower completion will behave as a Stand Alone Screen, which is a perfectly acceptable completion situation.

7.7. Wells operability

7.7.1. Operating envelope per well – Tubing Sizes

The operating envelope of the well can be designed by installing difference tubing sizes. In the friction concept a larger tubing diameter will provide a high injection rate and a smaller size will provide a smaller injection rate well. The inflow plays a minor role (when remaining stable and there is not significant deterioration of injectivity) in comparison to the choice of tubing size, Figure 7-12.

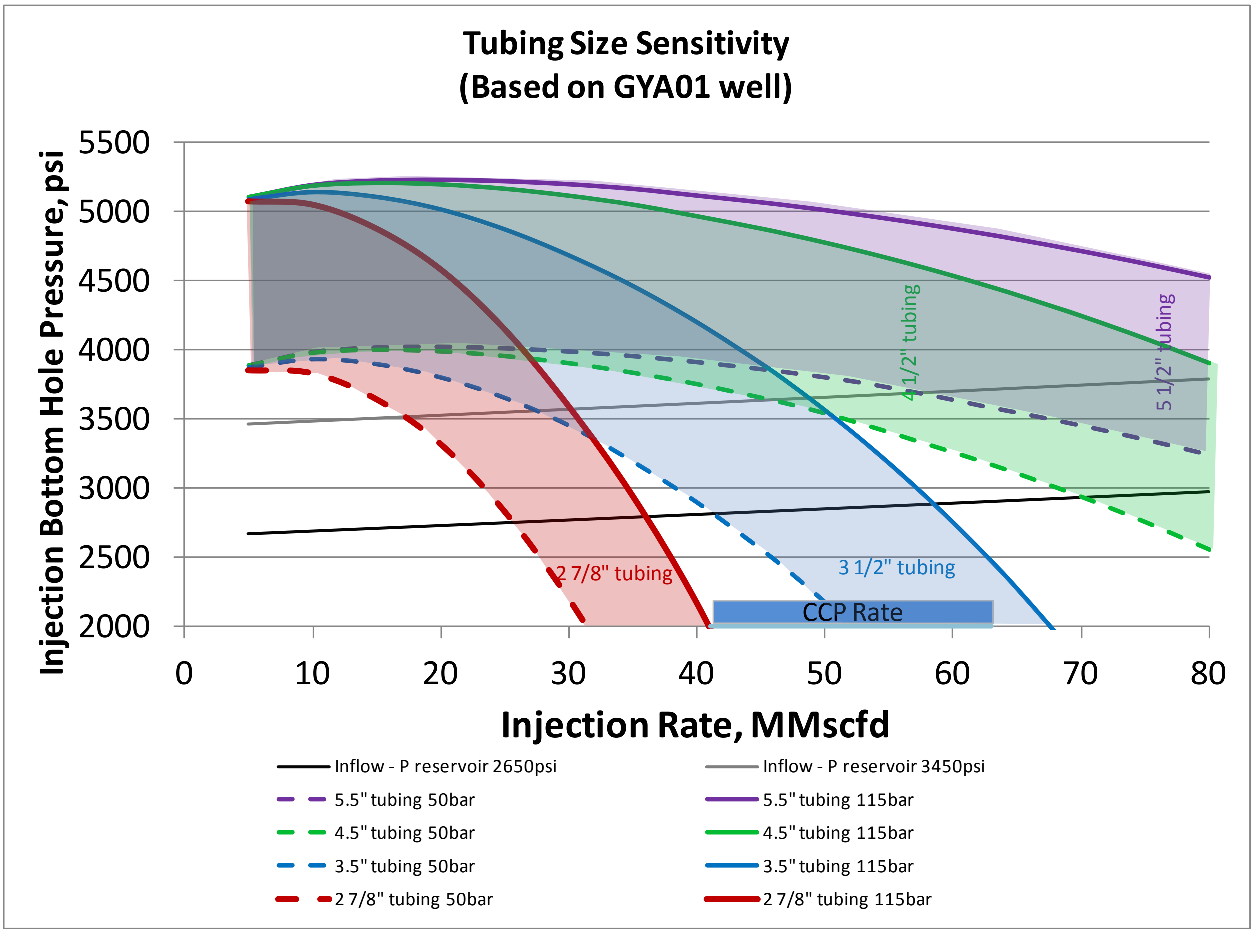


Figure 7-12: Friction dominated concept, sensitivity to tubing sizes

The reservoir pressure will increase due to the CO_2 injection and the aquifer strength.

The 2⅞" tubing is considered very small and the 5½" tubing seems very large for the Peterhead CCP rates. The tubing size required for the CCP rates is a combination of 3 ½" and 4 ½" completion.

The operating envelope per well will be engineered/tailored well by well considering the lifecycle of the project parameters (expected reservoir pressure, CCP rates, etc.).

7.7.2. Number of Wells

The Peterhead CCS bid submission, made in mid-2012, included four wells converted for injection/monitoring, with the recommendation to decide the way forward for the fifth well during further stages of the project.

The well(s) not converted for CO_2 injection will also need to be considered for the Peterhead project. Options included are to complete as an injector/monitor or to abandon the well.

GYA03 is planned to be a monitor well. The well can be converted to injection once the CO_2 has arrived into the well. The reason for carrying out the workover in this well are: risk distribution in the case of injectivity issues in the other wells, installation of a better and new completion string for monitoring the arrival of the CO_2 plume and synergy with the initial workovers.

The installation of small bore tubing in the wells limits the operating envelope of each well. In order to accommodate the range of injection rates at the different reservoir pressures during the injection life, each well will be completed with a different tubing size/configuration tailored to a specific rate range. The wells will then have overlapping operating envelopes and any rates specified in the integrated consortium basis-for-design will then be achievable through the choice of a specific combination of wells.

The number of required injector wells depends mainly on the injection estimates (reservoir pressure and injectivity); capture plant rates, CO_2 management, monitoring requirements and life cycle risk management.

In order to manage the CO_2 behaviour of the CO_2 and avoid integrity problems in the wells created by freezing, each well will have a limitation in terms of minimum rate dictated by a minimum of 50 bara of wellhead pressure. The maximum rate of a well will be dictated by the maximum available injection pressure, estimated at 115 bara at the wellhead dictated by the MAOP of the offshore pipeline.

Frequent opening-up and closing-in events should be avoided to limit the stresses in the well (temperature reduction during short periods of time) and to reduce operation intensity in the wells. As such, line packing will be important to reduce the level of well operations.

The injection range per well at a given reservoir pressure can be shifted by changing the length of the section of the different tubing sizes (4 ½" and 3 ½" tubing). However, the range per well cannot be expanded. The completion sizing also considers overlapping of well envelopes to give flexibility and redundancy in the system for a given arrival injection rate. At a given arrival rate different combinations will add flexibility to the system. The aim is to minimise the number of wells within the overall well restrictions.

A single well will not be able to inject from the minimum to the maximum CO_2 injection rate for the duration of the project. This is due to the limited injection envelope per well and the increase in reservoir pressure with injected CO_2.

The range of injection from the minimum to the maximum of the capture plant at the predicted reservoir pressure evolution can theoretically be achieved with only two wells. A small well might likely be injecting during the initial years of the project when the reservoir pressure is relatively low.

In case of unforeseen problems in a particular injector well, it is proposed to complete an additional or back-up well as a CO_2 injector to the number of wells required to cover the injection range. As such, at least three wells are required to be completed as injectors.

If the project chose to re-complete only four wells the utilisation of the fifth well would have to be addressed. The fifth well will be handed over to the storage license as part of the sale and purchase agreement of the assets from the current production license. This fifth well cannot be left under the current condition for the duration of the Peterhead CCS project given the risk of failure which would require significant expenditure. There are therefore only two options for the additional well: re-completion as injector/monitor; or abandonment.

A business decision has been made to abandon the fifth well.

8. Transportation and Injection Facilities

The project aims to reuse as much of the existing infrastructure as possible. However the facilities and pipelines were constructed for hydrocarbon production and transport. CO_2 in contrast, has a different phase behaviour, different dispersion characteristics (and hence safety implications), and becomes corrosive when mixed with water. As a result modifications have had to be made to facilitate the reuse.

The main reuse components are

- The offshore pipeline from St Fergus to Goldeneye.
- The Goldeneye platform.
- The production wells.

8.1. CO_2 Capture

The project intends to capture the CO_2 from the output of one of the existing three gas turbines from downstream of the Heat Recovery and Steam Generator (HRSG) – effectively abating ~400 MWe (CCGT) of output (pre CCS retrofit).

The proposed design for the CO_2 capture plant comprises a Prescrubber, a single very large absorber column, a smaller stripper column and associated pumps and heat exchangers. The capture plant uses steam from the new steam turbine, which will be installed at Peterhead Power Station, for amine regeneration. Power will be supplied from the UK grid.

8.2. CO_2 Compression, Dehydration and Oxygen Removal

The CO_2 product delivered from the Capture plant to the compression and conditioning plant, co-located at the Peterhead Power Station will be water saturated and contain traces of oxygen. The produced CO_2 stream will be cooled and partly compressed before having oxygen removed via catalytic reactions with hydrogen. Water will be removed using molecular sieve technology. The conditioned CO_2 will then further be compressed to ~120 bara and be ready for export to the Goldeneye Platform.

8.3. CO_2 Transportation

Following post-compression cooling, the resulting dense phase CO_2 stream will be transported directly offshore via a new short section of onshore pipeline which incorporates the pipeline landfall and a new offshore pipeline which will be tied in subsea to the existing Goldeneye pipeline. The pipeline landfall will be installed using a non-open cut technique; the proposed method is Horizontal Directional Drill (HDD). The tie-in between the new pipeline and existing Goldeneye pipeline will be made via a flanged spool which can provide expandability in future.

The CO_2 will then be transported via the existing Goldeneye pipeline to the depleted Goldeneye hydrocarbon field.

8.4. CO_2 Storage

The CO_2 will be permanently stored in an area centered on the depleted Goldeneye gas field. Studies indicate that the depleted field store can hold approx. 34 Mt CO_2. The existing unattended production platform is in excellent condition and will require minimal modifications. The five existing wells are suitable for conversion to CO_2 injection wells and will provide sufficient injectivity.

8.5. Modification Overview

The Goldeneye offshore pipeline will be partly re-used apart from the SSIV assembly adjacent to the platform. The section between the SSIV skid and the riser base will be replaced with 214 bara MAOP-rated spools.

The Goldeneye jacket will be retained with some additional protection applied to critical structural members shielding them from low temperature jets of CO_2 that could result from a failure of the riser. The jacket has some structural redundancy and currently passive fire protection is not provided. Further evaluation will be performed to evaluate whether the risk from cold CO_2 jets is greater than jet fires. If it is, a product has been identified that, if proven by testing, could be used to insulate critical members and protect from material failure caused by low-temperature embrittlement due to impingement of cold jets.

Topsides modifications are summarised as follows:

- The existing pig launcher will be converted to a pig receiver capable of handling intelligent pigs. This will require extension to the pig receiver barrel.
- From the pipeline riser, existing facilities fabricated in duplex stainless steel will be isolated and decommissioned. New stainless steel pipework and equipment will be installed to link the pipeline to the injection manifold.
- A new orifice plate meter will be installed on the pipework to measure the total flow of gas injected into the reservoir.
- A back pressure control valve will control the back pressure in the pipeline so that it operates in the dense phase above the critical pressure of CO_2.
- 2 x 100% filters will be installed to remove particulates from the well stream.
- A new injection manifold will be installed with new flowlines to injection well Christmas trees
- The flowlines will have orifice plate meters installed.
- New injection chokes will be installed on the flowlines, remote from the Christmas tree.
- A new methanol supply system will connect the existing 4" [102mm] MEG supply line to injection points at the wellhead and upstream of the choke valve.
- The existing vent and drains system will be largely removed to allow space for the new filters.
- A new vent system for depressuring the pipeline will be installed and routed up the existing vent tower.
- The existing 10" vent stack will be retained and adapted for use in the wellhead vent system.
- The wellhead vent system will be installed to allow depressuring of the wells required for SSSV testing.
- Several thermal relief valves will be installed on the process pipework and equipment. The discharge of these will be routed below deck.
- Several vents will be installed to allow depressuring of pipelines and equipment. The discharge of the vents will be installed below deck.

8.6. Pipeline Operating Envelope

Hydraulic analysis has been performed to confirm the capacity of the exiting for CO_2 service. This analysis confirms that the 20" pipeline can be used for transporting 138 tonne/hr. of CO_2 in dense phase.

The MAOP[6] of the existing pipeline system is 133 bara. Considering the pipeline elevation profile and change in density (between multi-phase fluid and dense phase CO_2) it was concluded that the maximum inlet pressure of the pipeline is limited to 121 bara.

Steady state simulations for summer and winter conditions have shown that the operating envelope is between 85 and 120 bara.

The pipeline can be operated acceptably over the anticipated flow range from 0 to 250 tonne/hr. Preliminary analyses have been carried out simulating the transient behaviour of the pipeline system. In absence of compressor curve information, the compressors' throughput has been assumed to be constant. Preliminary calculations have indicated that the sudden closure of an onshore ESD valve creates a negative surge pressure up to approximately 5 bara in the offshore pipeline. In order to prevent phase transition and two-phase behaviour along the pipeline and recognizing a vapour pressure of approximately 75 bara, it is advised to maintain a minimum back pressure of 85 to 90 bara.

8.7. Dense Phase Transportation of CO_2

The transportation of CO_2 down the Goldeneye pipeline will be in the dense phase, at pressures above the critical pressure of CO_2 (73 bara) or cricondenbars of expected CO_2 mixtures (74.1 bara).

There are four distinct regimes that can be used to transport CO_2. These are illustrated in Figure 8-1.

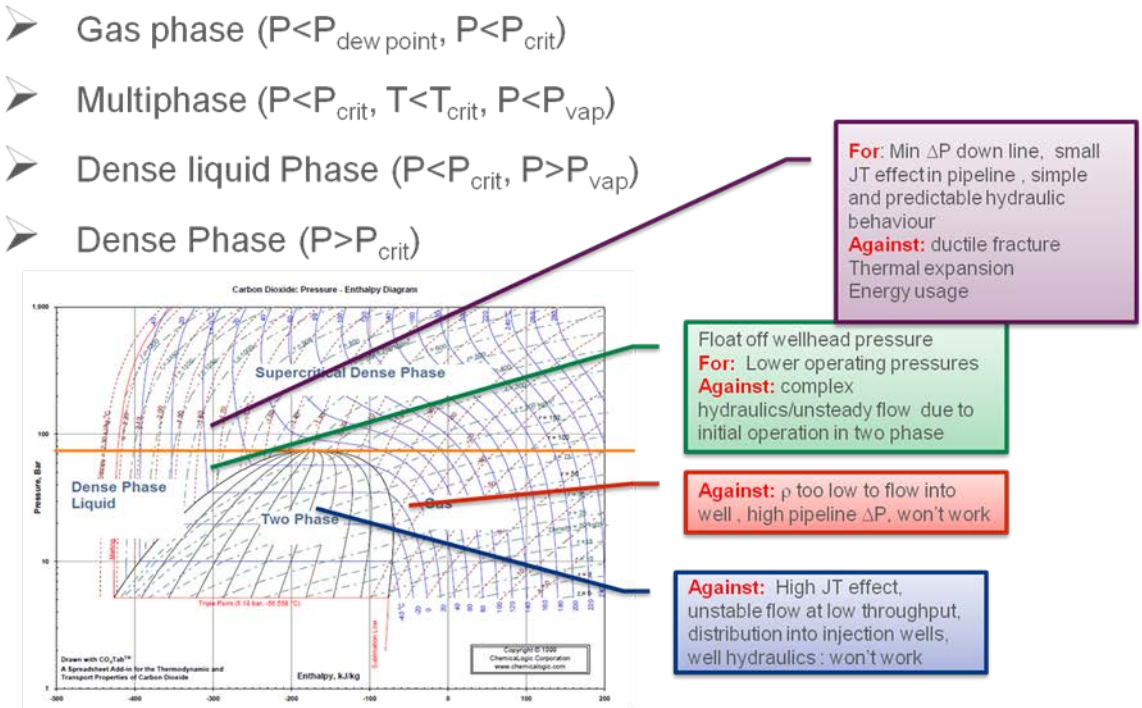


Figure 8-1: Modes of pipeline operation

[6] Maximum allowable operating pressure

8.7.1. Gas phase

This has been de-selected because there would be insufficient pressure to inject into the reservoir. Compression would therefore be required offshore and this is not feasible on the existing Goldeneye Platform.

Notwithstanding the above comments, the pipeline will operate with gas phase CO_2 during initial commissioning, final decommissioning and if the pipeline is required to be depressured during its operational lifetime.

8.7.2. Two Phase

For two-phase flow, the pipeline operates below the critical temperature and pressure and less than the vapour pressure at the operating temperature of the pipeline. Operation of the pipe in two-phase will be required when commissioning, decommissioning and during depressuring.

In general, two-phase operation would not avoid compression or the necessity to recomplete the wells but it *would* lead to complex operating constraints.

8.7.3. Dense Phase Liquid

This involves operating the pipeline at a pressure below the critical pressure but at a pressure below the vapour pressure of CO_2. This could be achieved by compressing the CO_2 to ~126 bara cooling to ~44ºC with air coolers and then reducing the pressure to ~50 bara/14ºC. The fluid would be two phase but would condense in the pipeline to a dense phase liquid. There would be a similar well and compression requirement to dense phase (i.e. where operating pressure $>P_{critical}$) and would offer no significant advantage apart from reducing the risk of running ductile fracture without the need for refrigeration. This would be due to operation below critical hoop stress levels necessary to for crack propagation in critical regions of the pipe. However, adopting this mode of operation would reduce the operating envelope of the wells, requiring well recompletion when the reservoir pressure increases. This would be extremely costly and hence this option has not been adopted for the Pipeline and facilities. It should be noted though that the upper sections of the injection tubing will effectively operate in this flow regime for a significant part of project life.

8.7.4. Dense Phase Flow

The Peterhead offshore system will be operated in 'dense phase'. In this context, 'dense phase' implies that the operating pressure is above the fluid critical pressure (or cricondenbar) but below the critical temperature. This will involve operating the pipeline at an inlet pressure of about 120 bara, with an arrival pressure of 115 bara upstream of the topsides pipeline back-pressure control valve.

In general, two-phase operation would not avoid compression or the necessity to recomplete the wells but it *would* lead to complex operating constraints.

8.7.5. Dense Phase Liquid

This involves operating the pipeline at a pressure below the critical pressure but at a pressure below the vapour pressure of CO_2. This could be achieved by compressing the CO_2 to around 126 bara cooling to 44ºC with air coolers and then reducing the pressure to 50 bar/14ºC. The fluid would be two phase but would condense in the pipeline to a dense phase liquid. There would be a similar well and compression requirement to dense phase (i.e. where operating pressure $>P_{critical}$) and would offer no significant advantage apart from reducing the risk of running ductile fracture without the need for refrigeration. This would be due to operation below critical hoop stress levels necessary to for crack propagation in critical regions of the pipe. However, adopting this mode of operation would reduce the operating envelope of the wells, requiring well recompletion when the reservoir pressure increases. This would be extremely costly and hence this option has not been adopted for the

Goldeneye Pipeline and facilities. It should be noted though that the upper sections of the injection tubing will effectively operate in this flow regime for a significant part of project life.

8.7.6. Dense Phase Flow

The Goldeneye offshore system will be operated in 'dense phase'. In this context, 'dense phase' implies that the operating pressure is above the fluid critical pressure (or cricondenbar) but below the critical temperature. This will involve operating the pipeline at an inlet pressure of about 120 bara, with an arrival pressure of 115 bara upstream of the topsides pipeline back-pressure control valve.

A minimum of two wells be on line to handle the full flow of 250 m^3/hr. The wellhead chokes will be manually adjusted to attain the required flow rates in each well and the injection manifold pressure will effectively float.

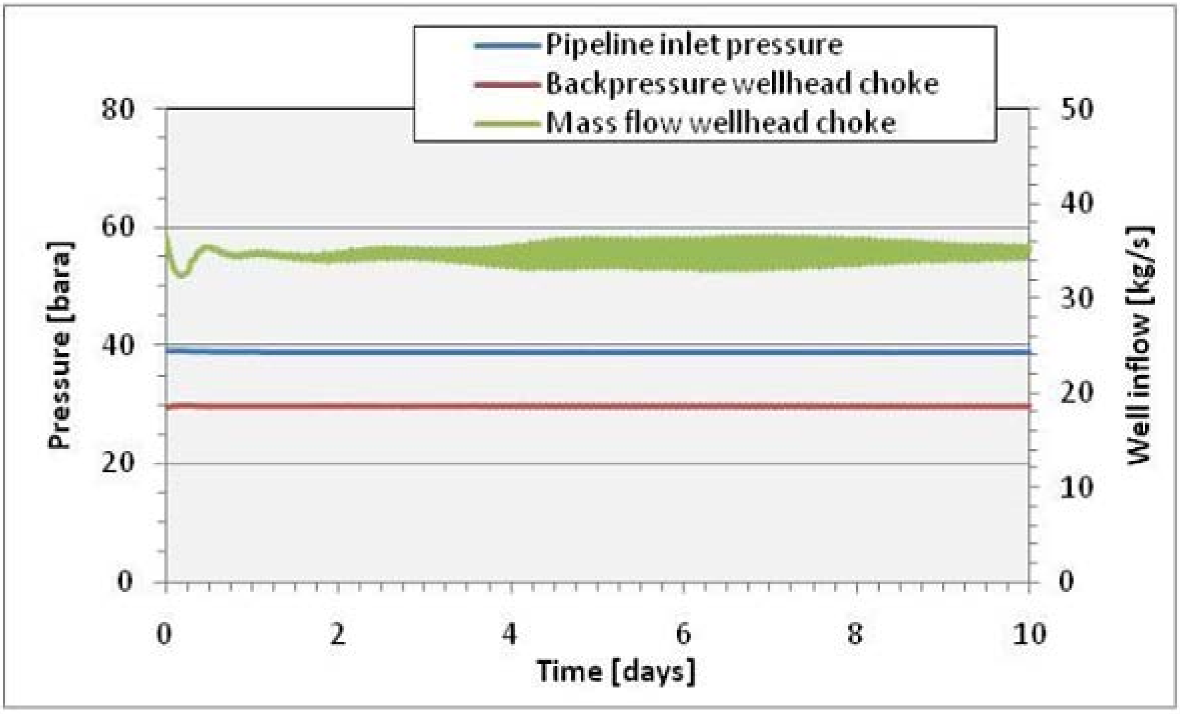


Figure 8-2: Stable behaviour: Two phase at 125 tonnes/hour.

8.8. CO_2 Filtration

There is a risk of blockage of the Lower Completions of the Goldeneye injection wells. In order to avoid costly workovers or re-drilling of wells, the injection fluids are required to exclude particles of larger than 5 microns.

Some coarse filtration will be provided by the riser. However, the velocity of 0.5 m/s will carry particles >35microns topsides and will not be sufficient. Topsides filtration is therefore required upstream of the injection wells. This will be provided by a filter separator.

8.9. Methanol Injection

8.9.1. Conversion of existing facilities

It is likely that the existing MEG system will be converted to a Methanol wellhead injection system. The existing system is primarily used for pipeline hydrate and corrosion inhibition. The onshore system currently comprises storage facilities for rich and lean MEG, a MEG regeneration system, injection pumps and a 4" pipeline to the platform. There is also a dedicated drainage system to handle drained MEG and recycle the fluid to the regeneration system. On the platform, the MEG is currently metered and commingled with the export gas before it goes into the pipeline. There are also facilities to inject MEG into the wellheads for cold start-up and equalisation across the riser ESDV.

Modifications will involve the decommissioning of the MEG regeneration system and the two injection points on the topsides associated with ESDV equalisation and pipeline inhibition. The MEG drainage system will be modified to isolate redundant feeds and remove the nitrogen blanket discharges and relief valves from the existing flare.

The MEG pumps, pipeline and lean MEG storage facilities will be retained and converted for methanol use. Methanol is more hazardous than MEG both in terms of its flammability and toxicity so its deployment must be subject to careful review. There are existing methanol facilities at St Fergus and methanol is commonly deployed both onshore and offshore so the changeover should be feasible.

8.9.2. Brittle Fracture

Drop Weight Tear Qualification Tests (DWTT) were carried out during fabrication of the 20" pipeline to evaluate the risk of a running brittle fracture in the offshore pipeline. The DWTT data show that the line pipe is qualified to a minimum temperature of -20°C for a running brittle fracture.

8.9.3. Inerts and Running Ductile Fracture

Although very unlikely providing proper design and operational measures are applied, fractures can occur in pipelines when a crack occurs at hoop stress levels sufficient to propagate the crack. The fluid in the pipe will depressure through the crack generating a rarefaction wave in the pipe that propagates at sonic velocities down the pipe. For fluids that remain in the gas phase such as methane, the rarefaction wave will propagate at a speed greater than crack propagation speed. The hoop stress on the pipe is relieved by virtue of the rapid loss of pressure and the crack arrests. For fluids such as dense phase CO_2, where isentropic depressurisation leads to entry into the two phase region as the fluid drops below the bubble line, the behaviour of the system is quite different. In this case the energy of the expansion wave is dissipated in the generation of vapour and there is a rapid reduction in sonic velocity. The reduction in sonic velocity is sufficient to reduce it below the ductile crack propagation velocity. As a result, the hoop stress on the crack tip is unrelieved and the crack propagates until other factors, e.g. an increase in pipe wall thickness, reduce the stress sufficiently to reduce the crack.

Analyses have defined a range of operating conditions that will avoid the risk of a running ductile fracture. These safe operating conditions depend on the pipe wall thickness. When the pipeline exhibits a general wall thickness reduction during any period of the design life or e.g. bottom line corrosion over a long distance, there is a limit on the operating condition. On the other hand when the nominal wall thickness is intact and the pipeline has only developed local corrosion patches there is no limit on the operating conditions with respect to running ductile fracture.

For the 15.9 mm wall thickness section of the pipeline there is no risk of a running ductile fracture even if the corrosion allowance has been used. However, for the 14.3 mm wall thickness section (further offshore) there is a risk of running ductile fracture if the corrosion allowance is used up. This imposes a maximum operating temperature limit depending on the water depth and this in turn is sensitive to CO_2 composition, particularly of low levels (<1%) of volatile components such as N_2, H_2 and Ar.

Based on this analysis it has been concluded that a maximum inlet temperature of 29ºC is required to eliminate the risk of running ductile fracture for an inlet composition within the limits specified i.e. 99% mole CO_2, ≤1% H_2+N_2+Ar, ≤0.3% H_2.

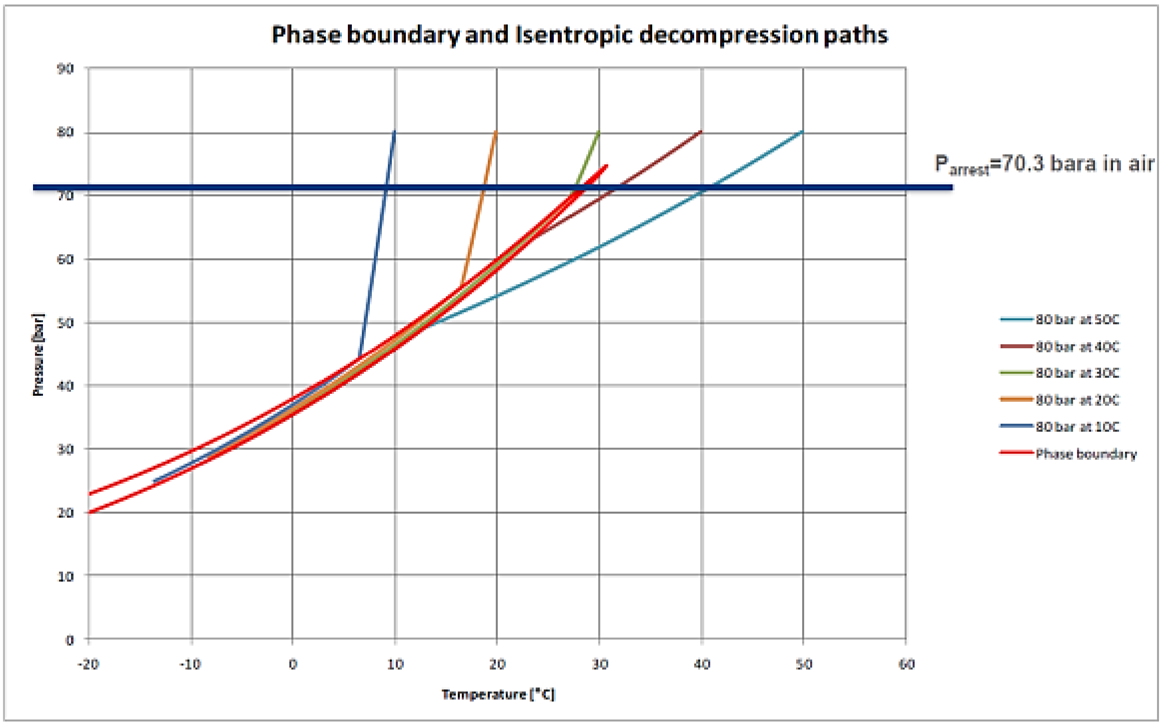


Figure 8-3: Phase boundary and isentropic decompression from 80 bara.

8.9.4. Water and Corrosion of Carbon Steel

The pipelines are constructed from carbon steel. Assuming proper control of the water content of the CO_2, specified at 20 ppmW to avoid formation of free water, a corrosion allowance of 2 mm is adequate to make the carbon steel reach the design life of 20 years. Based on an estimated CO_2 corrosion rate of 10 mm/y, this corrosion allowance is enough to cope with accidental wetting of the steel for 1% of time. In spite of this, presence of free water in the pipeline is unacceptable and it must be operated "dry". The actual corrosion allowance still in place upon cessation of hydrocarbon production needs to be confirmed.

The saturated water content of CO_2 exhibits a minimum between 30 and 40 bara (Figure 8-4:). This minimum is calculated to be about 100 ppmW. The water specification for the CO_2 exported from Longannet is specified to be ≤20 ppmW [50 ppmV] to allow a margin for uncertainty as recommended by DNV[7].

There is a small but finite risk of water backflow from the wells. This will be prevented by non-return valves installed topsides and isolation valves to prevent the flow of well fluids during periods when the pipeline is at a lower pressure than tubing head pressures. In general this will not be the case, but if the well becomes filled with light hydrocarbon, the tubing head pressure could be high. Also during an injection hold situation, the contents of the CO_2 pipeline can cool leading to a significant loss of pressure (8 bar/°C).

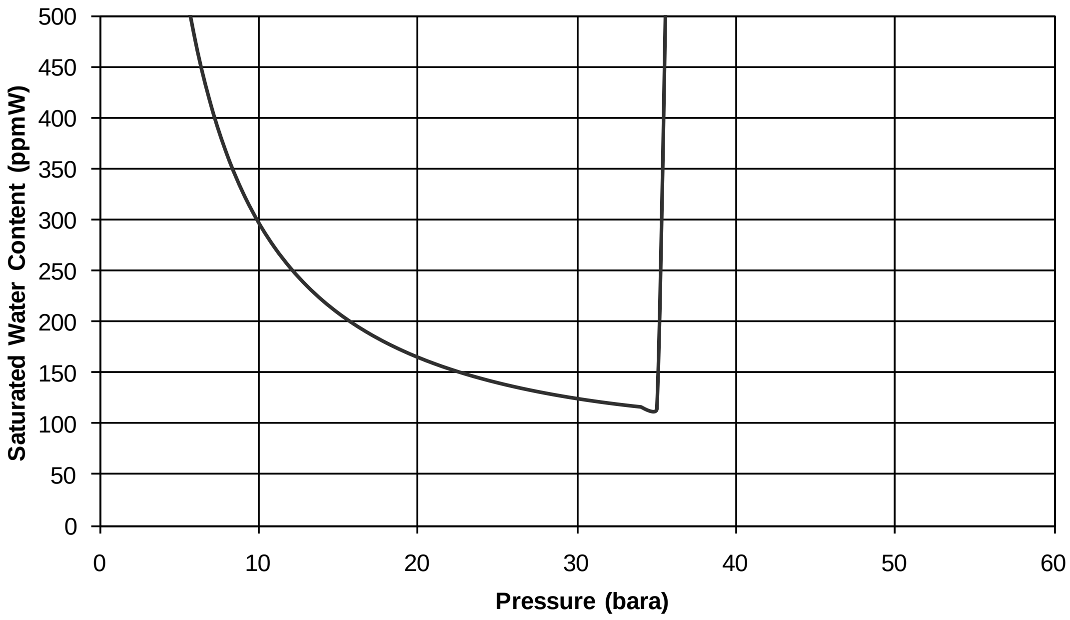


Figure 8-4: Saturated water content of CO_2 at 1°C.

8.9.5. Oxygen and 13Cr Pitting Corrosion

Oxygen control is required to prevent pitting corrosion of components made of 13Cr in the wells. For Peterhead CCS the decision has been made to adopt rigorous O_2 control based on Shell Group experience of tubing failures in water injection wells where oxygen levels have been poorly controlled.

The O_2 limit for Peterhead CCS is driven by the presence of 13Cr well completion material, not by carbon steel or other alloys. The corrosion resistance of Inconel (existing Goldeneye production separator liner if re-used) and 22Cr duplex (most of the existing pipework) in oxygen-containing environments is better than that of 13Cr.

Experience with water-injection wells, shows that there is no evidence for pitting-corrosion if O_2 concentrations in water are kept below 10 ppb (by mass).

The partition of O_2 between CO_2 and water has been calculated over a range of tubing conditions from 45 to 310 bara/0 to 85°C.

The results predict a greater solubility of O_2 in CO_2 compared with water and that O_2 transfers to the aqueous phase as pressure increases.

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[7] *DNV Recommended Practice DNV-RP-J202, Design and Operation of CO2 Pipelines, April 2010.*

The methods predict K values as an order of magnitude of ~10^2. For 10 ppb (mass) in the aqueous phase this equates to O_2 concentrations in CO_2 of the order 1 ppm (molar). It is therefore proposed that the design specification of O_2 in CO_2 is 1 ppm (molar/volume).

O_2 level is specified below 1 ppmV to prevention of attack of 13Cr steel well tubular. At these levels the contribution of O_2 to carbon steel corrosion is insignificant compared to that of CO_2. To achieve this level oxygen removal system is installed interstage of the compressor.

8.10. Compositional Analysis

8.10.1. Regulatory Framework and installation

The European Parliament has issued legislative requirements regarding Carbon Capture and Storage (CCS). These requirements are contained within the Commission of the European Communities "Directives". The directives contain the requirements for the monitoring and reporting of CO_2, composition at its entry into the pipeline transport system at the point of capture and at points in the transport system where waste or other matter could be added.

The Directives introduce the concept of an "Installation". The requirements for product composition analysis and reporting at the boundaries of installations are also detailed in the directives.

As the Metering System at Peterhead is the same Installation as the Goldeneye Platform, then, the primary location for the analysis of product composition will be at the metering station at Peterhead before entry into the transportation system.

8.10.2. Product Sampling and Analysis

Product sampling equipment will be installed at strategic points throughout the "Installation". Within the Shell assets temporary analyser(s) will be installed at the St Fergus onshore facility specifically for start-up activities and CO_2 manual sampling points will be installed at both the onshore facility and offshore on the Goldeneye platform.

Manual Sampling Points

Manual sampling points will be strategically placed throughout the Goldeneye onshore and offshore facilities. They will be used for random sampling purposes at predetermined intervals, the interval periods will be defined during detailed design by the interested parties e.g. pipeline management team, formation management team.

Automatic Sampling Points

Where necessary, or in lieu of manual sample points, automatic sampling systems will collect samples on demand or at predetermined intervals.

A sample cylinder will be installed in the sample collection system and when initiated the sample cylinder will be filled with a conditioned product sample.

Start-Up Analyser

H_2O Analyser/s will be specified to monitor the CO_2 product during start-up activities on its passage to the sequestration wells.

Analyser/s installed at St Fergus onshore facility will have accuracy equal to or better that the primary analyser system installed at National Grid at St Fergus.

It is envisaged that these analyser(s) would be used during the initial start-up phase to monitor for residual water left in the pipeline after the drying process and installed both onshore and offshore.

8.11. Goldeneye Pipeline Depressuring

Dynamic simulations of Goldeneye Pipeline depressuring indicate that, if uncontrolled, the pipeline could be chilled to temperatures below -15°C in low spots. This is shown in Figure 8-5.

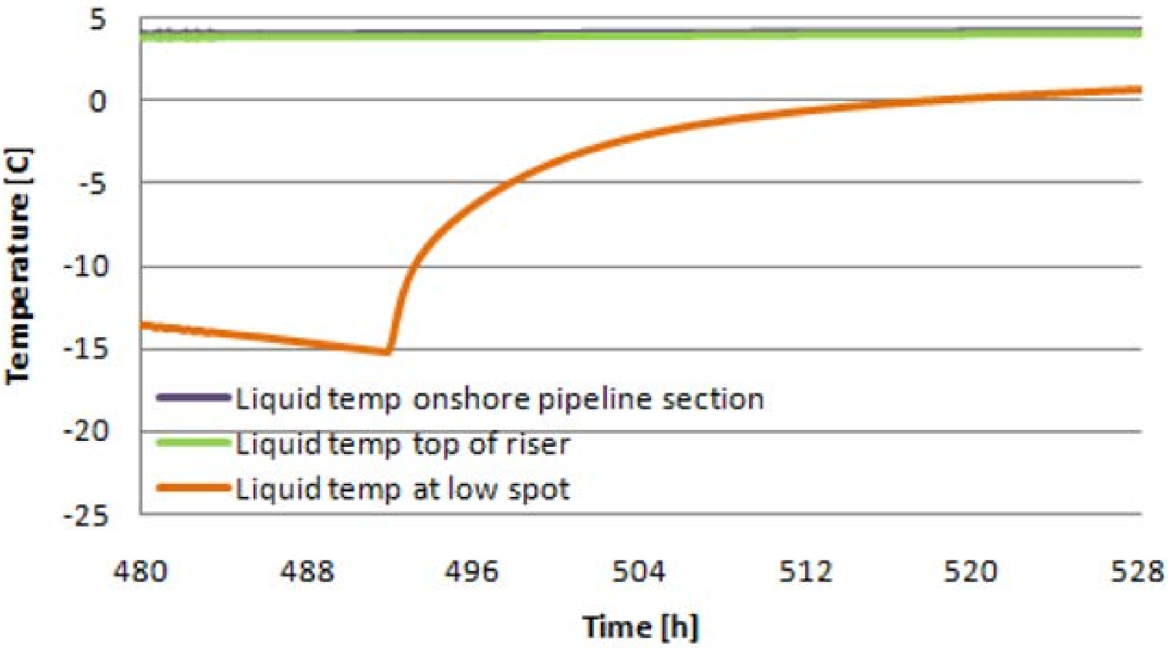


Figure 8-5 Pipeline fluid temperature 480 to 528 hours after depressuring start.

Although the pipeline material is qualified for temperatures down to -20°C, temperatures below zero could cause local freezing that may increase pipeline buoyancy and cause damage to concrete and other pipeline coatings. Pipeline depressuring therefore needs to be controlled to avoid these risks to integrity. The low temperatures mainly affect low points.

A strategy for depressuring the Goldeneye Pipeline whilst avoiding the problems of low temperatures is illustrated in Figure 8-6.

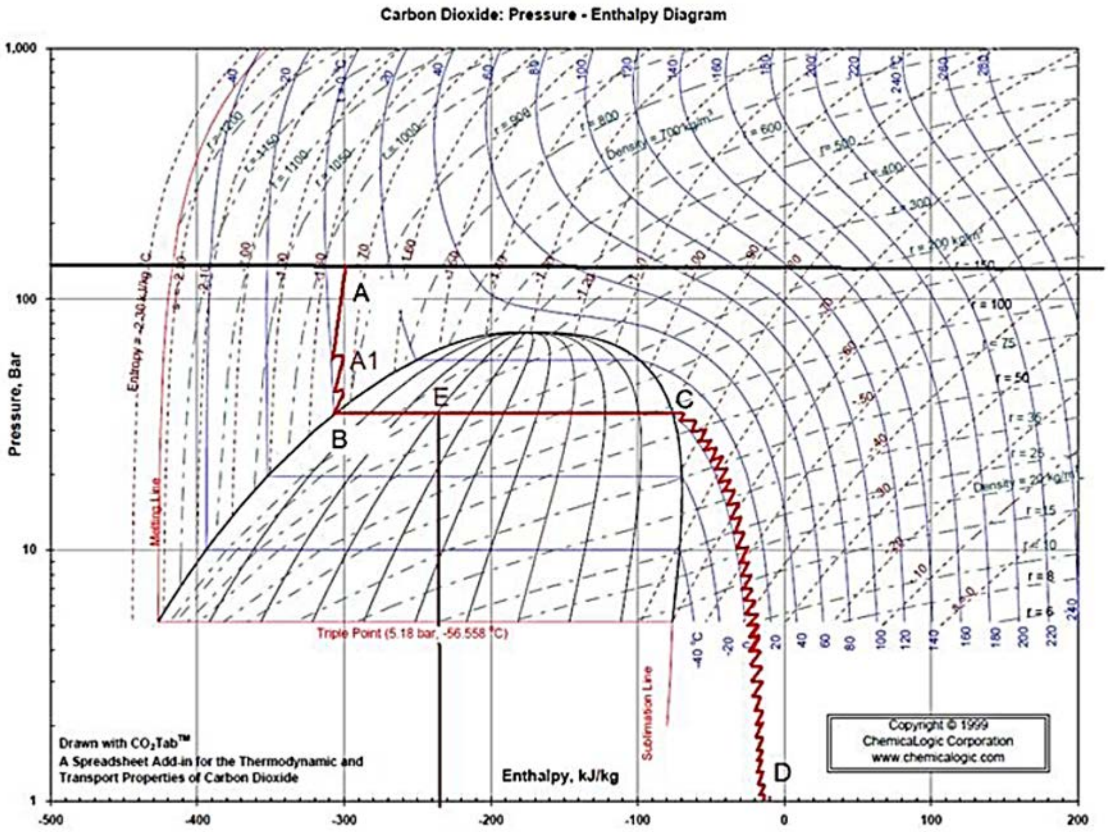


Figure 8-6 Depressuring of Goldeneye pipeline.

Goldeneye pipeline depressuring will be a rare event and performed under carefully controlled conditions on the offshore platform. This will involve disposing of some 20,000 Tonnes of CO_2 with the process expected to take several weeks.

The main constraints on the depressuring process are:

1. Avoiding a cloud of CO_2 that is sufficiently large to interfere with platform systems, pose a threat to personnel on the platform or on nearby vessels, impede helicopter movements and safe platform evacuation and escape.
2. Avoid chilling the pipeline to a level that will cause material damage by exposure to low temperatures and/or thermal stresses and stresses induced by ice formation on pipeline components and in the concrete coating. This will be controlled by carefully programmed pressure reduction of the contents in the pipeline.
3. Avoid precipitating water in the pipeline. This will be controlled by selection of a suitable water content specification for the CO_2 exported from Longannet
4. Avoid blocking the vent pipe-work and pipeline with dry ice. The vent pipe-work will be fully rated but repeated blockage will interrupt and lengthen the process. This will be minimised by controlling the pressures in the vent pipework during the depressuring process.

8.11.1. Design of Vent Systems

This section describes the design of the vent systems. The offshore vent system is required for the following duties in CCS operation:

1 Pipeline depressurisation. This will be CO_2.

2 Topsides maintenance depressurisation. This will be CO_2.

3 Topsides thermal relief valve discharge. This will be CO_2.

4 Venting wells for SSSV testing. This may contain hydrocarbons, water and methanol as well as CO_2.

5 Venting lubricators and other small inventories during well intervention. This may contain hydrocarbons as well as CO_2.

The existing offshore vent system is 150# rated and is not suitable for handling the disposal of dense phase CO_2 for the following reasons:

1 The system is 150# and designed to operate at near atmospheric pressure. Discharge of supercritical dense phase CO_2 into a system below 5.2 bara will result in solid CO_2 formation and blockage.

2 The liquid KO drum is no longer required and the space occupied by it will be used for the installation of filter packages.

The existing vent system apart from the 10" riser up the vent tower will therefore be decommissioned for CCS. The 10" vent riser will be used as a conduit to vent CO_2 from the well depressuring vent system.

8.11.2. Pipeline Depressuring System

Figure 8-7 provides a schematic of the pipeline depressuring system. The system will be fully rated. Depressuring is controlled by a Pressure Control Valve (PCV). The vent tip is designed to operate with an upstream pressure greater than 10 bara during the depressuring process. A low pressure alarm is provided to alert the operator to the potential for solids formation. This is to avoid solid CO_2 formation in the vent. The sizing of the orifice is determined by the calculated boil-off rate from the pipeline when the contents are in the two-phase regime. The PCV allows indirect control of the pressure in the pipeline which in turn allows indirect control of pipeline temperature. Should this fail, low pressure alarms and trips will prevent uncontrolled depressurisation. For the final phase of pipeline depressuring, when the pipeline is full of gaseous CO_2, the low temperature trip will need to be bypassed.

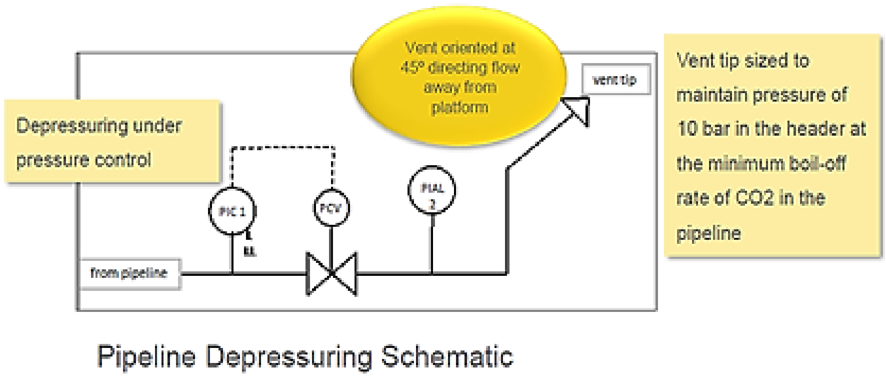


Figure 8-7: Pipeline depressuring vent schematic.

The vent tip will be oriented at 45º in the direction of platform north to ensure dispersal of CO_2 over the sea. Experimental work at Spadeadam has indicated that there is little, if any, solid CO_2 under these situations. This is due to the high levels of air entrainment in the sonic release. The entrained air shifts the equilibrium so that solid CO2 does not form. As a corollary to this, the jet itself can reach temperatures significantly below -78ºC, the equilibrium flash temperature for dense-phase CO_2 expanding to 1 atmosphere.

8.11.3. Well depressuring system

There is a requirement to vent high pressure gas from the wells. This gas may contain hydrocarbons and CO_2. This is required for:

a) Depressuring the lubricator during well work-over operations

b) Depressuring the well tubing above the subsurface safety valve for 6 monthly integrity tests

When the platform is converted to CCS mode, the facility to dispose of liquids via the Goldeneye Pipeline will be removed along with the existing vent system designed for hydrocarbons. The CO_2 vents proposed for the platform are designed to vent dense phase CO_2 without the presence of liquids and hydrocarbons. The proposed wellhead system will allow the safe disposal of small quantities of well fluids using the existing Goldeneye vent stack.

A new depressurising manifold will be used to connect the wellheads to the existing vent stack, through which the vapours from the well head can be discharged to atmosphere.

For a 4.5 in tubing, the rate of depressurisation of the production tubing above the Sub Surface Safety Valve (SSSV) has to remain below 0.2 kg/s corresponding to a pressure of 35 bara in order to prevent carry-over of droplets greater than 500 microns from the wellhead tubing to the platform. Similarly, for a 5.5" tubing, such rate must be kept below 0.3 kg/s corresponding to a pressure of 35 bara. Note that the diameter of the tubing is not yet fully defined.

Additionally, it is proposed to modify the base of the stack by installing a boot at its base to collect potential liquid carryover in order to decrease the risk of discharging liquids through the top of the stack. A schematic for the proposed system is shown in Figure 8-8.

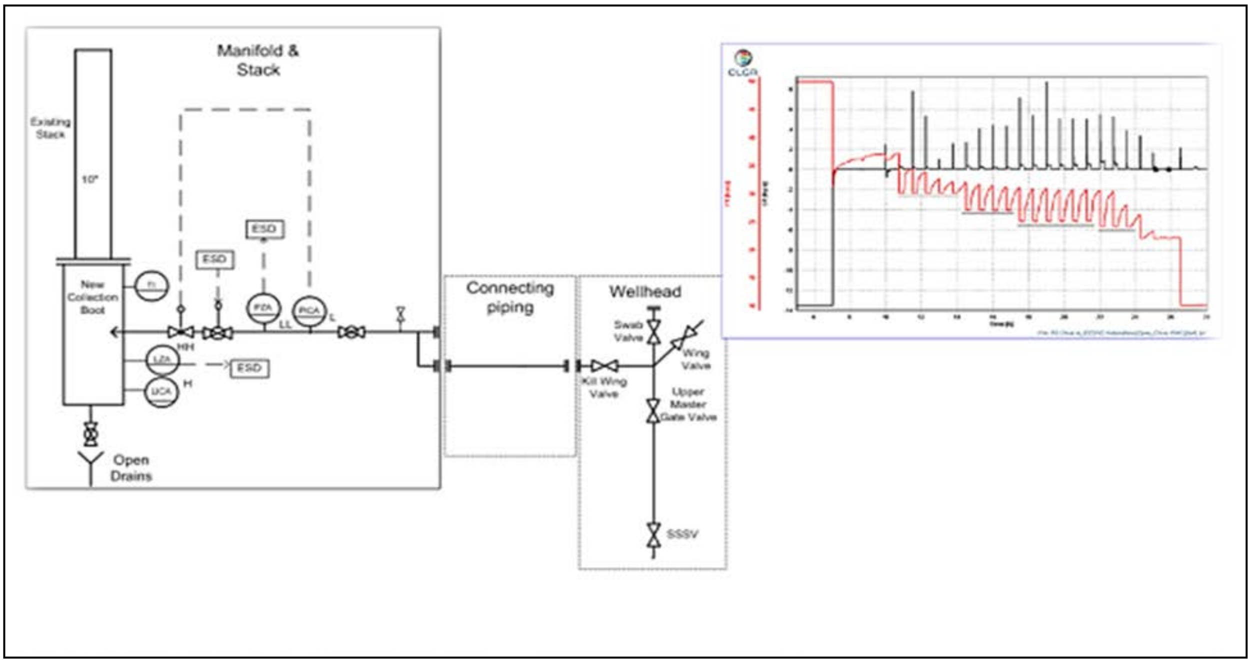


Figure 8-8 Well vent depressuring system schematic.

8.11.4. Topsides Process Vent Systems

A number of blocked-in inventories will be provided with relief valves and facilities to manually depressurise pipework and vessels. Discharges from the relief valves and vents will be routed below deck. Initial modelling of dispersion from the under deck discharges has indicated that the plumes will disperse adequately.

Each thermal relief valve will be equipped with a bursting disc upstream. This eliminates fugitive emissions and allows the detection of a thermal relief event by means of a pressure indicator installed between the bursting disc and relief valve.

Each vent valve and relief valve has its own separate vent. This ensures adequate isolation from other high pressure vent discharges when performing maintenance activities on individual vents. Discharging the vents below the platform ensures that the discharges are self draining thereby reducing the risk of ice blockage. It also avoids the construction of multiple discharge lines up the vent tower.

8.12. Thermal Expansion

Dense phase CO_2 has an expansion coefficient significantly higher than other liquids handled in the oil and gas industry. Figure 8-9: shows the values of thermal expansion coefficient over a range of pressures and temperatures of interest. These values can be compared to the value for water, $0.88.10^{-4}$/°C, and oil, $6.4.10^{-4}$/°C.

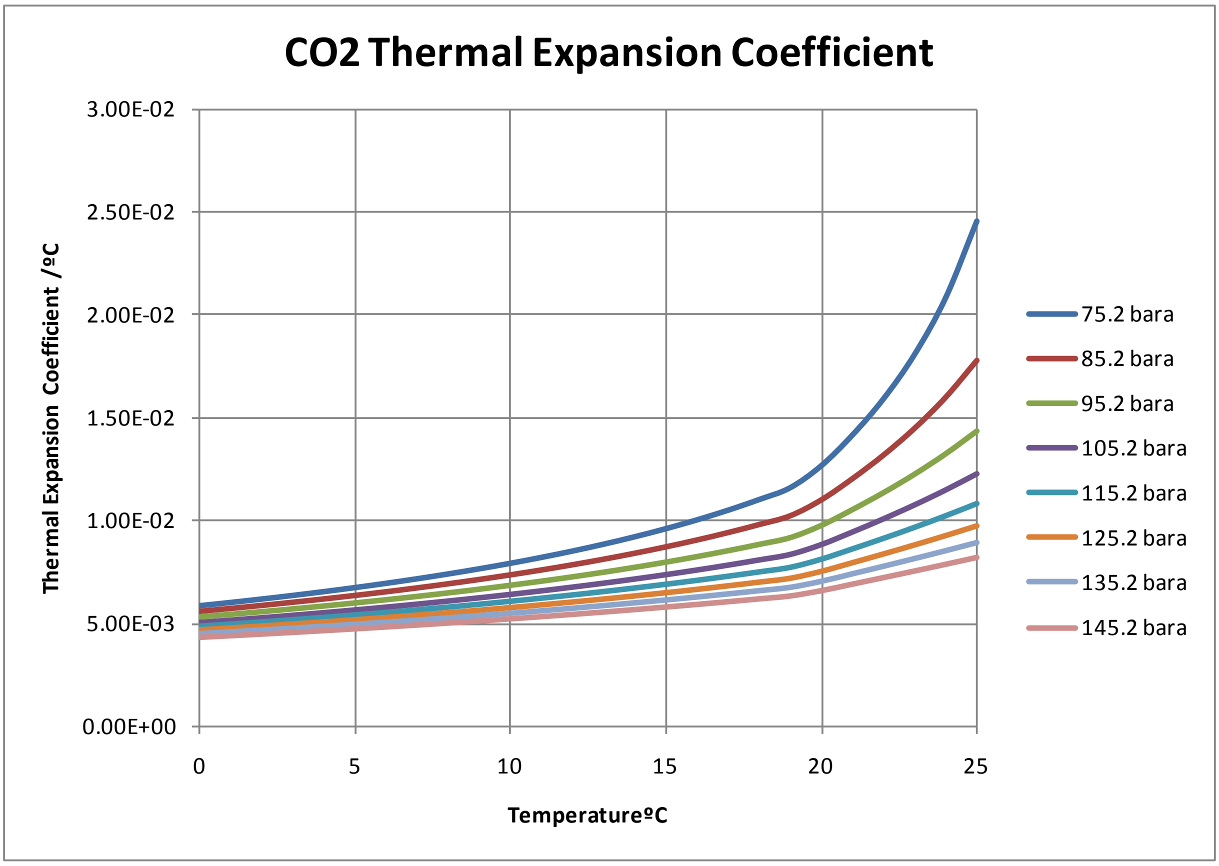


Figure 8-9: Dense phase CO_2 expansion coefficients.

This property drives many important decisions on this project, including the provision of thermal relief valves for blocked inventories and the replacement of pipe spools between the new SSIV and the riser base. Figure 8-10: shows the impact of thermal expansion on pipeline design. For a blocked-in inventory the rate of pressure rise is 7.8 bar/ºC. This gives a pressure rise of 54.6 bara for the annual range of sea temperatures (4-11ºC). A pipeline blocked in at a pressure of 78 bara and 4ºC will exceed MAOP (133 bara) when the sea temperature rises to 11ºC.

The reverse effect is seen when the pipeline is shut in as shown by OLGA (proprietary multiphase fluid flow simulation tool) simulations. Figure 8-11: shows the pipeline pressure and temperature profile immediately after shut-in and 84 hours after. The pipeline contents have cooled from the inlet temperature of 20ºC to ambient sea temperature and the pipeline pressure profile drops from approximately 113 bara to 90 bara over most of its length.

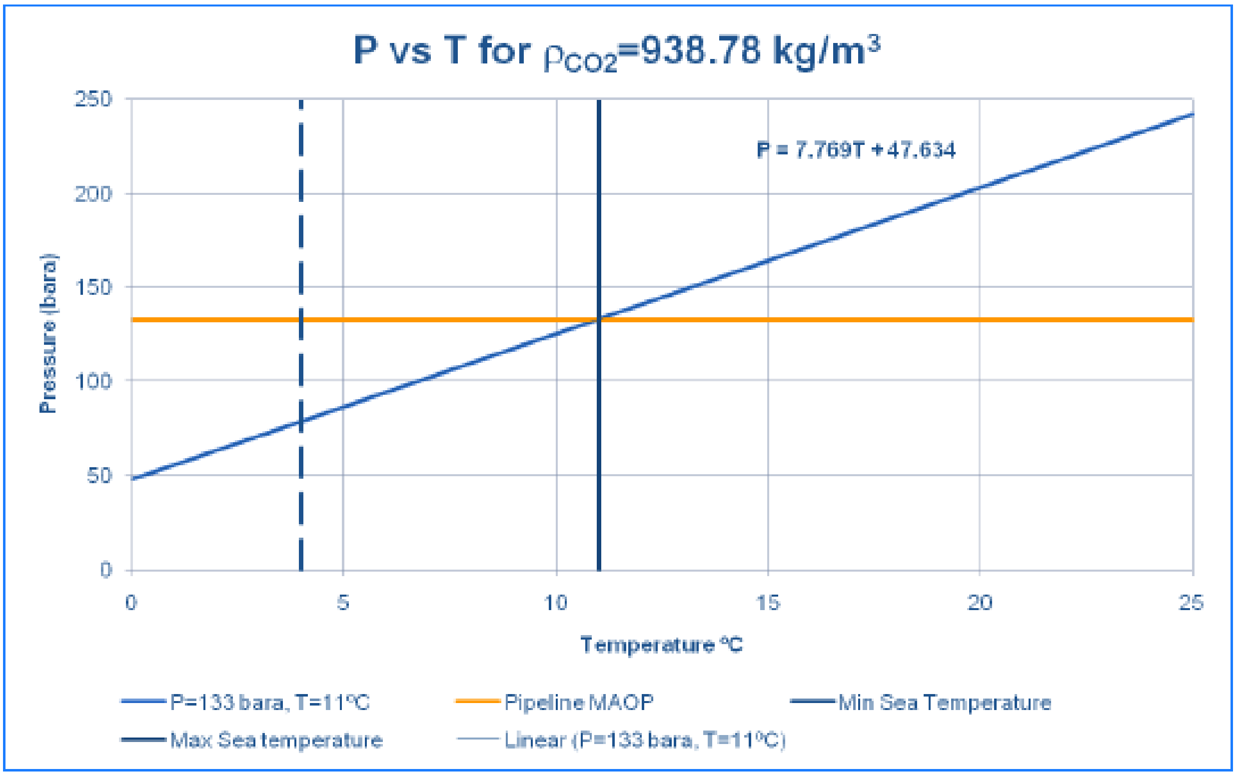


Figure 8-10: Graph showing pressure rise of dense phase CO_2 with temperature.

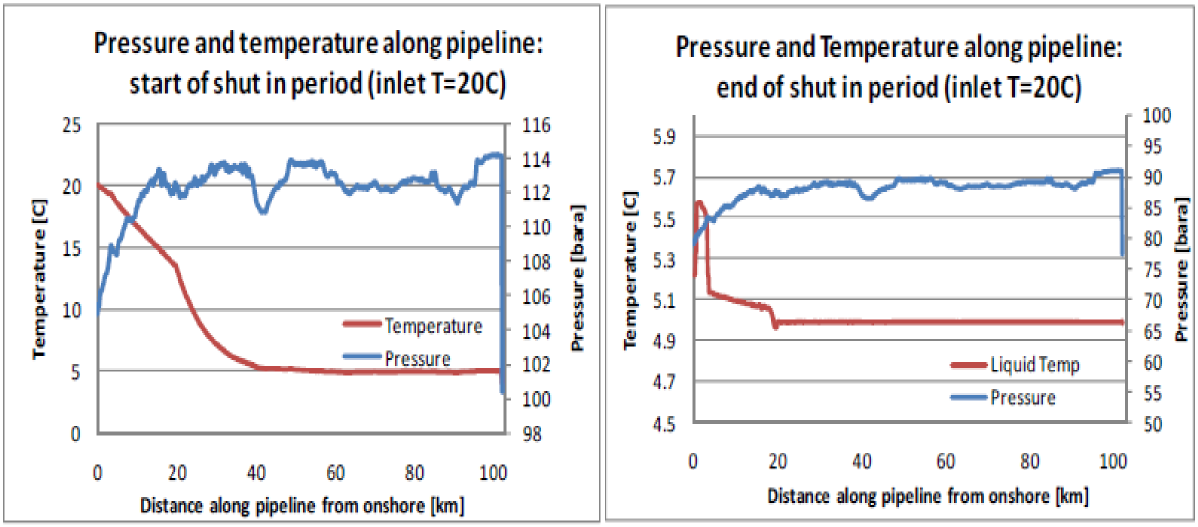


Figure 8-11: Pipeline pressure profile after shut in.

9. Management Plan for the Store - Site containment

The Goldeneye store has a competent and extensive caprock that has contained gas for around fifty million years. Above the caprock there are approximately 750m of low permeability chalk formations followed by a succession of approximately 700m of sandstones and mudstones beneath the secondary and tertiary seals to the complex – the Lista and Dornoch mudstones. These formations are overlain by more interbedded sands and silts that will provide a baffle to CO_2 movement.

The field has very few well penetrations (five production wells and four exploration and appraisal wells) and the status of these and of the penetrations in neighbouring areas is known. All penetrations in the storage complex that penetrate the Captain Sandstone have competent cement plug abandonments at this level.

There is limited evidence of faulting in the overburden, and no faults have been identified that penetrate both the storage and complex seals. None of the faults in the storage complex are critically stressed. Data on the position and intensity of earthquakes in the North Sea shows the area in the vicinity of Goldeneye to be seismically low-active.

Geomechanical assessment of the caprock has shown that re-pressurisation does not fracture the rock, while geochemical modelling has shown that the acidic fluids created by the CO_2 injection do not perforate the caprock or cemented fractures. A coupled geochemical/geomechanical experiment on the reservoir rock has shown that the strength does not decrease upon interaction with these acidic fluids even when the calcite cement is dissolved.

Assessment of monitoring feasibility shows that migration of CO_2 outside the store can be detected using time-lapse seismic.

9.1. Primary Containment

Demonstrating containment is the key element in CO_2 storage. The Goldeneye storage complex has a number of positive supporting factors to suggest that containment is at low risk. The primary containment will be provided by the structural trap of the Goldeneye field. This is a structure that has proven over a period of 50 million years to be a competent storage site for an estimated 750 Bscf of gas (containing 0.4% CO_2).

The components of the containment are described in the chapter on site description and are illustrated by Figure 9-1:.

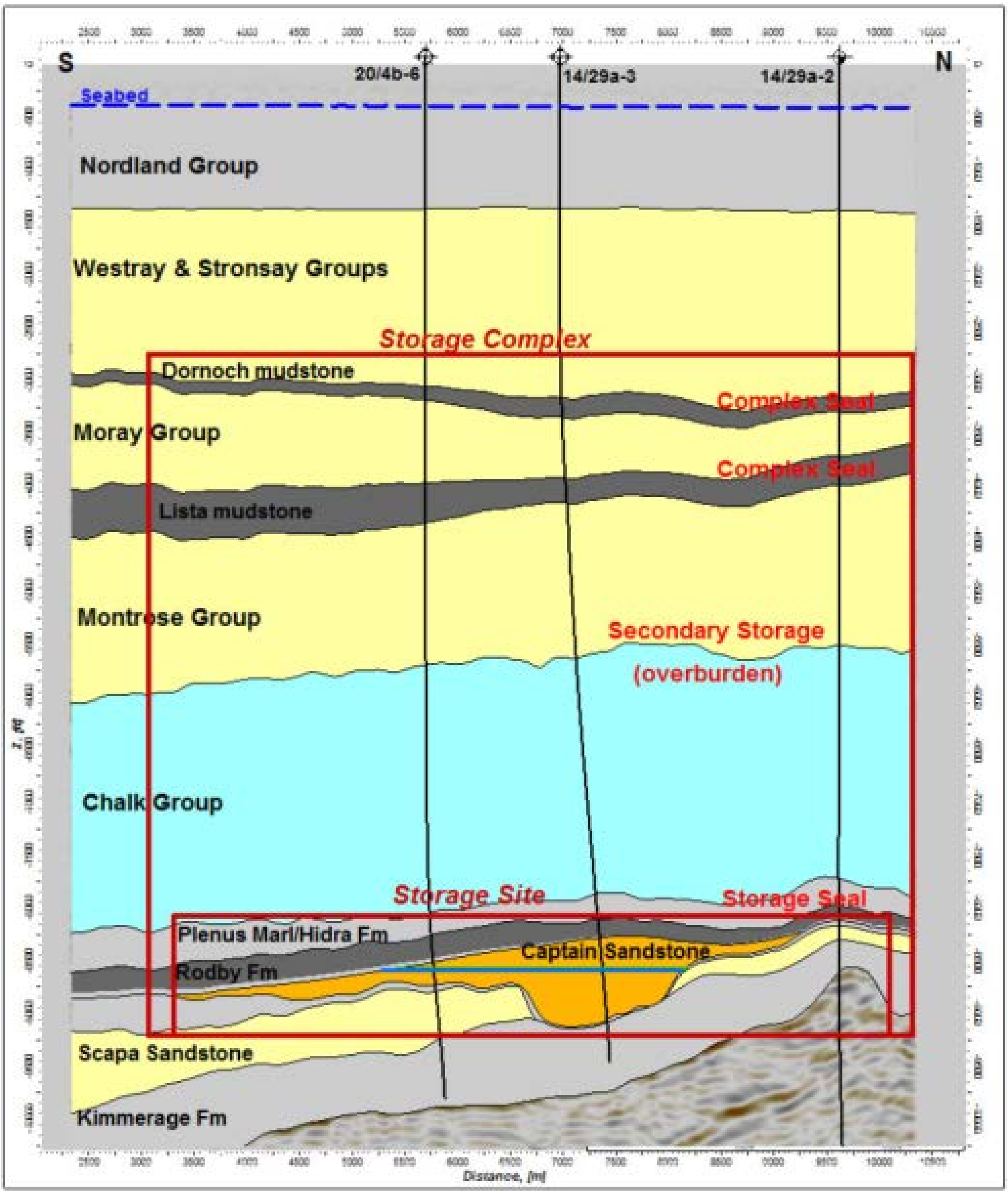


Figure 9-1: Cross section to indicate the vertical (subsurface) extent of the *storage site* and *storage complex.*

9.2. Factors affecting the integrity of the storage site

There are several factors that can potentially reduce the integrity of the storage site. These can either weaken the caprock itself to allow CO_2 to migrate slowly through the seal or, can create leak paths that bypass the seal entirely. CO_2 can also potentially migrate laterally from the storage site along the Captain Aquifer, or through juxtapositions with the underburden stratigraphy.

The following factors that can impact on the containment of CO_2 were identified as a result of a Bowtie risk assessment and are discussed below.

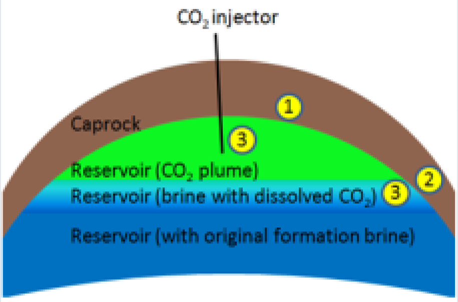
- Acidic fluids
- Diffusion of CO_2
- Stress of injection
- Lateral migration
- Faults and fractures
- Abandoned wells
- Injection wells

9.2.1. Acidic fluids (chemical reactive transport)

A study was performed to assess the impact of the changes in composition of the formation brine due to dissolution of CO_2, during CO_2 storage. As CO_2 dissolves, the bicarbonate (HCO_3^-) concentration increases and the pH decreases. This brings the brine out of equilibrium with respect to the various minerals that make up the reservoir and cap rock, leading to dissolution of some minerals and precipitation of others. For Goldeneye, some of these changes may have occurred already, due to the presence of 0.4% CO_2 in the hydrocarbon gas. Nevertheless, the storage leads to much higher CO_2 exposure than the reservoir has been exposed to before, and so dissolution and precipitation processes are expected to occur. The main results are summarised in Table 9-1.

Figure 9-2: shows an example of the results for the caprock showing the mineralogical changes over time (log-scale). It shows a slight porosity decrease owing to the overbalance of precipitation with respect to dissolution.

Table 9-1: Overview of the main reactivity study results. The numbers in the graph refer to key regions of the reservoir and caprock exposed to CO_2

	Region	Description	Conclusion
	1	Caprock exposed to CO_2 plume	CO_2 diffuses over a distance of 50-75 m in 10,000 years. Caprock alterations possible within this distance. Alterations tend to decrease porosity. Therefore low risk of induced leakage.
	2	Caprock exposed to formation brine with dissolved CO_2	Mostly same as above. Some dissolution is possible in any calcite rich features running through the caprock, but only over a small distance at their base (less than 33 cm in 10,000 years). Low risk of induced leakage.
	3	Reservoir within and close to CO_2 plume	Permeability decrease possible during injection period but unlikely to have significant impact on injectivity. Potential for a large CO_2 mineralisation in optimistic scenario. Dissolution storage relatively low (14% of injected CO_2 after 10,000 years).

9.2.2. Diffusion of CO_2

The chemical reactive transport study has shown that the CO_2 takes 10,000 years to diffuse between 50-75m. As the caprock is over 150m thick, this risk is negligible.

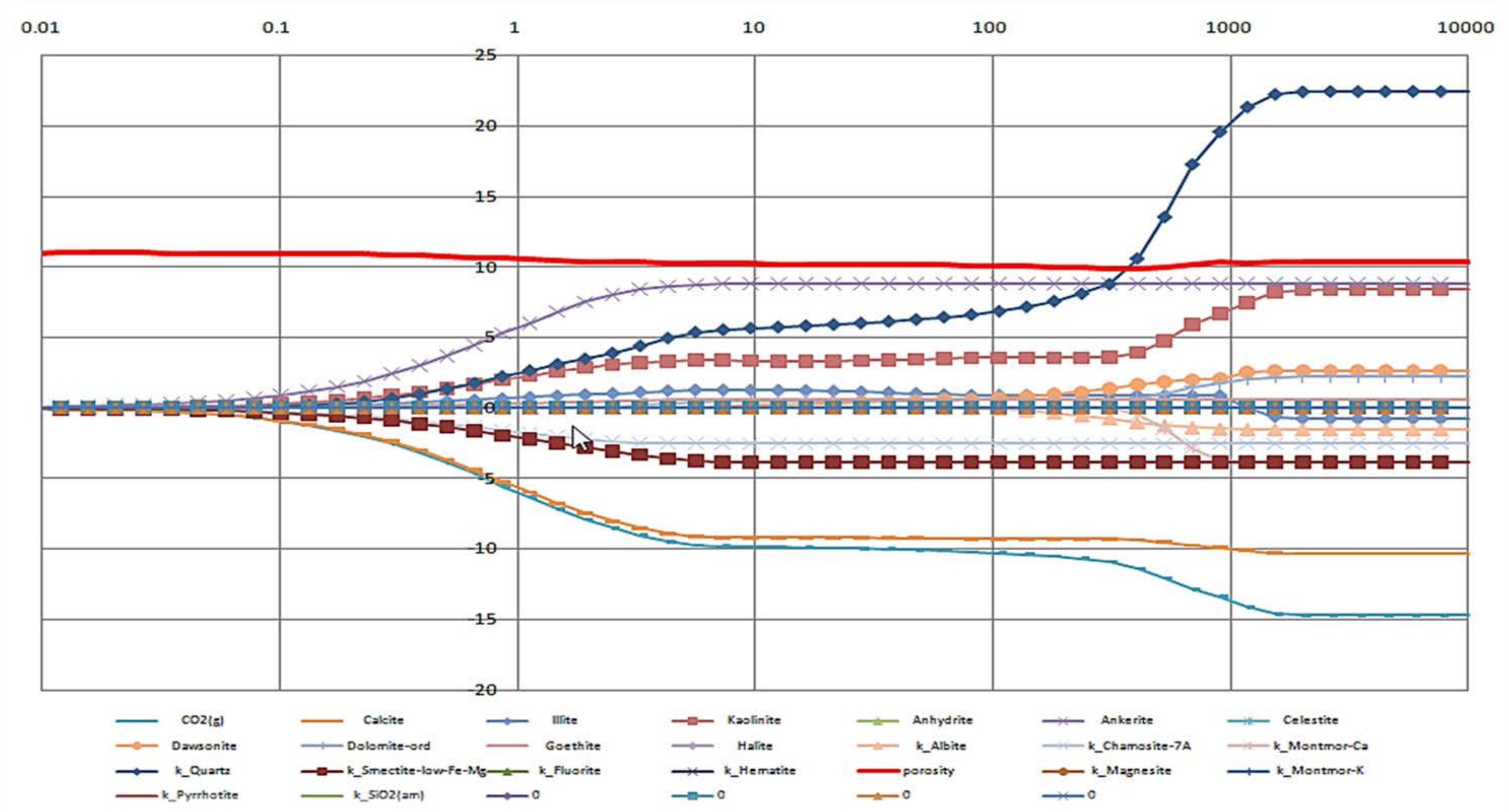


Figure 9-2: Mineralogical changes in caprock (full set of minerals).

Note: The horizontal axis shows time (in years), the vertical axis changes in mineral abundance (mol/kgW) and porosity (%).

9.2.3. Stress of injection

During production (of hydrocarbons), and subsequent injection of CO_2, the stress state both inside and outside the reservoir are or will be changed. A geomechanical appraisal of the Goldeneye structure was carried out to simulate injection scenarios and assess the geomechanical threats to the integrity of the storage site. There is no risk of shear or tensile failure in the reservoir or tensile failure in the caprock as during injection (assuming formation temperature), the reservoir will not be repressurised above the initial virgin pressure of 260.5 bara at a datum of 8507 ft. [2593 m] TVDSS. For an injection pressure of 24.4 MPa [244 bara] the shear capacity utilization of the caprock is 0.92. A slightly higher injection pressure leads to slightly higher stresses in the caprock, where the pressure is not changing. As a consequence, fracturing becomes less likely.

The behaviour of the Rødby Formation caprock directly adjacent to the cold plume of CO_2 in the Captain reservoir was also investigated. The simple uniaxial thermo-elastic response of the Rødby to 60°C cooling showed that, for the high case Young's modulus and linear thermal expansion coefficient, it is possible that with time the injection pressure in the field becomes high enough to induce tensile failure (under this simplified model). To understand this risk, fracture growth into the Rødby Shale formation was studied using a hydraulic fracture modelling tool (PWRIFrac), and taking into account fracture morphology considerations. It was shown that significant fracture growth within the caprock was highly unlikely. This conclusion was underpinned by a 2D analytical study of the in-situ stresses undergoing thermal alteration in an elliptical zone, which confirmed that the minimum principal stress remained significantly greater than the predicted injection pressures for the 15 year injection period. On the basis of the rock properties, in-situ stresses and pore pressures, it was concluded that hydraulic fracture from the Captain reservoir into the Rødby caprock will not occur, but instead that slip along the reservoir-caprock interface is most likely.

A detailed study on the coupled effects of temperature and pore pressure in the caprock close to the wellbore also showed no risk of failure. This relates to the difference in temperature between the lower temperature, near wellbore area in the top of the reservoir and the bottom of the overburden compared to the higher temperature, formation temperature. This cooling will induce significant stress and strain changes in the reservoir and the overburden near the wellbore. Therefore, the possibility of failure of the caprock in the near wellbore region due to temperature changes and the possibility of migration resulting from failure required investigation. In the cemented section above the casing shoe, the results of the analysis presented showed a very low probability of failure of the caprock. Analysis of the caprock below the casing shoe also showed a very low probability of failure due to thermal loading. Should failure occur, it is not clear if it would lead to significant migration, as failure could lead to a permeability decrease (ductile behaviour) or permeability increase (brittle behaviour). However, in this case, the CO_2 flux from the permeability increase is expected to be negligible. The introduction of a water pill before injection has the potential to enhance ductile behaviour of the caprock however it could also lead to damage of the gravel pack. It is therefore recommended that this possible mitigation strategy be explored as part of the well workover design.

Fault slip reactivation was studied in the same rigorous manner as the integrity. For every fault, the slip-tendency was investigated by calculating the shear capacity for all the three stress stages (before production, after production/before injection and after injection). No fault-slip is expected to occur. Even the worst case scenario was not significantly close to slip. This conclusion is based on the assumption that the initial stress state of the faults, before depletion or injection, is the same as the initial stress sate of the surrounding rock. Assessment showed that that the faults are not critically stressed as a result of hydrocarbon extraction and subsequent CO_2 injection. This result implies that if faults are currently not leaking (which they are unlikely to be, given that a gas field was present) then they are extremely unlikely to start leaking as a result of CO_2 injection.

9.2.4. Lateral migration

CO_2 can also migrate laterally from the storage site. Movement to the west and east could occur by migration along the Captain Aquifer, and to the north and south through juxtapositions with the underburden stratigraphy.

Each direction will be discussed separately below.

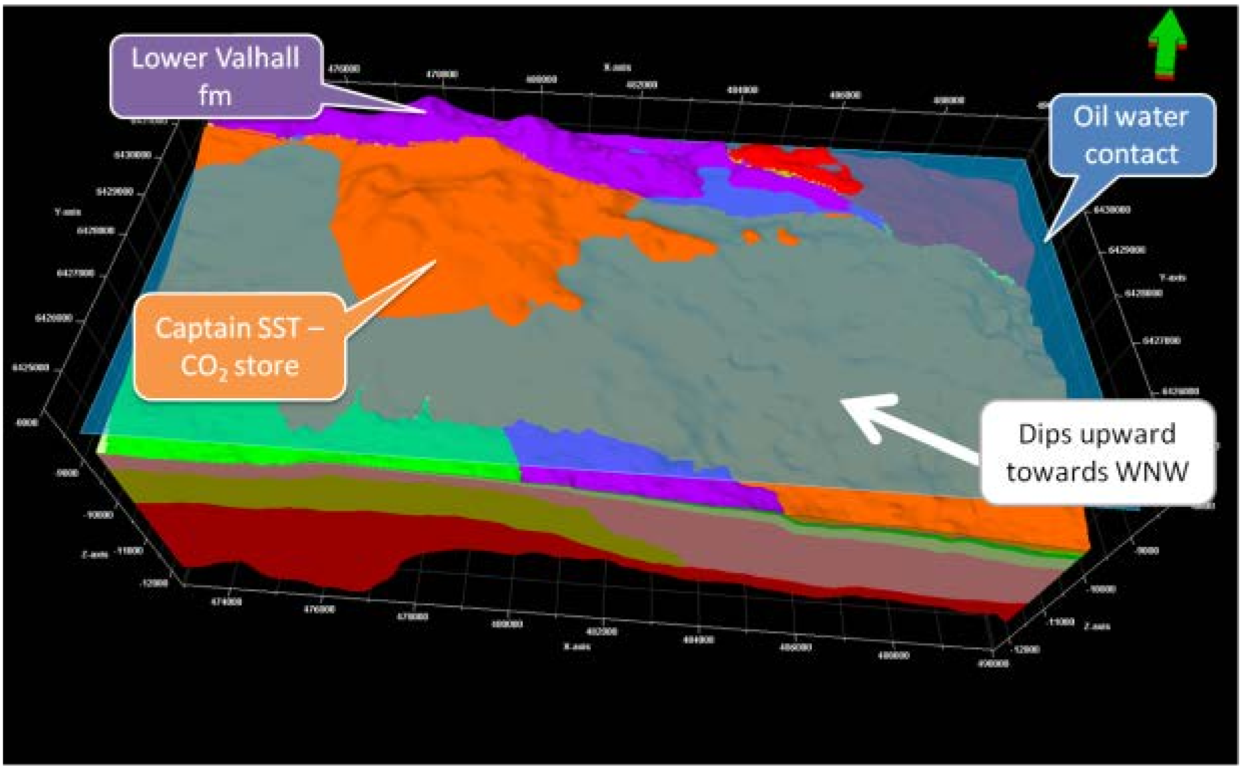


Figure 9-3: The Goldeneye structure.

9.2.4.1. Up-dip westerly migration in the Captain Sandstone Member

The potential for up dip migration along the Captain Aquifer is discussed in detail in the CO_2 storage estimate report and the Dynamic Modelling output report. The Captain Aquifer is interpreted to extend over 100km running west to east along the southern margins of the Halibut Horst and South Halibut Shelf. The spill point of the Goldeneye closure is in the northwest corner of the structure, at the original hydrocarbon water contact 8592 ft. [2168 m] TVDSS.

The risk of migration under the spill point is controlled by several factors relating to the distance of injection from the spill point and the rate of movement of the CO_2 front. The CO_2 storage estimate report shows that there is sufficient capacity in the storage site to store over 20Mt of CO_2. This leaves a significant storage buffer. Dynamic and analytical modelling has been performed (see Dynamic Modelling output report) simulating injection of 20Mt of CO_2 and in none of the scenarios did CO_2 migrate under the spill point. Because we are only partially refilling the available voidage space with CO_2, the risk of migration of CO_2 from the structural closure is limited.

As CO_2 is injected, it is possible for it to flow below the original hydrocarbon contact. The viscous forces associated with injection can create a Dietz tongue, as shown in Figure 9-4:.

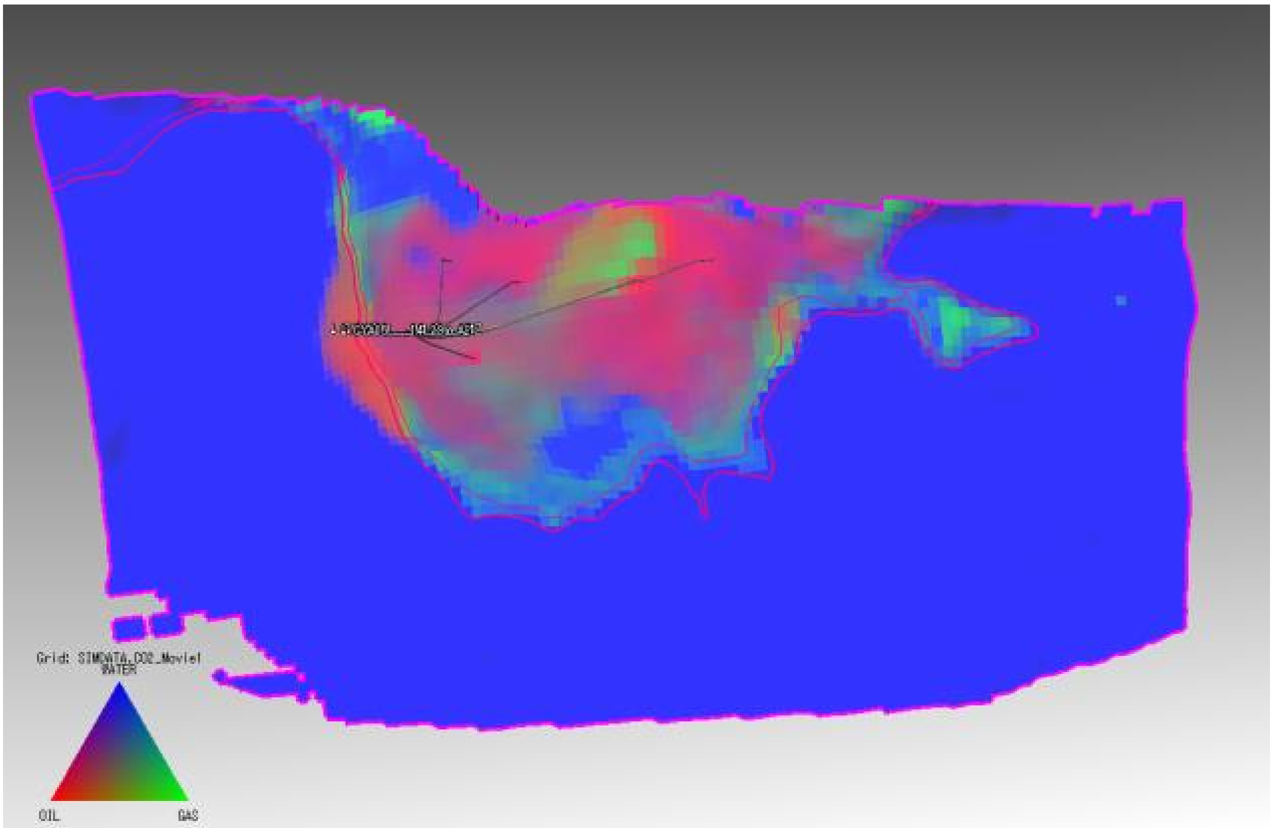


Figure 9-4: FFM3.1: Extent of CO_2 plume at top Captain D, at end of injection (2029) showing the Dietz tongue on the western flank of the field.

Note: CO_2 is shown in red, hydrocarbon (gas and condensate) in green and water in blue. Original OWC and GOC are pink lines.

In the unlikely event that CO_2 were to migrate under the spill point it would be contained in the Captain Sandstone aquifer under the store caprock of the Upper Valhall, Rødby, Hidra and Plenus Marl. The CO_2 would then be trapped by capillary forces, dissolution and geochemical reactivity.

9.2.4.2. Down-dip easterly migration in the Captain Sandstone Member

Down-dip migration takes place through two different mechanisms. A Dietz tongue can occur in a similar fashion to that observed in Figure 9-4: in the up-dip direction. The second mechanism is gravity flow associated with dissolved CO_2. Figure 9-5: shows the process of CO_2 dissolution over 10,000 years in a simplified structure model while Figure 9-6 and Figure 9-7: show the CO_2 dissolution and the pH with geochemical reactivity taken into account. When CO_2 dissolves in water it creates HCO_3^- and CO_3^{2-} ions and protons (H^+). The dissolved CO_2 and additional ions increase the density of the water, making it sink relative to pure water. With the addition of dissolved mineral species in the water, additional ionic species are also formed. However, the result is the same and the density is increased.

When geochemical reactions take place the acidity (and activity) of the carbonic acid is eventually neutralised and the plume loses its corrosive ability. It should be noted that there is considerable uncertainty on the timescale of the geochemical reactions. Figure 9-6 represents a fast reactivity case. The expected distance of the dissolved plume migration lies between the no reactivity case (Figure 9-5:) and the high reactivity case (Figure 9-6 and Figure 9-7:). As this down dip migration will result in dissolution trapping (complemented in the long term by geochemical trapping) it is not a risk to the project.

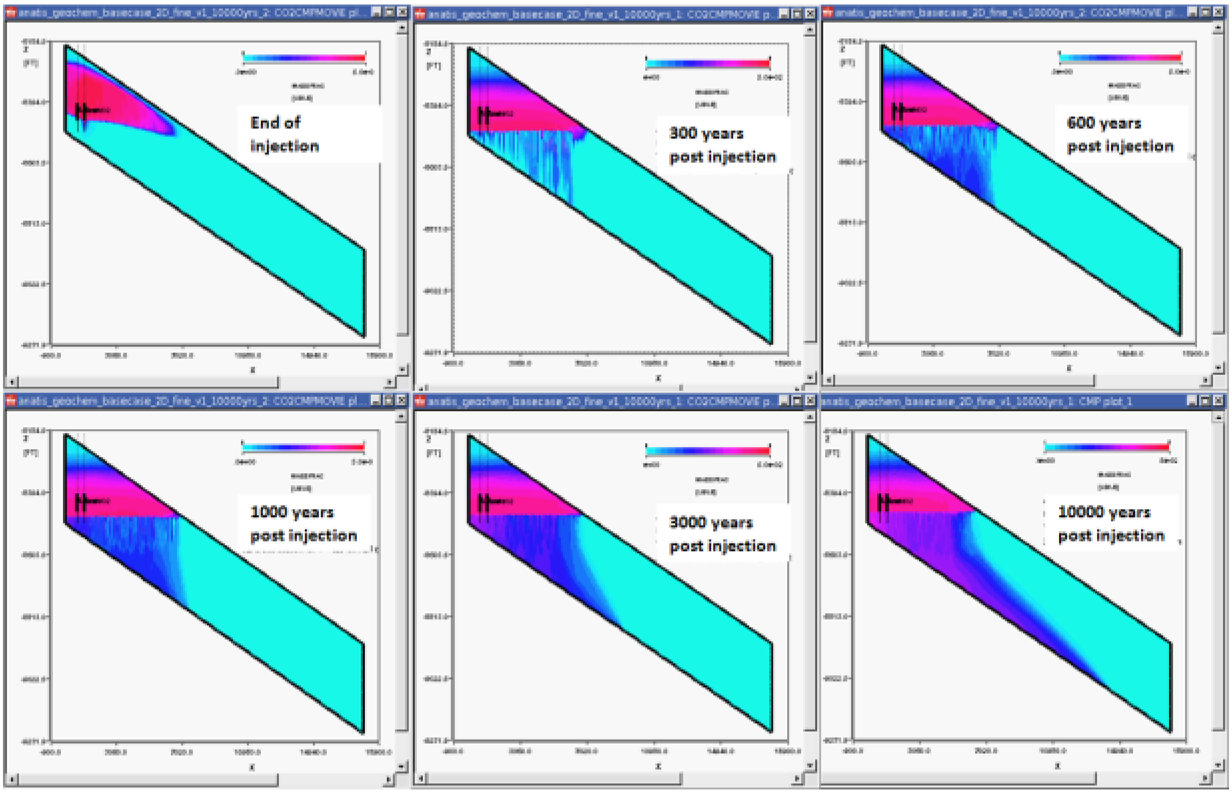


Figure 9-5: Movement of dissolved CO_2 through time (no geochemical reaction modelling). Colour scale runs from 0 to 0.05 (mass fraction).

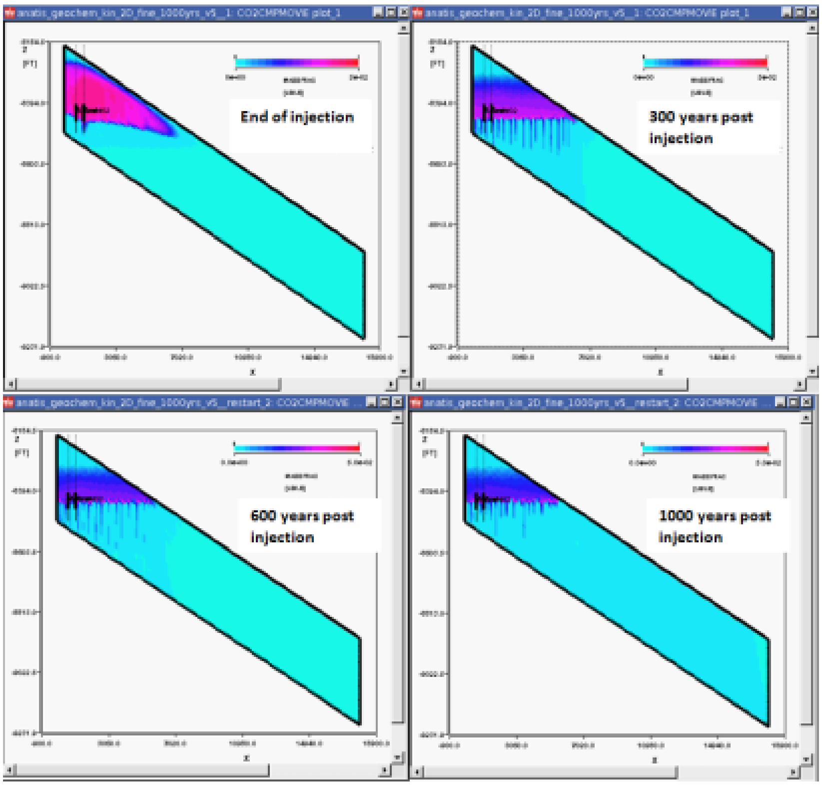


Figure 9-6: Movement of dissolved CO_2 through time (geochemical reaction modelling incorporated). Colour scale runs from 0 to 0.05 (mass fraction).

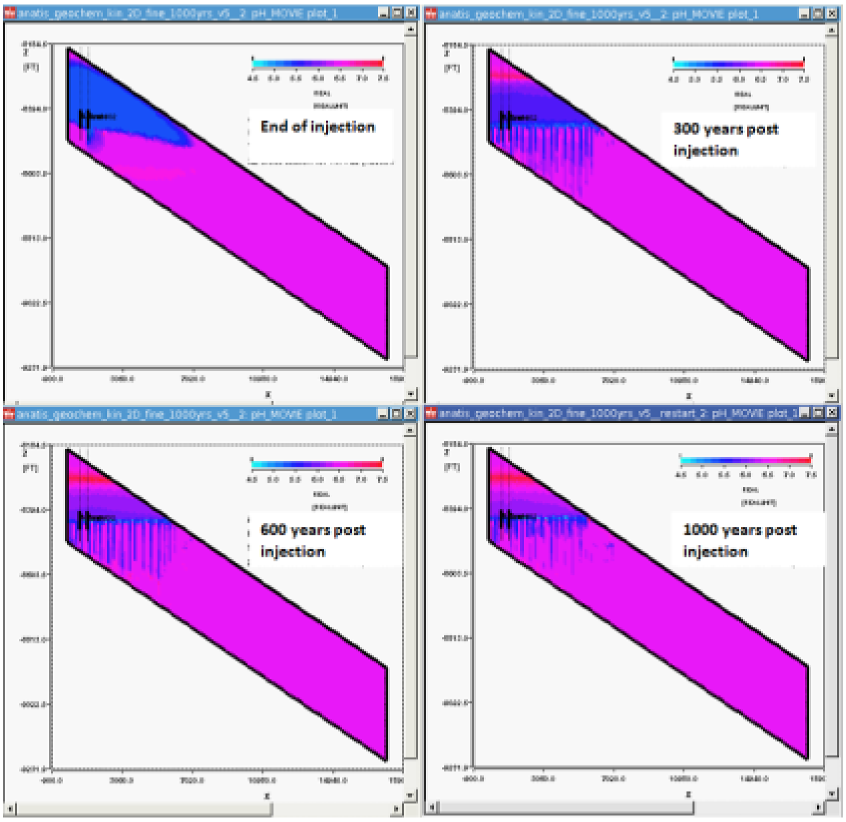


Figure 9-7: pH evolution through time. Colour scale runs from pH 4.0 to 7.5.

9.2.4.3. Northerly migration into the underburden

The Captain Sandstone reservoir pinches out on to the rotated fault block to the north, forming the northerly component to the hydrocarbon trap. However, the combination of stratigraphic overstep and erosion means that there is the potential for juxtaposition of the Captain Sandstone Member with the Scapa Sandstone Member, which underlies the field. This is shown in more detail in Figure 9-8 which shows cross-sections through the reservoir section of the overburden model. The Scapa Sandstone and Yawl Sandstone Members of the Lower Valhall Formation have been included within the defined storage site to take account of this potential juxtaposition. However, it is important to note that no hydrocarbons have been encountered in the Yawl or Scapa Sandstone Members and no pressure connection has been proven. In addition, the seismic evidence for juxtaposition is equivocal (compare image C with image D in Figure 9-8, which show two equally valid seismic interpretations – the former showing Captain sands juxtaposed with Scapa sands above the hydrocarbon contact and the latter showing the connection below). The rotated fault block to the north of the Goldeneye field was drilled by well 14/29a-2 and found no hydrocarbons in the cemented Scapa sands.

The conclusion of this analysis is that there is no communication between Captain Sandstone Member and any other porous medium in the area of the field. The *storage seal* extends with significant thickness beyond the mapped extent of the Scapa and Yawl Sandstone Members. A more detailed discussion can be found in the Static model (overburden) report.

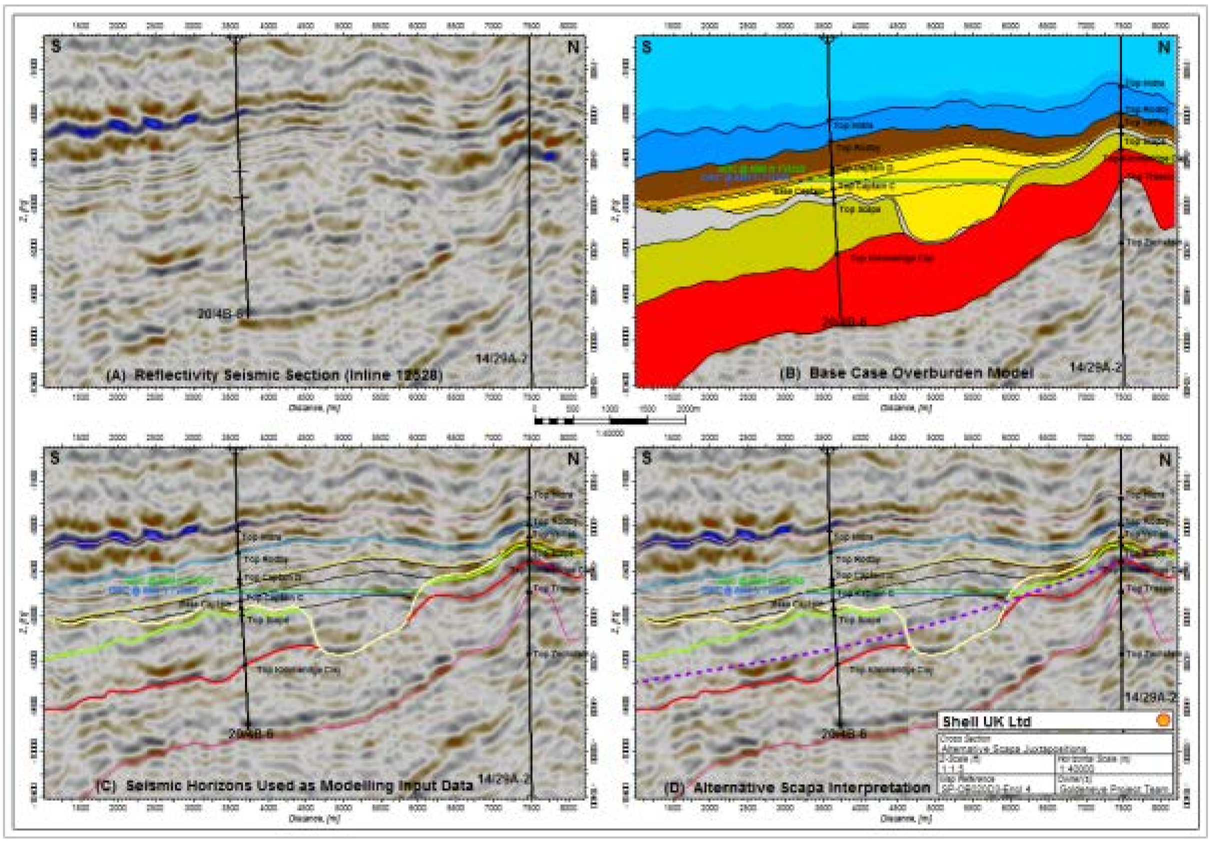


Figure 9-8 Potential juxtapositions between Captain Sandstone and Scapa Sandstone Members (north-south section between wells 14/29a-2 and 20/4b-6).

Note: Apparent continuity of (grey) Lower Valhall mudstone beneath Goldeneye field in (B) is an artefact of the modelling programme used and does not represent geological reality.

9.2.4.4. Southerly migration into the underburden

The Captain Sandstone Member also pinches out in a southerly direction, though this occurs beyond the original field boundary. For the CO_2 to migrate in this direction, similar processes have to take place as described in the down-dip migrations section. Connectivity also has to exist to the Scapa or other permeable unit. This is assessed as unlikely, based on interpretation of available seismic and wireline log data. Additionally, no pressure support from the south was required to achieve a history match in the dynamic modelling.

9.2.4.5. Secondary migration in the Mey and Dornoch Sandstones

If CO_2 bypasses the storage seal – *e.g.* through well bores or faults – it is expected to migrate into shallower, permeable formations beneath the complex seal of the Lista and Dornoch mudstones. These include the low permeability Chalk Group and the interbedded sandstones and mudstones of the Montrose Group (including the Balmoral and Mey sandstones) and the lower part of the Moray Group (Lower Dornoch sandstone). Any CO_2 reaching the base of the Lista mudstone is expected to migrate in the direction of the regional dip (west to northwest) until it is trapped by local structure, capillary, dissolution or chemical trapping. The Lista Formation is interpreted to crop out at the seabed over 150km to the west of Goldeneye, within the Inner Moray Firth.

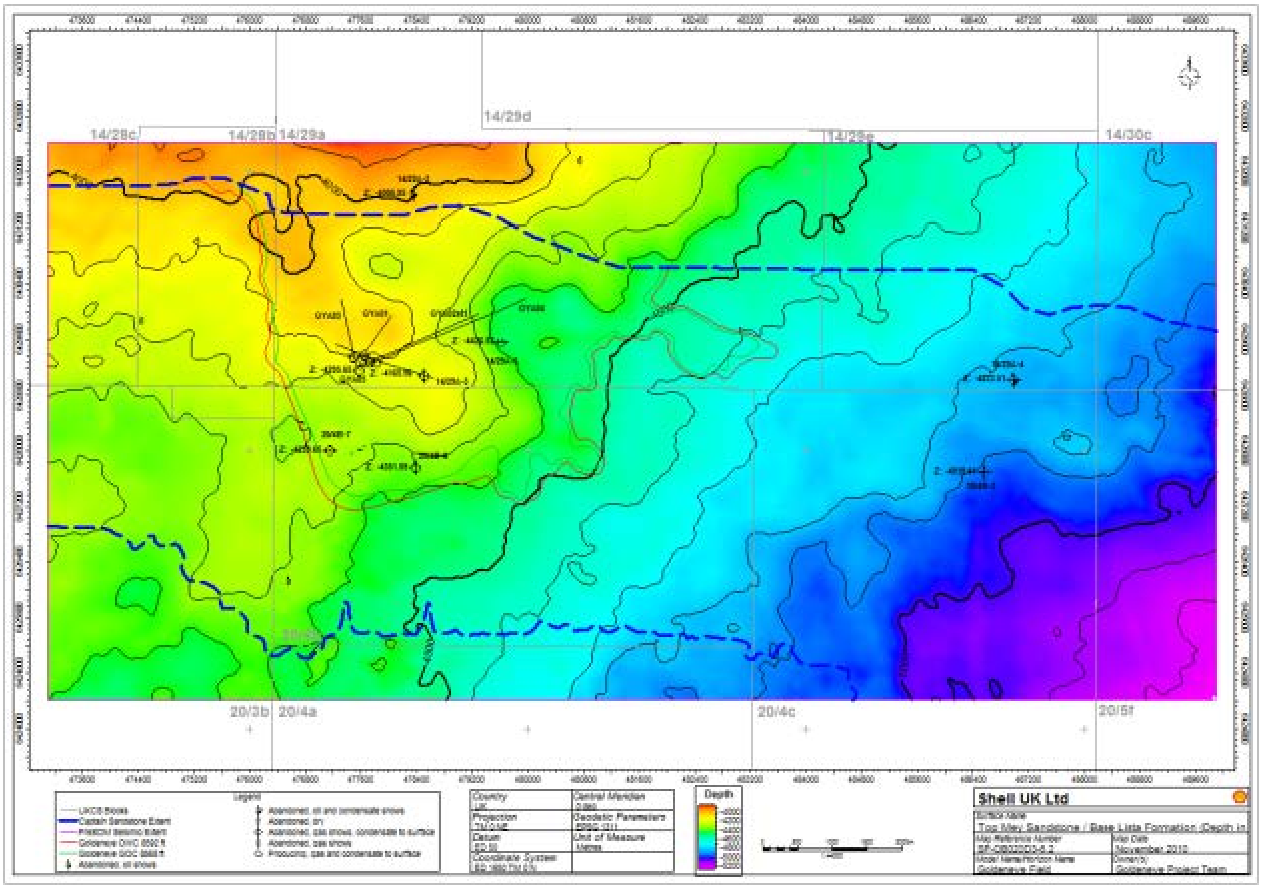


Figure 9-9: **Base Lista Formation /top Mey Sandstone Member depth map [in feet], Goldeneye field area.**

9.2.5. Faults and fractures

Faults and fractures can potentially provide natural leak paths through the overburden lithologies that can reduce the integrity of the storage complex. As a result, a detailed study was undertaken to review the extent of faulting in the overburden interval above the Goldeneye field. The key conclusions of this work are as follows:

- No faults have been identified that cross both storage seal and complex seal.
- The fault pattern at the storage seal parallels the observed regional structural trends, orientated WNW-ESE to E-W. Faulting is relatively minor, with faults of only limited vertical and lateral extent, and small throws. Any faults propagating up through the reservoir from deeper horizons appear to have little or no throw.
- Faults within the Chalk Group trend NW to SE and are mainly developed over the eastern and south-eastern flank of the field. These faults are unconnected to the faults at storage site level or to those in the shallower overburden.
- Above the Chalk Group, there is little evidence of any significant faulting.
- None of the faults in the storage complex are critically stressed – *i.e.* they are unlikely to be open, and will not be reactivated during injection.
- An analysis of fracture density and patterns in the storage seal and the Chalk Group shows that, fracture growth and distribution is controlled by the internal mechanical variability within the rock units. Therefore, they are "disconnected" in the vertical direction and are considered not to pose a risk for containment to the storage site.

Further detailed discussion of the faulting and fracturing in the overburden interval above the Goldeneye field can be found in the Static Model (Overburden) report.

9.2.5.1. Gas chimneys

No gas chimneys (which may be an indication of a leaking trap) have been identified on seismic above the Goldeneye field. There is no seismic signature of shallow overburden gas accumulation.

9.2.6. Abandoned wells

The excellent regional seal that has trapped a large volume of hydrocarbons over geologic time has been penetrated by several wells which might act as leak paths direct to the surface. As a result, the integrity of all abandoned wells in the proximity of the Goldeneye field has been investigated. Secondly, abandonment concepts for the five existing Goldeneye production wells post-injection have been studied.

The Goldeneye field itself was penetrated by four exploration and appraisal (E&A) wells within the Captain Sandstone Member, and five production/injection wells, with GYA02 also being side-tracked. All the production wells are now suspended with downhole wireline retrievable suspension plugs. Nine additional abandoned E&A wells that are located near the Goldeneye field were also evaluated. The quality of the abandonments of each E&A well at storage seal zone has been assessed in detail in the Well Integrity Assessment report. Figure 9-10 shows the location of the thirteen abandoned E&A wells that were evaluated. Of these, only one – 14/28b-4, has been identified to have a poor barrier at the storage seal. However, this well is located 3.8km to the west of the storage complex boundary and the results of dynamic simulations show that any CO_2 plume leaking in the direction of this well will not reach it but will be capillary, dissolution or chemical trapped.

Table 9-2: shows the height of the primary cement barrier in place. The combination of good quality cementation jobs and long cement columns means that the risk of leakage through the abandonment well plugs is judged to be very low. Literature reviews for Goldeneye cement type, pressure and temperature show the expected cement corrosion rate for the Goldeneye field to be in the order of 2.0 meters/10,000 years.

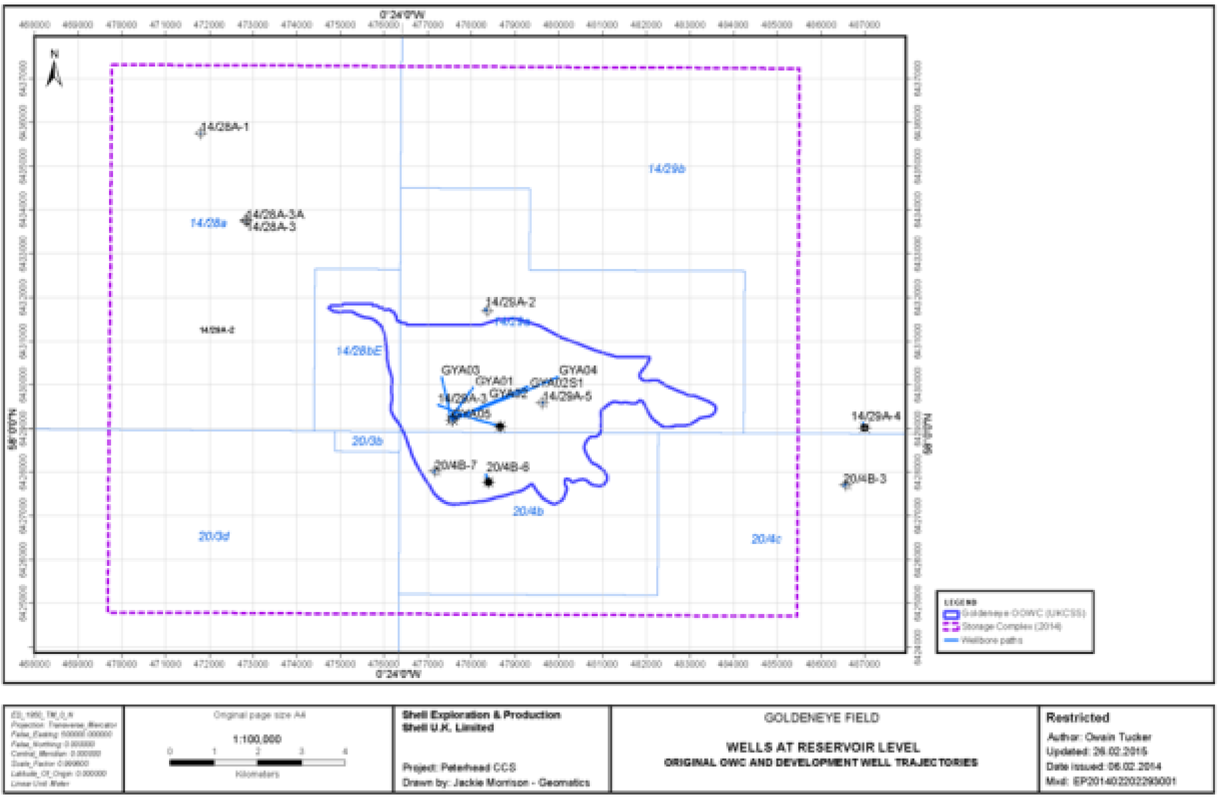


Figure 9-10: Goldeneye platform and abandoned E&A wells in storage complex.

Table 9-2: Assessment of well abandonment quality

E&A Wells	Height of Primary Barrier above Captain reservoir	Well abandonment quality at storage seal	Contact with mobile CO_2 [Mt]
14/28a-1	N/A	No Captain reservoir	N/A
14/28a-3	N/A	No Captain reservoir	N/A
14/28b-2	261'	Good	Outside complex
14/28b-4	0'	Poor	Outside complex
14/29a-2	743'	Good	No Captain reservoir
14/29a-3	765'	Good	13
14/29a-4	542'	Good	Down dip from Goldeneye
14/29a-5	375'	Good	8
20/3-1	N/A	No Captain reservoir	N/A
20/4b-3	309'	Medium	Down dip from Goldeneye
20/4b-4	N/A	No Captain reservoir	N/A
20/4b-6	200'	Good	1
20/4b-7	333'	Good	0

Figure 9-11: shows the volume at risk below each well within the Goldeneye field after the system has reached equilibrium in 2050, after injection of 20Mt. The chart separates CO_2 into mobile and immobile gas. CO_2 is considered immobile where its saturation is below critical gas saturation.

The chart shows that wells 20/4b-7 and 20/4b-6 have no or very little mobile CO_2 (0Mt & 1Mt) at risk, respectively. Even if an integrity issue occurred in these wells, the volume of CO_2 that is available to leak is minimal. The crestal wells have larger volumes at risk with the largest mobile volume being 13Mt in well 14/29a-3 though this has a cement column of 765ft [233m] thickness immediately above the reservoir.

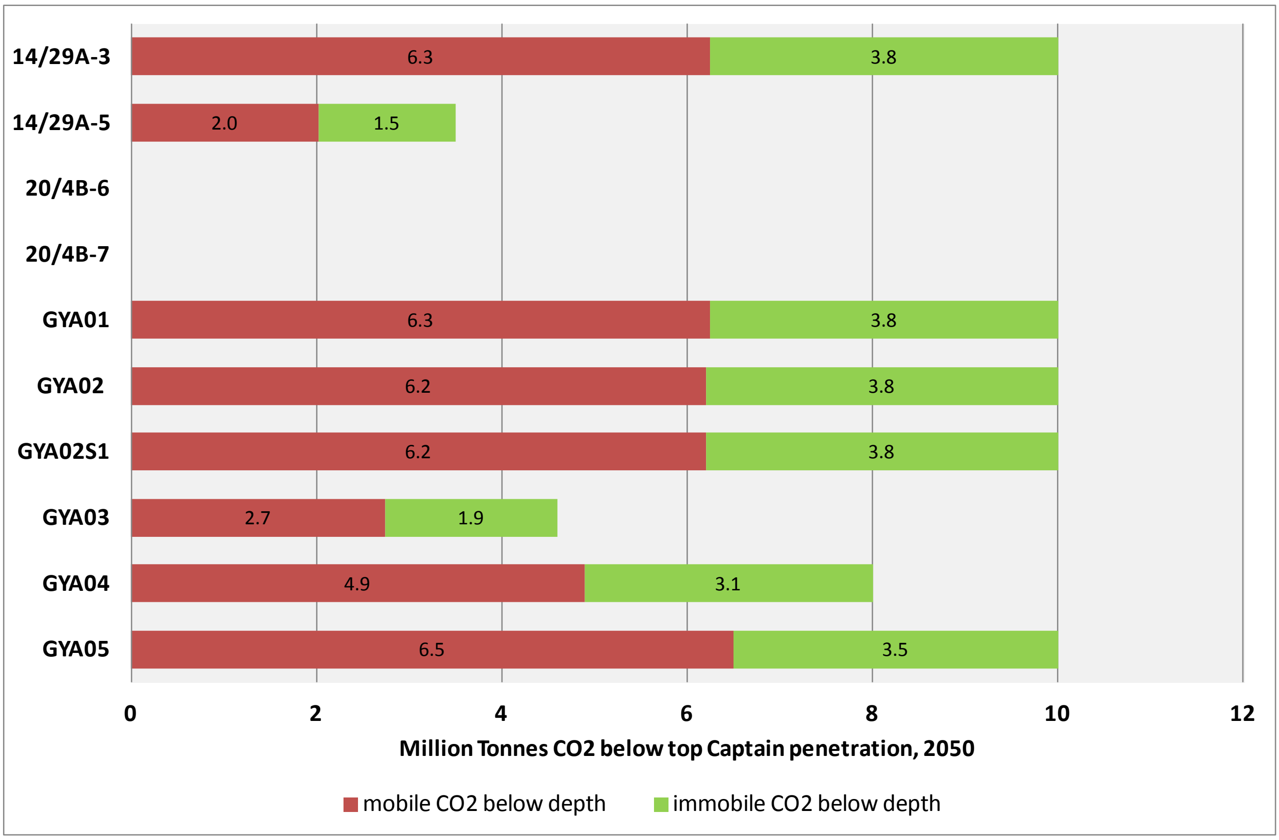


Figure 9-11: CO_2 below the top Captain Sandstone Member penetrations of wells within Goldeneye at year 2050. For 10Mt injection.

The quality of the well abandonment at the complex seal level has also been assessed. In order for CO_2 to take advantage of potential leak paths, it must first breach the storage seal – via a well bore; a fault or fracture-network in the caprock; or via diffusion through the caprock matrix – then migrate to the location of the well bore without being trapped by capillary, dissolution or chemical processes. Only then can it migrate up this path.

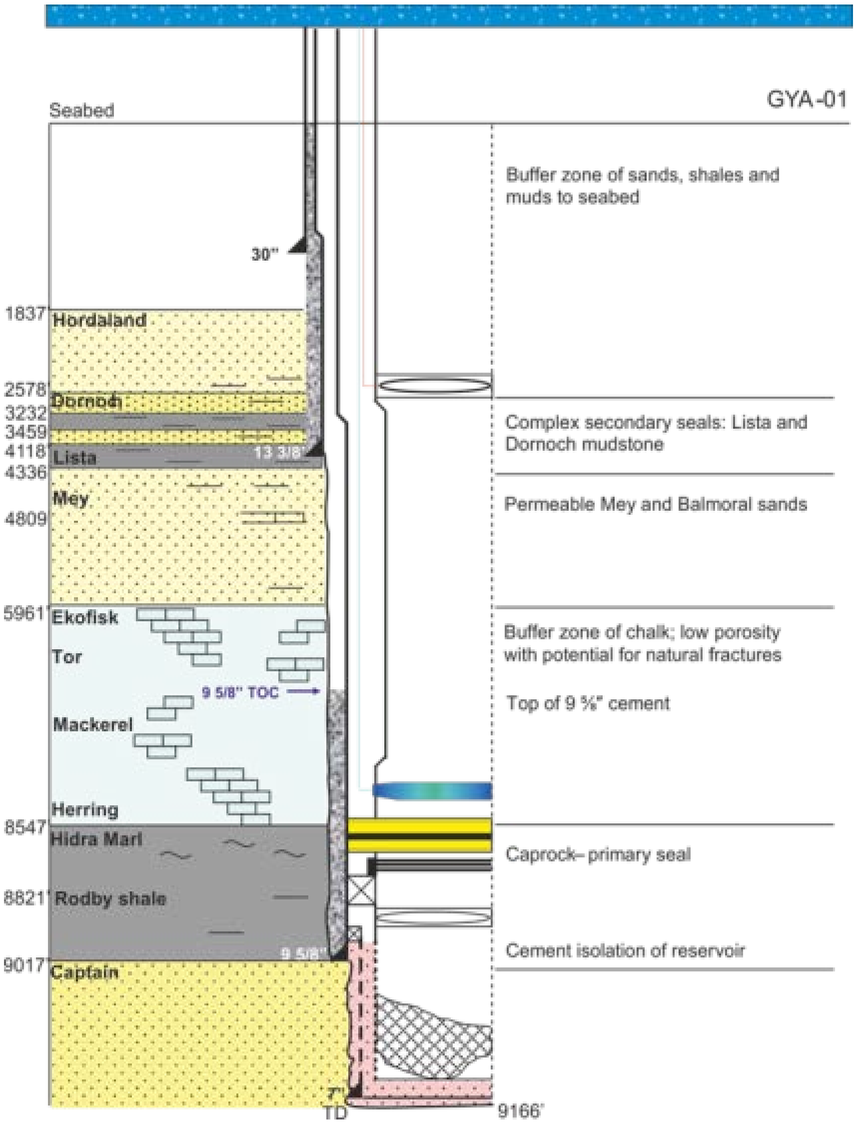


Figure 9-12: Example of Goldeneye injection well showing proposed injection completion and location of primary and secondary barriers.

9.2.7. Injection wells

Four of the wells are planned to undergo a workover in preparation for CO_2 injection.

Figure 9-12: shows an example injection well. The key points to note are:

- a good cement isolation of the reservoir from the Chalk Group with the 9 5/8" shoe set in the caprock formations.
- the 9 ⅝" cementation ceases in the Chalk Group leaving the B-annulus open – and filled with drilling mud. The annulus is in hydraulic contact with the Mey and Balmoral sands (barring any residual mud filtrate layer). It is therefore most likely to be at hydrostatic pressure. It does provide a potential path for CO_2 to reach the wellhead were it to enter the B-annulus. The B-annulus pressure is permanently monitored reducing the risk that CO_2 and carbonic acid remain undetected in this annulus for long enough to perforate it at above the complex seals. Additional monitoring is being placed at sea bed should CO_2 manage to escape from the full set of annuli and make it to the top of the well.

Full isolation of the injector wells will be restored at abandonment. This is discussed in detail in the Injection Well Abandonment Concepts report.

10. Proposed monitoring plan

This chapter outlines the current provisional monitoring and verification philosophy and plan. This plan is still subject to regulatory change as part of the storage permitting process. A detailed description is contained in the MMV (Measurement, Monitoring and Verification) Plan (1) and discussion of the effectiveness of the tools to be employed is covered by the Monitoring technology feasibility report. This chapter specifically describes monitoring and verification measures.

The monitoring plan is intended to be 'trigger-based', with triggers related to leakage scenarios built from identified leakage threats. To address these, a two-part monitoring programme was devised:

- *Base case plan*: monitors the conformance of the injection against prediction and identifies unexpected CO_2 migration (*detect*) within the storage complex, allowing action to be taken (if required) to ensure the integrity of storage before leakage occurs.
- *Contingency plan*: in the unlikely event of leakage, the *contingency plan* is mobilised to locate the source of the leak (*delineate*) and enable corrective measures to be implemented (including quantification or *define*). The monitoring plan encompasses all phases of the project and is illustrated schematically in Figure 10-1.

The rationale and detail of the plan are summarised here. Full details are provided in Peterhead Carbon Storage Permit Part III (MMV), reviewed and approved by DECC EDU in 2015.

To ensure the MMV plan reaches its objectives, the current state of the site and complex *pre-injection* will be profiled through the acquisition of baseline data across all domains.

In the event of a leak being confirmed mitigation will be addressed by a Corrective Measures Plan, which is summarized in the following chapter.

10.1. Definitions

In this chapter the following definitions are implied (from the EU directive on the geological storage of CO_2)[8]:

- '*migration*' means the movement of CO_2 *within* the storage complex;
- '*leakage*' means any release of CO_2 from the storage complex;
- '*significant irregularity*' means any irregularity in the injection or storage operations or in the condition of the storage complex itself, which implies the risk of a leakage or risk to the environment or human health.

[8] 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

10.2. Base case monitoring plan

10.2.1. Risk associated strategy

The risk based *base case* plan is designed to meet two objectives:

- Demonstrate conformance: show long-term effectiveness of CO_2 storage;
- Demonstrate containment: detection of significant irregularities or leakage.

If a significant irregularity or leakage is detected, the contingency plan is then enacted.

In order to develop effective base case and contingency plans, it is important to identify the likeliest leakage event scenarios. These are based on the residual risk after natural and engineered barriers have been taken into account. The leakage scenarios are grouped by categorising threats/risks identified in the containment risk assessment. It must also be taken into account that individual risks may act in combination to turn a containable threat of migration into a leak. The scenarios are used to generate requirements for data acquisition and technology selection. The leakage scenarios are discussed in detail in the contingency plan section. The base case plan was designed by examining the overlap between the risk assessment for each monitoring domain, the modelled behaviour of the injected CO_2 and the capabilities of the candidate monitoring technologies. The aim of this plan was to reduce the possibility of an undetected migration leak occurring to as low as reasonably practicable (ALARP). The plan is implemented in phases, defined by the activity level within the project (Figure 10-1:):

- *pre-injection*;
- *during injection*;
- *post injection/closure* and;
- *post-handover*.

In the *pre-injection* phase, baseline surveys are required to establish pre-injection conditions of the storage complex and its environment. This is in addition to surveys required to demonstrate compliance with the standard industry environmental impact assessment requirements.

During injection pressure from the injectors increases the reservoir pressure to the highest values seen since before production start-up. Monitoring is used to identify potential migration in pathways which may be activated as reservoir pressure approaches hydrostatic pressure during the injection period.

One year after cessation of injection, the various monitoring domains will be re-baselined. The year's delay is designed to allow the temperature of the injection wells to equilibrate with the formation. Other decisions with regard to additional *post-injection/closure* monitoring will be taken towards the end of the *during injection* phase in order to allow inclusion of the reservoir performance data taken during CO_2 injection. Specifically, this will enable a decision to be made as to whether to use a combination of pressure monitoring and time-lapse seismic surveying or just time-lapse seismic surveying alone for monitoring the *post-injection/closure* phase.

The monitoring programme that will be carried out in the *post-handover* phase (when responsibility for the security of the site is passed to the UK Competent Authority) will be informed by data collected in the *during injection* and *post-injection/closure* phases. It is worthwhile to note that it is expected that the platform will have been removed at this stage, making 'in-well' monitoring difficult but possibly obviating the need for Ocean Bottom Nodes (OBN) when acquiring time-lapse seismic surveys. This phase of the project will not be considered further in this report.

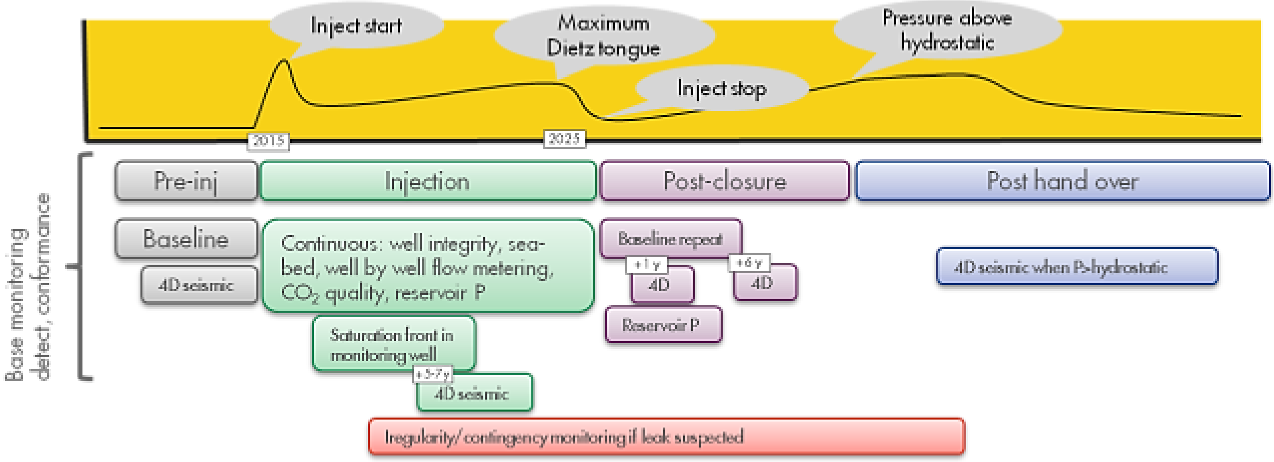


Figure 10-1: Schematic of the monitoring plan. The vertical axis on the schematic represents risk of *significant irregularity*.

10.2.2. MMV domains

Feasibility studies have shown that different physical domains are susceptible to different suites of monitoring techniques.

Storage site:

The primary geologic storage volume includes the Captain Sandstone members as well as all the formations down to the base of the Cromer Knoll Group.

Injection and monitoring wells:

The five production wells in Goldeneye field will be converted. One will be plugged; four will be recompleted; three will be connected as injectors while one will be reserved for monitoring and will also be an "ultimate backup" injector. This domain comprises the storage site and the injection wells within (from well head to total depth – TD). The focus is to monitor the location of the CO_2 plume in order to calibrate *conformance* modelling and to demonstrate that actual storage site performance matches modelled performance. Well and reservoir monitoring requires installation of gauges (preferably in all wells) and measurement of CO_2 saturation in observation wells. The geosphere includes all of the rock below the inhabited sediment immediately beneath the seabed contained within the geographical boundary of the storage complex, with the exception of the storage site. It also includes plugged and abandoned wells. The storage site is specifically excluded from this domain because time-lapse seismic surveying will be assessed by 'in-well' technology. CO_2 detection techniques in the geosphere 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.

Overburden and aquifers:

This is the subsurface region from the top of the secondary seal complex (Dornoch/Lista mudstone) down to the base of the primary seal (intra-Upper Valhall Formation) and laterally to the Captain Sand fairway (the lateral continuation of the Captain Sandstone reservoir which is hydraulically connected to the store).

Marine biosphere and shallow subsurface:

This includes the seawater column, the seabed and the shallow subsurface down to the base of the formation above the secondary seal complex (Dornoch/Lista mudstone). The area around abandoned E&A wells will be specifically targeted for monitoring. All techniques applicable in this domain rely on point measurement techniques (rather than techniques that can remote sense over a whole area) and, therefore, have to be placed at locations which have been assessed to have higher local risk – *e.g.* wellheads. These techniques also need well-defined baseline data since CO_2 and CH_4 occur naturally in this domain and this would need to be accounted for before any assessment of leakage were made.

Transport:

This includes pipelines and facilities. The main tools for leakage detection in this domain are the pipeline and plant monitoring systems from Peterhead to the injection wells on the Goldeneye platform. These are described in the transport and injectivity chapter and will not be considered further in this section. The existing leak detection systems on the platform will be upgraded to CO_2 service.

10.2.3. Timeframe of Review

MMV activities will be adapted through time to meet the different requirements during distinct phases of the Project lifecycle as outlined in the Guidance Document 1 of the EU CCS Directive:

- **Assessment Phase:** Assess and define storage site.
- **Characterisation Phase:** Monitoring tasks are identified, monitoring solutions evaluated and selected, risks are characterized. Milestone at end of phase two: Award of the storage permit.
- **Development Phase (Pre-injection):** Baseline monitoring data are acquired, possible updates to the MMV and Corrective Measures Plan. Milestone at end of phase three: Start injection.
- **Operation Phase (Injection):** During injection, monitoring activities are undertaken to manage conformance and containment risks, and, if necessary, are adapted through time. Milestone at end of phase four: Site closure after injection is completed.
- **Post-Closure/Pre-Transfer Phase (Post-injection)**: Some monitoring activities continue during this phase to manage containment risk and to demonstrate storage performance is consistent with requirements for long-term secure storage. Post-closure activities will be executed including facilities decommissioning, pipeline abandonment and reclamation, and wells abandonment and reclamation in agreement with the competent authority. Shell will apply for transfer to the UK competent authority following the execution of post-closure activities. Shell is proposing a 7 year transfer period post-injection, provided there are no significant issues arising from project operations and that storage performance and CO_2 containment in the storage complex are demonstrated to the satisfaction of the regulatory authorities in accordance with agreed criteria.
- **Post-Transfer Phase**: The storage site is handed over and liability is transferred to the UK competent authority for long term stewardship.

10.2.4. Summary of the base case plan

The base case monitoring plan, see Table 10-1, allows for multiple independent monitoring systems with comprehensive coverage through time and across the storage complex within each of the environmental domains.

The diversity of monitoring technologies mitigates the risk of any one technology failing. The base case monitoring plan includes baseline surveys which are required to establish pre-injection conditions of all domains. This requirement is in addition to compliance with the usual industry environmental impact assessments. The base case monitoring plan below does not include any monitoring required post hand-over of the store to the Competent Authority. Monitoring during this period is covered in the Provisional Post Closure Plan. Some technologies have been provisionally included as they are still under development, if the development efforts show that they are not in fact feasible then they will have to be regretted. These are indicated by R&D labels.

The technologies to be applied are identified by the domain in which they are effective. Further details on each of the monitoring techniques can be found in the Peterhead CCS Storage Permit Application Part III (MMV).

Table 10-1: Summary of the base case monitoring plan

Data	Technology	Coverage	Time	Reason
Pre-injection				
Seabed and Shallow Layers				
Seabed maps (pockmarks)	MBES & SSS	Storage complex	Pre-injection	Leakage identification and quantification (no alternatives)
Water column & seabed profiling	Geochemical probe (CDT) Subsea sensor package (R&D)	Seabed and water column under platform. Landers under platform.	Baseline 1 year pre-injection	Baseline for indication of increased CO_2 flux and changes in environmental properties
Bubble detection	ROV bubble detection	Seabed and water column under platform	As part of routine platform inspection	Leakage identification
Seabed samples (seabed sediment, flora & fauna)	Van Veen Grab	Sampling points within storage complex- emphasis on high risk area (wells, seismic anomalies, platform)	Pre-injection	Baseline for seabed leakage identification and quantification
Platform movement (height and horizontal)	GPS	Platform	Pre-injection Continuous	Baseline to monitor the development of surface displacement due to CO_2 injection
Geosphere				
Time-lapse seismic	3D streamer (full-field)	Storage complex	Pre-injection	Baseline covering large area of field overburden and aquifer (alternatives cover smaller areas)
	OBN	Storage site	Pre-injection	Baseline for containment monitoring. Provides best resolution
	DAS VSP (R&D)	Monitoring and Injection wells	Pre-injection	Baseline for containment monitoring near wells
Wells				

Data	Technology	Coverage	Time	Reason
Well integrity measurements	Cement bond logging	Injection wells	Pre-injection during workover	Baseline condition of cement bond between casing and formation
	Casing integrity logging	Injection wells	Pre-injection, during workover	Baseline condition of casing thickness
CO_2 conformance	Sigma and neutron logging	Monitoring and Injection wells	Pre-injection,	Baseline the fluid contacts Injection wells: For contingency monitoring
Pressure conformance	PDG	Injection 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
Injection				
Seabed and Shallow Layers				
Seabed maps (pockmarks)	MBES & SSS	Storage complex	Mid-injection	Leakage identification and quantification (no alternatives)
Water column & seabed profiling	Subsea sensor package (R&D)	Seabed and water column under platform	Continuous	Indication of increased CO_2 flux and change of environment properties
Bubble detection	ROV bubble detection	Seabed and water column under platform	As part of routine platform inspection	Leakage identification
Platform movement (height and horizontal)	GPS	Platform	Continuous	Monitor the development of surface displacement due to CO_2 injection
Geosphere				
Time-lapse seismic	OBN	Storage site	Mid-injection	Containment monitoring Provides best resolution

Data	Technology	Coverage	Time	Reason
	DAS VSP (R&D)	Monitoring and Injection wells	Mid-injection	For containment monitoring near wells
Wells				
Well integrity measurements	Annular pressure and DTS and DAS(R&D)	Assume 4 wells	Continuous	Indicate leakage at casing by pressure profile and along tubing by temperature profile
	Tubing integrity logging	Active injectors (assume 3 wells)	Yr 3, 7, 11 (indicative)	Indicate leakage in the tubing using direct measurement
CO_2 detection	Downhole sampling	Monitoring wells	Yr 7, 9, 11, 13 (indicative)	Identify CO_2 concentration profile for saturation performance (the alternative is restricted due to well & completion constraints for installation)
CO_2 conformance	Sigma and neutron logging	Monitoring wells	Pre injections plus Yr 7, 9, 11, 13 (indicative)	Identify breakthrough CO_2 interval profile for saturation conformance
Pressure conformance	PDG	Assume 4 wells	Continuous	Identify pressure conformance in Captain reservoir
	Long term pressure gauges	Assume 4 wells	Replace PDG if needed	Identify pressure conformance in Captain reservoir
Conformance	Onshore flow meter		Continuous	
	Offshore allocation meter		Continuous	
	Onshore monitor composition THP and THT		Continuous	
Post-injection				
Seabed and Shallow Layers				

Data	Technology	Coverage	Time	Reason
Seabed maps (pockmarks)	MBES & SSS	Storage complex	Yr 1 post injection/ pre-handover	Leakage identification and quantification (no alternatives)
Seabed samples (seabed sediment, flora & fauna)	Van Veen Grab	Sampling points within storage complex-emphasis on high risk area (wells, seismic anomalies, platform)	Yr 1 post injection	Leakage on seabed identification and quantification
Geosphere				
Time-lapse seismic	OBN	Storage site	Yr 1 post injection/ pre-handover	Containment monitoring Provides best resolution
	DAS VSP (R&D)	Monitoring and Injection wells	Yr 1 post injection/ pre-handover	For containment monitoring near wells
Wells				
Pressure conformance	PDG	Assume 4 wells	Potentially 1 to 2 years post injection	Identify pressure conformance in Captain reservoir
	Long term gauge	Assume 4 wells	Replace PDG	Identify pressure conformance in Captain reservoir

10.2.4.1. Base case plan costs

Costs cannot be fully defined until the monitoring plan has received regulatory approval and data acquisition has been put out to tender (during the detailed design phase of the project). In addition, some of the proposed technologies are not presently at a maturity level which gives confidence that they will be ready for deployment at the required stage of the project (e.g. addition of geochemical tracers). For these reasons, costs are not reported in this document.

11. Corrective measures plan

This chapter outlines a corrective measures philosophy and plan.

11.1. Key grounding principles

The key factors in the development of the corrective measures plan are the boundary conditions and definitions as described in the EU directive. The boundary conditions and definitions are summarised below:

(i) Corrective measures are actions, measures or activities taken to correct *significant irregularities* or to close leakages in order to prevent or stop the release of CO_2 from the *storage complex*.

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

(iii) *leakage* means any release of CO_2 from the *storage complex*;

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

The corrective measures plan acts to (in order of priority):

1. Prevent risks to *human health*
2. Prevent risks to the *environment*
3. Prevent *leakage* from the *storage complex*

The plan is *site specific* and *risk based* and covers the storage complex. The release of CO_2 at the surface, be it from a well head or surface pipe work, is covered by standard operating practices and the facilities HAZID and HAZOP.

11.2. Annuli designations

Reference is made to annuli in this report, especially when referencing potentially leaking tubulars and annular monitoring. It is important to understand where the annuli are with respect to the casing strings and also to the formations (Figure 11-1):

- The 'A' annulus is between the production tubing and the production casing. It is a completely enclosed volume with metal-to-metal (casing or tubing) or high reliability seals (packer). During the workover of the production wells to injection wells, it is planned to fill this annulus with an oil based fluid, potentially with a nitrogen cushion in order to compensate for the cooling effects from injection of CO_2.
- The 'B' annulus is between the production and intermediate casing strings. It is connected to permeable intervals via an "open shoe" (production casing cement below the base of the intermediate casing). These permeable intervals are the secondary containment units below the secondary seal (Lista/Dornoch shales).
- The 'C' annulus is the volume between the 30in conductor and the surface/intermediate casing. This volume is open at the top (wellhead) and is also in communication with the sea via slots in the conductor above seabed level. The surface/intermediate casing string is cemented up to seabed.

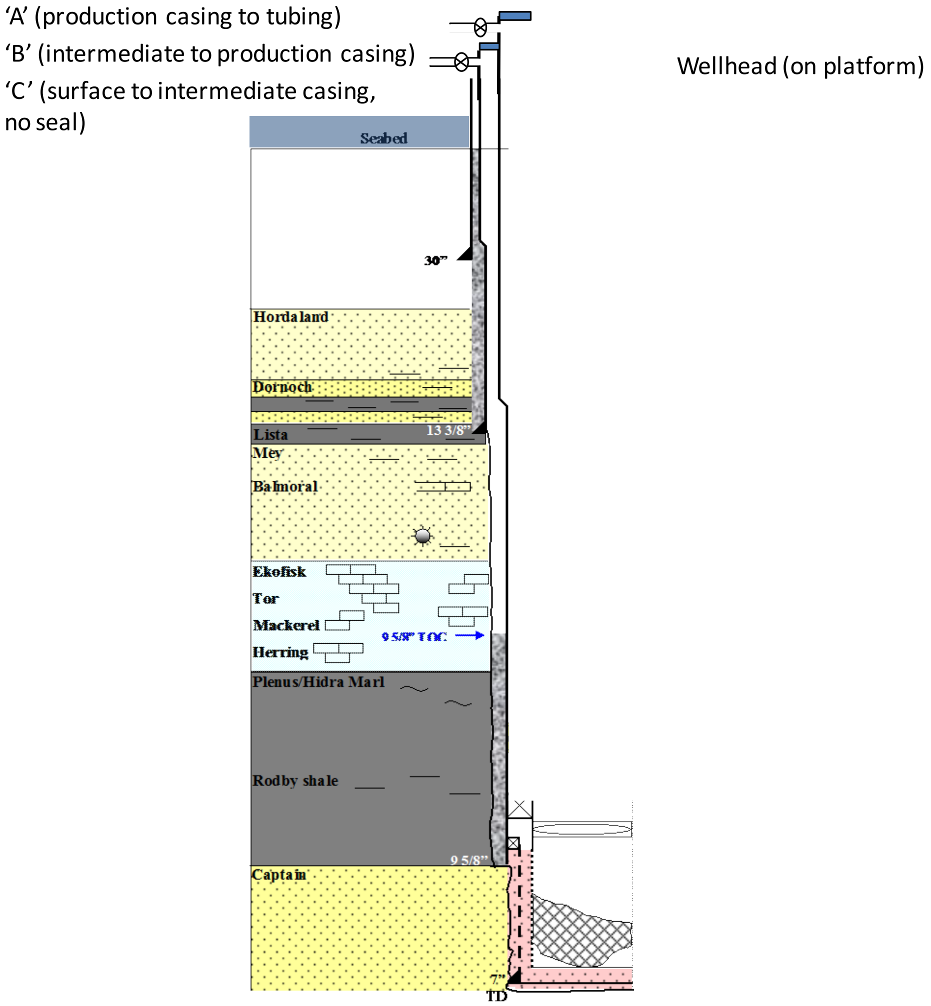


Figure 11-1: Proposed completion design and annuli designations.

11.3. Potential migration classes

A site specific containment risk assessment was performed using the bow-tie risk assessment methodology. The Goldeneye bow-tie selected a *leak from the storage complex* as the top level event – in line with the principles outlined above. The risk assessment details the potential subsurface migration paths that CO_2 can take. These are grouped into five classes as shown in Figure 11-2.

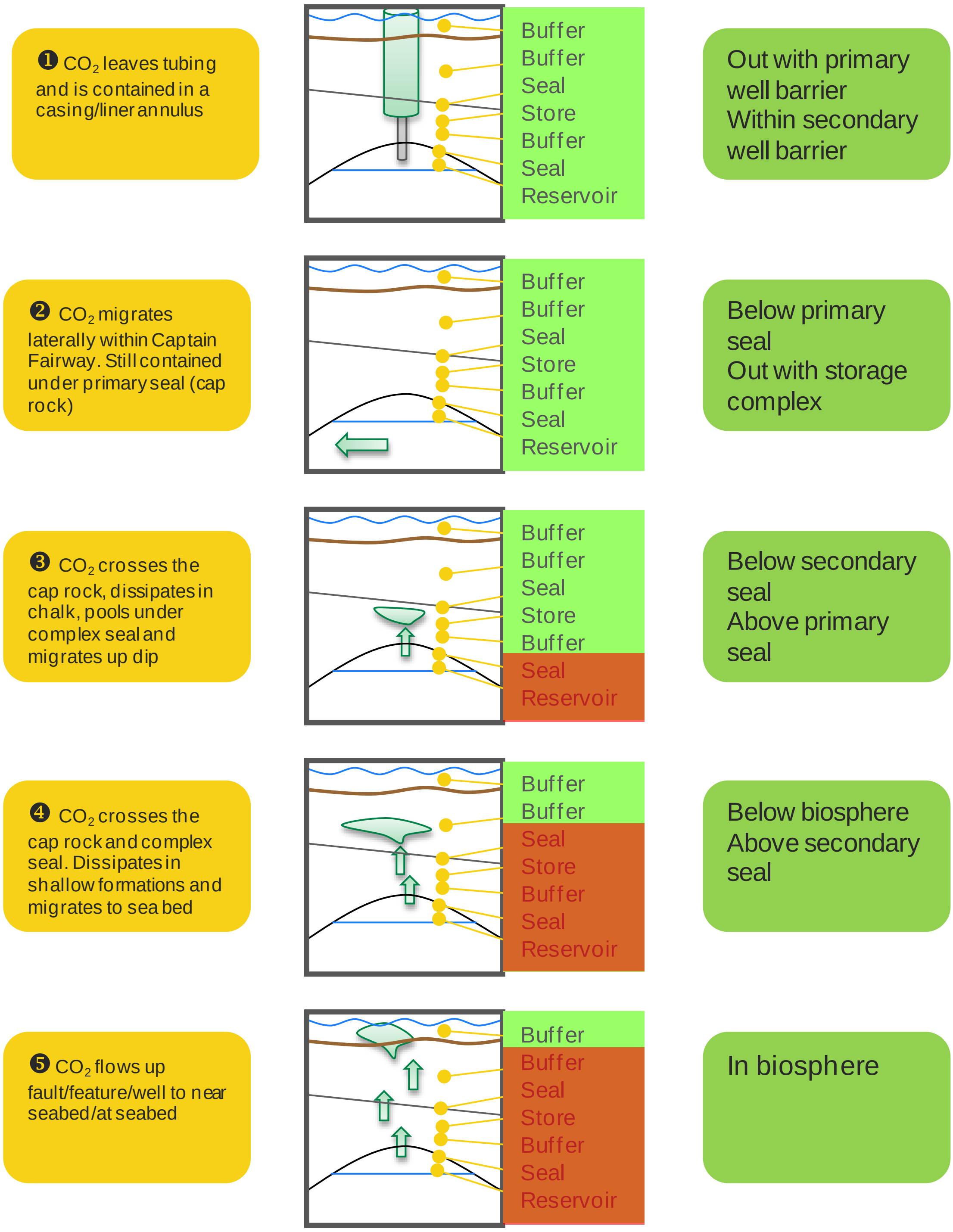


Figure 11-2: Potential migration routes in the Goldeneye system.

The first two are potential precursors to the other three. Only with escalation and the failure or bypassing of the primary and secondary seal and the failure of the multiple buffers and secondary stores to disperse or absorb CO_2 will there be a migration of CO_2 into the biosphere.

It is important that a systematic approach be adopted for the detection and assessment of any suspected irregularity. If this is not done there are risks that incorrect corrective actions may be employed that could increase the impact of any irregularity. An example could be the drilling of an additional well into the complex adding an extra potential leak path. Mitigating a single risk (or perceived risk) should always be premised on the basis of an overall reduction in the total risk.

The process for detecting and then analysing any suspected irregularity is outlined below:

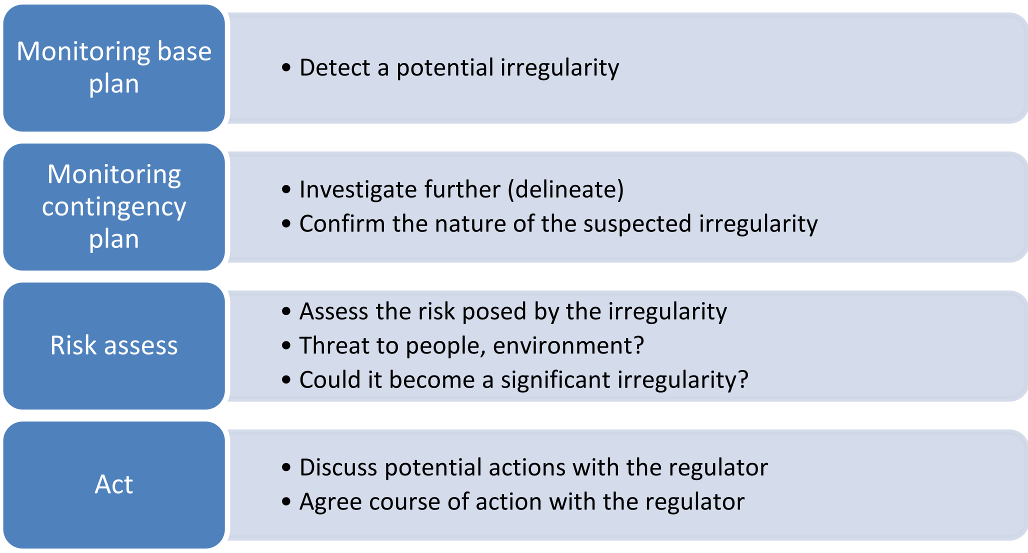


Figure 11-3 Process for detecting and analysing a suspected irregularity

It is essential to note that the actions depend strongly on the risk assessment. Referring to Figure 11-2:, the potential actions depend on the assessment of the potential consequences. Reading from left to right in the figure:

❶ CO_2 leaves tubing and is contained by the production casing.

This leak is outside the subsurface complex, but is still within the storage site as the site definition includes the surface facilities. However, it has the potential to impact humans and the environment if the final engineered barriers were to fail. This type of leak is relatively common in some oil fields, hence, the design of multiple independent engineered containment barriers. Well established oil field techniques would be rapidly employed to fix the leak thereby preventing further escalation.

❷ CO_2 migrates laterally within Captain Fairway, remains contained under primary seal (caprock).

In this scenario, the CO_2 is still contained and no risk to humans and the environment is present. However, CO_2 has moved out of the licensed store and the defined complex. This results in an increased risk of exposure because CO_2 is migrating in an area that could have additional risk features - primarily decommissioned E&A wells.

The initial response would be to risk assess the size, nature and magnitude of migration, increase the monitoring and model the current and potential migration. The risk assessment establishes the threat of further escalation (primarily CO_2 encroachment towards a poorly decommissioned E&A well). Corrective measures such as changing the injection pattern and planning an intersection well for such decommissioned wells would be assessed.

❸ CO_2 crosses the caprock, dissipates in chalk, pools under complex seal and migrates up dip.

There is no immediate risk to people and the environment as the CO_2 is still contained by the secondary seal. The contingency monitoring and risk assessment would identify the potential causes of the migration. Any solution would be determined based on the risk assessment and in consultation with the regulator.

If the leak is injection well related, then a fix might be appropriate.

If the leak were found to be geological in origin, then a range of solutions exist based on the exact nature of the irregularity: the initial action could be to stop injection, plug wells, or potentially even to adjust monitoring and apply to licence additional storage volume.

❹ CO_2 crosses the caprock and complex seal, dissipates in shallow formations as it migrates towards seabed.

This is an escalation from ❸, but there is still a low risk to people and the environment as CO_2 has not yet migrated to the biosphere. However, there is now a significant irregularity as both the primary and secondary seals have been crossed. Focussed contingency monitoring would again inform a risk assessment to establish the likelihood of CO_2 reaching the seabed. Additionally, the monitoring plan dictates quantitative monitoring of the seabed to determine if CO_2 flux is present.

The response will depend on the nature and severity of impacts or potential impacts as determined by the risk assessment. It will also depend on the source of the leak:

If it is a point source (wells related), then the leak could potentially be repaired. Note that CO_2 already migrating through shallow sediments cannot be halted.

If the source is entirely geological in nature (for example a fault zone), the application of potential corrective measures is reduced. Depending on the nature and scale of migration, the most likely corrective measure is to reduce the leak rate where possible, by adjusting the injection pattern.

❺ CO_2 flows up to near seabed/at seabed.

This is an escalation from ❹ and is the HSE critical risk. CO_2 could enter the environment (the biosphere) and potentially impact flora and fauna. If the release is large enough it could increase the concentration of CO_2 at sea level enough to be a risk to humans.

Once the monitoring efforts have identified the source of the leak, quantification would take place. An effects assessment has been performed as part of the environmental statement which would allow estimation of the potential impact when the location and severity of the migration are known.

In the most likely scenario of a well providing at least part of the flow path through either the primary or secondary seal, it is likely that the agreed corrective measure would be to repair or plug the leak path at the primary seal or secondary complex seal.

The risks assessment concludes that it is highly unlikely that CO_2 would migrate to the surface in significant quantities independent of any wellbores. In the unlikely event that leakage to the seabed occurs independent of any wellbore, the application of potential corrective measures is limited with current technology. It is theoretically possible to remove the reservoir of CO_2 behind the leak. For example, this could be done by building a platform, drilling wells, and pumping the CO_2 out again, and disposing of it into another as yet undeveloped store or the atmosphere. The challenge would then be to weigh up the impact of the corrective measure against the impact of the leak. This would be done in conjunction with the regulator. Alternatively, leak rates may be reduced by adjusting the injection pattern or reducing / curtailing injection.

12. Provisional closure and post-closure plan

12.1. Legislative framework

The provisional closure and post-closure plans have been prepared with reference to draft, unpublished guidelines from DECC EDU[9]in connection with UK regulations on the storage of carbon dioxide, and to EU CCS Directive, relevant excerpts from which are given below.

12.1.1. DECC EDU guidelines

A provisional Post Closure Plan shall be submitted with the permit application, for approval by DECC EDU, and shall describe the monitoring, reporting and implementation of corrective measures for any leakages.

The Post Closure Plan requires a discussion of the monitoring techniques that will be conducted after the operational phase of CO_2 injection has finished. The details of this long-term monitoring plan shall be discussed in a provisional Post Closure Plan, which shall be submitted [with the application for a Storage Permit] as a separate document for approval by DECC EDU. The long-term monitoring plan will be site specific and may include use of dedicated pressure observation wells, ongoing seismic surveys etc. Whatever techniques are selected, they must be able to identify any leakages or significant irregularities. The plan should be updated as necessary, taking account of risk analysis, best practice and technological improvements.

The long term monitoring plan should also include the options for remedial action if test results are not as anticipated.

12.1.2. EU Directive on the geological storage of carbon dioxide

(31) A storage site should be closed if the relevant conditions stated in the permit have been complied with, upon request from the operator after authorisation of the competent authority, or if the competent authority so decides after the withdrawal of a storage permit.

(32) After a storage site has been closed, the operator should remain responsible for maintenance, monitoring and control, reporting, and corrective measures pursuant to the requirements of this Directive on the basis of a post-closure plan submitted to and approved by the competent authority as well as for all ensuing obligations under other relevant Community legislation until the responsibility for the storage site is transferred to the competent authority.

(33) The responsibility for the storage site, including specific legal obligations, should be transferred to the competent authority, if and when all available evidence indicates that the stored CO_2 will be completely and permanently contained.

To this end, the operator should submit a report to the competent authority for approval of the transfer. In the early phase of the implementation of this Directive, to ensure consistency in implementation of the requirements of this Directive across the Community, all reports should be made available to the Commission after receipt. The draft approval decisions should be transmitted to the Commission to enable it to issue an opinion on the draft approval decisions within four months of their receipt. The national authorities should take this opinion into consideration when taking a decision on the approval and should justify any departure from the Commission's opinion. The review of draft approval decisions should, in the same way as the review of draft storage permits at Community level, also help to enhance public confidence in CCS.

12.2. Conditions upon which this plan has been based

The post closure plan is provisional, notwithstanding this fact, and given the condition that the storage of CO_2 at Goldeneye does not exhibit any significant irregularities, it is expected that the final plan will not deviate materially from the details herein.

[9] Note that since the original creation of this document DECC EDU has now become the Oil and Gas Authority OGA

In order to develop the plan a number of boundary conditions have to be placed in accord with the current storage permit and current development plans for the Outer Moray Firth. These are laid out below:

1. There are no significant irregularities (as per the EU Directive (3)) during the injection phase: the CO_2 is contained within the currently proposed store and the currently planned injection facilities are used.
2. 10-15 Mt of CO_2 is injected over a period of 10-15 years.
3. No other storage takes place in the formations hydraulically connected with the Goldeneye store. It is key that the details of any planned developments are shared with the Goldeneye operator before permitting so that interactions between the stores can be modelled and understood (as per DECC guidance).
4. Extraction of hydrocarbons (and potentially water injection) in adjacent hydrocarbon fields is as currently understood:
    - Atlantic & Cromarty: ceased production.
    - Hoylake: continuing production.
    - Rochelle: starting depletion drive production.
    - Blake: continuing with voidage replacement.

Any changes to these boundary conditions may affect the plan. The operator will need to be informed and given sufficient notice to understand the impacts and consider the implications. It is expected that all available data, including extractions forecasts and maps if necessary, will be shared with the storage operator.

12.3. Site closure performance criteria

The aim of *post-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:

(i) ***Behaving as predicted and is unlikely to deviate from prediction:*** 3D dynamic simulation forecasts of the movement of continuous phase[10] CO_2 indicate that the continuous phase CO_2 is approaching a gravity stable equilibrium[11] within the site. This means that data from the monitoring programme, when combined with the updated history matched 3D dynamic simulation, forecast that the system will relax and approach gravity stable equilibrium over time. This will also demonstrate that the storage system is behaving as expected.

(ii) ***No leaks or unexpected migration paths are observed:*** Two separate seismic surveys[12] (with an expected separation of five years) show that the continuous phase CO_2 is not migrating laterally or vertically from the licensed storage site. The second survey is designed to validate the assertion, determined from the monitoring data from the whole performance

[10] Continuous phase means: dense phase or gaseous phase – not dissolved CO_2 which will slowly sink downwards over thousands of years.

[11] In the Goldeneye specific case this means that the *Dietz* tongue is contracting back into the structure and the CO_2 is moving to the location where it is expected to stay for 1000 years.

[12] In the Goldeneye specific case a post closure survey is a combination of a time-lapse 3D seismic survey for subsurface profiling and site surveys of well locations to look for surface indications of CO_2 leakage.

history of the site, both during hydrocarbon production and CO_2 injection, that the site is secure and not leaking. This survey is approximately twelve to thirteen years after the mid-life survey (so covers the approximately seven years of operation when the store was exposed to the highest injection pressures) and five years after the post injection survey. The gap gives sufficient time to detect any significant or moderate leakage from the store to the secondary storage formation, and minor leakage rates to the near seabed. The seabed detection will identify miniscule leaks – small bubble streams.

Given the fact that the proposed storage site is a structural store based on a depleted hydrocarbon accumulation then, once these conditions have been met, the site will be considered to be in a position that is suitable for handover.

It is noted that CO_2 which has undergone dissolution trapping will sink vertically downwards and the dissolved CO_2 (and associated ionic compounds) will migrate down dip. This CO_2 is sequestered and cannot be practicably monitored.

12.4. The Provisional closure and post-closure plan

12.4.1. Monitoring, facilities and hand-over

The following section describes the base case plan for the provisional closure and post-closure plan. Should the monitoring activities highlight any significant irregularities in the behaviour of CO_2, the timings and activities proposed below will be reviewed, in discussion with the Competent Authority and the closure and post-closure plan revised if required.

The results of this monitoring taken together with the reservoir history match provide a base for comparison in the post closure period. The pre-injection, injection and post-injection phase monitoring plan, described in detail in the MMV plan (4), is summarised in Table 12-1. In addition, the information from this monitoring will also be combined with the following information:

- The evidence that the Goldeneye reservoir has an estimated greater than fifty million years of containment of hydrocarbon (with some CO_2) charge.
- The data acquired since the drilling of the first hydrocarbon appraisal well in 1996.

The six year hydrocarbon production and second by second monitoring history of the Goldeneye gas/condensate field, acquired since the construction of the platform wells in 2003.

Table 12-1: Summary of Base Case MMV Plan in the Phases Pre-Handover

Pre-Injection	During Injection	Post-Injection
■ Data collected from production and between production and injection: pressure, temperature, production rates	■ Continuous monitoring in injection wells: pressures, DTS, DAS	**Survey 1**: before wells are sealed. Wells will only be sealed after successful indications of no issues. If issues (flow behind casing) are observed, then abandonment plan will be modified to ensure formation isolation.
■ Seismic survey: OBN over site, streamer over complex	■ Regular inspection of wells	■ OBN and 3D VSP over site
■ 3D VSP proof of concept	■ Continuous GPS	■ Seabed mapping over complex
■ Seawater monitoring baseline	■ Continuous seawater monitoring – continuing to measure natural variation	■ Seabed sampling over complex
■ Passive seismic baseline	■ Continuous tracer injection (assuming it passes partitioning tests)	■ Continuous well monitoring until sealed
■ Seabed mapping over site and complex	■ Periodic saturation logging in monitoring well (frequency increasing after year 6)	■ Wells sealed and platform removed
■ Seabed sampling over site and complex	■ Periodic tubing integrity logging in injection wells	**Survey 2**: planned for 5 years after survey 1, no earlier. Period set to give time for low rate migration to build up sufficient volumes for seismic detection.
■ GPS baseline	■ Periodic (3 yearly) ROV bubble surveys below platform	■ OBN over site
■ Cement integrity logging during workover	**Mid-life survey**	■ Seabed mapping over site
■ Saturation logging baseline	■ OBN over site if 3D VSP proof of concept is unsuccessful	■ Additional intrusive sampling is part of the contingency monitoring plan
	■ Seabed mapping over site	
	■ Additional intrusive benthic sampling is part of the contingency monitoring plan	

The post-injection surveys will be compared to the previous surveys to look for any changes hinting at irregularities. Dynamic modelling indicates that post-injection the CO_2 that will have moved both laterally and downwards under viscous forces during injection, will flow back upwards under buoyancy drive and the CO_2 /water contact will move towards a stable (and horizontal) equilibrium. There will also be minor thermal, mixing and dissolution effects. These processes will be slow and will occur over long to even geological time scales.

The first post-injection survey will provide evidence supporting confirmation that the CO_2 is still remaining in the store and will also be able to establish if CO_2 has migrated beyond the original oil water contact – this was modelled as likely for 20 Mt injection and is possible though less likely for 15 Mt. Any CO_2 in the water leg will increase the amount of dissolution and capillary trapping for the whole site. The seismic survey of the storage site will be executed as soon as possible after the end of injection. This is the point in the evolution of the depleted field store where:

1) The store has seen the highest injection pressures.

2) The CO_2 has the largest footprint as shown in the Figure 12-1, below.

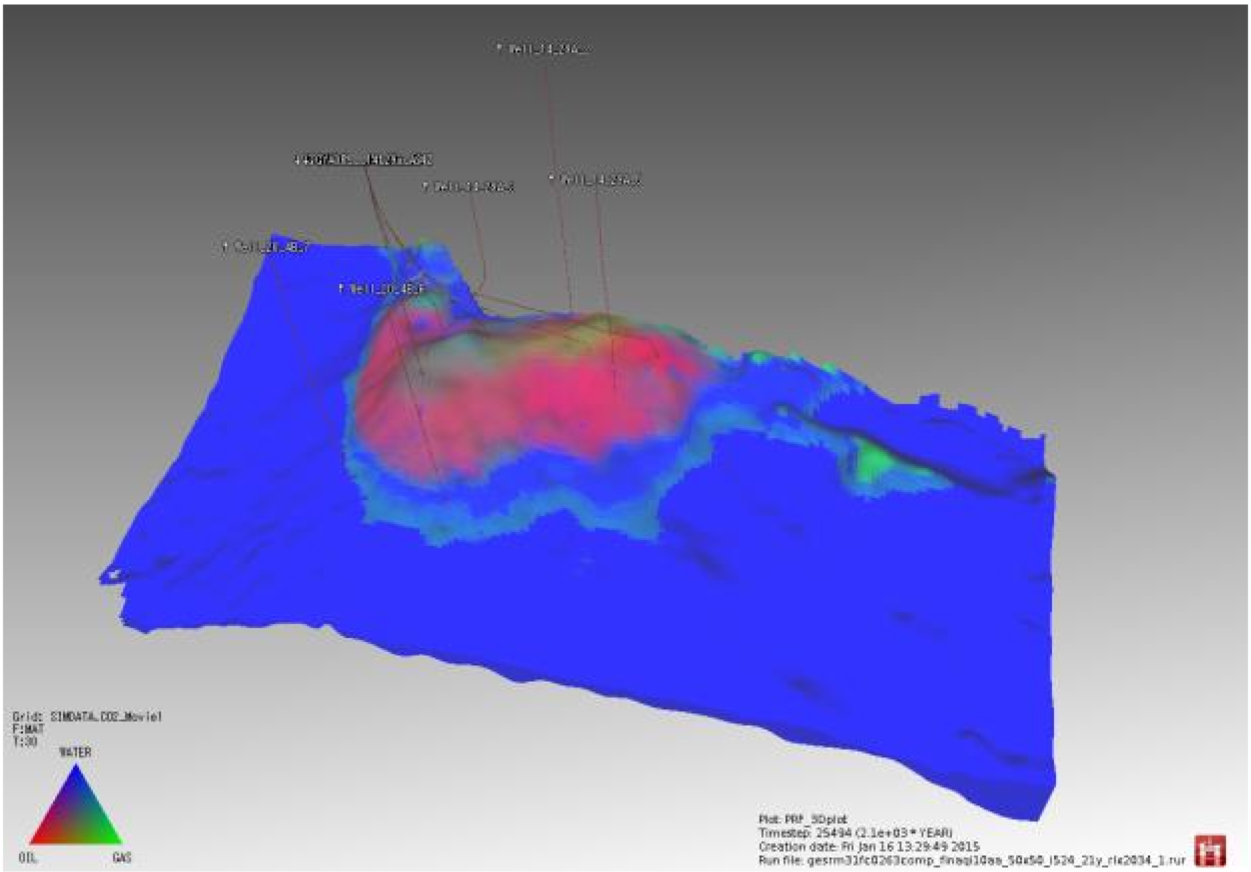


Figure 12-1: Modelled distribution of CO2 at the end of injection

Red=CO_2, Green=hydrocarbon, Blue=Water

While watching for any potential evidence of plume extent, the primary purpose of the survey is to look for indications of flow behind casing, injection out of zone or excessive migration of the CO_2. If CO_2 is identified where it is not expected this could alter the plugging strategy for the injection wells, for example, indicating that rock-to-rock plugs are required. The wells and facilities will only be plugged and removed once the results of the seismic and seabed surveys have been interpreted and discussed with the regulator.

The second seismic survey will take place five years after the first one. Its aim is to validate the lack of leakage. Neither survey is expected to see into the store and examine the distribution of CO_2 within the depleted field store, though as mentioned above if water leg storage has taken place this should be detected. The advantage of using a depleted field is that the store has a seal proven over geological time and, in this case is characterized by the combination of the results from five exploration and appraisal wells, five production wells, continuous down hole pressure monitoring of all production wells, which continues to the time of writing of this note, and well by well production metering. The disadvantage of the depleted field store is that the residual hydrocarbon gas masks the seismic signature from the CO_2, meaning that it is not possible to “image inside the box”. The 4D seismic feasibility modelling has, however, shown that it is possible to see small masses of CO_2 in the adjacent and overlying formations, with sensitivity increasing as the CO_2 gets nearer to the surface. This makes seismic surveys an excellent tool for looking for irregularities.

12.4.2. Contingent timings and actions within the plan

The post-closure monitoring will be able to show whether CO_2 is moving outside the storage site. Should any significant irregularities be observed following the results of the post-injection seismic survey, further investigation will be carried out better to understand the causes and if required, take the appropriate corrective action. Such actions will alter the risk assessment, and the monitoring and post closure plans would be updated.

Partial decommissioning will start at the earliest opportunity after the cessation of injection (for example of the pipeline as detailed in earlier sections) and it is aimed to complete the decommissioning of all facilities within two years of cessation of injection. The wells will be left in place and decommissioned at the last possible time within the abandonment sequence, in order to allow a longer period to monitor pressure. This will allow the collection of pressure build up information to calibrate the aquifer response in the dynamic models. After an 18 month period to allow for the collection and analysis of the seismic survey, and once containment has been demonstrated, all the injection facilities (platform) are to be removed. Once the wells are sealed pressure monitoring will cease, however the risk of open well leakage is removed, dramatically reducing the risk of a significant irregularity. These timings are based on the base case plan. The exact timing of the Goldeneye facilities decommissioning will be reviewed should the results of the monitoring require further action.

At a period of five years after the initial post closure survey, a second post-closure time-lapse seismic survey will be collected covering the storage site – and including seabed surveying and sampling at the abandoned well locations. Once the survey results have been processed, approximately a year after survey initiation, and the results demonstrate containment of the injected CO_2, a request will be made to the Competent Authority for handover as the risk profile will not change for the foreseeable future as the CO_2 within the store relaxes and re-equilibrates over millennia.

12.4.3. Corrective measures

The corrective measures pertaining to the post-closure period are outlined in detail in the *Corrective Measures Plan*. After the injection wells have been abandoned, naturally all corrective measures associated with standard well interventions into the wells are no longer applicable. The corrective measures take a stepwise approach using the Detect, Delineate, Define and Determine philosophy.

1. Detect a potential irregularity.
2. Delineate the irregularity.
    a. Confirm that it is taking place.

   b. Identify the source of the irregularity (is it a well related, fault related etc.).
3. Define the irregularity.
   a. Assess the magnitude – how much has leaked?
   b. Assess the impact – what ecosystems are being affected and in what manner?
4. Determine the best course of action to remediate – in agreement with the regulatory authorities.

The potential courses of action are outlined in the Corrective Measures plan while details of contingency monitoring are outlined in the MMV plan.

12.5. Summary of plan and monitoring

The table below summarizes the post closure plan.

Table 12-2: Summary of Post-Closure Plan

Timing post cessation of injection	Detail of activity	Monitoring
+0 to +1.5	Platform remains with wells accessible	Pressure monitoring, well integrity inspections, DAS and DTS monitoring, GPS, sea water monitoring
+1	Repeat the baseline surveys, check for irregularities	Time-lapse seismic over site, and environmental monitoring over complex
+2 contingent on monitoring results	Decommissioning of platform and sealing of wells is completed	
At year 6, contingent on minimum 5 year separation from previous survey	Final survey	Time-lapse seismic and MBES over site
At year 7, contingent on survey being shot	Processing of survey results. Request for handover contingent on survey being shot, monitoring results and agreement of competent authority.	
Post handover (30 years)	Post handover monitoring	2 MBES surveys over site

12.6. Post hand-over monitoring

As per the containment assessment once the wells have been sealed the possibility for migration is significantly reduced. The twin seismic surveys post-injection are designed to check for unpredicted migration paths. Assuming an absence of such migration paths, then the dynamic modelling shows that the risk profile for the store does not alter for centuries. After the processing and interpretation of the second post closure seismic survey and following the demonstration of containment, handover will be requested from the Competent Authority.

For validation of this two seabed leak detection surveys are included in the post closure monitoring plan. It is currently envisaged that storage containment will be checked with an MBES survey after 10 years post hand-over and at 30 years post hand-over. These surveys have the potential to detect small streams of bubbles and are therefore well suited to confirming that the site is not releasing CO_2 into the environment. The financial mechanism will include financial provisions sufficient to cover these two post-handover surveys and may be revised before hand-over to reflect any technological development that could lead to a more efficient and cost-effective solution.

12.7. Data Transfer

At the point of handover, the operator will transfer all of the relevant raw data and documents related to the site to the CA. This could include, among other data:

- Core samples.
- Drill cuttings.
- Construction material samples (cement).
- Fluid samples of reservoir fluids.
- Sample of injected CO_2 and any tracers.
- Seismic data.
- Static and dynamic models.

13. Future work and data collection

13.1. Pre-Development Data Enhancement

The FEED study that has been completed used data available from the production and pre-production phases of the Goldeneye gas condensate field. Whilst some new data characterisation were initiated during this phase of work (*e.g.* petrographic analysis of reservoir and caprock), most new data has yet to be collected, due to the lack of time to execute a comprehensive study within the eleven months of the FEED phase. There are also additional work elements that might be required by the regulatory bodies before the granting of a licence – partially because this is a first of a kind project and there are few precedents.

Post-production, *pre-injection* baselines are required for all the domains that will be monitored both during and after injection into the field. These are necessary to allow the operator to demonstrate that any changes in fluid distribution within the reservoir are the result of CO_2 injection, to calibrate conformance modelling and to allow for the identification of irregularities that may lead to leakage. These baselines are listed in section 13.2.

Finally, one of the purposes of the FEED study is to identify work required to prepare the site and the operator for the injection phase of the project.

13.1.1. MMV design

The MMV plan describes the techniques intended to be applied to monitoring the performance and conformance of the Goldeneye CO_2 store. All of the domains that will be monitored will require post-production, *pre-injection* baseline surveys, which now need detailed design. Many of the technologies that are proposed for the monitoring plan are novel and their maturation and qualification for use in the manner envisaged needs to be progressed. As well as detection of leaks, quantification of any escaped CO_2 volume is necessary and techniques to achieve this must also be progressed. As this is expected to be a general requirement for any offshore CO_2 storage venture, it is assumed that this will require the establishment of industry or academic research partnerships.

13.1.2. Well Integrity

Modelling work related to temperature and pressure calculations in the wells under a CO_2 release scenario to verify the safety elements used in the wells (wellhead, SSSV, packer, etc.). Further qualification of equipment (e.g. SSSV) might be required base on the dynamic simulation work.

PEC surveys to monitor conductor and casing corrosion to verify the use of the wells for the life cycle time of the project.

Lab experiments to verify the compatibility of 13 Cr steel with Oxygen and CO_2.

13.2. Monitoring plan baselines

The largest part of the remaining data collection envisaged for the project prior to injection start-up is in the form of baseline surveys for the *during injection* monitoring plan. This plan is set out in detail in the MMV plan. The data collection planned for the *pre-injection* phase is as follows:

- seabed mapping (MBES surveying).
- seabed sampling (van Veen grab, vibro-corer, cone penetration tester, BAT probe, hydrostatically sealed corer, geochemical probe installation).
- time lapse seismic (streamer and OBN).
- well integrity assessment (cement bond and casing integrity logging).
- saturation conformance (logging and sampling).
- well gauge installation (Probe/PDG/DTS/DAS).

It is anticipated that pre-injection seismic survey will be used in three ways. Firstly, it will be compared to the pre-production seismic survey (1997 Greater Ettrick 3D seismic survey) to attempt to identify changes in fluid distribution within the reservoir due to hydrocarbon extraction. This information will enable the conditioning and calibration of dynamic models of the field. A second function of the seismic baseline survey is to provide the basis of for an update of the static reservoir and dynamic full field simulation models of the field. Finally, the survey will function as the baseline to which the *injection* seismic surveys are compared.

13.3. Further characterisation work

As mentioned in section 13.2 above, one of the pieces of work envisaged to be completed during the pre-injection phase is a full rebuild of the static reservoir model and full field simulation model for the Goldeneye field. Only small modifications of these were considered as part of the FEED study as no new information had come available since their original construction and they were performing their tasks of predicting production performance adequately. However, as discussed in a number of documents produced during FEED (*e.g.* Static Model Report (Field)), it is recognised that the hazards and uncertainties associated with CO_2 storage are different to those associated with producing hydrocarbons and, once a significant dataset – such as a new seismic survey – becomes available, it is appropriate to recreate them with a new focus.

13.4. Key update cycles

The collection of new data – be it from baseline surveys, experience from analogue projects, or from monitoring during injection – will lead to an update of the risk assessment. This in turn can lead to an update to the monitoring and corrective measures plans. Additionally the introduction of new technologies, or a change in use of areas adjacent to the store, can lead to an update of monitoring and corrective measures plans. Notwithstanding the above there is also a five yearly update cycle for the plans.

Figure 13-1: Key update cycles

14. Decommissioning

Decommissioning of facilities and wells will be in accordance with the regulations and best practice in place at the time of decommissioning.

Once it is decided to cease the injection of CO_2, activities need to be undertaken to safely shutdown, isolate, drain/vent/clean and decommission the facilities.

These activities have been grouped in 4 sections that can be physically isolated (refer to Table 14-1).

- Onshore Peterhead: Capture, Compression & Conditioning Plant (CCC) + Peterhead power station isolation.
- Offshore: topside, structure and wells.
- Offshore pipelines (both 20" [508mm] and 4").
- Methanol system.

The table below provides an overview of sections and the steps to be undertaken to decommission the facilities.

Table 14-1: High level steps for decommissioning

PCCS Project - decommissioning steps by section
1. Onshore
1.1 Capture, Compression & Conditioning Plant (CCC).
• Shut down booster fan & circulation in the washing section.
• Isolate shut down valve downstream the compressor to block-in pipeline.
• Shut down CO_2 compressor.
• Run amine until all CO_2 is released (1-3 cycles).
• Cool down amine unit.
• Stop circulation & depressurise.
• Drain amine and water flush (decontaminate). • Purge with air to CO_2 free. • Empty all storage tanks.
• De-energise CCC plant.
• Demolish CCC plant. • Remove buildings. • Decommission and remove waste water treatment plant.
1.2 Peterhead Power Station.
• Stop steam supply - cool down the steam and condensate system - drain and demolish until Peterhead Power Station tie-in point (at start of amine unit cool down).

• Stop other utilities - drain/flush and demolish until the current Shell/ Peterhead Power Station interface tie-in point (after amine unit draining and flushing is completed). • Stop and remove CCS cooling water system. • Remove PCCS duct-in tie in point at the chimney and return to its current arrangement. • Note: it is assumed the SCR system will continue in operation after the Peterhead CCS project has stopped.
2. Offshore
2.1 Wells • Isolate/plug wells. • Goldeneye well abandonments using a deep water Jack-Up.
2.2 Topsides and Structure • Depressurise and drain liquids. • De-energise topside equipment. • Remove integrated topsides through reverse installation. • Single lift substructure removal.
3. CO_2 Pipeline (20")
• Depressurise pipeline through Goldeneye vent. • Purge with air to CO_2 free. • Isolate/spade.
• Demolish/mothball pipeline (different sections) and SSIV.
4. Methanol System
4.1 Methanol pipeline (4").
• Remove methanol by pigging operation.
• Flush pipeline.
• Demolish/mothball pipeline (different sections).
4.2 Methanol package at St Fergus (owned by SEGAL).
• Empty/decontaminate.
• De-energise methanol unit. • Since SEGAL own the assets the PCCS Project will not need be responsible for their abandonment.

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16. Glossary of terms

ALARP	As Low As Reasonably Practicable
Bscf	Billion Standard Cubic Feet
CBIL	Circumferential Borehole Imaging Log
CCS	Carbon Capture and Storage
CDT	Conductivity, Depth and Temperature
CH4	Methane
CNS	Central North Sea
CO_2	Carbon Dioxide
CPT	Cone Penetration Testing
DAS	Distributed Acoustic Sensing
DTS	Distributed Temperature Sensing
DWTT	Drop weight tear qualification tests
E&A	Exploration and Appraisal
EGP	External Gravel Pack
EIA	Environmental Impact Assessment
ES	Environmental Statement
ESS	Expandable Sand Screens
ETS	Emissions Trading Scheme
EU	European Union
FDP	Field Development Plan
FFM	Full Field Model
FFSM	Full Field Simulation Model
Fm	Formation
FMI	Formation Micro Image
GIIP	Gas Initially In Place
GNNS	Global Navigation Satellite System
GOC	Gas-Oil Contact
ICES	International Council for the Exploration of the Sea
K	Permeability
LOT	Leak-Off Test
LT	Limit Test
LTMG	Long Term Memory Gauge
MBES	Multi-Beam Echo Sounder
MEG	Monoethylene Glycol
Mst	Mudstone
MMV	Measurement, Monitoring and Verification
N/G	Net-to-Gross
NGL	Non-Gas Liquids
NTG	Net-to-Gross

NUI	Normally Unattended Installation
OBN	Ocean Bottom Nodes
OLGA	Proprietary Oil and Gas Multiphase fluid flow simulation tool
OOWC	Original Oil-Water Contact
OWC	Oil-Water Contact
P&A	Plugged and Abandoned
PCV	Pressure Control Valve
PDG	Permanent Downhole Gauge
PEC	Pulsed Eddy Current
PVT	Pressure, Volume, Temperature
RAM	Reliability and Availability Model
SAC	Special Area of Conservation
SCAL	Special Core Analysis Laboratory
SC-SSSV	Surface Controlled Subsurface Safety Valve
SEA	Strategic Environmental Assessment
SH	Maximum Horizontal Stress
Sh	Minimum Horizontal Stress
Sst	Sandstone
Sv	Vertical Stress
TVDSS	True Vertical Depth Subsea
UBI	Ultrasonic Borehole Imager
UKCS	United Kingdom Continental Shelf
UR	Ultimate Recovery (volume)
VRE	Vitrinite Reflectance Equivalent
WBT	Water Break Through
Φ	Porosity

17. Glossary of Unit Conversions

For the provision of the SI metric conversion factor as applicable to all imperial units in the Deliverable.

Table 17-1: Unit conversion table

Function	Unit - Imperial to Metric conversion Factor
Length	1 Foot = 0.3048 metres 1 Inch = 25.4 millimetres
Pressure	1 Bara = 14.5psia
Temperature	ºF=(1.8)(ºC)+32 ºR=(1.8)(K) (absolute scale)
Weight	1 Pound = 0.454 Kilogram