Programme Area: Carbon Capture and Storage

Project: DECC Storage Appraisal

Title: Progressing Development of the UK’s Strategic Carbon Dioxide Storage Resource

Abstract:
This report documents a summary of the results from the strategic UK CO2 storage appraisal project.

Context:
This project, funded with up to £2.5m from the UK Department of Energy and Climate Change (DECC - now the Department of Business, Energy and Industrial Strategy), was led by Aberdeen-based consultancy Pale Blue Dot Energy supported by Axis Well Technology and Costain. The project appraised five selected CO2 storage sites towards readiness for Final Investment Decisions. The sites were selected from a short-list of 20 (drawn from a long-list of 579 potential sites), representing the tip of a very large strategic national CO2 storage resource potential (estimated as 78,000 million tonnes). The sites were selected based on their potential to mobilise commercial-scale carbon, capture and storage projects for the UK. Outline development plans and budgets were prepared, confirming no major technical hurdles to storing industrial scale CO2 offshore in the UK with sites able to service both mainland Europe and the UK. The project built on data from CO2 Stored - the UK’s CO2 storage atlas - a database which was created from the ETI’s UK Storage Appraisal Project. This is now publically available and being further developed by The Crown Estate and the British Geological Survey. Information on CO2Stored is available at www.co2stored.com.

Progressing Development of the UK's Strategic Carbon Dioxide Storage Resource

A Summary of Results from the Strategic UK CO_2 Storage Appraisal Project

April 2016

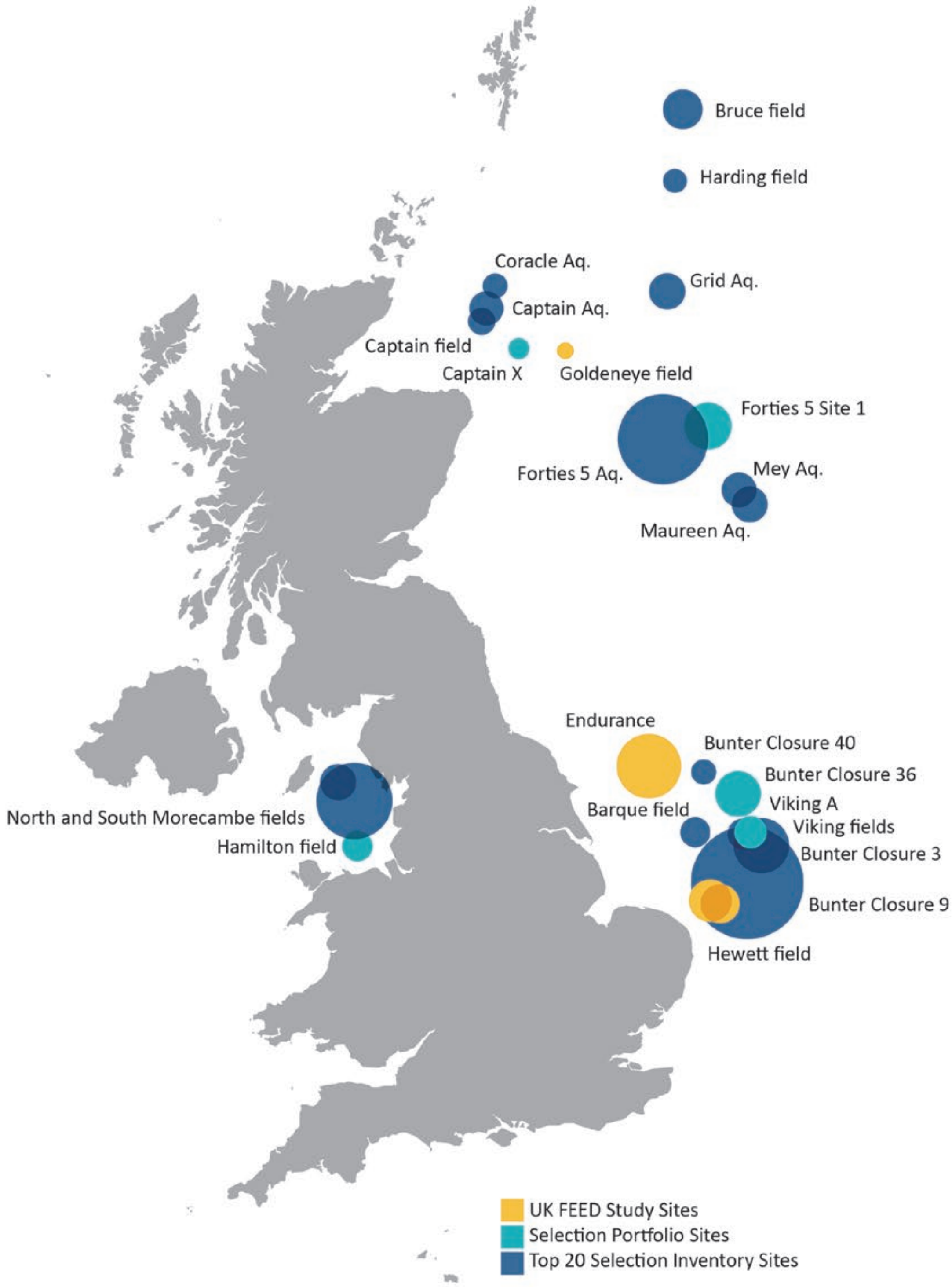
COSTAIN

energy technologies institute

Pale Blue Dot.

AXIS WELL TECHNOLOGY

Strategic UK CO_2 Storage Appraisal Project Select Site Inventory



Note: areas of the circles are indicative of CO_2 storage resource potential.

Cover Image

The areas of the full circles on the cover image represent magnitudes of potential UK CO_2 storage resource. The smallest circle represents the storage resource from the projects Hewett, Goldeneye and Endurance which have already had FEED studies completed. The next circle up includes the additional resource offered by the portfolio of 5 sites selected in this project, Hamilton, Viking A, Captain X, Bunter 36 and Forties 5 Site 1. The third circle includes the remaining top 20 sites of the Select Inventory selected from this project. The fourth circle represents all of the sites that met the selection qualifications for this project. The area of the largest circle represents the total UK storage resource potential as outlined from the CO2Stored project.

On 12th December 2015, for the first time in history, all of the world's nations united to tackle climate change. The headline emerging from the summit was the agreement to limit the increase in global temperatures to "well below" 2.0°C above pre-industrial times and to "endeavour to limit" the temperature increase even further, to 1.5°C. Delivering the associated goal of net zero emissions during this century will require bioenergy and CO_2 storage to play a substantial role in the UK.

Carbon Capture and Storage (CCS) is critical for the delivery of a cost effective transition to the low carbon economy required by the COP21 agreement. CCS is one of few technologies that can support the decarbonisation of heat, heavy industry and power generation. It is the only technology that can enable the continued use of almost 80% of the world's proven fossil fuel reserves in a manner compliant with the 2.0°C limit, allowing countries such as the UK to maintain their energy security.

Analysis by the Energy Technologies Institute (ETI) has shown that failure to deploy CCS at scale could double the cost to the UK government of achieving its 2050 decarbonisation targets, effectively adding costs equivalent to around 2% of GDP per year from 2050. The decisions taken in the 2015 Comprehensive Spending Review will inevitably delay deployment of CCS in the UK and, consequently, bring much earlier cost increases if we are to remain on track to meet national carbon budgets in the 2020s and '30s.

Mitigating the impact of these decisions requires sustained efforts on many fronts to develop CCS and to prove its value to investors. Crucially, work is required to reduce the costs of the development and implementation of CCS technology and further engagement is needed to address society's concerns and potential outrage about the storage of CO_2. Beyond capture and storage, there remains a significant opportunity for a breakthrough in CO_2 use.

CCS technology has already been successfully demonstrated at scale around the world. In the UK, we have a strong foundation of the key requirements for deployment in place including the alignment of the electricity market reform mechanisms, a mature regulatory system, large domestic centres of excellence in the offshore oil and gas industry and, potentially, plentiful resources deep under the sea bed to store CO_2 emissions.

This project has verified the potential of almost 1000 million tonnes of storage in UK waters. Taken alongside the work carried out in the recent CCS competitions on the Hewett, Goldeneye and Endurance stores, this gives a range of storage options sufficient for 30 years or more into the future – enough to give investors in UK projects which may need CO_2 capture the confidence that capacity exists to meet their needs. All the project findings are being placed into the public domain, allowing them to be used by storage site developers wishing to progress the capital intensive parts of storage development, as well as providing an invaluable resource for storage researchers.

One of the main challenges to the roll-out of CCS is managing the risk involved in CO_2 storage – currently unquantified for investors. Carrying out storage appraisal work up front, to provide assurance of the quality and security of stores, greatly reduces the complexity and financial risk for associated onshore investment in CO_2 capture and transport systems. Few incentives exist currently to justify early private sector investment in storage appraisal, so this project, and the support from DECC for it, is to be greatly welcomed.

From a UK perspective, we now have available in the public domain one of the most comprehensive and mature propositions for CO_2 storage potential. I hope these new assessments will support ongoing public and private sector debate on the value and the opportunities presented by CCS and fuel early development of the first UK carbon capture and storage projects, supporting both secure power generation and, critically, the UK's future industrial base.

Lord Browne of Madingley

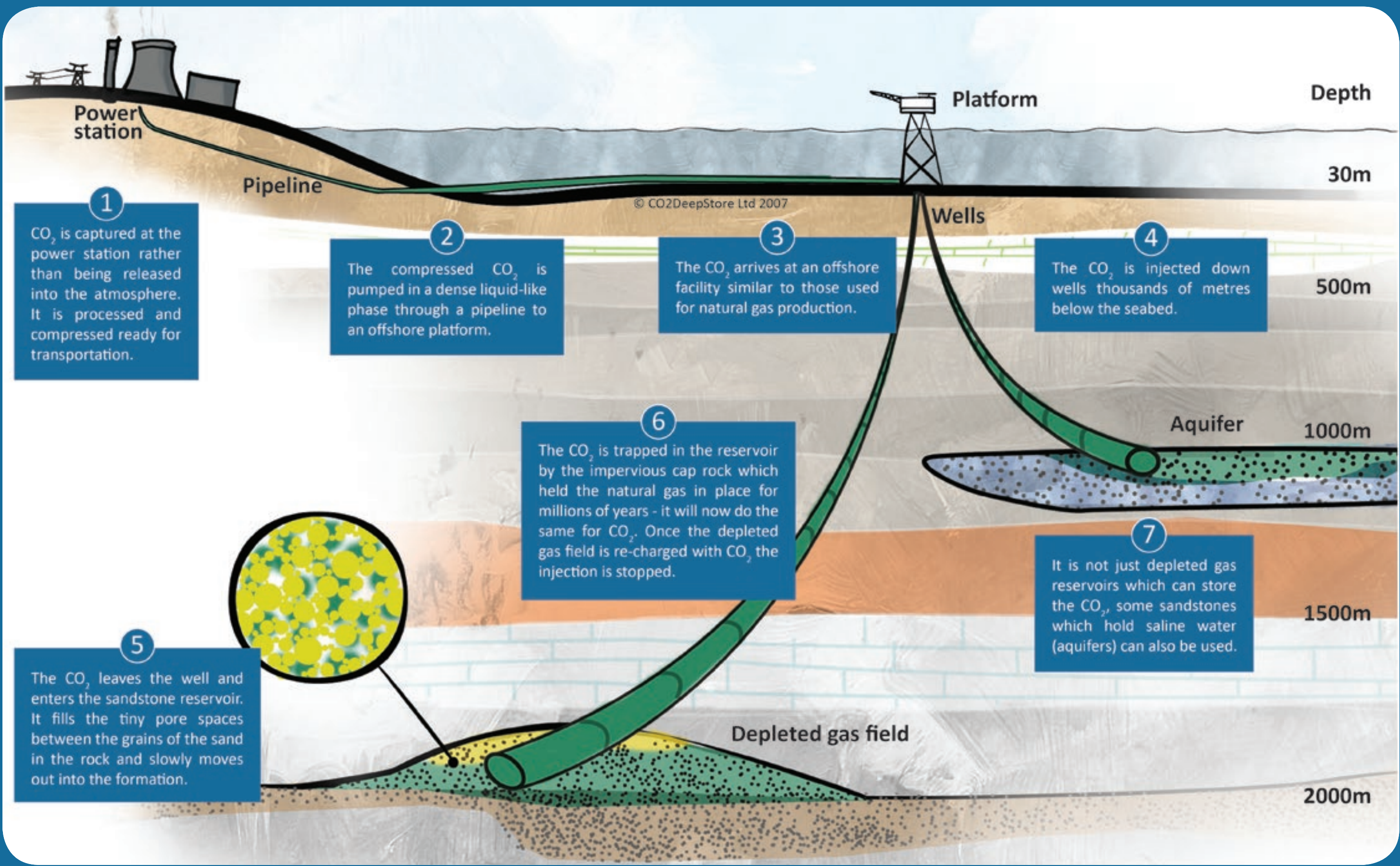
Browne of Madingley

ⓘ Geological CO_2 Storage Sites

The deep geological storage of CO_2 is the process whereby CO_2 captured from the combustion of fossil fuels and other industrial processes is transported and then injected deep underground into porous sandstones, where it is trapped and stored indefinitely so isolating it from the atmosphere and preventing it from causing greenhouse warming effects and climate change. At its simplest, successful CO_2 storage requires three main components:-

1. **Capacity:** Connected underground pore space of storage reservoir within which to hold the CO_2
2. **Injectivity:** The ease with which CO_2 can be pushed into the storage reservoir adjacent to injection wells. This depends upon permeability, thickness and ability to dissipate pressure
3. **Containment:** An impermeable cap rock which assures that the injected CO_2 will be contained safely for the long term within the storage reservoir and trapping mechanisms which together work to retain the injected CO_2 within a defined area of the subsurface

A schematic of the basic process is outlined below.



Executive Summary

Carbon Capture and Storage (CCS) is widely recognized as a critical technology to meet the 1.5/2°C ambitions agreed at the Paris COP 21 meeting. Much progress is being made on carbon capture technologies, with mature industrial scale projects having been in operation for many years. Whilst the use of CO_2 for enhanced oil recovery is commonplace in some parts of the North America, CO_2 storage at industrial scale has only been demonstrated at a small number of sites around the world. Two of these sites are located offshore in the Norwegian sector of the North Sea at Sleipner and Snohvit, with Sleipner reaching a key milestone in 2016 of 20 years of offshore CO_2 storage operations.

The UK is fortunate to have completed three large FEED study projects for offshore CO_2 storage, all of which are already or will be placed in the public domain. These were for storage sites called Hewett, Goldeneye and Endurance. Enabling CCS in the UK requires the rapid assembly of mature plans for further offshore CO_2 storage sites around the UK Continental Shelf (UKCS). Collectively, these plans will contribute towards supporting investor confidence around large energy and industrial CCS systems by assuring the presence, location and cost base of high quality offshore CO_2 storage site development options. This will support the early industrial mobilisation of full chain CCS technology.

Achieving this goal requires:

1. Data and information about the offshore subsurface environment;
2. Subsurface and offshore industry expertise to develop the plans;
3. A catalyst to initiate the project.

In 2015 the ETI commissioned a 12-month project, with £2.5M funding from DECC, to bring these three factors together. The resulting study has built upon the development of the UK's national CO_2 storage database CO2Stored to identify a select inventory of 20 specific CO_2 storage sites which together represent the tip of a very large strategic national CO_2 storage resource estimated to be around 78GT (78,000 million tonnes). A portfolio of five of these sites were selected for their potential contribution to mobilising commercial-scale CCS projects in the UK (for power and industry). Outline storage development plans and budgets have been prepared for each. Together with the sites which have completed FEED studies, this portfolio presents a mature and well qualified UK storage proposition in excess of 1.5GT which could be fully operational as early as 2030. This would be enough to service a significant roll out of commercial projects, including up to 10GW of power generation and major industrial sources fitted with CCS as highlighted in the ETI's Scenarios work. This represents the development of only 2% of the UK's national storage resource potential.

The natural decline in the North Sea oil and gas industry presents opportunities for the development of CO_2 storage in several ways. Firstly, the potential for competing use of subsurface pore space is significantly reduced. In addition, much of the highly developed offshore oil and gas supply chain has the potential to switch into CO_2 storage activities with relative ease. Finally, once CO_2 is being routinely transported and stored offshore, the potential for enhanced oil recovery (EOR) using CO_2 might also be progressed.

The project has successfully progressed the appraisal of five substantial stores, well-placed in relation to the UK's major emission sources, towards readiness for final investment decision (FID) so that prospective capture projects will have a range of storage options 30 years into the future. The project, completed in March 2016, has significantly de-risked these stores and the results are transferable to storage developers wishing to progress the more capital intensive parts of the development programme.

By selecting geological storage sites (both depleted oil and gas fields and saline aquifers) that already have had a great deal of information gathered and analysis completed through oil and gas exploration and production activities, the UK storage proposition could be available for injection from the early 2020's. Three of the five new sites considered would not require any further appraisal drilling. This is a significant factor and serves to reduce the time required from identification to FID to between two and four years.

All five sites have been studied in detail. As a result, there is confidence regarding the ability to inject CO_2 at commercially significant rates, the capacity to store CO_2 in commercially significant volumes and the capability to retain the injected CO_2 within the defined storage reservoir on a permanent basis.

Summary reports, detailed reports, geological and reservoir engineering models arising from the project will be made publically available from Q2 2016. These will enable academic and industrial practitioners to build upon these results in the future. This work has successfully moved almost 1GT of CO_2 storage resource from an unclassified status to a specific Contingent Resource.

Key findings of this work include:-

Summary

1. The UKCS is endowed with a rich and diverse national offshore CO_2 storage resource, key components of which can be brought into service readiness without extensive appraisal programmes thanks to decades of petroleum exploration and development activity.
2. The portfolio of 5 sites selected is geographically and technically diverse, and presents options for clean

energy and industrial development around the UK.
3. Only 2 of the 5 sites require any further appraisal drilling before an investment decision.
4. This study, alongside the detailed knowledge transfer products from the Hewett, Goldeneye and Endurance FEED studies characterise one of the most comprehensive and mature CO_2 storage potential propositions available within the public domain. This will provide confidence for carbon capture projects and also act as a catalyst for future storage development projects.
5. This project could not have been completed within the timeframe required without the platform of the CO2Stored database.
6. In general, most oil & gas infrastructure is likely to be unsuitable for use as CO_2 storage infrastructure. There are however important exceptions which can serve to reduce initial CAPEX requirements. Infrastructure re-use should focus upon pipelines which retain high pressure ratings.
7. Access to detailed well by well production and pressure records coupled with detailed well abandonment records are key requirements for any detailed storage site assessment.

Storage Site Types

1. Saline aquifers and depleted oil & gas fields both present development opportunities. Each have their own specific challenges and characteristics.
2. Low pressure depleted gas fields such as Hamilton and Viking A can present excellent CO_2 storage opportunities subject to legacy well containment integrity. They have excellent storage efficiency (utilising between 70% to 80% of the available pore space), but do require careful operational management because of their very low pressure. The Southern North Sea in particular contains a large portfolio of gas fields which will contribute significantly to this potential. More work is required to understand the recovery of caprock strength once these sites are re-pressurised.
3. Saline aquifers in Bunter 'domes' in the Southern North Sea, such as Endurance and Bunter 36 appraised in this study, also offer great potential. The domes have good storage efficiency of around 20% and are an ideal first step in development of offshore saline aquifer sites. They represent an important strategic national resource play given their proximity to major UK emissions sources. All the available evidence points to there being substantial secure capacity in the domes with high injection rates. However, with limited dynamic data from production history to calibrate long term injection performance a degree of uncertainty remains. This will only be settled when sustained CO_2 injection has been monitored over an extended period.
4. In this project, Captain X and Forties 5 Site 1 represent a potential first step in the staged development of two very large open aquifer storage resources. Open saline aquifer sites such as the Captain and Forties aquifers have huge potential capacity to store future UK emissions, but they have low storage efficiencies (2% to 7%). The key to enabling these sites lies in:-
   - Successful control of injected CO_2 to ensure it stays within the storage site boundary.
   - Optimising storage efficiency or the amount of CO_2 that can be securely stored in each square kilometre of the site.

   These measures will support consenting and contribute to reduction in unit costs although regulatory approval for open aquifer systems will be more challenging than for other storage systems within discrete structures.
5. Many saline aquifers within the UKCS can be considered as "brown field" as they have been drilled during the search for and the production of oil & gas. These "brown field" sites could be brought into service relatively quickly because of the data acquired during oil and gas exploration. Detailed structure mapping from high quality seismic data with a good seismic response are essential for development of these systems.
6. The geological caprock containment of all the sites within the portfolio is considered to be robust. Each site was geochemically and geomechanically stable for the development plans considered.
7. The key containment risk component is linked to the uncertain integrity of legacy wells which fall within the CO_2 plume extents. Whilst older wells are generally of more concern, there are also wells abandoned as recently as 2007 that represent significant integrity risks which would need to be managed as part of any development and operation plan.

Costs and cost reduction

1. The transportation and storage development plans developed for this project have been based on current best practice for offshore operation, minimising operational risks. Re-use of existing infrastructure has been limited to specific pipeline re-use options where these were available and such re-use clearly benefited the development. Further site specific optimisation of asset re-use may present further cost reduction opportunities.
2. The lifecycle cost for offshore transportation and storage of a significant offshore CO_2 storage project in the UKCS (60-300MT) can be expected to range from £166m to £288m (NPV10 2015 Real). Levelised unit costs for offshore transport and storage (i.e. excluding capture, compression and any onshore transport) range from £11/T to £18/T (£ per Tonne of CO_2 stored). This would contribute between £5/MWh and £9/MWh (£ per megawatt hour) to the levelised cost of gas fired power generation.

3. On a portfolio basis, the largest proportion of the average levelised cost of £19/T is associated with transportation CAPEX at 25%. Other major contributor elements to the levelised cost include injection OPEX (24%), wells CAPEX (21%) and facilities CAPEX (17%). Site monitoring, during and after injection generally contributes to less than 1% of the levelised cost.
4. Key cost reduction opportunities lie in the use of shared infrastructure such as pipelines. Other cost reduction efforts should focus on the larger components of levelised cost along with improving storage efficiency. The potential for subsea injection may support reductions of both CAPEX and OPEX.
5. Analysis has suggested that whilst there are clear cost benefits in increasing the scale of CO_2 storage operations upwards from 1MT/yr, most of these will have been realised at a supply rate of 4 to 5MT/yr. This is because replicating such injection rates will normally require additional platforms or drill centres, and many more wells which are primary cost items in any project. Furthermore, installing oversized transportation systems can be helpful, as long as the additional flow potential does not remain unused for an extended period.
6. The levelised costs presented in this report are based on the cost of ownership and a discount factor of 10%. A commercial transportation and storage developer may seek significantly higher returns to justify the investment and risks taken.
7. Each of the five sites in the portfolio has different site specific development risks. Progression towards FID will depend upon matching site specific risks to developer risk appetite.

Way Forward

This project and the results it has delivered have confirmed that there are no major technical hurdles to moving industrial scale CO_2 storage forward in the UK. The UK is endowed with offshore geology that presents a superlative national CO_2 storage proposition. The UK offshore could form the basis of a storage resource that could service the needs of many parts of Europe in addition to the UK. Careful site selection will enable storage developments to proceed quickly in a cost effective manner with a limited impact upon electricity costs.

Learnings from this project identify that two linked, but parallel, future work streams are required:-

Commercial – create the environment to re-engage industry, build the business case for CCS and CO_2 storage in the UK and bring forward CO_2 storage developers from the marketplace. Momentum should be maintained on further development of the UK storage resource towards FID.

Research and Development – this work has demonstrated that there is ample cost-effective storage available to meet UK needs using current technology. However, it also illustrates the opportunities to maximise use of UK pore space and reduce costs further. Ongoing R&D should focus on and deliver practical measures which will deliver within the next 5 to 10 years in the areas of:-

- **Operational efficiency** – reducing the ongoing cost of CO_2 storage operations.
- **Storage efficiency** – optimising the amount of safely stored CO_2 that can be held for each square kilometre of any storage site.
- **Industry and public confidence** – further develop stakeholder confidence in the technologies used to plan, operate and monitor safe CO_2 storage sites.

Together these activities will contribute strongly to delivering the best chance of early mobilisation and delivery of CCS and offshore CO_2 storage in the UK and make a positive contribution to achieving the UK's carbon emission reduction commitments for 2030 and beyond.

ⓘ Wells

Wells are an essential component of any CO_2 storage project. They are the only way by which CO_2 can be introduced into the deep subsurface in the timeframes required. It is important to recognise that the injected CO_2 is not stored in the wells, the wells are simply transportation routes to the deep sandstone reservoirs.

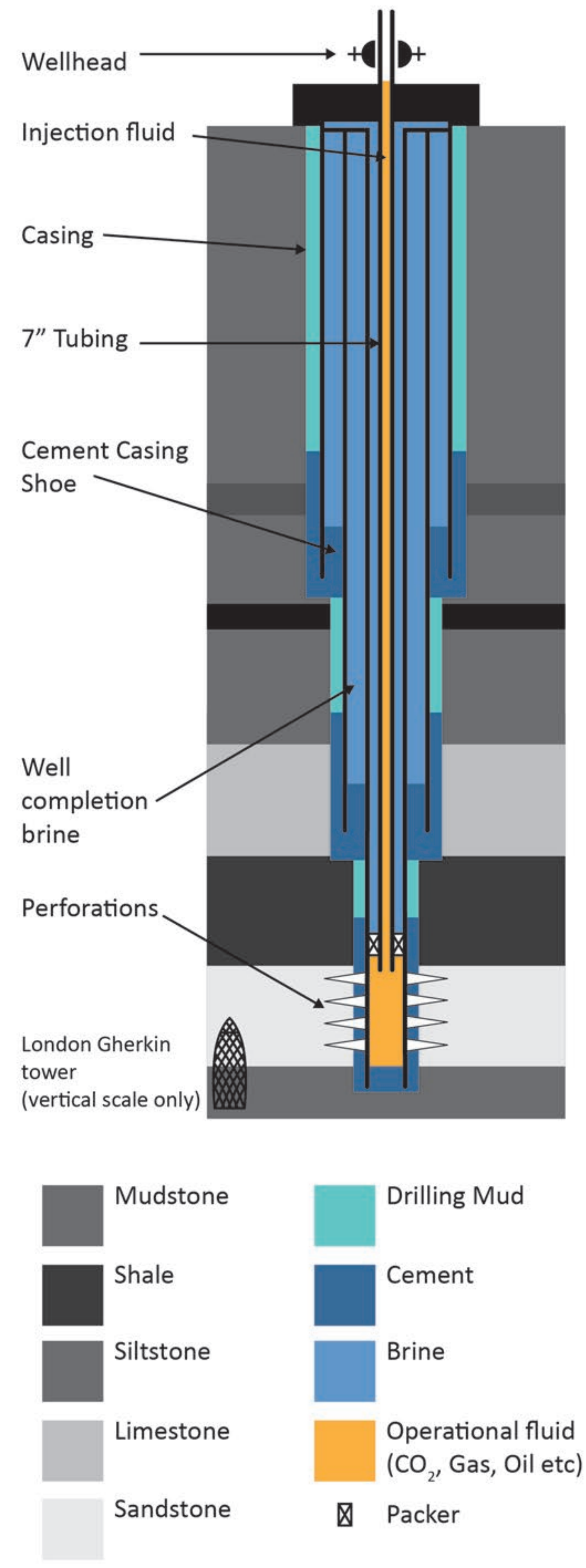
Wells are drilled for a range of purposes such as exploration, appraisal, production, injection or monitoring. The well objectives strongly influences its design, depth, size and cost. Simple exploration or appraisal wells are commonly near vertical, but injection and production wells are often highly deviated and may even be horizontal through the reservoir interval. This geometry enables a development to reach a wide area of the reservoir from a single centralised drill centre. A higher angle can also improve the potential of the well to inject or produce fluids.

The information from existing wells drilled by oil and gas operators can be very useful in characterising the subsurface geology of a site as long as the appropriate types of data are collected. Wells drilled specifically for characterising a CO_2 storage site will be subject to extensive data acquisition.

As a general guideline, it is very unusual for an existing well drilled for producing oil and gas to be viable as a long term CO_2 injector because they were designed and located for completely different objectives. As a result, existing well infrastructure is generally of limited value to CCS.

A simple well schematic shows that most wells are drilled in sections with different sized drilling bits. After each section is drilled, steel casing is put into the well to secure it and this is cemented in place at the base of the well before the next section is drilled with a smaller bit. This continues until the well reaches its total depth or TD. At this point, the drilling fluid is replaced with inert completion brine before a slim production tubing is placed in the well and isolated from the annulus with a circular packer. Typically the final step is for the deepest string of casing to be perforated over the reservoir interval using a perforating gun which is lowered into the tubing on a wire.

Once a well has fulfilled its objectives, it is abandoned. The tubing is pulled out and metal plugs and cement plugs are set to ensure the integrity of the well in the future so that subsurface fluids cannot migrate up, within or around the outside of the casing. Abandonment standards have improved over time, but uncertainties in how wells have been abandoned can lead to increased risk for CO_2 injection projects, especially for old wells.



Introduction

Carbon Capture and Storage (CCS) is critical to enable the progressive decarbonisation required to limit global emissions cost effectively. This will help to maintain average global temperatures within two degrees Celsius of pre-industrial levels. The important role of CCS has been well reported by the UN Intergovernmental Panel on Climate Change.

In addition to its role in decarbonising electricity generation from fossil fuels, CCS is also the only technology capable of supporting large scale industrial decarbonisation. This includes cement, steel, fertiliser and chemicals in addition to large scale hydrogen production. Together with biomass combustion, CCS also offers the potential to achieve net negative emissions through biomass energy CCS or BECCS. All the elements of CCS technology are proven at significant scale and have also been demonstrated working together in full chain integrated CCS chains. In their 2015 summary report on the global status of CCS, the Global Carbon Capture Storage Institute (GCCSI) reports 15 operational CCS projects worldwide.

The deployment of CCS across the world has however been very slow. The GCCSI has suggested that part of this is due to a high need for customisation around each project as CCS is energy feedstock specific for capture and geology specific when it comes to storage. Furthermore, the first projects are also often burdened with the requirement to carry the cost of developing the initial infrastructure for CO_2 transportation.

In November 2014, DECC provided £2.5 million funding to the ETI to deliver a project which would accelerate the development of strategically important storage capacity in the UK offshore area and thereby leverage further investment to develop this capacity to meet UK needs. Appraisal projects can be time consuming and expensive and few companies can accommodate these costs on their balance sheets at this time considering the uncertainty and cost of proceeding to a full CCS project. Ideally the appraisal effort is carried out before the larger onshore investment is progressed, greatly shortening and reducing the complexity and financial risk of the larger, onshore investment.

ETI's Scenarios work has suggested that in order to reach a target of having 10GWe of power generation fitted with CCS by 2030 some 1500MT of commercial storage capacity will have to be appraised by the late 2020s.

The primary objective of this Project is to progress the appraisal of five strategically important stores, selected as part of the Project, towards readiness for FID so that prospective capture projects will see an abundance of storage options 30 years into the future. The work adds significantly to the technical and financial de-risking of these stores and is transferable to storage developers to complete the more capital intensive parts of storage development. Potential oil field sites which might have a reasonable chance of a positive response to CO_2 enhanced oil recovery were assumed to be unavailable to CO_2 storage developers and are not considered further in this project as potential storage sites.

In 2012, the ETI and its partners completed a study to build an inventory of all the potential CO_2 Storage locations in the UKCS. This "UK Storage Appraisal Project" was the source of a national CO_2 Storage resource database called CO2Stored now made publically available and being further developed by the Crown Estate and British Geological Survey. Through a systematic process, this work identified almost 600 potential storage sites and developed an outline description and the first nationwide assessment of the CO_2 Storage capacity resource using a consistent methodology. In total some 78GT of potential CO_2 storage resource was identified. Whilst almost all of this potential has been "discovered" by existing drilling, very little (~140MT) of this resource has been matured through appraisal characterisation towards being FID ready. The outcome of this project moves much more of this resource from being an "unclassified contingent resource" to a "classified contingent resource" with a viable development plan and thereby significantly improving confidence regarding its availability for deployment.

The CO2Stored database was therefore the fundamental starting point for this project which involved six key steps:-

1. Specification of the attributes of target stores that should reside with a strategic UK CO_2 storage site portfolio (WP1)
2. Develop a data collection and assembly approach for the project (WP2)
3. Careful consideration of the match between almost 600 UK sites from CO2Stored database and the target storage site attributes (WP3)
4. Selection of a portfolio of five strategic storage sites from the initial list of almost 600 sites (WP4)
5. Detailed interpretation and analysis of the subsurface information for each site and the preparation of an outline storage development plan and budget and detailed risk assessment roll (WP5)
6. Development of a strategic roll out plan for CO_2 storage in the UKCS to meet the aspiration of having 10GWe of power generation fitted with CCS by 2030 (WP6)

The project was commissioned by the ETI in May 2015 and was completed in April 2016.

The ETI selected an industry based consortium led by Pale Blue Dot Energy to deliver the project. The consortium includes:

- Pale Blue Dot Energy - A management consultancy for the Energy Transition.
- Axis Well Technology - A provider of independent consultancy services in well technology and reservoir development.
- Costain - An engineering solutions provider operating in Energy, Water and Transportation.

The project was also supported by experts from the Scottish Centre of Carbon Capture and Storage, British Geological Survey, Liverpool and Durham universities, and through engagement with a wide range of stakeholders across the CCS industry in the UK and around the world.

A key requirement of the work was that the results should be made available in the public domain. Specifically, in addition to summary reports, this includes the digital interpretations and geological and reservoir engineering models arising such that other academic and industrial practitioners can build upon these results in the future. Whilst this objective has been achieved, the requirements associated with the licenses for commercially available seismic and well log data means that the models provided only contain derivative interpretations of this data. The requirement for public disclosure was also a challenge for many oil and gas operators who, whilst supportive of the project objectives, were not ready to release data to the project which might be publicly disclosed.

The primary areas of the project impacted by the constraints outlined above were:-

1. Model calibration. The lack of well by well fluid production and pressure data from operating oil and gas fields to support the dynamic pressure characterisation of some subsurface systems.
2. Containment assessment. The lack of routine presence of detailed well abandonment records for exploration, appraisal and development wells to characterise the engineering containment characteristics of some sites.

These constraints did not unduly influence the outcome or results of the project, however it highlights specific gaps in the national hydrocarbon data archive systems which should be addressed going forwards. From a development perspective, it is expected that such data will be readily available to a prospective developer from an oil and gas operator under appropriate confidentiality agreements.

This document represents a high level summary report describing the key outcomes of the project. It is aimed at stakeholders with a broad knowledge of CCS, but only basic knowledge of the subsurface and associated language.

Further technical reports are available for each work package and in particular there are outline storage development plan and budget reports for each of the five selected storage sites in the portfolio.

Access to these reports, stakeholder presentations and digital subsurface models is available from the ETI at www.eti.co.uk/project/strategic-uk-ccs-storage-appraisal/.

ⓘ Types of Geological Storage

There are several types of underground configuration which offer potential for deep geological storage including volcanic rocks and coal seams. In this project, the focus is entirely on porous and sedimentary strata such as sandstones & limestones (limestones only comprising around 10% of the potential in the UKCS). The geological requirements for CO_2 storage include a large porous and permeable sandstone or limestone reservoir overlain by an extensive impermeable cap rock layer of mudstone, shale or other impermeable formation such as rock salt. The reservoir must also be at a depth which can retain the CO_2 in a dense phase for maximum efficiency. These attributes are also pre-requisites for oil and gas and so petroleum basins such as the North Sea are also prime targets for CO_2 storage. In fact, depleted oil and gas fields are often excellent target sites because of the database of wells, seismic and production information acquired during petroleum exploitation. This can significantly reduce storage uncertainty. It is in saline aquifers however, where most of the potential UKCS storage resource resides. These can be less well drilled, although some have been extensively investigated.

It is helpful to characterise potential storage sites according to their subsurface configuration. This was done for all potential UK sites as part of the CO2Stored database build. Some key configurations are outlined here:-

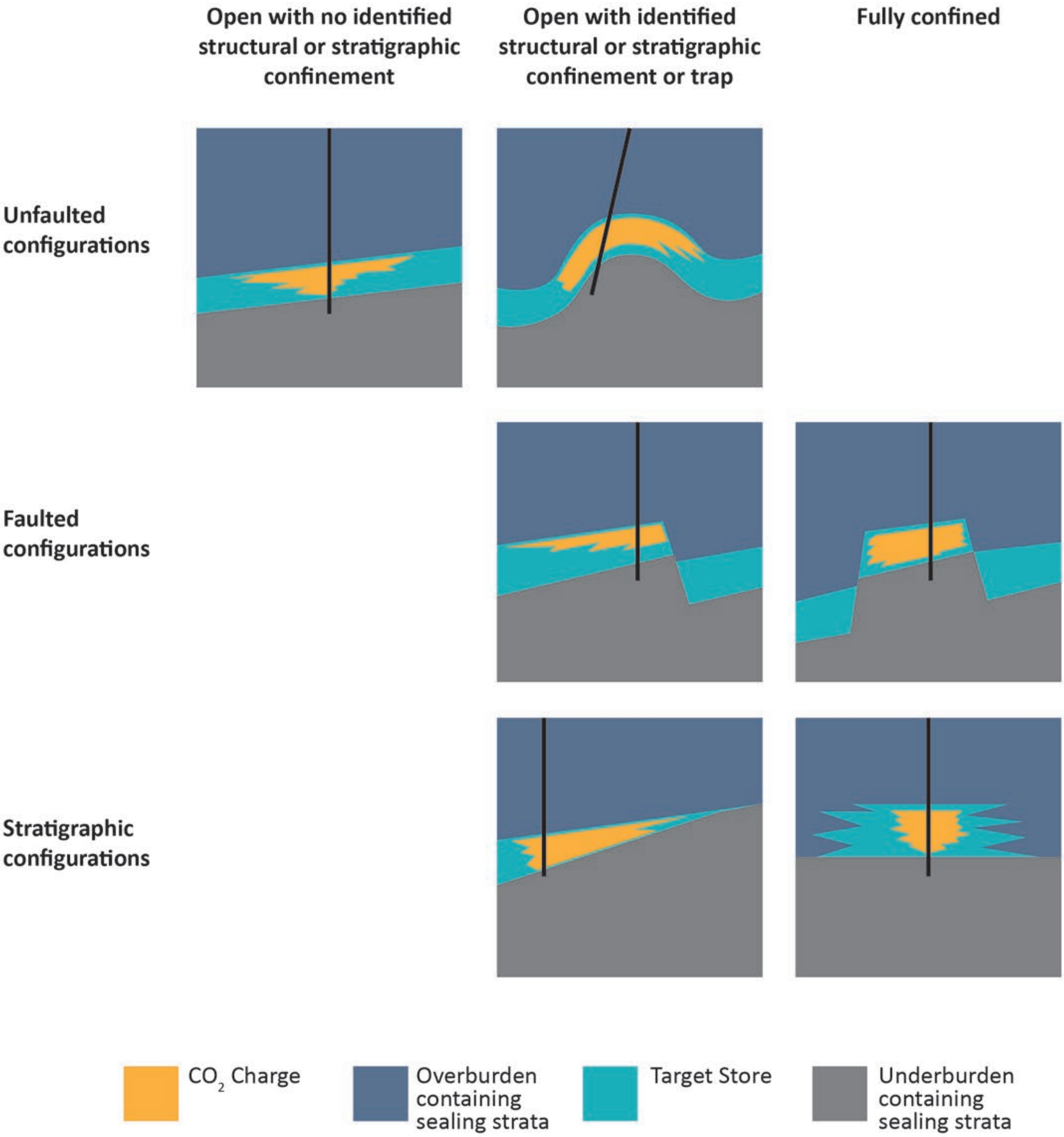
1. Open with no identified structural or stratigraphic confinement.
This configuration is an extensive storage formation which has a high degree of lateral hydraulic connectivity and therefore considered to be "open". These sites are also characterised by an absence of large trapping structures within which buoyant fluids such as oil, gas or CO_2 could be held. As a result, these sites are almost exclusively saline aquifers. CO_2 can be successfully injected and stored in these sites, but the CO_2 plume is often highly mobile, dependent upon residual trapping and can have low storage efficiencies (2 to 10%). These sites present particular issues in relation to lateral containment that will require careful resolution in order to achieve regulatory consent.

2. Open with identified structural or stratigraphic containment.
These are also "open" extensive storage formations, but there are also identifiable trapping structures within them capable of holding buoyant fluids against a caprock seal. As a result, the traps may have once contained oil and gas, which were connected to a large saline aquifer system. These sites offer a range of CO_2 storage development options including the filling of the reservoirs in the trapping structures with CO_2 where the plume can be constrained by the geometry of the trap offering a higher storage efficiency (20-40%). These sites also often present an opportunity to extend this buoyant storage into the connected aquifer beyond the trapping structure.

3. Fully confined.
These sites are hydraulically sealed reservoir cells. They can still be sizable features, but might only be small aquifer systems. This might have arisen because of faulting of the subsurface formations, or because the reservoir is an isolated sandstone within a shale background. The result is a hydraulically isolated fluid filled pore volume. These sites can contain oil and gas, or simply be filled with brine. Where such sites have been filled with gas which has been depleted through petroleum extraction, very low reservoir pressures can result which provides an excellent opportunity for CO_2 storage. These "depleted gas field" sites commonly have an abundance of static and dynamic data and can offer very high storage efficiencies of over 70%. Where such sites are predominantly brine filled, a key constraint on storage will be ensuring the confined nature of these sites does not result in a rapid increase in reservoir pressure towards the maximum at which safe integrity can be assured. Elevated pressure can lead to mechanical failure of the caprock and result in loss of CO_2 from the storage reservoir. In such circumstances, pressure relief through brine production might be advantageous.

Oilfields are common contributors to configurations 2 & 3 above. In an offshore environment, oil production is boosted by maintaining high reservoir pressures throughout the production cycle. As such any space once occupied by oil is invariably replaced with injected seawater which is used for pressure maintenance. For CO_2 storage this injected seawater has to be displaced or removed to create space for injected CO_2.

Of course some oilfields also present opportunities for enhanced oil recovery (EOR). Injected CO_2 can be used successfully as an agent for increasing oil recovery. It helps to maintain high reservoir pressure and productivity, but is also useful in mobilising trapped oil and moving it towards production wells. EOR is a complex topic both technically, commercially and in respect of its emissions balance. Detailed discussion is beyond the scope of this report, it may however have a role to play in the future of CCS in the UK.



Schematic cross sections through different store types

Storage Site Selection

In the context of this report, CO_2 storage means permanent storage or sequestration as opposed to temporary storage ahead of subsequent withdrawal. The key elements of CO_2 storage are outlined on page 4.

A viable storage site must be able to demonstrate that it has appropriate levels of capacity, injectivity and containment. This must be developed to a high level of confidence such that it can comply with regulatory requirements and have the potential to support a final investment decision. The geological history of the UK offshore area (UKCS) has resulted in a rich diversity of deeply buried strata which contain many potential storage sites. These include the deeply buried sandstones of both depleted hydrocarbon fields and saline aquifer storage sites.

The CO2Stored database is an ideal tool for supporting the storage site selection process. It is an excellent resource developed after a rapid and high level review of almost 600 storage sites across the UKCS. It represents the first, comprehensive, auditable and defensible estimates of CO_2 storage capacity for the UKCS. As such it captures a recent view of the whole inventory of offshore sites in an internally consistent and robust way.

The CO2Stored database was supplemented by additional information including:-

- Cumulative production volumes from oil and gas fields to February 2015 from DECC. This supports the consideration of depleted oil and gas field storage sites.
- 2015 estimates for dates of the end of commercial operations or Cessation of Production for oil and gas fields from Wood Mackenzie prepared specifically for this study. This enables the mapping of the schedule of availability of depleted oil and gas fields for CO_2 Storage. This information helps to avoid conflicts linked with simultaneous oil production and CO_2 injection operations in a specific site. It also informs potential options for infrastructure re-use.

The table below outlines the storage site count across the full UKCS potential storage site inventory for a range of “Storage Unit Types” and “Storage Unit Designations”.

Together, the final selected portfolio of five sites had to present a significant resource base, which when combined with other well studied storage sites such as Goldeneye (Longannet & Peterhead CCS projects), Hewett (Kingsnorth CCS Project) and Endurance (White Rose CCS Project), would make significant progress towards delivering 1500MT of commercial storage capacity by 2030.

The process to select the portfolio of five sites was split into two stages. The first “Many to Twenty” stage selected the most promising storage site potential from the large initial inventory. The second “Twenty to Five” stage selected the most promising portfolio of five storage sites from the selected inventory of twenty.

Many to Twenty

This selection stage comprised a “Qualification Step” and a “Ranking Step”. Best practice guidance from the 2009 IEAGHG report for screening requirements for saline aquifers was helpful and presents several key criteria which were used to highlight the most promising sites. In addition two further project criteria were adopted to ensure that the “Qualified Inventory” of sites also met with the overall project objectives. These were:-

- The distance from selected pipeline landfalls (or beachheads) to the centre of the storage site was less than 450km.
- The estimated theoretical storage capacity within the CO_2 Stored database was at least 50MT at a P50 level of confidence (A P50 estimate has a 50% chance of being exceeded).

Site Numbers	Unit Designation				
Storage Unit Type	Saline Aquifer	Oil & Gas	Gas Condensate	Gas	Total
Fully confined (closed box)	228	3	1	8	240
Open, with identified structural/ stratigraphic confinement	20	0	0	0	20
Open, no identified structural/ stratigraphic confinement	62	0	0	0	62
Structural/ Stratigraphic confinement	50	85	15	101	251
Uncategorised	1	0	0	0	1
Total	**361**	**88**	**16**	**109**	**574**

Collectively, these criteria effectively define a "Selection Basis of Design".

Five additional depleted hydrocarbon sites were added to the CO2Stored inventory before the selection criteria were applied to make a total inventory of 579 with a combined capacity of 78.1GT (Average 135MT per site).

37 specific sites met the high hurdle to qualify as potentially strategic storage sites. Beyond this there were many other excellent sites which present a rich diversity of storage resource. Together the qualified inventory had a combined CO2Stored capacity of 8.3GT (average 224MT per site).

The final ranking step was performed using a simple multi-criteria decision making method. For each site in the "Qualified Inventory", a set of six relatively independent factors important to a successful CO_2 storage site were chosen. These were:-

1. Capacity - CO2Stored P50 estimate
2. Injectivity - the product of reservoir permeability and net thickness, a measure of how easily CO_2 can be injected into the reservoir
3. Engineered Containment Risk - Legacy well density
4. Geo Containment Risk - CO2Stored risk assessment
5. Development Cost Factor - A function of pipeline length and reservoir depth
6. Upside Potential - sum of capacity within 20km

Several sensitivity tests were conducted to ensure the most promising twenty sites proposed were robust, before the list was tested and verified with an experienced stakeholder group from industry and academia.

The final "Select Inventory" of twenty sites has an equal balance between saline aquifers and depleted hydrocarbon fields. It has a wide representation of storage strata from Permian to Tertiary age and also presents strong geographic diversity from all parts of the North Sea and the East Irish Sea. The "Select Inventory" is capable of servicing all the major UK emissions centres and beachheads identified in the ETI scenarios plan (2015).

The "Select Inventory" is outlined on Page 2. It should be noted that neither the Goldeneye nor Endurance (5/42) sites are included. Both of course provide excellent potential, but they were excluded because:-

1. At the time of the analysis, it was considered that neither site would be available to other prospective third party developers and would most likely be developed by Shell UK and National Grid Carbon respectively.
2. With both projects having been through multi million pound FEED programmes, it was most unlikely that this project could further materially progress the maturity of these sites.
3. The estimated capacity of Goldeneye did not meet the 50MT threshold required by this project.
4. The full coverage of 3D seismic for Endurance was unavailable to this project.

Twenty to Five

Once the inventory had been reduced to twenty sites, it was possible to look more closely at each site to ensure it really has the qualities that are attributed to it. Each site was subjected to a rapid due diligence. This involved a review of seismic data over the site and a preliminary reservoir review using site specific well information. The primary sources of this information were the commercially available PGS seismic mega-survey for the North Sea and the Common Data Access database (CDA) for well information which is managed by Oil and Gas UK. At this stage, due diligence activity sought to confirm that the site could form the foundation of a cost effective and viable Storage Development Plan to accept the delivery of between 3 and 10 MT/yr over a minimum 15 year period starting between 2025 and 2030. The hypothesis was broken down further into three key areas of consideration:-

Subsurface Characterisation

Does the site have appropriate blend of capacity, injectivity and containment that give confidence that the site can meet the primary hypothesis?

Development Potential

Does the site have a potentially important role in the build-out programme of UK CCS infrastructure and can it be developed in a cost effective manner such that the pipeline, facilities, and wells capex requirements together with anticipated opex provide confidence that the site can meet the primary hypothesis?

Ability to Progress

Does the site have the right combination of data availability (type, quality and quantity), uncertainty reduction potential and Operator collaboration or support (from whichever domain oil & gas, offshore wind, sand & gravel etc.) to materially progress the appraisal status of the site in this project?

The importance of "data" in the development of understanding of the subsurface environment cannot be overstated. Here "data" comprises any information acquired from offshore activity such as drilling wells, shooting seismic data and production or injection of fluids from wells. Data can be broadly divided into "static" or "dynamic" depending upon whether it describes unchanging or changing attributes of the subsurface during its exploitation. Once it is interpreted, data can reduce uncertainty associated with a development decision or forecast outcome. This can enable project decisions to be made and this progress represents the value of that information. It is a calibrated judgement of the value of information delivered that should drive any data acquisition plan. The recommended five sites must act together as an effective portfolio that meets the following goals:-

1. Each individual site is effective and has good potential to be developed into a CO_2 Storage site as part of a build out programme to support CCS development in the UK.
2. The portfolio as a whole fits the narrative around the ETI CCS Scenarios (2015) and in particular the geographic, timing and capacity growth needs.
3. The portfolio effectively manages risk across its extent and specifically looks to minimise critical "single point of failure" risks through its diversity.

A review of the make-up of the top performing portfolios revealed a strong consistency in those sites included. Specifically, Viking Gas Field, Captain Aquifer, Hamilton Gas Field, Grid Sandstone Aquifer and Forties 5 Aquifer were strongly represented in the Top 10, 20 and 40 portfolios. Bunter saline aquifers within the Southern North Sea are also well represented with Bunter Closure 36 being the most significant.

Side Code	Description
SNS_Site_7_139.016	Bunter Closure 36
SNS_Site_5_141.035	Viking Gas Fields
CNS_Site_14_218.000	Captain Aquifer
EIS_Site_19_248.002	Hamilton Gas Field
CNS_Site_2_372.000	Forties 5 Aquifer

The final recommended portfolio of five sites was verified by external stakeholders and is outlined in the table above. The final portfolio carries two depleted gas fields with different challenges, one from the Southern North Sea and one from the East Irish Sea. It also includes a large Bunter Closure with a saline aquifer storage reservoir similar to the Endurance structure. Finally, it includes two open saline aquifers in the Central North Sea, the Captain Sandstone near to Goldeneye and also a large Forties aquifer deeper into the basin which would be available later in the build out programme. The last two sites also carry the potential to support the development of CO_2 enhanced oil recovery projects in the Central North Sea by routing CO_2 destined for storage to near by oil fields.

ⓘ Capacity

The CO_2 storage capacity of a geological storage site is the total mass of CO_2 that can be injected, stored and safely retained within a specific site. It is routinely measured in millions of tonnes of CO_2 (MT). The capacity depends upon several factors. Some of these are underground factors and therefore subject to subsurface uncertainty, others are engineering factors and depend upon how a particular site is developed and indeed the technology that is deployed.

There are distinct parallels between the challenges of capacity estimation to those of resource and reserve assessment in oil and gas. Formal capacity resource classifications based upon oil and gas experience are under development.

There are two main approaches to capacity estimation.

1. The first starts at a basin or regional scale. This approach adopts norms from research and project experience to make best statistical estimates of the total ultimate capacity available.
2. The second is from detailed site research or project development which evaluates capacity under a range of development options to select a reasonably optimised case which could be progressed within a specific regulatory framework.

The latter approach is subject to many more commercial constraints than the regional approach and has been deployed in this work.

Capacity of a geological storage site such as the sandstone in a depleted gas field or a saline aquifer depends upon several groups of factors.

1. Geological factors such as the area, thickness, depth and total pore volume and reservoir pressure of a site.
2. Mechanical factors such as the strength of the formation or its ability to withstand increases in pressure without damage resulting.
3. Flow factors such as the ability to sweep the injected CO_2 into the full target volume.
4. Regulatory factors such as the definition of the proposed lease boundary within which CO_2 must be retained.
5. Economic factors such as cost of development including transportation (pipeline or shipping), facilities, well construction, operational costs, abandonment and site monitoring costs.

The first three of these groups of factors require subsurface data to define. Such data are acquired through exploration and appraisal drilling, seismic acquisition and oil and gas production performance. The more relevant data that is available then the more confident the estimate can be.

Capacity can be expressed as a deterministic number which is normally the outcome of a specific development scenario, or as a probabilistic outcome which attempts to account for the uncertainty of the input data.

Storage efficiency
The storage efficiency is a key parameter which describes the volume proportion of pore space within the target storage complex reservoir volume that can be filled with CO_2 given the development options considered. This ranges from 2 to 5% in some Open Aquifers without structures, through to 70-80% in highly depleted gas fields. It is broadly the equivalent of recovery factor in the oil and gas industry.

Depleted Gas Fields

CO2Stored Site Code	Description
SNS_Site_5_141.035	Viking gas fields
EIS_Site_19_248.002	Hamilton gas field

Depleted gas fields have several advantages as potential CO_2 storage sites. Firstly, the fact that they have already retained hydrocarbon gas for many millions of years is encouraging for their ability to do the same for injected CO_2. Another advantage is that the capacity of the site is strongly correlated with the volume of gas extracted. This is especially so when gas production has resulted in very low pressure and highly depleted reservoirs.

Many of the challenges associated with CO_2 storage in heavily depleted gas fields have been highlighted within the Hewett FEED study of 2011-2012. These challenges are focused in three areas:

1. Managing the phase of the injected CO_2 during its journey into the very low pressure reservoir.
2. Managing the integrity risks associated with the abandonment of old wells with limited documentation.
3. Ensuring that the reservoir and cap rock are robust enough to withstand the deep depletion and re-pressurisation cycle of gas production and CO_2 injection without mechanical failure (fracturing).

CO_2 storage development projects at Hamilton and Viking both face these challenges to different degrees. In addition, Hamilton is very shallow, at only 700m at the crest. Nevertheless, calculations confirm that it will be possible for CO_2 to exist in its dense phase at the shallowest point after re-pressurisation so that more CO_2 mass can be stored in the space available. In Viking the challenges are focused on reservoir quality and injectivity. Together Hamilton and Viking will further qualify the East Irish Sea and Southern North Sea depleted gas field potential.

Aquifers with Structural Closures

CO2Stored Site Code	Description
SNS_Site_7_139.016	Bunter Closure 36

There are 50 sites within the CO2Stored database that are saline aquifers with structural closures. Every one of them is Triassic in age with 34 located in the Southern North Sea and 16 in the East Irish Sea. The East Irish Sea examples are challenged with very poor quality reservoirs.

Overall the Bunter Closures in the Southern North Sea are seen as attractive targets, but like most aquifers they are often sparsely drilled with minimal dynamic data and therefore subject to significant uncertainty.

Much effort has been expended over the last 5 years on the Endurance storage site (Bunter closure 35). The results of the recent FEED programme are not available to this project and so the progression of Bunter Closure 36 relied upon public information and released well data together with excellent 3D seismic data coverage from the PGS Mega-survey.

Open Aquifer Systems with or without identified structural or stratigraphic closures

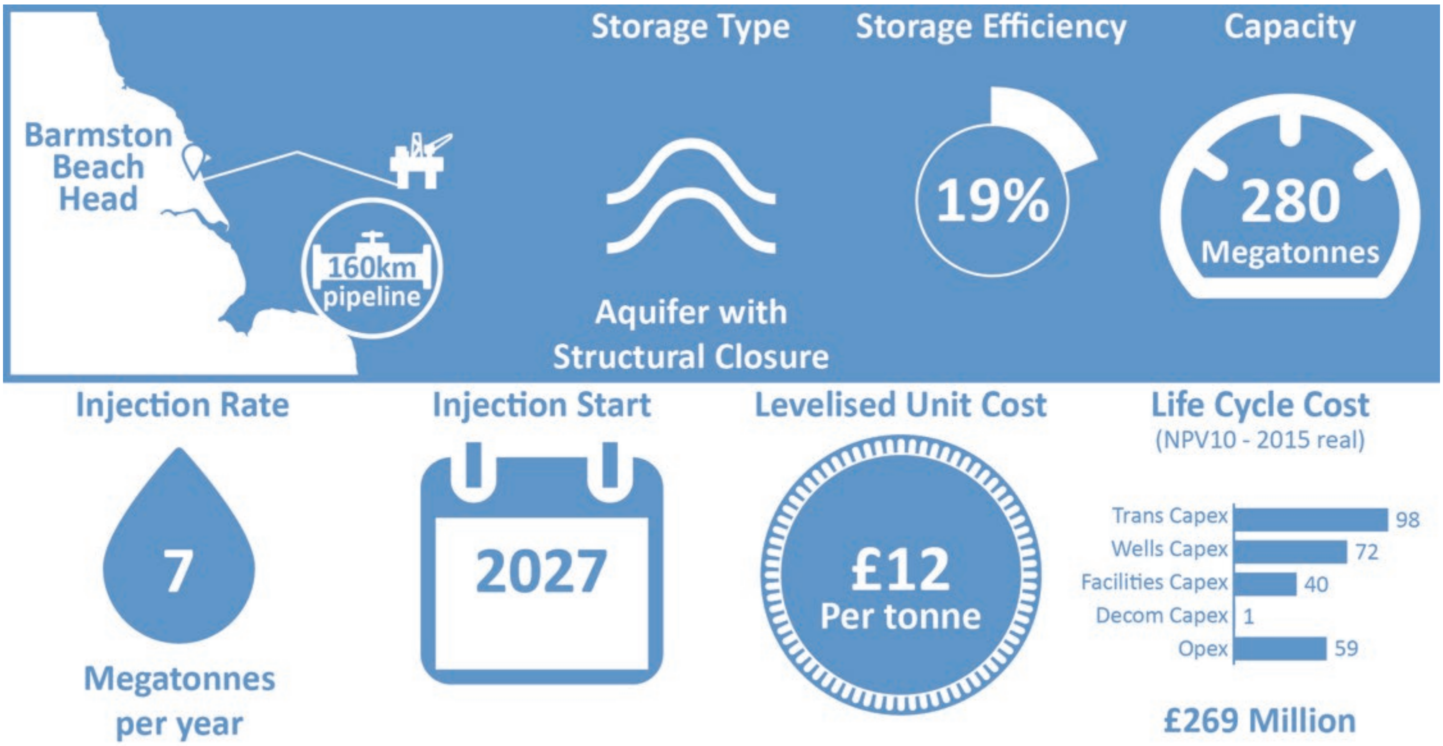
CO2Stored Site Code	Description
CNS_Site_14_218.000	Captain Aquifer
CNS_Site_2_372.000	Forties 5 Aquifer

Within the CO2Stored database there is over 68600 Mt of potential theoretical storage located within saline aquifer systems, representing over 85% of the total inventory. 12% of this potential lies in structural closures, 46% in closed boxes or deeply buried fault blocks (half of these are deeper than 3600m). This leaves over 42% of this potential in open aquifer systems. It is strategically important therefore that such systems are progressed within the UK if CCS is to be rapidly deployed effectively at scale.

Open aquifer systems are more complex than aquifers with structural closures. Their primary challenge is in the definition of the area required for the storage complex since there is not a neatly defined geological structure to delineate it simply like in an oil and gas field. However there is more CO_2 injection experience globally with open aquifers than with any other type of saline formation thanks to the Norwegian Sleipner project which has been operating successfully for 20 years.

The ultimate fate of injected and contained CO_2 will be in one of the following forms (page 31):

- A buoyant continuous (and therefore mobile) plume of CO_2 within the pore space of the aquifer.
- A discontinuous (and therefore immobile) residual saturation in the form of microscopic bubbles located in the pore space of the aquifer after the buoyant plume has passed through.
- As a dissolved phase within the saline water in the pore space itself. In time, this may eventually end up as new carbonate minerals in some parts of the formation.
- In addition, some CO_2 will continue to move , but at velocities that are so slow (<10m/yr), that they are effectively locked in place for the purposes of climate mitigation. This is referred to as low velocity trapping.



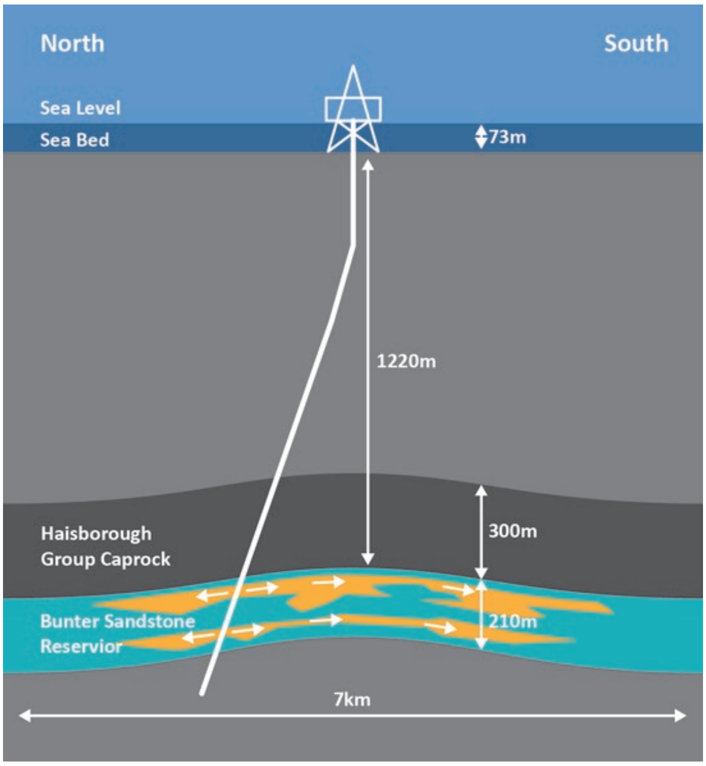
The Bunter Closure 36 site (BC36) is one of many dome shaped, structural closures within the Lower Triassic Bunter Sandstone Formation in the Southern North Sea Basin. It is located in blocks 44/26 and 44/27 some 150km from the Yorkshire coast and around 85km east and south of the proposed Endurance CO_2 storage site.

The BC36 "Saline Aquifer" target has good 3D seismic coverage from the regional Mega-survey from PGS. It has also been specifically drilled with six wells since 1968 and in addition is supported by a larger regional well database.

Site Description

The Bunter Sandstone is located 1200m to 1800m (4000ft to 6000ft) below sea level and is around 210m (700ft) thick. It was deposited in a broad dried river plain in a desert environment. It comprises "sheet flood" sands from rivers with some finer grained silts and muds deposited in temporary lakes. The reservoir quality is "good" with over 80% of the thickness considered to be effective reservoir (net to gross). An average of 22% of the rock is brine filled pore space (porosity) and its average permeability is 200mD. This indicates the potential for fluids to be injected and flow through the rock with relative ease. There are multiple sealing formations above the Bunter Sandstone which serve to seal in any injected CO_2 and prevent it from finding its way back to the surface.

These caprocks are a combination of laterally continuous mudstones deposited in large lakes and also thick halite or "rock salt" which is formed when such inland lakes are evaporated away under hot desert conditions. The primary seal is provided by the Rot Halite formation which is 60m (200ft) thick and supplemented by 300m (1000ft) of overlying mudstones of the Haisborough Group. Together these strata provide a very effective caprock system. Below the Bunter Sandstone reservoir there are more thick mudstones of the Bunter Shale, again deposited in large shallow dried lakes or salt flats. This provides an effective impermeable floor to the storage site. No adverse geochemical reactions between the site strata and the injected CO_2 are anticipated.



The target Bunter Sandstone storage reservoir is configured in a broad dome structure or closure which is around 7 to 10km across and some 550m (1800ft) tall. It is unfaulted and its crest is at 1200m (4000ft) below sea level. Elsewhere in the North Sea, such structures are often productive oil or gas fields. However in the Southern North Sea, it is unusual for oil or gas to find its way from the deeper Carboniferous source rocks through the thick impermeable layers of Permian Zechstein halite and into the Triassic. To the north of BC36, some migration pathways have been identified which have resulted in a group of small Bunter Sandstone gas fields (Caister, Hunter, Esmond, Forbes and Gordon).

In 1968, however, 44/26-1 was drilled into the crest of BC36 and found only water bearing Bunter Sandstones. The structure is therefore considered to be fully water bearing.

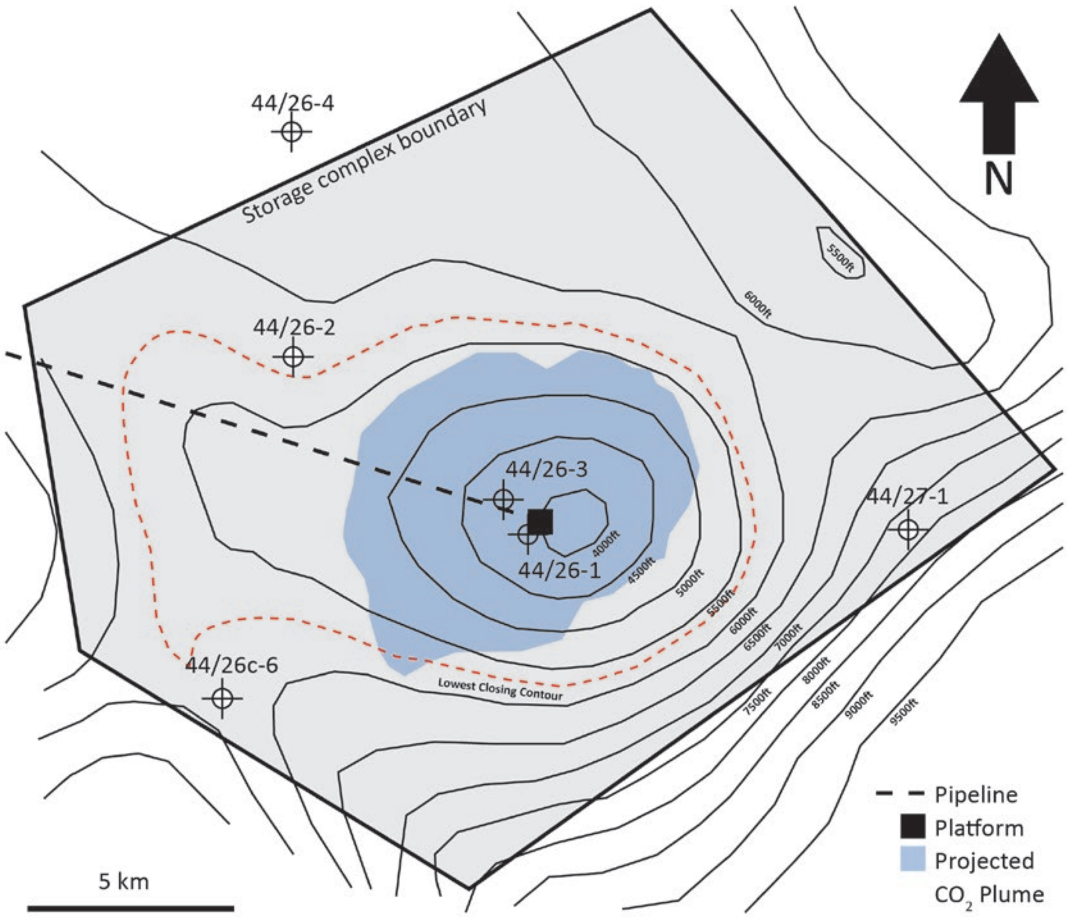
Development Plan Outline

The BC36 site partially overlies the deeper Schooner Gas Field which is estimated to cease production in 2021. A development plan for BC36 has been devised. It is envisaged that this would commence with a single appraisal well in 2020 followed by a new 3D seismic survey, a FEED programme and a final Investment decision at the end of 2022. The appraisal well will be required to further reduce uncertainty regarding reservoir quality distribution across the site and collect specific reservoir, caprock and fluid samples to support detailed development planning. Construction could begin in 2024 leading to first injection in 2027.

The development has been configured to service a CO_2 supply of 7MT/yr from the Humberside area over an operational life of 40 years. This is equivalent to a coal fired power plant of 1.2GW or gas fired power plant totalling 2.4GW.

The development would comprise a new multi-deck, minimal facilities unmanned platform on a four legged steel jacket in 73m (240ft) of water. It will be connected to a beachhead at Barmston with a new 160km long 20” steel pipeline. The platform will be operated by satellite links and be capable of operating for up to 90 days between routine maintenance visits. Whilst a fully subsea solution might be possible and cost effective, a platform based approach was preferred to manage operational risks in common with most southern north sea gas development projects.

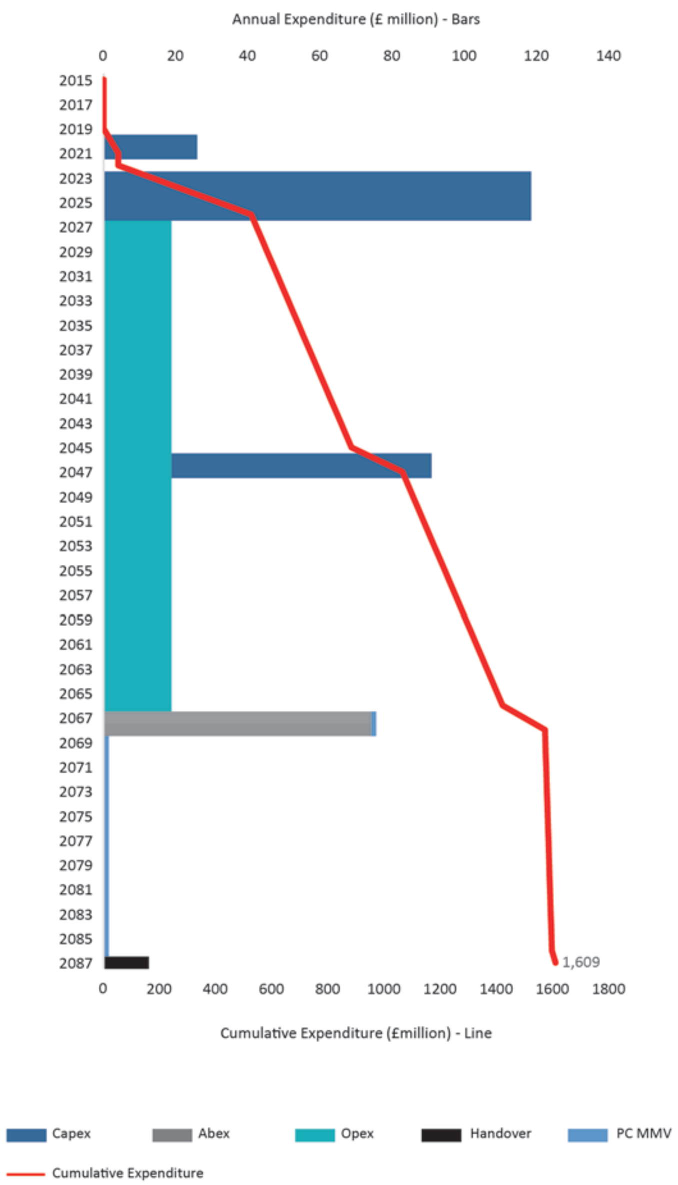
Geoscience and reservoir simulation modelling have indicated that five wells would be required. These would be deviated from the platform into the north west flank of the dome and be completed with 5.5” chrome steel tubing. It is anticipated that four wells will be injecting continuously with a fifth well retained as a back up to improve the operating

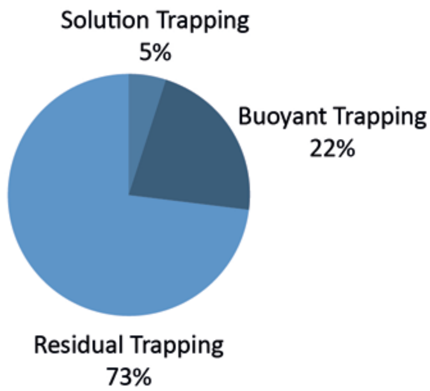


robustness. After some 20 years of operation it has been conservatively assumed that this well stock will require full replacement in a Phase 2 drilling campaign. Over the 40 year period, detailed modelling work has indicated that the site could accommodate the injection of 280MT of CO_2. Results suggest that the site could store a further 111MT of CO_2 at the same rates before the 7MT/yr CO_2 supply rate could no longer be injected. The ability to do this would be subject to the longevity and condition of the jacket and topsides after 40 years of service. Throughout the project, CO_2 injection operations will be in liquid phase.

Development Cost

The development of the offshore transportation and injection infrastructure is estimated to require a capital investment (including Pre-FID costs) of £669m (Real, 2015 or £209m PV10, Real, 2015). Full lifecycle costs including OPEX, decommissioning and site monitoring are estimated to be £1609m (Real, 2015 or £269m PV10 - 2015). Levelised unit costs are estimated at £12.33/T.





Trapping Mechanism Inventory (page 31)

Way Forward

Whilst there is good quality 3D seismic data and reasonable well data coverage from six wells in and around the site, there are some key uncertainties that will require careful and considered appraisal effort ahead of any development decision. A new 3D survey and appraisal well are required. It is estimated that the cost to reach FID would be £52m (2015 real). This will include a 3D seismic survey, an appraisal well and FEED studies.

Some further subsurface analysis of the local and regional Bunter Sandstone hydrology or aquifer strength is also required as this has a major influence on performance of the site. Specifically, a detailed analysis of production and pressure information from nearby Triassic gas fields may illuminate how these structures are connected hydraulically through the Bunter Sandstone aquifer. This uncertainty regarding the long term dynamic performance of Bunter Dome storage sites is one of the key remaining issues for this type of storage play in the UK.

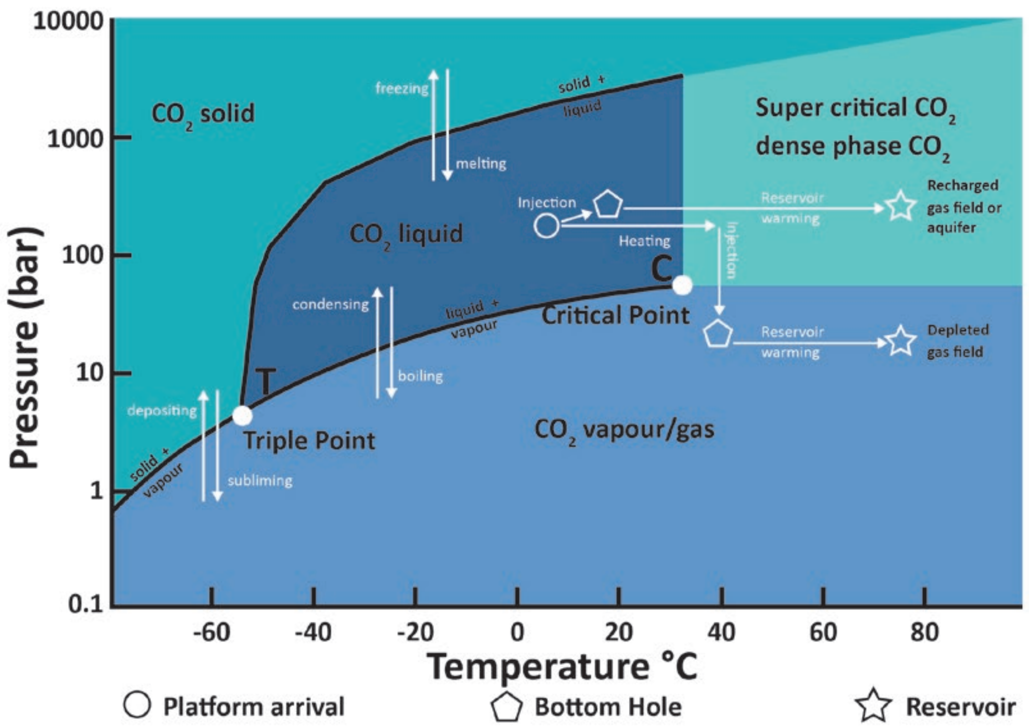
ⓘ Carbon Dioxide Phase Management

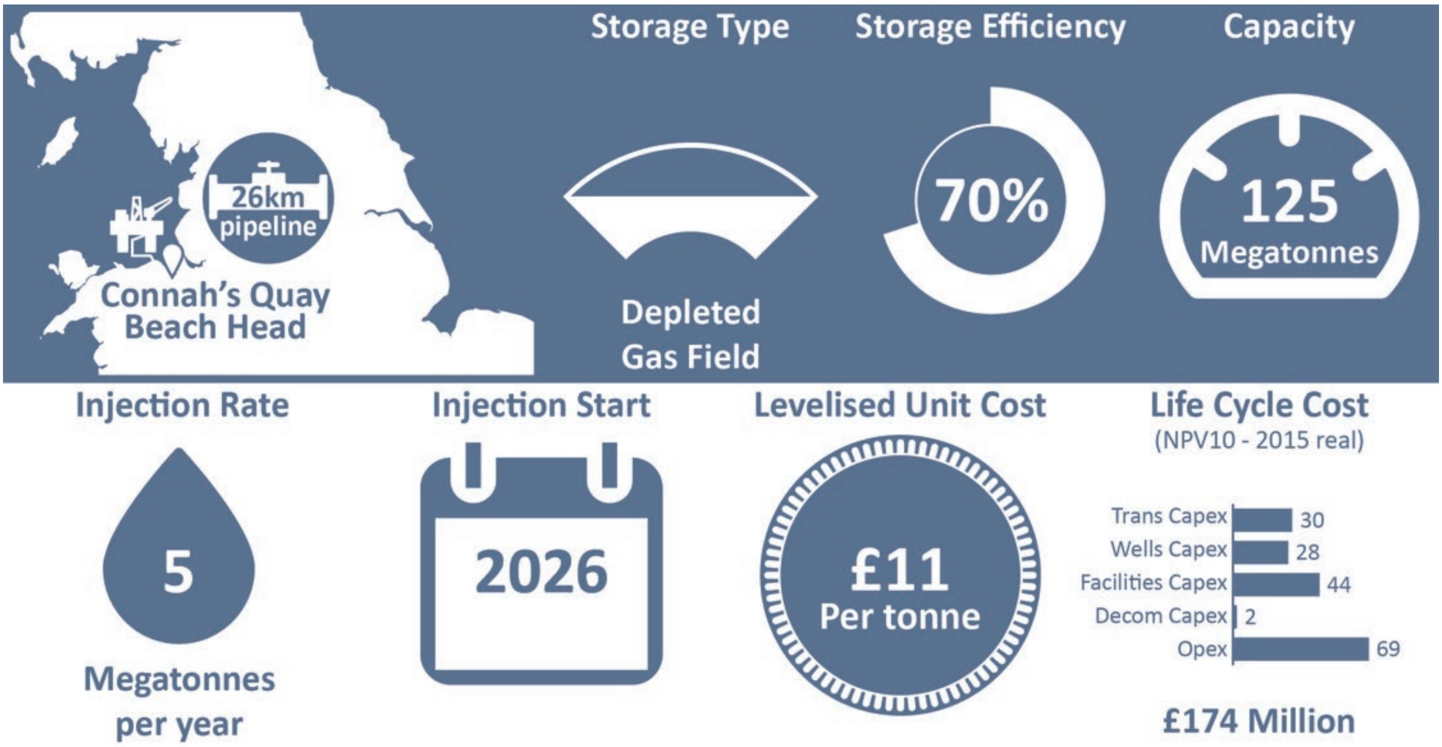
Phase is just another term for solid, liquid or vapour and CO_2 can exist as all three in common with most substances. Whilst at normal conditions CO_2 is a gas, its phase depends upon the pressure and temperature of the CO_2. The phase diagram below has three lines and two special points, T and C. The three coloured areas represent the temperature and pressure conditions under which CO_2 is a solid, liquid or a vapour. Phase is important for CO_2 storage because as the CO_2 is injected into the earth its pressure and its temperature will normally increase. If this journey (in pressure and temperature) takes the CO_2 across a line on the diagram then the phase will change. Some examples of these journeys are posted on the diagram and can result in freezing, melting, boiling, condensing, subliming and depositing. These phase transitions have important implications for the flow of CO_2 through pipes and reservoirs and also for the management of heat in the system. These changes are routinely exploited in technologies such as air conditioning, refrigeration and heat pumps.

The Triple Point, T is the pressure and temperature where solid, liquid and vapour states of CO_2 are all in equilibrium at the same time.

The Critical Point, C is the temperature beyond which it is not possible to condense a vapour into a liquid just by increasing the pressure, the molecules simply have too much energy and all that results is a highly compressed vapour. In this condition the vapour has a high density almost like a liquid, but low viscosity like a vapour or gas.

Ideally, during CO_2 transportation, injection and storage the CO_2 is kept dense and mobile either as a liquid or as a dense phase vapour. In this way more mass of CO_2 can pass through pipes and be stored in reservoir pore space for any given volume. This requires a high pressure throughout the journey. Sometimes however, this high pressure is not available and cannot be easily engineered. This happens when trying to inject into very low pressure saline aquifers shallower than around 800m in depth or into very low pressure depleted gas fields. The former places a practical limit on the shallowest depth of CO_2 storage into saline aquifers. The latter is a temporary situation which will change once the depleted gas field is re-pressurised. It is important to manage the change in conditions down the wellbore where excessive cooling from rapid expansion of liquid CO_2 into a vapour might cause damage to both the well materials and mechanical integrity of the rocks themselves. One potential solution is to heat the CO_2 on the platform until the liquid CO_2 can be injected without crossing the 'liquid + vapour' line.

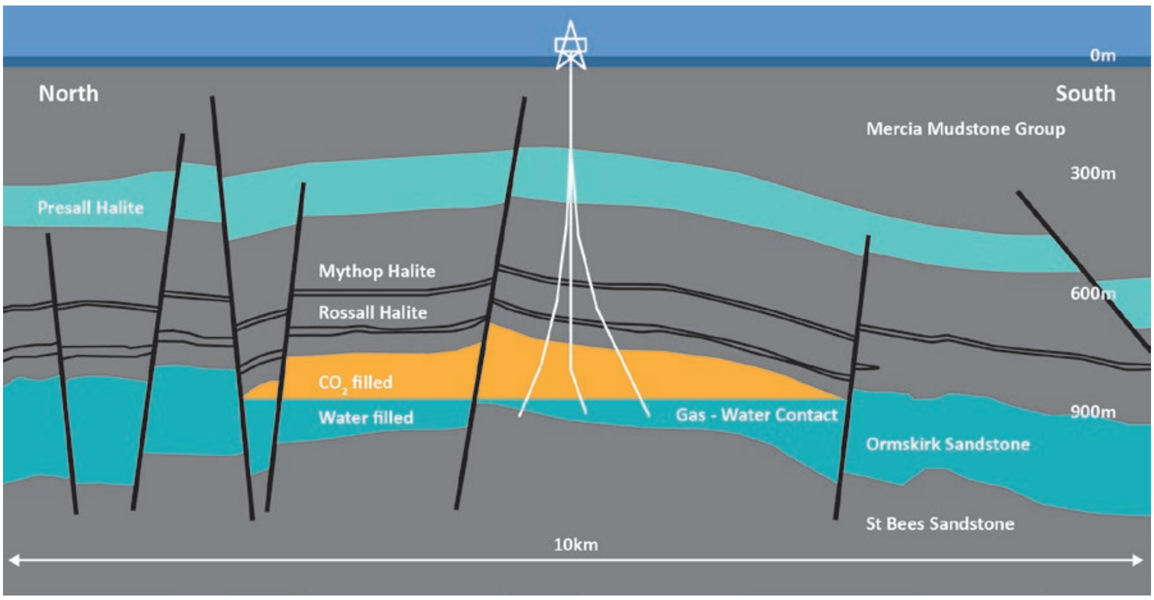




The Hamilton depleted gas field site is one of the largest of a series of fields located in the Liverpool bay area of the East Irish Sea. It is located around 40km south of the large Morecambe Bay gas field in block 110/13 some 23km from Merseyside. The field was discovered by well 110/13-1 in June 1990 with first gas delivered in February 1997. A cessation of economic production has been estimated to be in 2017 by Wood Mackenzie for this study.

Hamilton is notable for its significant pressure depletion and its shallow depth. Whilst its depth contributes to lower drilling costs, the target storage reservoir depth (700m or 2300ft at the crest) is slightly less than the minimum depth recommended by the IEAGHG for saline aquifer sites to ensure that CO_2 remains in dense phase at reservoir conditions. At Hamilton, the heavy pressure depletion means that initially, CO_2 injection will be in gas phase, with a phase transition to liquid phase injection after some 13 years.

The target site is covered by a single 3D seismic dataset which was acquired in 1992 ahead of the gas field development. The data were procured from ENI, the owner under the CDA agreement. The data used was processed in 1992 and was of moderate quality. An improved 2010 re-processed version exists but was not available to this project. A total of 17 wells were available over the area. Of these 11 had good quality information over the target reservoir with 4 also having core sample data.

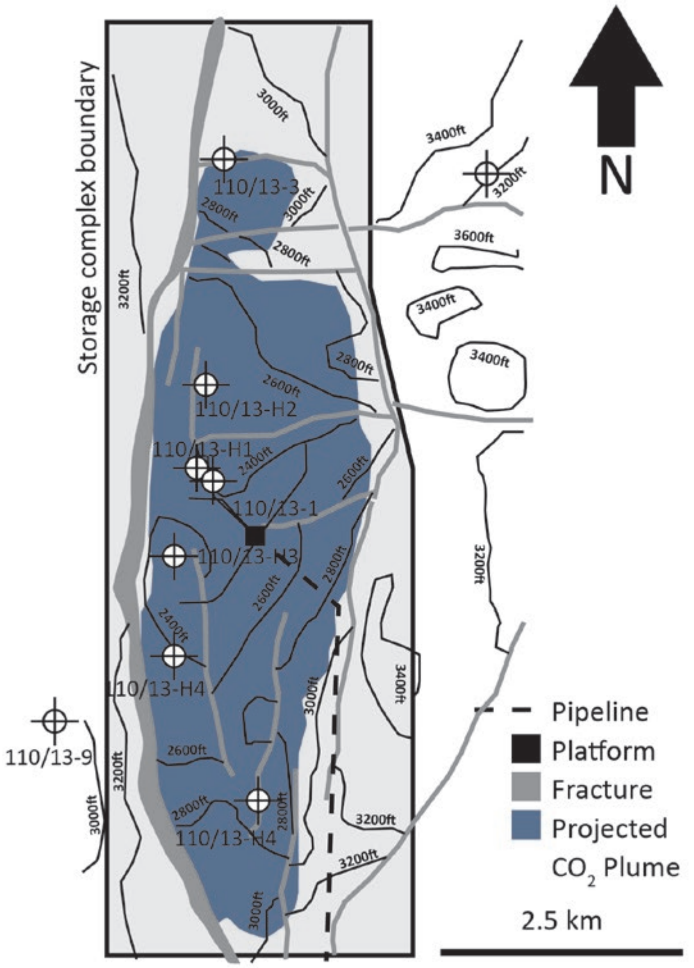


Site Description

The Triassic age Ormskirk sandstone is the target storage reservoir. It lies in the upper part of the Sherwood Sandstone Group which is the equivalent of the Bunter Sandstone in the Southern North Sea and is some 900m (3000ft) thick at the Hamilton site. The Ormskirk Sandstone was deposited in a desert environment as a sequence of windblown dune sands, with some river channel sands and thin salt flat and lake mudstone intervals representing periods of wetter climate which divide the Ormskirk Sandstone into three zones. The total Ormskirk Sandstone is some 230m (760ft) thick at Hamilton.

The reservoir quality is “very good” with almost 80% of the thickness of the Ormskirk Sandstone considered to be effective reservoir (net to gross). An average of 19% of the rock is pore space (porosity) and its average permeability exceeds 500mD. This reservoir has supported high natural gas production rates during depletion and is expected to receive injected CO_2 with ease. As a gas field, Hamilton produced 640bcf to the end of February 2015.

The target Ormskirk Sandstone storage reservoir is configured in a faulted structure or closure which is around 2.5 km across, 10km long and 180m (600ft) tall, with its crest 700m (2300ft) below sea level. Whilst some of the faults in the structure do extend to the seabed in places, they have proved effective at holding in natural gas under pressure and are expected to be similarly effective for CO_2. The mudstone and particularly the halite in the overlying cap rock tends to flow under pressure and seals up any potential migration routes to the surface along the faults. It is in this regard an ideal cap rock, although generally, the recovery of rock strength as sites re-pressurise requires further work to confirm their behaviour. This might be done by a review of hydrocarbon gas storage systems. No adverse geochemical reactions between the site strata and the injected CO_2 are anticipated.



To date 2 of the 7 wells located within the proposed storage complex have been abandoned, one in 1990 and one in 2012. Unfortunately no abandonment records are available for these wells within the CDA database. As the wells were abandoned recently, the legacy well leakage risk should be low, but this requires further work to confirm. It is assumed that the remaining 5 wells would be abandoned to a high standard before any storage development proceeds and would therefore present minimal risk.

The primary caprock is the Mercia Mudstone Group which is composed of five cycles of alternating red mudstones and thick rock salt (halite) deposited in desert lakes subject to periodic dry out. These caprocks provided effective seals to all of the oil and gas fields of the East Irish Sea including the Morecambe Bay gas field. Below the Ormskirk Sandstone lies the St Bees Sandstone. Across the East Irish Sea area, almost all the water bearing Triassic sandstones suffered a period of cementation after the structures were charged with natural gas. This resulted in the pore space being filled with a clay mineral called illite which reduced permeability by up to two orders of magnitude. This renders the deeper water bearing sandstones as quite effective sealing formations with little or no storage potential. This provides an effective low permeability floor to the storage site.

Development Plan Outline

The Hamilton Gas Field is estimated to reach the end of its economic life in 2017. Whilst there is some possibility of re-using some components of the natural gas infrastructure such as the jacket, at present a CO_2 storage development plan has been devised assuming no re-use of Hamilton Gas Field infrastructure so as to enable the gas field operator to progress its decommissioning operations along their preferred timeframe.

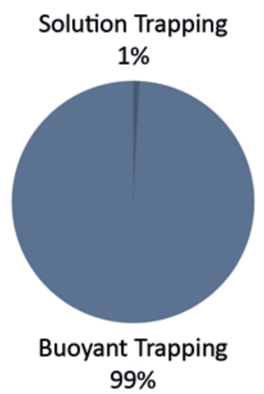
With 11 good quality wells drilled in the target reservoir, and a high degree of confidence provided by the performance of the natural gas development, no further appraisal drilling is considered necessary ahead of an investment decision. Some further rock samples can be acquired during development drilling to support inventory management and monitoring work during injection. It is envisaged that a new 3D seismic survey would be acquired in 2020 in the early part of the FEED programme to support development well placement and also serve as a baseline survey for site monitoring. A final investment decision could follow in late 2022 with construction starting in late 2023 leading to first injection in mid 2026.

The development has been configured to service a CO_2 supply of 5MT/yr from the Liverpool Bay area over an operational life of 25 years. 5MT/yr is equivalent to 0.8GW of coal fired power plant or 1.5GW of gas fired power plant. The development will be have two stages. Stage 1 will involve gas phase CO_2 injection. A later Stage 2 will switch to liquid phase CO_2 injection.

Geoscience and reservoir simulation modelling have indicated that two active injection wells would be required. These would be deviated from the platform into the western crestal part of the structure and be completed with 9 5/8" chrome steel tubing for the initial gas phase of injection. It is anticipated that two wells will be injecting continuously with a third retained as a back up to improve the operating robustness. After around 13 years of operation the Stage 2 development will commence. It has been conservatively assumed that the active operating well stock will be replaced at this time with two new wells each with 5.5" tubing in 13% chrome steel.

Over the whole 25 year period, the site could accommodate the injection of 125MT of CO_2. Since excellent storage efficiency of 70% is anticipated there is relatively little upside available at this site and once full, a step out development at other nearby sites such as Morecambe Bay is possible.

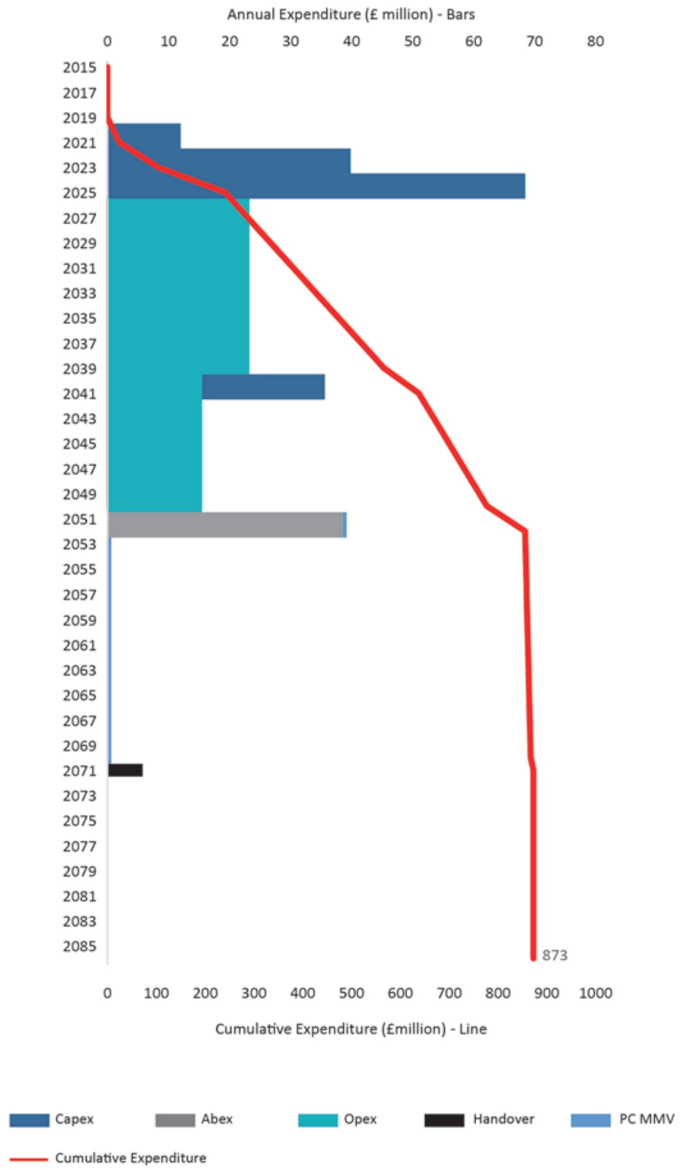
The platform will comprise a new multi-deck, minimal facilities unmanned platform on a three legged steel jacket in 24m (80ft) of water. It will be connected to a beachhead at Connah's Quay with a new 26km 16" steel pipeline. The platform will have six well slots and also carry 10MW of electrical heating to warm the CO_2 ahead of injection during Stage 1. Power will be supplied by a cable from the shore. The platform will be operated by satellite links and be capable of operating for up to 90 days between routine maintenance visits.



Trapping Mechanism Inventory (page 31)

Development Cost

The development of the offshore transportation and injection infrastructure is estimated to require a capital investment (including Pre-FID costs) of £281m (Real, 2015 or £102m PV10, Real, 2015). Full lifecycle costs including OPEX, decommissioning and site monitoring are estimated to be £874m (Real, 2015 or £174m PV10 - 2015). Levelised unit costs are estimated at £10.94/T.



Way Forward

A new 3D seismic survey is recommended ahead of final well placement. There is good quality well information already available and no further appraisal drilling is required. There is however residual uncertainty linked with the dynamic performance of the store under injection. This arises from the unavailability to this project of well by well production and pressure data during the gas production cycle. Such data is unfortunately no longer routinely placed into the national archive and would require consent from the field operator to access. This uncertainty could be significantly reduced through such data access agreement.

The key uncertainty is associated with the operational management of the change from gas to dense phase injection after around 13 years. This would benefit from further engineering consideration. Further work also needs to be done to improve the assessment of formation strength as a depleted gas field is re-pressurised.

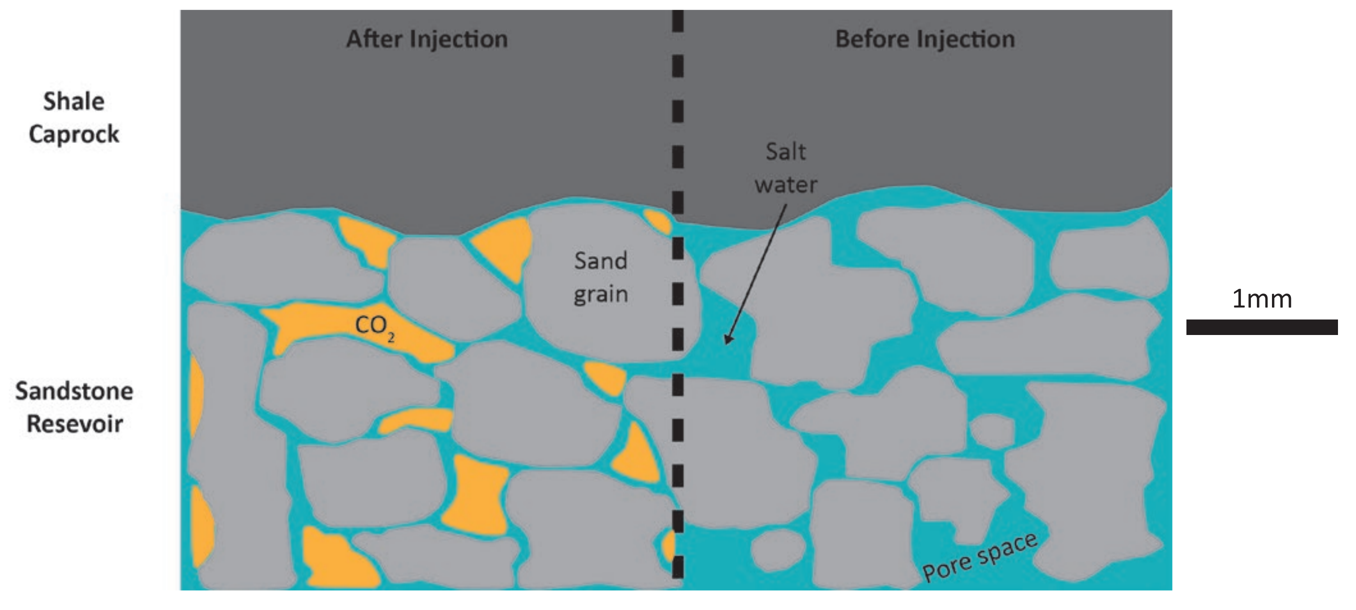
It is anticipated that around £24m of expenditure will be required to reach the final investment decision. This will be largely focused upon FEED studies.

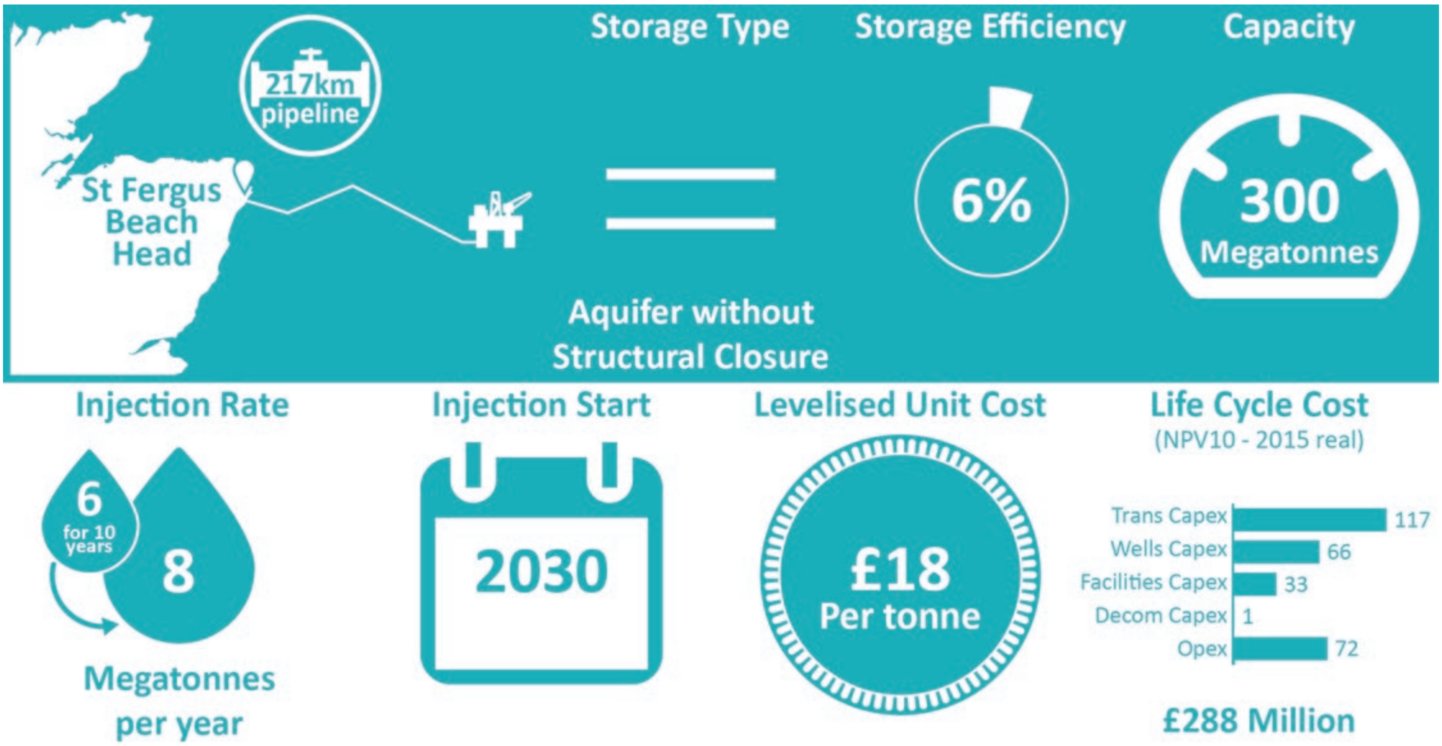
Any future developer may also be keenly interested in the potential for cost reduction options through re-use of some components of Hamilton infrastructure.

Porosity and Permeability of Reservoir Rocks

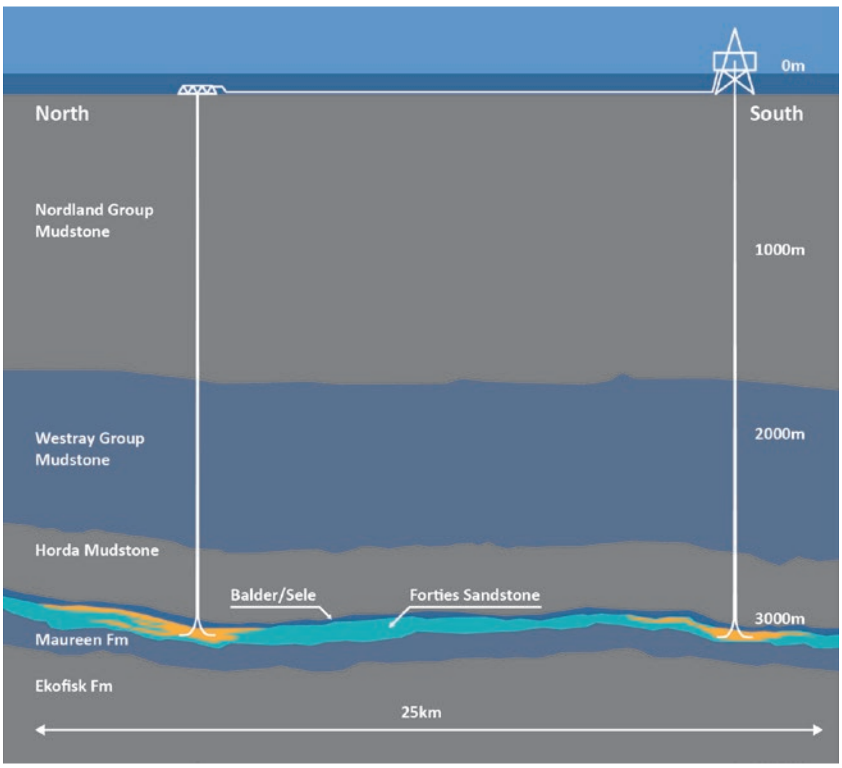
At a microscopic scale, reservoir rocks such as sandstones contain spaces between the sand grains, which are filled with fluid. In most cases this fluid is salt water, but in some cases can also include oil and gas. In CCS, some of this space is used to permanently store CO_2. The proportion of this pore space compared to the total rock volume of the reservoir is known as its porosity and practically ranges from 0% - where the pores are filled with solid mineral material through to perhaps 35% for a high quality sandstone reservoir. This is an important factor controlling how much CO_2 can be stored within a target sandstone.

The interconnection of one pore space with its adjacent pore spaces enables fluid to move through the rock. The ease with which fluid flow can take place is described by its permeability. This is measured in millidarcies (mD) and effective storage sites generally have average permeabilities of 50mD and greater. This is an important factor controlling the rate at which CO_2 can be injected into the target sandstone and also how the CO_2 moves once it has been injected. Both these properties are measured directly from core samples of the rocks. In addition, porosity is routinely measured using sensors lowered downhole during the drilling process. It is common for the permeability and porosity values to be strongly correlated.





The Forties 5 sandstone aquifer covers some 20,000 square kilometres of the Central North Sea in a region adjacent to the international boundary 220km due east of St Fergus. The Forties sandstone is a prolific hydrocarbon reservoir hosting fields such as Montrose, Arbroath, Nelson, Everest and of course the Forties field itself. Despite the fact that some of these fields are excellent potential CO_2 storage sites in their own right, the primary storage target here is the salt water bearing Forties sandstone aquifer. This has been selected because over 42% of the UKCS aquifer storage resource potential lies in systems like this one. With a potential storage capacity of the whole aquifer thought to be in excess of 10GT, the proposed initial stage of development at Site 1 is located in the very favourable eastern part of the site. The Forties 5 Site 1 area is 1634 square kilometres. It is located 250km from St Fergus, 370km from Redcar and 410km from Barmston and so whilst it is a considerable distance offshore, it is accessible from three important beach heads.



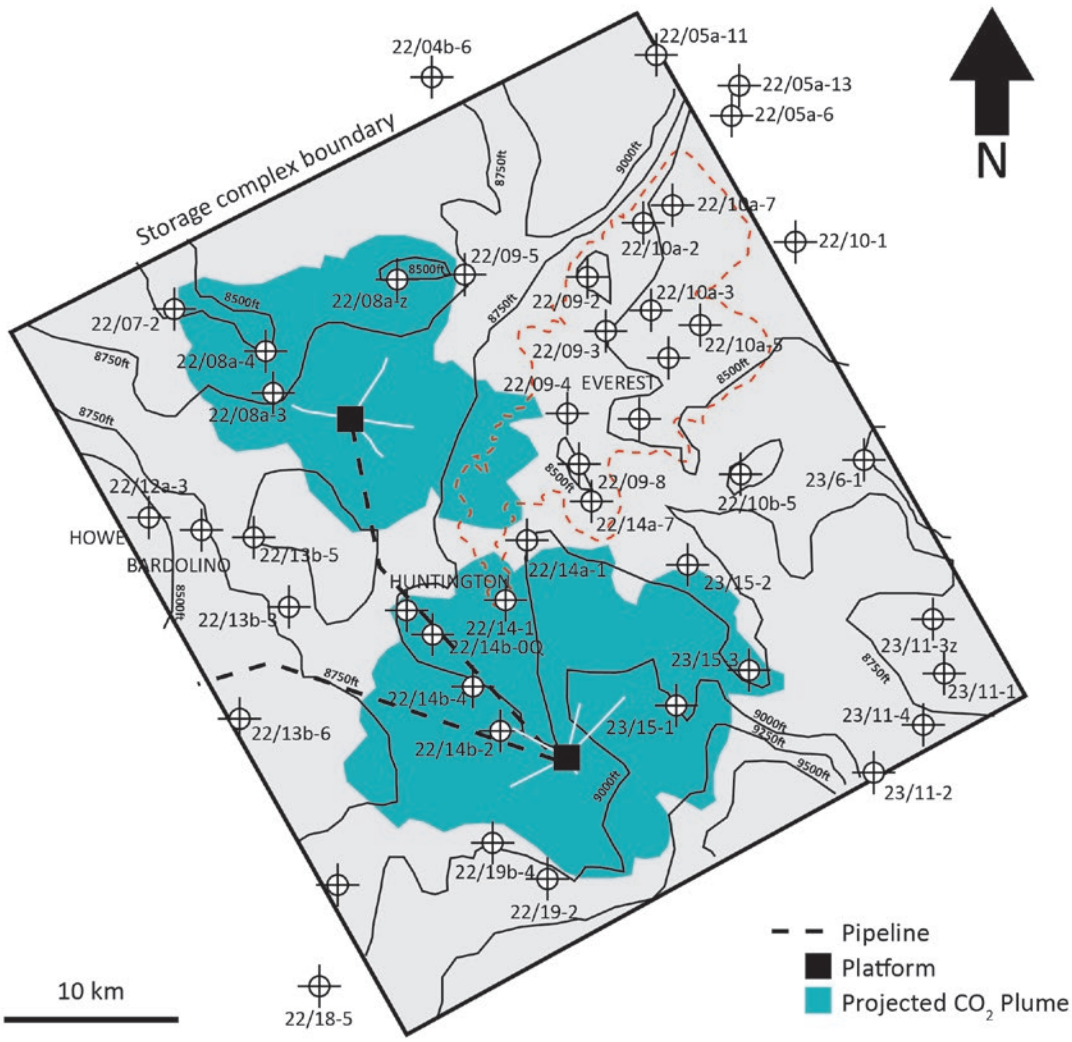
95% of Forties 5 Site 1 is covered by 3D seismic data surveys from the PGS MegaSurvey. Some 45 wells on the site were sourced from CDA. A much larger regional well database is available within CDA. The quality of log data from existing wells is generally good and includes core materials.

Site Description

The Forties Sandstone lies from 2400m to 3050m (7900ft to 10000ft) below sea level. It reaches 170m (560ft) in thickness but thins to zero in the east. It was deposited in deep water around the edge of the shelf as a submarine fan. This has a series of stacked sand filled channels which flowed from the shelf on the north west to the deeper water in the south east. In between the channels there are mudstones and shales. The reservoir quality is "good" with over 70% of the thickness considered to be effective reservoir (net to gross). An average of 18% of the rock is brine filled pore space (porosity) and its permeability is up to 700mD. Overall permeability is highest in the channel areas in the north and north west, and reduces to the south. There are thick multiple sealing formations above the Forties Sandstone which serve to contain injected CO_2 and prevent it from finding its way back to the surface.

The primary caprock is made up by 130m (425ft) of overlying mudstones of the Sele and Balder Formations. These strata are laterally extensive and continuous, representing the abandonment and covering of the Forties fans by basin shales. These formations are proven and effective caprocks for both oil and gas fields with Forties Sandstone reservoirs. The mineralogy of the formations is such that no adverse geochemical reactions are expected between them and the injected CO_2.

The target site is a largely unstructured area with low dips which becomes progressively deeper to the south and east. It was specifically selected as an "Open Aquifer system" to demonstrate and characterise how such a rock formation without a structural closure could be developed as an effective store. Site 1 contains the Everest gas field closure, but the development has been planned beyond the limits of Everest to the south and west. The pore space in the gas field therefore represents additional upside to the development outlined here. Neither the Everest gas field or the adjacent Huntingdon oilfield are anticipated to be commercially viable for hydrocarbon production beyond 2026.



Development Plan Outline

Site 1 is too large to be developed from a single drill site and so a phased development is proposed with two drill centres, consisting of a normally unmanned platform and a subsea template 24km to the North. Ahead of a final investment decision, it is recommended that a new 3D seismic survey is acquired across the Site 1 area. There is excellent potential to image the reservoir quality directly with seismic data and so a new survey could be used to locate the development wells at optimal locations. An appraisal well is recommended to test and further calibrate this tool and also obtain specific reservoir quality and overburden samples and tests to support the final investment decision at the end of 2025. First injection from the proposed development would be in 2030.

The development has been configured to service a CO_2 supply of 6MT/yr from 2030, increasing to 8MT/yr from 2040 until 2070. 6MT/yr is equivalent to 0.9GW of coal fired power plant or 1.8GW of gas fired power plant.

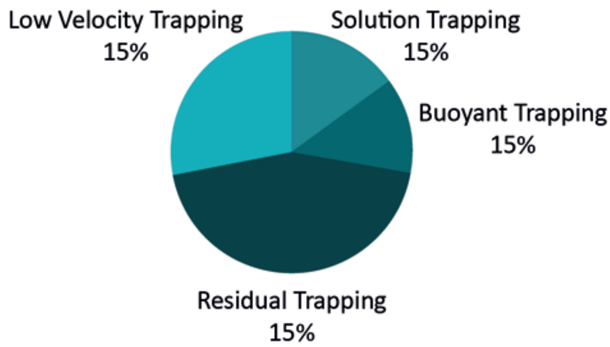
The development will comprise a new multi-deck, minimal unmanned facilities platform on a four legged steel jacket in 85m of water with 6 drilling slots. It will be connected to a beachhead at St Fergus with a new 217km 24” steel pipeline. The platform will be operated by satellite links and be capable of operating for up to 90 days between routine maintenance visits. After 10 years of operation an additional drill site will be established some 25km to the north where a 4 slot subsea drilling template will be located and connected to the platform with a 12” steel pipeline.

Geoscience and reservoir simulation modelling have indicated that four injection wells would be required in the south with an additional well held in reserve to maintain operational robustness. The wells would be deviated from the platform and be completed with 7” chrome steel tubing. After 10 years of injection, the northern subsea site will be developed with a further 4 injectors each with 5.5” chrome steel tubing. The injection will be allocated between the sites to manage reservoir pressure and subsurface CO_2 plume distribution.

It has also been conservatively assumed that the platform well stock will require full replacement after 20 years. Detailed modelling work has indicated that over a 40 years injection period and with the development plan specified, the site could accommodate 300MT of CO_2. The ultimate capacity of the site may be considerably more if it were to be further developed. Throughout the project, CO_2 injection operations will be in liquid or dense phase.

As the CO_2 migrates through the subsurface, over time, it becomes ever increasingly trapped as it passes through new pore space. There are several types of trapping mechanism, the most important being residual, solution and buoyant trapping. Additionally low velocity trapping is defined for any remaining CO_2 that is mobile, but with a velocity of less than 10m per year. Simulation of the CO_2 plume migration for 1000 years after injection ended has confidently shown that the injected CO_2 continues to migrate away from the injection sites, but that the maximum plume extent eventually stabilises within the storage complex. Modelling also shows that such migration can be tracked using time lapsed 3D seismic surveying through injection and the post closure period. This allows the actual mobility of the subsurface plume to be measured and tracked to calibrate the simulation models until it fully stabilises. Storage efficiency is low at only 6%.

Two legacy wells have been identified that present specific containment risks. These are 21/15-1 and 22/8a-3. These wells are within the anticipated plume area and further work is required to optimise the plume placement to minimise this containment risk.



Trapping Mechanism Inventory (page 31)

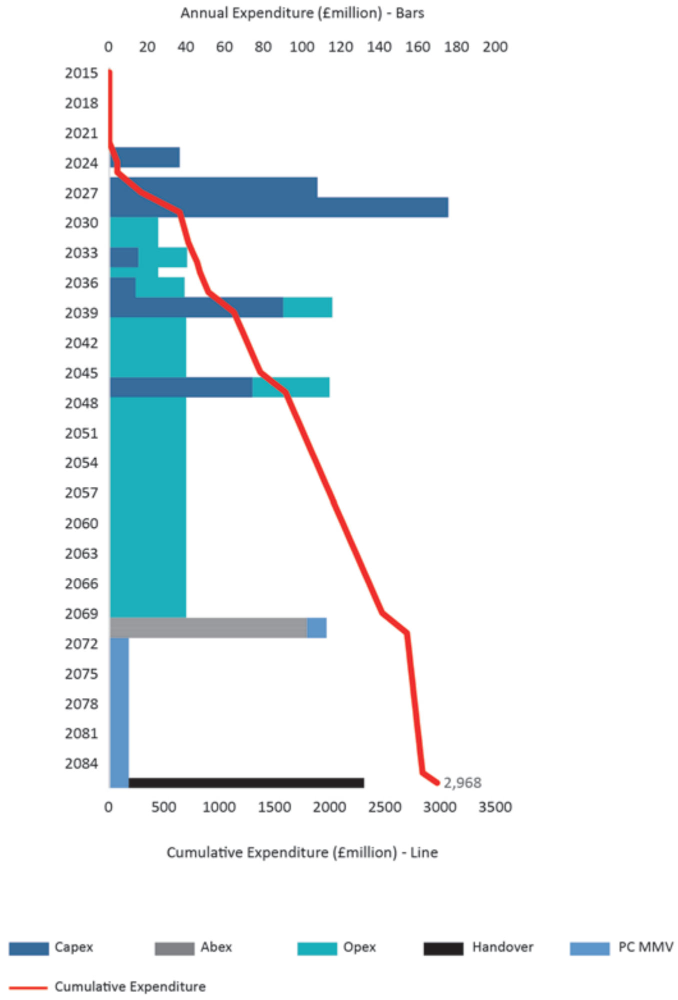
Development Cost

The development of the offshore transportation and injection infrastructure is estimated to require a capital investment (including Pre-FID costs) of £1025m (Real, 2015 or £215m PV10, Real, 2015). Full lifecycle costs including OPEX, decommissioning and site monitoring are estimated to be £2968m (Real, 2015 or £288m PV10 - 2015). Levelised unit costs are estimated at £18.27/T.

Way Forward

Whilst there is good quality 3D seismic data and well data coverage from 45 wells in and around the site, the very large area of this site compared with others considered must be clearly understood. The importance of new, high quality 3D seismic survey for final investment decision making cannot be underestimated since the reservoir characterisation through appraisal drilling alone would be impractical.

Whilst there is high confidence regarding the vertical containment qualities of the site, the key remaining



uncertainty is associated with the final extent of the lateral migration and plume development. To this end, further careful definition of the position of the storage complex boundary is required to ensure site integrity is assured. Such a boundary would be very dependent upon the quantity of CO_2 injected and the final selected injection well locations.

The main opportunities for potential cost reductions are: price reduction due to quantity of pipeline materials, commercial optimisation of pipeline size and well intervention frequency and cost.

The Forties 5 Site 1 has considerable further upside potential both within the site itself, within the Forties 5 aquifer beyond Site 1 and in deeper sandstone aquifers such as the Maureen and Mey formations.

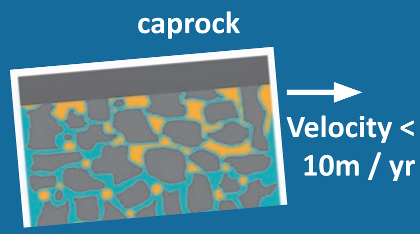
Whilst this proposed development would not be operational until 2030, precise timing will be important to ensure potential interactions with oil and gas developments are optimised.

It is anticipated that an expenditure of around £103m will be required ahead of any final investment decision to include a large 3D seismic survey, an appraisal well and FEED studies.

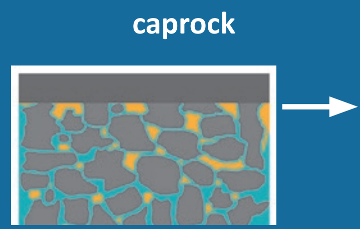
ⓘ Trapping Mechanisms

There are five mechanisms by which CO_2 can be locked into the deep geological storage strata. These are outlined below. All five can take place to different extents in different kinds to store type at different times.

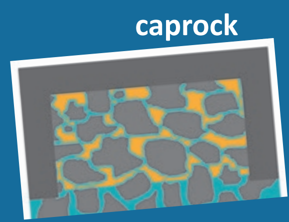
Low Velocity Trapping
Even after injection ends, CO_2 will continue to move up slope through aquifers long into the future. As it does so residual CO_2 is left behind reducing the inventory "on the move". Eventually the rate of CO_2 migration will fall to such low levels that it would take many tens of thousands of years to reach key boundaries. This CO_2 can be considered to be trapped from the perspective of greenhouse gas control.



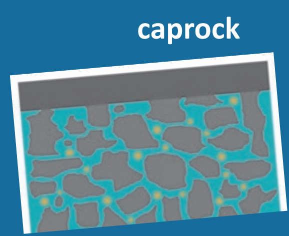
Residual Trapping
After a plume of CO_2 moves through a volume of rock it leaves a small bubble of CO_2 inside each pore space. These bubbles are stranded and cannot move any further and are left in place to slowly dissolve into the brine over time.



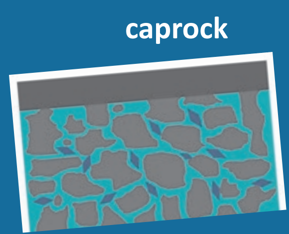
Buoyant Trapping
After Injection into the reservoir, the CO_2 plume will move upwards in aquifers under buoyancy until it reaches caprock. If a structure or trap provides lateral containment then the CO_2 will be trapped permanently and locked in place.



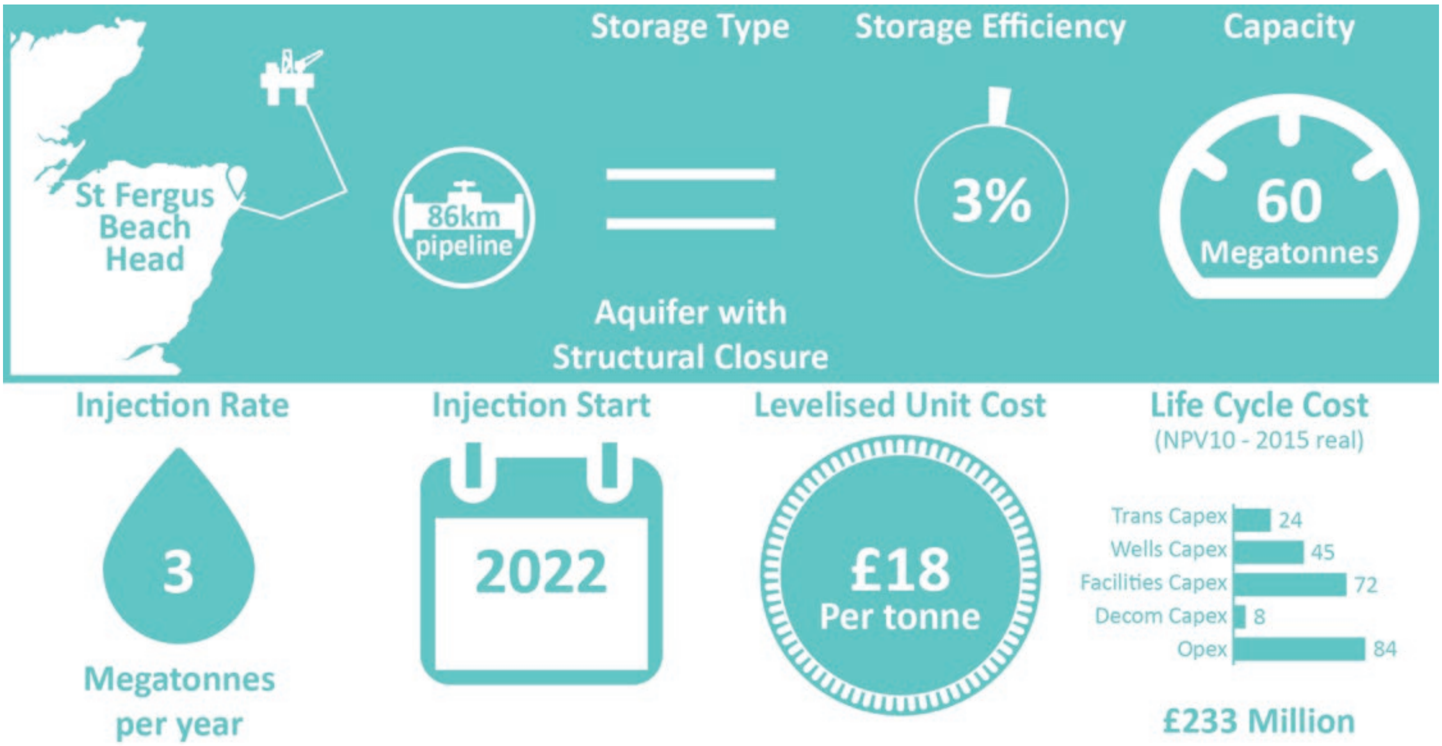
Solution Trapping
When CO_2 is dispersed through an aquifer in small bubbles, the large contact are between the CO_2 and the brine can lead to solution of the CO_2 into the brine. When it is dissolved, the CO_2 laden brine becomes heavier than normal brine and slowly sinks to the base of the reservoir over tens of thousands of years, holding it in place.



Mineral Trapping
The CO_2 dissolved into brine can react with the rock materials to precipitate new minerals and becomes part of the rock itself. This can take place over many thousands or even millions of years.



Sand grain **Brine** **CO_2** **New Mineral**

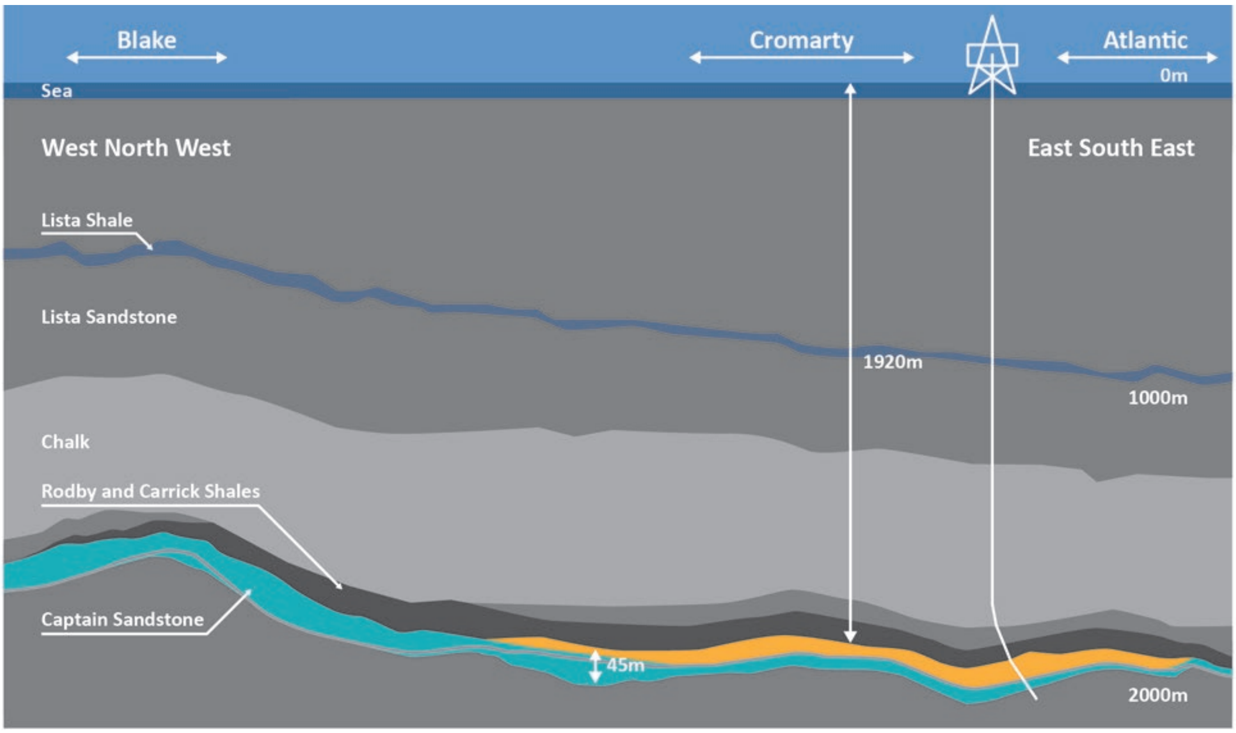


The Captain X injection site is a part of the Lower Cretaceous Captain aquifer system which extends in a WNW-ESE trending fairway for over 100km in the Central North Sea. The region includes the Goldeneye depleted gas field which has been the subject of detailed FEED work. The Captain fairway has been the subject of several CO_2 storage research projects which have suggested that the fairway could accommodate over 360 MT.

The Captain X site has been designed as a practical CO_2 storage development project and was located to co-exist with CO_2 storage at Goldeneye and existing oil and gas development projects in the area.

The Captain X site is an open saline aquifer system with some identified structural and stratigraphic traps. The site is located some 40km west of Goldeneye in UKCS quadrants 13 and 14 and stretches from the Blake oil field in the north west to the Atlantic gas field in the south east.

Although Captain X is a “Saline Aquifer”, it lies within a mature petroleum province which has moderate quality 3D



seismic coverage from the regional Megasurvey from PGS. It also benefits from a large regional well database of almost 60 wells. Specific high quality reservoir data is available from 16 wells within the site area. It is a good example of an extensively investigated saline aquifer which has the potential to be quickly brought to CO_2 storage readiness.

Site Description

At the Captain X site, the Captain Sandstone is located 1500m to 2100m (4900ft to 6900ft) below sea level. The formation was deposited in a long WNW-ESE trending fairway 5 to 10km wide in the deep water of the evolving North Sea as sands resulting from the erosion of the Scottish Highlands poured off the shallow water shelf area. Along the axis of the fairway, the reservoir can reach 150m (500ft) thick, but it thins to zero and pinches out on either flank. Reservoir quality is "excellent" with net to gross of over 75%, and average porosity of over 25%. Average permeability is 1400mD. With such high reservoir quality, CO_2 injection is expected to be straightforward, with deviated wells capable of high injection rates.

There are high quality and laterally continuous caprock strata in the Rodby and Carrack Formations overlying the Captain which have been proven as effective seals for local oil and gas fields and are expected to be similarly effective for CO_2 containment.

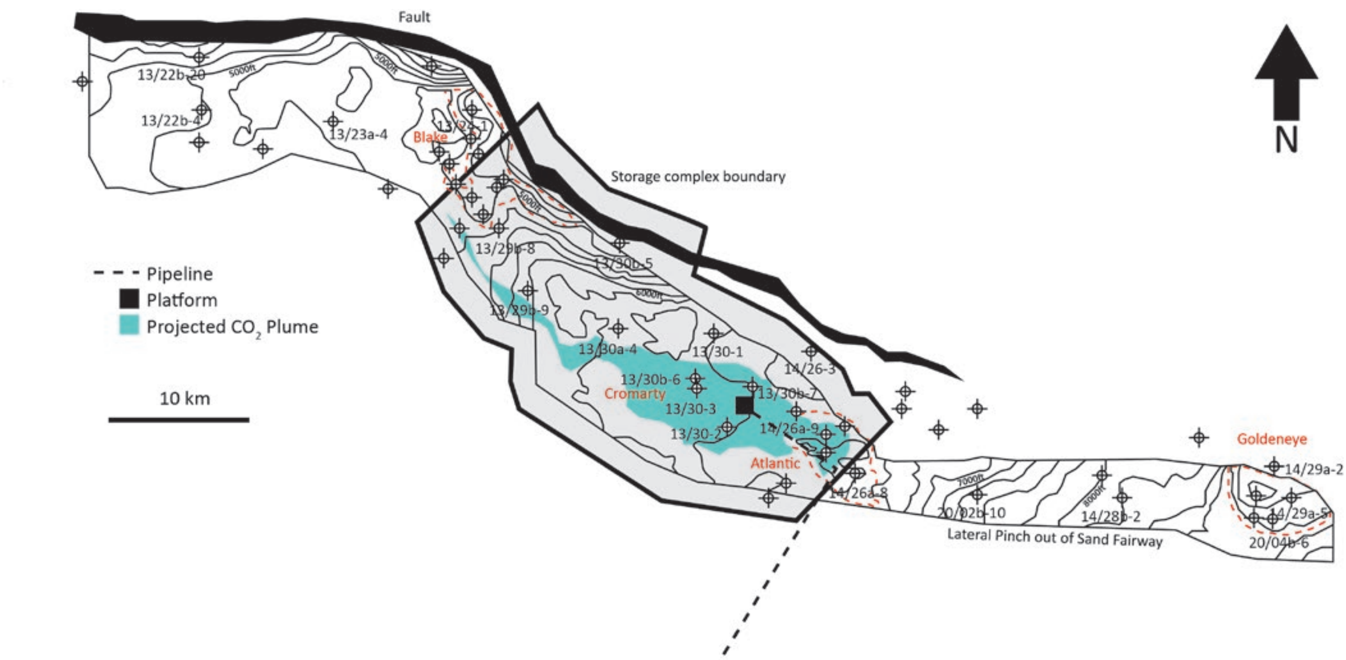
It is the very high quality reservoir and the resulting high mobility of the CO_2 plume that presents both the main opportunity and the main challenge at Captain X. That is the lateral containment of CO_2 within the Storage Complex boundary.

The structural definition of the top of the Captain Sandstone using seismic data is difficult for two main reasons:-

1. The seismic reflection at the Top Captain Sandstone is small and variable. This makes the boundary almost seismically transparent and therefore very hard to identify and map consistently with seismic data.
2. The overburden strata have rapidly varying seismic wave velocities which makes the conversion of the two way seismic travel time into real depth problematic.

Together, these factors result in considerable uncertainty regarding the Top Captain Sandstone depth map. This challenge is not new and was experienced by the petroleum operators in their work in the fairway without full resolution and also by Shell in their work on Goldeneye. This means that depth uncertainty away from existing wells is perhaps only accurate to +/- 20 to 30m (60 to 100ft). This is adequate for identifying larger structures such as gas fields, but cannot resolve smaller structural features which can have an impact upon CO_2 migration velocities.

The injection site itself has been selected to be in the deepest easternmost part of the formation to maximise the storage efficiency as the injected plume migrates updip to the west. Specifically it was located to the west of a structural feature called the Grampian Arch. Here, the Captain fairway narrows and turns to the east towards the Goldeneye field. The CO2Multistore modelling project has already demonstrated that there is an ability to inject successfully into the Captain aquifer system in multiple locations, but that injection at one site can somewhat limit the capacity of another. Locating the Captain X site west of the Grampian Arch helps to minimise any such negative interaction with Goldeneye injection with which the Captain X development was designed to co-exist.



A dynamic model of the site was developed. This was used to assess a range of development options. These were calibrated to production and pressure data from the nearby oil and gas fields. These models confirmed that the Captain Sandstone has significant potential for CO_2 injection, with some cases tested capable of injecting up to 180MT over a 40 year period. The Captain X injection site has been located between the structural closures of the depleted Atlantic and Cromarty fields. In themselves, these depleted gas fields present only a limited target capacity for buoyant trapping. At the injection site, the Captain Sandstone consists of an upper and a lower sandstone interval separated by a regionally extensive shale. The primary injection target is the upper sandstone as the lower sandstone is laterally discontinuous acting almost like a closed box, limiting the amount of CO_2 that can be injected into it.

The dynamic modelling showed that the injected CO_2 rises quickly under its buoyancy to the “roof” of the sandstone because of its high quality. It then migrates away from the injection site exploiting the highest flow pathways available quickly filling any structural closures it encounters such as the Cromarty gas field. Its migration pathway after this is very dependent upon the precise shape of the structure map, which is very uncertain for reasons already discussed. Without confidence in the pattern of plume development, the injected volume has been limited to 60MT. This enabled more confidence to be developed around the ability to retain this inventory within the proposed storage complex boundary.

A further concern has been highlighted with a legacy exploration well 13/30b-7 which was abandoned in 2007 using only a single cement plug. This well is near to the planned injection site and will require further detailed investigation and potential remediation. The cost of remediation has been included in the development budget.

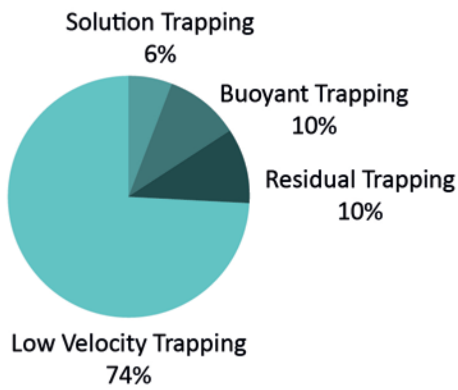
Development Plan Outline

It is proposed that the Captain X site is developed using a single unmanned platform with a six slot well bay in 115m (380ft) of water. Three wells will be drilled initially using a heavy duty jack up rig temporarily located over the platform. Two wells will be active with the third as a permanent back up in the event that it is required. The platform will be operated by satellite links and be capable of operating for up to 90 days between routine maintenance visits.

The platform will be connected to the beachhead at Peterhead using the existing, but disused 78km 16” Atlantic gas pipeline which is considered very likely capable of re-use. A new 8km section of pipe will be required to connect the seaward end of this line to the new platform. This pipeline system could be capable of delivering up to 5MT/yr. The proposed development has been configured to service a CO_2 supply of 3MT/yr over an operational life of 20 years.

If FEED were to commence in 2016, FID could follow in 2018 leading to first injection in 2022, although it is accepted that this is an ambitious schedule.

Geoscience and reservoir simulation modelling has indicated that three wells would be required. These would be deviated from the platform and be completed with 5.5” chrome steel tubing. It is anticipated that two wells will be injecting continuously with a third well retained as a back up to improve the operating robustness. Over the 20 year period, modelling work has indicated that the site could accommodate the injection of 60MT of CO_2. Throughout the project, CO_2 injection operations will be in liquid and dense phase.



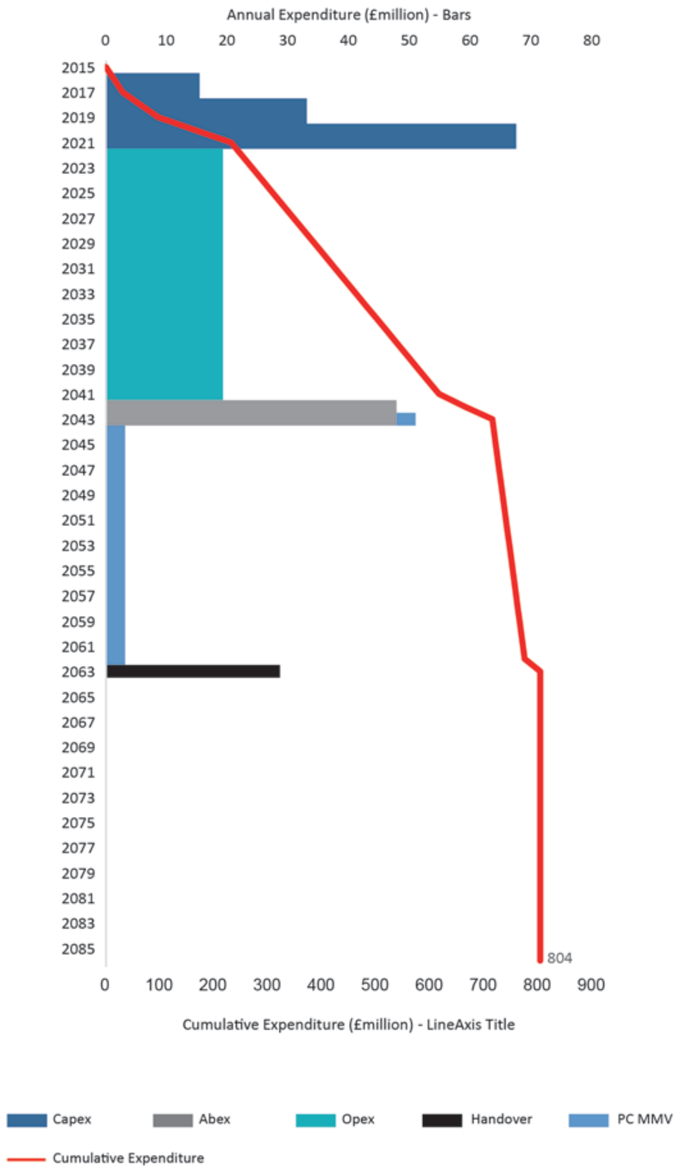
Trapping Mechanism Inventory (page 31)

Development Cost

The development of the offshore transportation and injection infrastructure is estimated to require a capital investment (including Pre-FID costs) of £232m (Real, 2015 or £140m PV10, Real, 2015). Full lifecycle costs including OPEX, decommissioning and site monitoring are estimated to be £804m (Real, 2015 or £233m PV10 - 2015). Levelised unit costs are estimated at £17.74/T.

Way Forward

Whilst there is an ability to inject significant volumes of CO_2 at the Captain X site, capacity is limited to 60MT in this proposed development. Although there is good quality 3D seismic and well data over the site, the capacity of the site is currently being limited due to low confidence in the precision of the depth mapping at the Top Captain Sandstone level. There are other 3D seismic data sets available over the area including re-processed and newly acquired speculative data which may offer routes to significantly improve confidence regarding the structure map.



Any new interpretation and dynamic model arising from improved seismic data should be calibrated with well by well production and rate information available from each of the incumbent petroleum operators to further improve confidence over model predictions of CO_2 plume development. Operators may also be able to provide more detail on abandonment records for old wells to develop improved specific assurance on well containment, especially for those wells which are likely to lie within the CO_2 plume extent.

Further detailed study of 13/30b-7 is required to develop a detailed plan for further mitigating and managing the containment risk that this well presents.

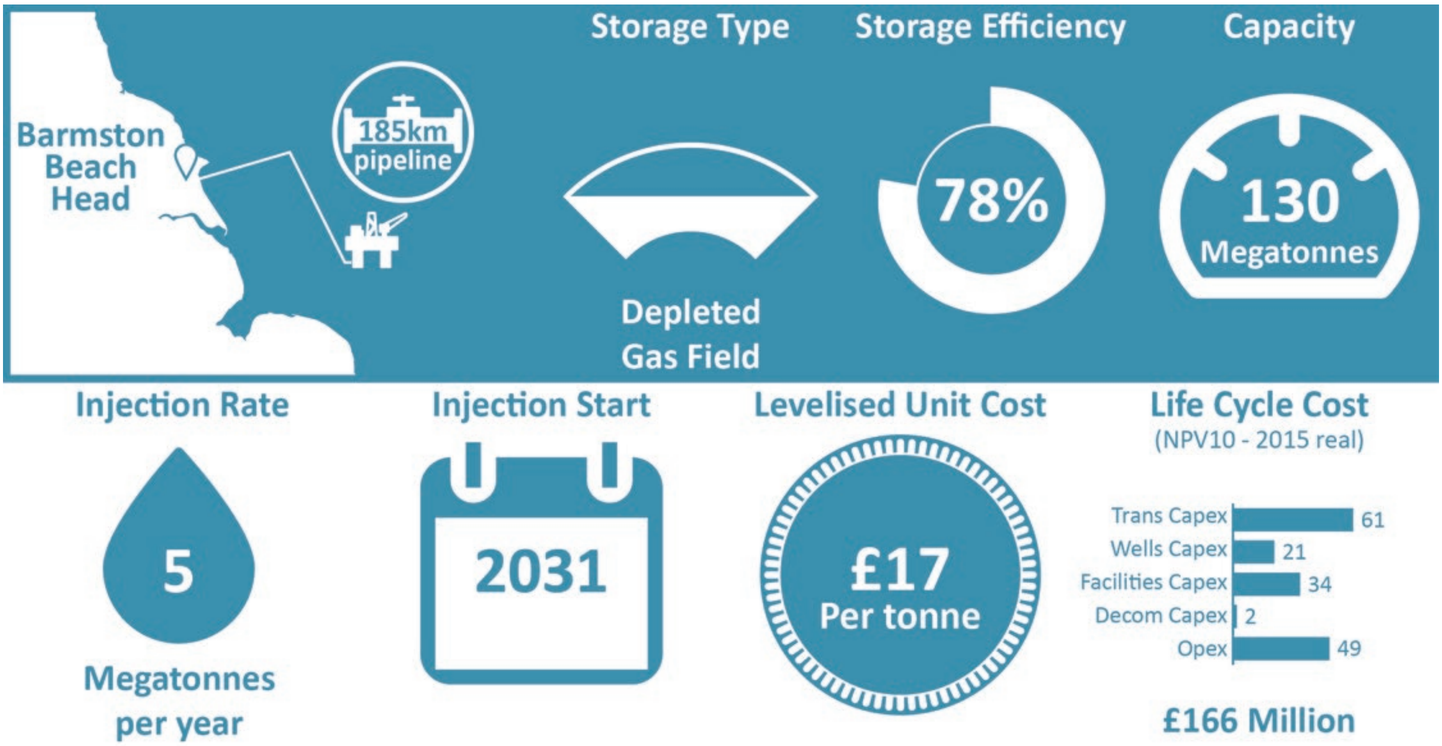
Direct detection of CO_2 plume using seismic is expected to be challenging in this environment and requires further detailed assessment.

As with all open aquifer systems, early discussions with the regulator will be particularly important to build confidence in the initial consenting and the ultimate transfer of liability at the end of field life in the context of uncertainties associated with the final CO_2 plume distribution.

Careful monitoring of oil and gas activity will be important during planning to ensure that any potential interactions with oil and gas developments are optimised.

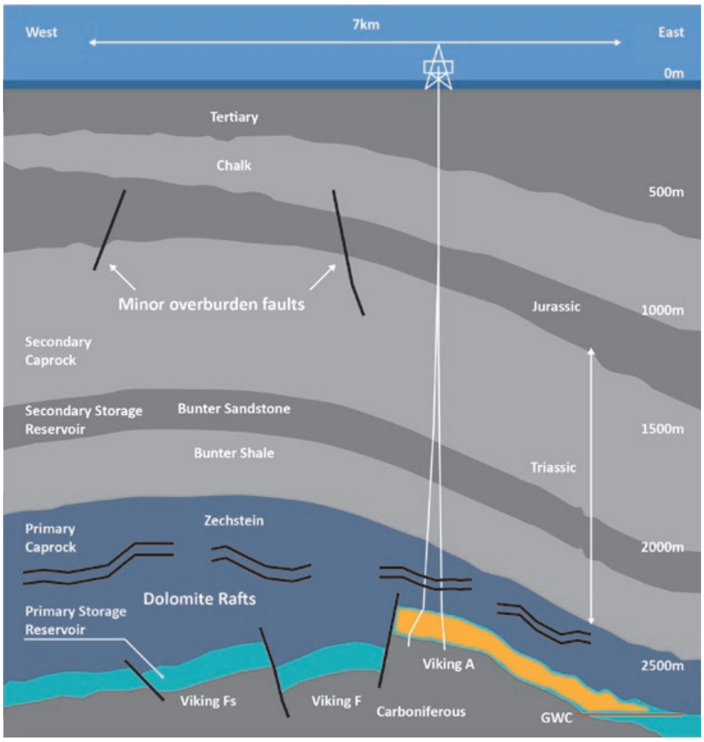
It is anticipated that around £31 million of expenditure would be required ahead of any final investment decision.

Finally, any storage developer or regulator should work quickly with the current petroleum operators to secure key pipeline assets which might otherwise be fully decommissioned such that they can no longer be re-used.



The Viking gas fields in the Southern North Sea are in blocks 49/12, 49/16 and 49/17 and comprise more than 9 individual faulted structures some 90km from the Norfolk coast. The Viking "A" site is the largest of these fault structures, with the best quality reservoir and has been selected as the initial CO_2 storage site at Viking. The fields were discovered in March 1969 by well 49/12-2 and came on-stream in October 1972.

Much like the Hamilton storage site the Viking A storage site is highly pressure depleted after the production cycle.



The structure is deep and hot enough to ensure that CO_2 remains in dense phase at reservoir conditions 2500m (8200ft) at the crest. During the early injection period however pre-injection heating of the CO_2 is required in order to manage the phase in the well bore (page 22). CO_2 injection will initially be in dense phase until the reservoir pressure recovers sufficiently to support cooler liquid phase injection without heating. Good quality 3D seismic coverage is available over the structure together with 21 wells. Of these 13 had suitable data for reservoir analysis including 4 cored wells.

Site Description

The target reservoir of the Viking A site is the Leman sandstone of Permain age. It is almost 150m (450ft) thick and was deposited in an arid continental environment dominated by wind-blown sand dunes. The reservoir is divided into five zones. Two of these are thin poor quality intervals with net to gross of 25-35%. They were deposited during periods when the water tables were higher. They separate thicker good quality dune sandstones with 65 -85% of the thickness considered to be effective reservoir.

The Leman sandstone is overlain by a thick sequence of Permian Zechstein evaporites that serve as a very effective and proven primary caprock (360m - 1200ft). This interval is dominated by halites or "rock salt" and anhydrites with some interbedded limestones and dolomites. The evaporites were deposited following the formation of the Zechstein Sea due in part to global sea level rise.

The base of the Leman sandstone is underlain by Carboniferous strata made up of shales, clays and siltstones with some coals. Any sandstones are reported as being cemented with very low porosity.

The structure was created by a series of earth movements linked with subsidence of the southern North Sea basin. The earth movements created breaks or faults in the structure which displace the rock strata. These faults often form sealed compartments between them.

There is some uncertainty regarding the abandonment status of some legacy wells which will require more detailed investigation, but as these were all gas wells, it is likely that they have been abandoned to a reasonable specification and would not present an excessive containment risk.

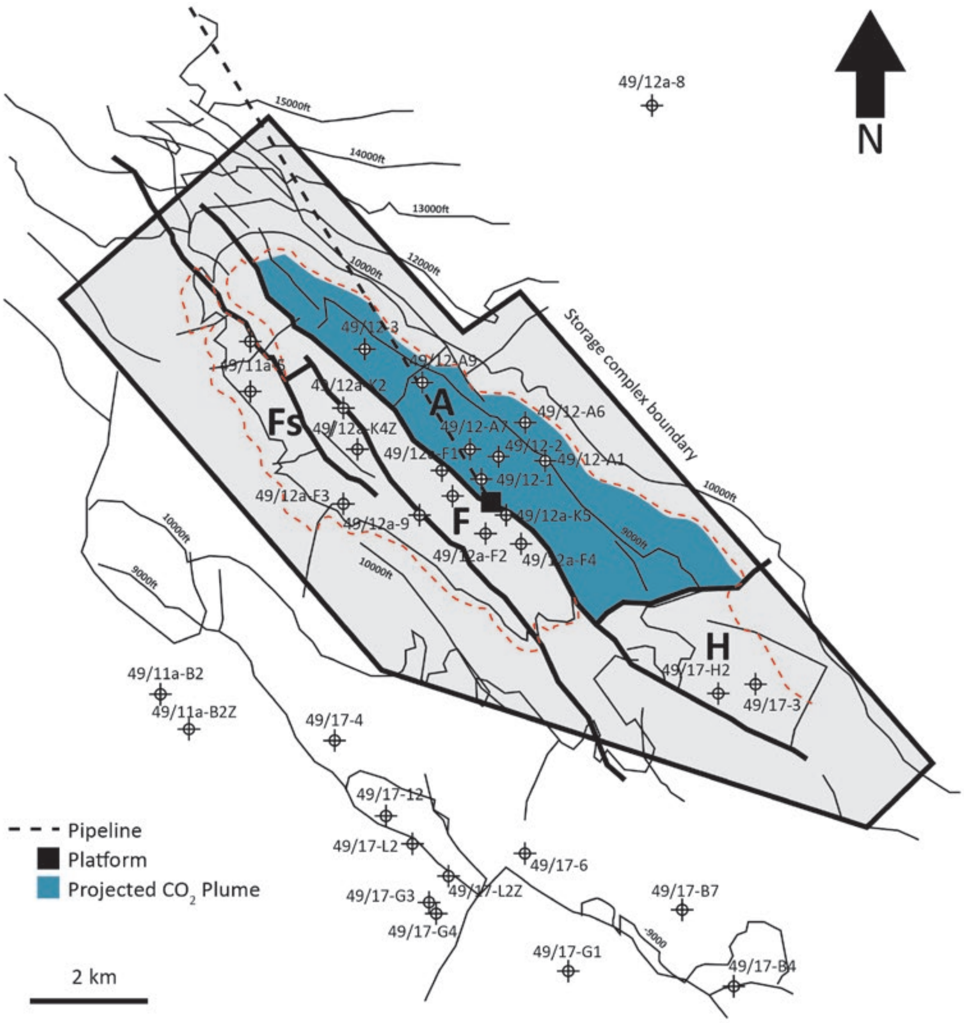
Development Plan Outline

With ten existing wells in the Viking A block itself and many others in the nearby vicinity to help characterise the subsurface, no further appraisal drilling is considered necessary ahead of an investment decision. Furthermore, no more seismic acquisition is required either, however it would be very helpful to obtain re-processed 3D seismic from the operator to improve the accuracy of positioning subsurface features such as boundary faults.

Although Viking A has already ceased production, it is proposed that this site may not be required until the early 2030s. With a final investment decision in summer 2027, first injection could be achieved at the end of 2031. The development has been designed to accommodate a CO_2 supply profile of 5 MT/yr arriving at the site from a Barmston shore terminal for a duration of 26 years. This supply is equivalent to the full emissions of an 0.7 GW coal plant or a 1.5 GW gas plant.

The offshore development will require two stages of injection in order to manage the CO_2 phase within the well. The first stage of operation will heat the CO_2 from its liquid arrival conditions to approximately 35°C such that it is in its supercritical dense state as it is injected. During injection reservoir pressure will increase such that eventually, it will be possible to inject CO_2 at the wellhead as a liquid without heating.

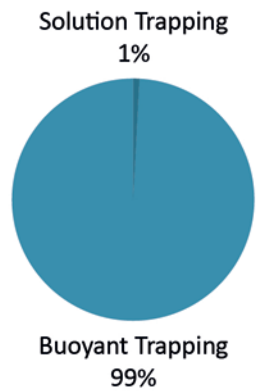
The geoscience and reservoir modelling concluded that two wells would be sufficient to inject 5MT/yr. The wells will cross the full reservoir at an angle of 60° from the vertical in order to optimise injectivity. The wells will be completed with 7” chrome steel tubing. The development anticipates that two wells will be injecting continuously with a third



well drilled and retained as a back up to support operating robustness.

The detailed reservoir modelling work indicates that the Viking A site is capable of containing 130 MT of CO_2. It is expected that the gas water contact will act as an effective floor to CO_2 migration downwards into the aquifer. The lateral limits of the site are defined to the south and the eastern end by faults, and to the north and northwest by dip closure of the interpreted gas water contact. The southern bounding fault has a large throw which offsets and isolates the Leman sandstone reservoir in Viking A from that in Viking F. Storage efficiency for the site is anticipated to be excellent at 78% and as a result upside potential within the site is limited. However, step out developments to access further upside could be considered. Potential options include; the H fault block to the south east, the F and Fs fault blocks to the south west. In addition the large Bunter closure 3 site above the Viking A site can be accessed from the Viking A location.

A single new unmanned platform is required. This will take the form of a multi-deck minimum facilities topside sitting on a 4-legged steel jacket standing in 27m (90ft) of water. A new 185km 20” steel pipeline will connect the facility to the Barmston landfall. The platform will have a 4 slot well bay and will also require 10MW of heating supplied via a 90km power cable to Bacton. The platform is designed to be operated via satellite and be unattended for up to 90 days between routine maintenance visits.



Trapping Mechanism Inventory (page 31)

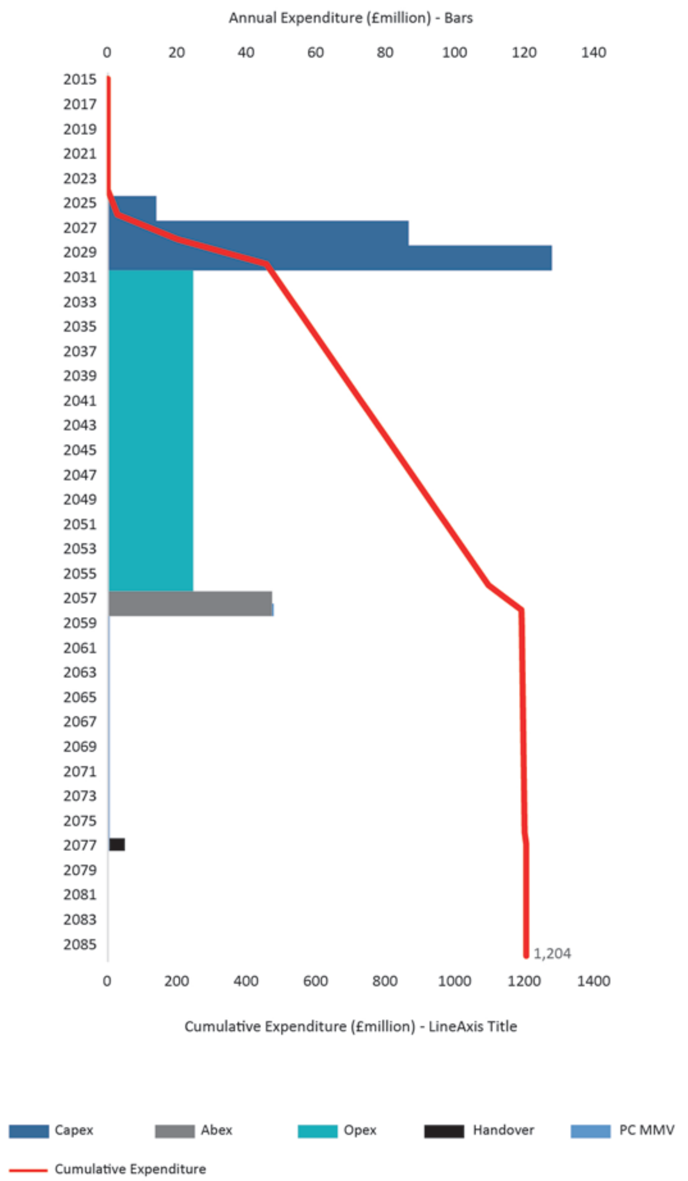
Development Cost

The development of the offshore transportation and injection infrastructure is estimated to require a capital investment (including Pre-FID costs) of £457m (Real, 2015 or £116m PV10, Real, 2015). Full lifecycle costs including OPEX, decommissioning and site monitoring are estimated to be £1204m (Real, 2015 or £166m PV10 - 2015). Levelised unit costs are estimated at £16.66/T.

Way Forward

While there is no need to acquire a new 3D seismic survey ahead of development well placement, access to the more sophisticated reprocessed data available to the current operator will improve imaging accuracy and confidence in depth conversion. This is especially true along the flanks of the storage site. Access to detailed well by well pressure and production rate records would benefit dynamic modelling and permit fine calibration of the model. This improved reservoir pressure definition will further reduce the remaining uncertainty regarding the CO_2 storage capacity. In particular improved definition or reservoir pressure will contribute to a better understanding of the aquifer pressure support to the site and confirm the degree of compartmentalisation and re-pressurisation at the start of operations. It is estimated that around £28m of expenditure will be required to reach a final investment decision.

Further work should also consider the best option available to manage the CO_2 phase in the wells during injection to seek alternative operational modes which might reduce the requirement for the electrical heating of injected CO_2 early in the injection phase.



This project has distilled a portfolio of five storage sites from an initial inventory of over 570. An important criteria for their selection was the ability to materially progress the understanding of these sites on their pathway towards being capable of supporting a final investment business case. It is important to understand that there are many other high quality storage sites that have not been considered in the final portfolio. Several additional sites are identified here as particularly important for consideration in any future UK build out of CO_2 Storage potential. These are drawn from two general groups:-

1. Storage sites which have previously been the subject of comprehensive characterisation and development FEED programmes.
2. Other key sites from the Select Inventory of this project

Of these sites, many have already been the subject of either proprietary or academic research and CO_2 Storage concept study development. The key characteristics of these sites are summarised here.

- **Goldeneye** - a depleted gas field in the Central North Sea operated by Shell and the subject of two FEED studies to support the 2011 Longannet and 2012 Peterhead CCS projects. The 2011 FEED programme for this project is fully documented in the national archive. The development is characterised by the significant re-use of existing offshore infrastructure used for the Goldeneye gas field development including the pipeline, unmanned wellhead platform and the 5 existing wells. The reservoir target was a depleted gas field in the Lower Cretaceous Captain Sandstone located within a large dome structure. The wells were configured to injected 2MT/yr for the Longannet project and 1MT/yr for the Peterhead project. Maximum theoretical storage capacity was estimated to be 37MT, although development storage capacity of 10-20MT was designed. 2011 estimated development capex was £252m. Goldeneye's primary role in any build out was as a first mover demonstrator which combines the confidence and security afforded by a depleted gas field. Whilst its capacity as a depleted gas field is limited, it is also a potential access point to the Captain aquifer fairway. It is understood that the development of the aquifer over a period of more than 15 years would significantly stretch the design life of the existing jacket and facilities. It is understood that the platform is now awaiting decommissioning, but that a future development using a new purpose designed facility and new wells could be developed cost competitively with the re-use development plan.

- **Hewett** - a depleted gas field in the Southern North Sea operated by ENI. This was the subject of a FEED study in 2011 to support the 2010 Kingsnorth CCS project. The 2011 FEED programme for this project is fully documented in the national archive. Whilst there is significant existing infrastructure on the Hewett field, it was on production for over 40 years and has already significantly exceeded its design life. The development was therefore based upon a single new platform connected to the Kingsnorth power plant by a new 270km pipeline. 2.5 MT/yr CO_2 was to be transported and injected in gas phase initially using 4 wells with capability to expand to 9.6MT/yr later with 12 wells. The reservoir target is very low pressure, heavily depleted gas field in the Triassic Bunter Sandstone located within a very large anticlinal structure. Geological containment is high quality similar to Bunter Closure 36, but Hewett contains a large number of legacy wells that would require careful integrity assessment before any development. Development capacity is estimated to be 110MT with further potential available up to 206MT and yet more in the Upper Bunter sandstone.

- **Endurance or 5/42 (Bunter Closure 35)** - An open saline aquifer within in a dome structure in the Southern North Sea. This concept was developed by National Grid Carbon originally to support the 2009 Don Valley CCS project through the European Energy Programme for Recovery project. Subsequently it was focussed upon supporting the 2012 White Rose CCS Project. Full knowledge transfer deliverables are awaited, but early analysis of an appraisal well 42/25d-3 has been published. The proposed store is in the Triassic Bunter Sandstone which would be developed using three deviated wells from a single platform connected to a beach head at Barmston on the Yorkshire coast with a single 24" pipeline. An initial injection rate for the project was proposed at 2.65 MT/yr for a 20 year period. This injected inventory of 53MT is thought to represent around 10% of the ultimate potential capacity.

- **South and North Morecambe** - These are very large depleted gas fields located in the East Irish Sea. As strategically important natural gas production assets they represent prime CO_2 storage targets once natural gas production has been completed. Cessation of commercial production is estimated to be in 2028. The reservoir for both target stores is the Triassic Ormskirk Sandstone. Both reservoirs are at around 1000m (3300ft). Any development is likely to be deployed with new infrastructure since the platforms will have exceeded their design life at the end of the gas production phase. South Morecambe has an ultimate potential capacity of around 850MT with North Morecambe providing an additional 180MT. Key development challenges are likely to include CO_2 phase management when injecting into a strongly depleted reservoir and also assurance of effective containment in legacy and gas production wells through careful abandonment programme. The Hamilton outline development plan presented in this study is a strong analogue model for both North and South Morecambe, albeit much smaller. These fields provide an obvious step out from the Hamilton CO_2 storage development in due course.

- **Bunter Closure 9** - This is a very large open saline aquifer within a dome structure. The reservoir target is again the Triassic Bunter Sandstone, but in this case the reservoir is located in the southern part of the gas basin above the giant Leman gas field which is expected to cease commercial production in 2030. The estimated ultimate potential capacity is almost 2000MT with further upside located in the deeper depleted Permian Leman gas reservoir below. A target of this size would require a phased development with at least one central platform and a series of subsea sites. A detailed assessment of Bunter Closure 9 has not been completed and reservoir quality assurance will be required. Key development challenges would include assuring effective containment in legacy gas production wells some of which date back almost 50 years. If the deeper Leman sandstone is also developed then this might add a further capacity but would probably involve some phase management complexities in any development. This development could be cost effectively reached from Medway as well as Humberside and possibly even European CO_2 sources.

- **Bunter Closure 3** - Another large open aquifer system within a dome structure from the southern gas basin. It is located almost above the Viking A site detailed previously and could be tested using a side stream of CO_2 from this project on a long term basis to further de-risk its long term performance. This site was not progressed to the last five as there are some indications of faulting at the top of the dome with faults extending to shallower than 790m (2600ft). This would require more detailed study. As with Bunter Closure 9, the deeper gas producing field creates a legacy well containment concern which would require further detailed assessment. Ultimate potential capacity is estimated to be around 230MT. A development plan could involve a stand alone platform and perhaps 5 wells, although if Viking A was under CO_2 injection then there are options for shared use of infrastructure which would reduce the development cost.

- **Forties 5 Site 3,4, and 5** - During the selection of Forties 5 Site 1 as a preferred portfolio store, several other large and attractive development locations were reviewed from the full extent of the Forties 5 aquifer which covers some 20,000km². These were all characterised as having excellent reservoir quality, but did possess some subsurface complexity that added potential capacity, but complicated lateral and vertical containment in comparison to Forties 5 Site 1. It is considered likely that each of these sites can be engineered to establish a development plan which is at least as significant as the Forties 5 Site 1. Such developments are assumed to follow a similar design, although there may be opportunities for shared infrastructure use subject to precise phasing.

Together these sites represent a build out portfolio of some 4.5 GT of mature storage capacity that can be brought to FID readiness quickly and cost effectively. Some sites require further appraisal drilling ahead of FID, and most will require new 3D seismic data before developments proceed.

Of course it is also important to recognise that potential CO_2 enhanced oil recovery operations in existing oilfields also represents additional permanent storage potential.

ⓘ Levelised Cost

The Levelised Cost of CO_2 transportation and storage is the discounted lifetime cost of ownership and use of the offshore transportation and storage assets, converted into an equivalent unit of cost of transportation and storage in £/tonne.

Step 1: Gather Data

Capital Costs	Operating Costs	Operating Data
Pre-development	Transportation	CO_2 injection rate
Design	Platform	Injection quantity
Construction	Wells	Timing
Installation	Operations MMV	
Decomissioning	Financial Securities	

Step 2: Sum the net present value of total expected costs for each year

$$\text{NPV of Total Costs} = \Sigma n \frac{\textit{Annual total capex and opex costs}}{(1 + \textit{discount rate})^n}$$

n = time period

Step 3: Sum the net present value of expected CO_2 injection for each year

$$\text{NPV of } CO_2 \text{ Injection} = \Sigma n \frac{\textit{Annual } CO_2 \textit{ injection}}{(1 + \textit{discount rate})^n}$$

n = time period

Step 4: Divide 2 by 3

$$\text{Levelised Unit Cost of CO2 Injection} = \frac{\textit{NPV of Total Costs}}{\textit{NPV of } CO_2 \textit{ Injection}}$$

The levelised cost is the ratio of the total costs of a CO_2 storage development (including the capital, operating and decommissioning costs for the offshore transportation and storage plant), to the total amount of CO_2 expected to be stored over the store's lifetime. Both are expressed in net present value terms. This means that future costs and outputs are discounted, when compared to costs and outputs today.

This is sometimes called a life cycle cost, which emphasises the "cradle to grave" aspect of the definition. The levelised cost estimates do not consider revenue streams available to store owners (e.g. from sale of storage capacity or revenues from other sources) so that the estimates reflect the cost of CO_2 transportation and storage only.

The box above provides a high level illustration of how levelised costs are calculated.

The levelised costs in this report are therefore quoted as 2015 real values with a discount factor of 10%.

The primary sources of OPEX considered are outlined below together with their estimation methodology:-

Transportation
Annual costs calculated as 0.95% of capital outlay, based on estimating norms.

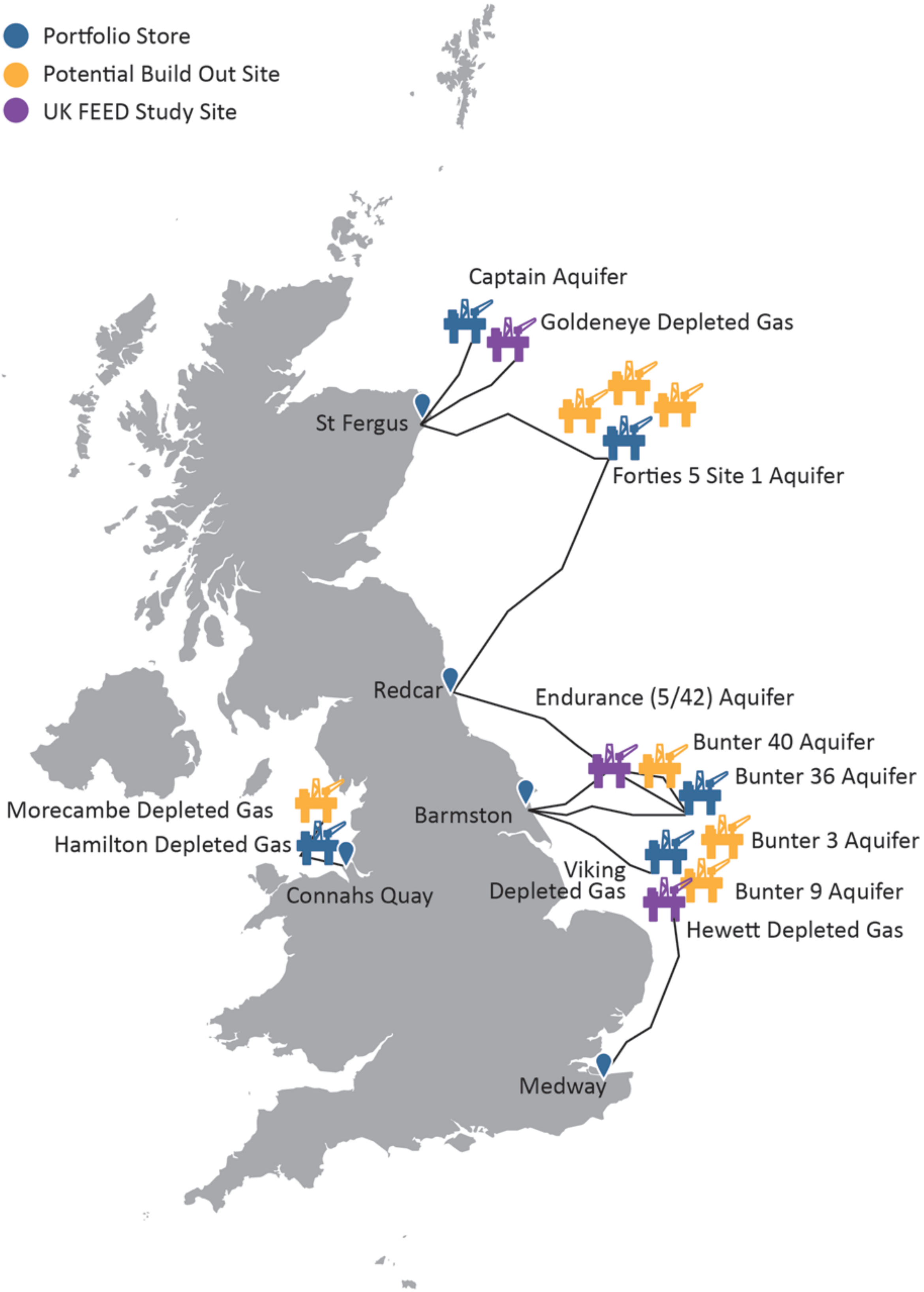
Platform
Annual costs calculated as 5.5% of capital outlay, based on estimating norms. Wellhead heating costs (where appropriate) calculated based on estimated power requirements and cost of electricity supplied to the installation.

Wells
Based on an assessment on likely well intervention requirements, frequency and cost.

Operations MMV
Primarily related to area and frequency of seismic surveys required during the operating period.

Financial Securities
Based on material published by the ROAD CCS Project. Predominantly linked to the life-time operating cost of the offshore facility and penalties for an assumed minor migration of CO2 outside the defined storage complex. Security provided by a financial instrument renewed annually.

The term "Facilities Opex" category as used in this report comprises items 2-4 above.


Portfolio Store
Potential Build Out Site
UK FEED Study Site
Captain Aquifer
Goldeneye Depleted Gas
St Fergus
Forties 5 Site 1 Aquifer
Redcar
Endurance (5/42) Aquifer
Bunter 40 Aquifer
Bunter 36 Aquifer
Morecambe Depleted Gas
Hamilton Depleted Gas
Barmston
Bunter 3 Aquifer
Viking
Depleted Gas
Connahs Quay
Bunter 9 Aquifer
Hewett Depleted Gas
Medway

UK Storage Development and Build Out

To illustrate how the storage portfolio developed in this project might support future roll out of CCS in the UK, supply profiles from the ETI Scenarios work published in 2015 were used. These described a situation in which approximately 50MT/yr of CO_2 is captured and injected from 2030. For the purposes of this study, these profiles were extrapolated to 2070 in order to evaluate the storage development plans.

The build-up of CO_2 supply around the country and the 50MT/yr plateau require multiple sites across the offshore regions. One plausible scenario is that initially the CO_2 is stored in just eight sites: the five sites evaluated as part of this study and the three sites where FEED studies have already been completed, as illustrated on page 42.

Whilst is is unclear at the moment which sites will be developed first, it is likely that the first stores to be developed are amongst those closest to the Barmston and St Fergus beach heads with their broad hinterland of emissions points. Both are represented by relatively well appraised sites with Goldeneye / Captain X in the north and Endurance in the south. The Captain Sandstone may be one of the first formations to be developed through either or both of the Goldeneye and Captain X sites. Here it is assumed that Goldeneye will be developed initially and then Captain X added soon after with reuse of existing pipelines in both cases.

By 2030, the Forties 5, Site 1 store would be needed to accommodate the CO_2 being supplied from St. Fergus. Sites in the Southern North Sea will be used to store CO_2 supplied from the three beachheads on the east coast of England: Redcar, Barmston and Medway. Endurance is probably the most mature site close to Barmston and is likely to be one of the first sites to be exploited. Other sites such as Bunter Closure 36, Hewett and Viking are required to manage the quantities of CO_2 and the sources of supply. Hamilton is the primary initial store for CO_2 emissions from the north west of England.

The scenario outlined in the following figures illustrates the growth of storage from 3MT/yr in 2022 to a plateau of 50MT/yr running until around 2070 by which time some 1.6GT of CO_2 will have been stored and this portfolio of stores will be full. Other stores such as the Morecambe Bay fields, Sites 3,4 and 5 in the Forties 5 aquifer and other structures in the Bunter aquifer could provide the necessary geographic spread and capacity to continue injecting at this level for some time into the future.

Economics

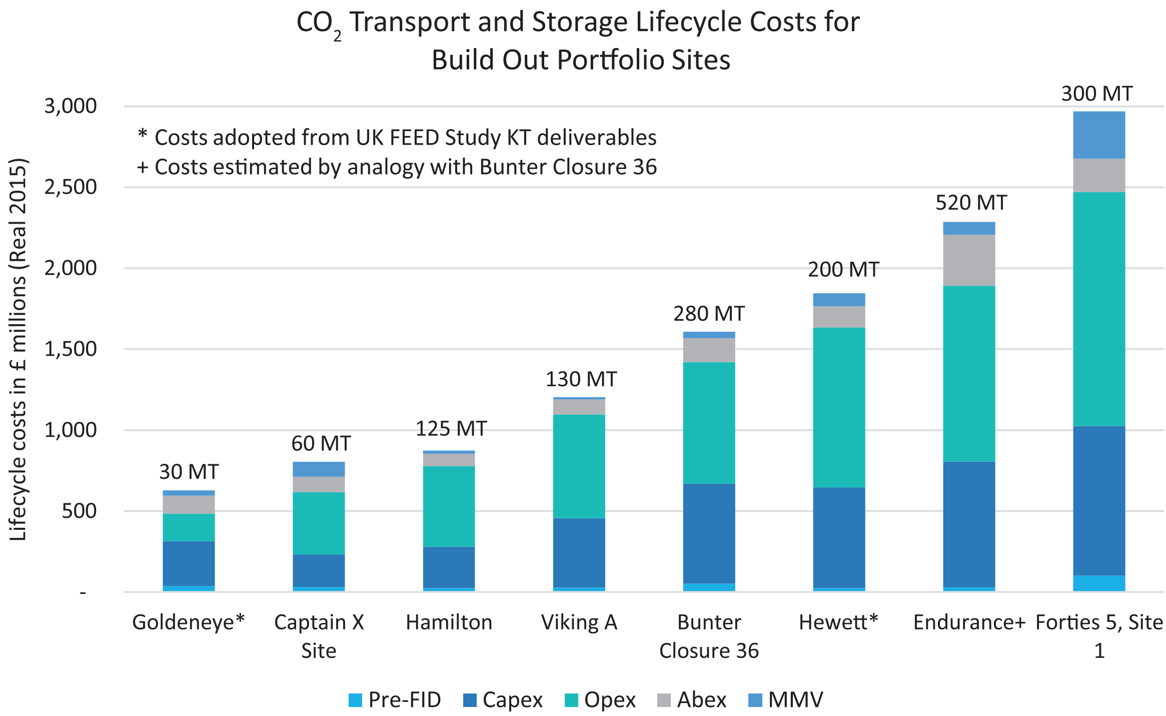
The cost estimates for the five storage sites evaluated during this project were prepared on a consistent basis and derived from their bespoke development plans. These detailed plans were not available for the other three sites and consequently an alternative approach was required. Development of the Hewett depleted gas field and Endurance aquifer sites for CO_2 storage are assumed to be analogous to those for the Hamilton and Bunter Closure 36 sites. Outline development schemes accounting for the key differences to the respective analogues (capacity, depth, location and injection rate) were prepared and the costs estimated in the same way as for the five project sites. Estimating the costs for CO_2 storage at Goldeneye required a different approach because the development would require modification and enhancement of existing infrastructure rather than a wholly new development. Information published from the 2011 Goldeneye FEED study was used to estimate the cost of developing the store.

The cost estimates for each site were prepared so that they could be readily translated into a levelised cost metric. The estimates include the appraisal, capital investment, operating, decommissioning, post closure monitoring and handover costs for the offshore transportation and storage plant but exclude the cost of capital and any profit for the store developer.

The costs presented here and on page 45 represent comparable lifecycle costs for CO_2 transportation and storage developments at the different sites. This set of comparable cost estimates is believed to be one of the first developed for a potential storage site portfolio of this maturity and will serve as useful analogue guidance to lifecycle costs for other sites.

The development of the full portfolio of eight sites (1645MT) would require a total capital investment of £4.4 billion (Real, 2015), operating expenditure of £6.0 billion (Real, 2015) and £1.8 billion (Real, 2015) for the decommissioning and post closure monitoring activities. Total life-cycle costs are £2.1 billion (NPV10, Real, 2015). The levelised cost of ownership for each CO_2 transportation and storage asset ranges from £9/T to £32/T for the different stores and is dependent on the development timing, injection profile as well as the cost. The levelised full life cycle unit cost for offshore transport and storage across the whole portfolio is £14.45/T which would contribute around £7/MWh to the levelised cost of power from a gas fired plant fitted with CCS.

The lifecycle unit cost of CO_2 transport and storage developments is complex and dependent upon many factors. The influence of some factors such as the length of the pipeline or the number and depth of wells required are both obvious and clear. Factors such as the volume of CO_2 stored in any project are equally important but often less obvious. Whilst storage efficiency (page 17) is less well understood than other factors, it is a fundamental



influence on overall lifecycle costs. Storage efficiency is high in pressure depleted gas fields which means that a large mass of CO_2 can be stored safely in a relatively small area. This means fewer platforms and wells and lower monitoring costs.

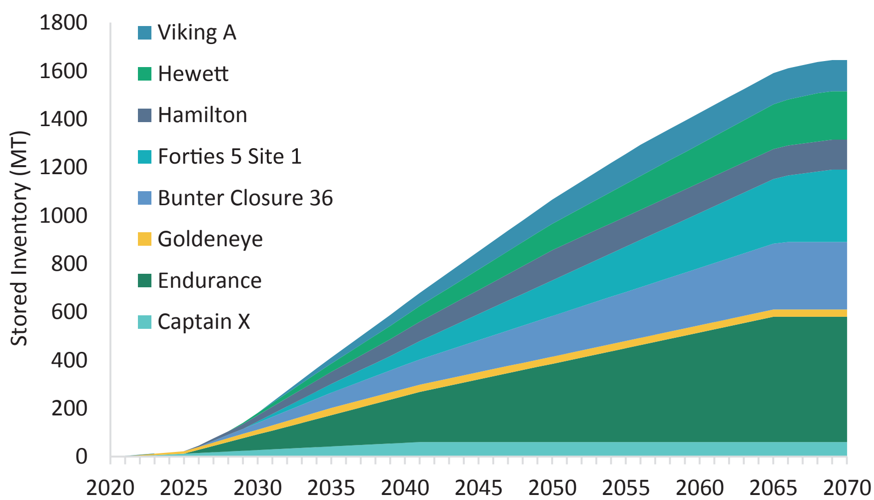
Pressure depleted gas fields may however require heating of the CO_2 before injection early in the projects (page 22) which can increase the operating costs. The levelised cost burden from this heating has about same effect as adding an extra 25 - 75km to the pipeline length for a 5MT/yr project. It is therefore another important factor. Aquifers within structures have lower storage efficiencies, meaning developments require more space and more wells. Finally open aquifer systems have very low storage efficiencies and require large development areas with multiple drill centres, many more wells and more expensive monitoring.

Finally, whilst all these sites presented here have been significantly matured as potential CO_2 storage sites and have comparable cost estimates, each site has its own specific risk profile. In detail, the cost of mitigating these site specific risks will depend upon the experience, cost of capital and risk appetite of the developer and its financiers together with the approach of the regulator. Due to the evolving nature of the sector, it is likely that these risk based costs have not yet been fully quantified within cost estimates.

Key Infrastructure

The primary opportunity for significant cost saving in the development of multiple CO_2 stores is in the sharing of key offshore infrastructure, primarily pipelines. However, the contribution this can make to overall cost reduction will depend upon the concentration and build out rate of CO_2 capture points.

Typically the useful life of offshore infrastructure assets is designed to be approximately 40 years and exceed the anticipated project requirements by some margin. The longevity of a storage development is likely to be similar to the useful life of its infrastructure. Consequently conventionally designed pipelines etc. will have no residual value and may not be suitable for reuse by later projects. To maximise the opportunity for several stores to use common infrastructure either sequentially or concurrently it may be desirable to invest in infrastructure that has a design life sufficient for two or more storage projects and enough capacity for both projects.



		Data and cost estimates for sites in this study					*Comparable estimates from earlier FEED study sites*			
		Viking A	Captain X	Forties 5, Site 1	Bunter CL36	Hamilton	*Goldeneye*	*Hewett*	*Endurance*	Total
Cost Components (£m 2015 Real)	Pre-FID	28	31	103	52	24	*38*	*24*	*30*	330
	CAPEX	429	201	922	617	257	*277*	*623*	*777*	4103
	OPEX	639	385	1446	751	497	*110*	*988*	*1085*	5961
	ABEX	94	96	205	148	77	*110*	*130*	*315*	1175
	MMV	14	92	293	40	19	*33*	*81*	*78*	650
	Total	1204	804	2968	1609	874	*629*	*1846*	*2285*	12219
Site Data	Start date	2031	2022	2030	2027	2026	*2021*	*2029*	*2026*	
	Store Type	Depleted gas field	Open Saline Aquifer	Open Saline Aquifer	Saline Aquifer Structure	Depleted gas field	*Depleted gas field*	*Depleted gas field*	*Saline Aquifer Structure*	
	Injection Rate (MT/yr)	5	3	6 then 8	7	5	*3*	*5*	*13*	47
	Capacity (MT)	130	60	300	280	125	*30*	*200*	*520*	1645
	Pipeline length (km)	185	86	217	160	26	*100*	*250*	*110*	1134
	Storage Efficiency %	78%	3%	6%	19%	70%	-	-	-	
	Water Depth (m)	27	116	85	73	24	*122*	*37*	*59*	
	Reservoir Depth (m)	2500	1890	2670	1220	730	*2510*	*1300*	*1100*	
Life Cycle Cost (£m NPV10 2015 Real)	Trans Capex	61	24	117	98	30	*50*	*121*	*76*	577
	Wells Capex	21	45	66	72	28	*59*	*31*	*176*	497
	Facilities Capex	34	72	33	40	44	*106*	*31*	*58*	417
	Decom Capex	2	8	1	1	2	*14*	*1*	*2*	32
	Opex	49	84	2	59	69	*49*	*64*	*93*	539
	Life cycle cost	166	233	288	269	174	*278*	*248*	*405*	2061
	Levelised Unit Cost (£/T)	16.66	17.74	18.27	12.33	10.94	*32.32*	*19.24*	*9.09*	14.45
	% offshore transport	28%	7%	24%	26%	11%	*16%*	*35%*	*14%*	20%
	% offshore storage	72%	93%	76%	74%	89%	*84%*	*65%*	*86%*	80%
	Contribution to Gas £/MWh	7.93	8.44	8.69	5.87	5.20	*15.37*	*9.15*	*4.33*	6.88

Note:-

- Cost estimates developed for Bunter Closure 36, Hamilton, Captain X, Forties 5 Site 1 and Viking A have been compiled on a consistent basis using the analysis in this project. Cost estimates for the Goldeneye, Hewett and Endurance sites have not been developed in the same way, but are believed to be comparable on a like for like basis (page 43).
- The costs outlined here are for offshore transport and storage only and exclude the costs of CO_2 capture, onshore transportation and compression

This project and the results it has delivered have confirmed that there are no major technical hurdles to moving industrial scale CO_2 storage forward in the UK. The UK is endowed with offshore geology that presents a superlative national CO_2 storage proposition. The UK offshore could form the basis of a storage resource that could service the needs of many parts of Europe in addition to the UK. Careful site selection will enable storage developments to proceed quickly in a cost effective manner with a limited impact upon electricity costs.

Learnings from this project identify that two linked, but parallel future work streams are require:-

1. **Commercial & Regulatory** – Create the environment to re-engage industry, build the business case for CCS and CO_2 storage in the UK and bring forward CO_2 storage developers from the marketplace. Momentum should be maintained on further development of the UK storage resource towards FID.

   Well by well production rates and pressure data from hydrocarbon production projects should be included routinely the national data archive. These data are essential in the calibration of dynamic models which improves confidence in forecasting plume movement.

   Detailed well abandonment records should also be routinely included in the national data archive.

   Part of the Oil and Gas Authority's responsibility is to consider potential reuse of infrastructure before decommissioning. This project has highlighted some key aspects of this in relation to CO_2 storage. Consideration should be given the upgrading of well abandonment standards to minimise the potential for "site sterilisation" through unacceptable legacy well containment risk. This should be irrespective of whether the well has encountered hydrocarbon shows or not.

   Early dialogue with regulators around the permitting and consenting of open aquifer stores such as Captain X and Forties 5 Site 1 should be developed to "road test" the regulatory issues that arise from their containment attributes. This should include consideration of the ultimate transfer of liability at the end of the post injection phase.

   Particular care should be taken in the abandonment of depleted gas fields which are expected to serve again as a strategic national storage resource. The abandonment programmes should leave the subsurface asset re-use ready and preserve any usable pipeline infrastructure.

   It is recommended that each depleted gas field should be subjected to an independent assessment of CO_2 storage potential ahead of any consent to decommission to ensure that nationally important assets are not compromised for short term operational efficiency.

2. **Research and Development** – this work has demonstrated that there is ample cost-effective storage available to meet UK needs using current technology. However, it also illustrates the opportunities to maximise use of UK pore space and reduce costs further. Ongoing R&D should focus on and deliver practical measures which will deliver within the next 5 to 10 years in the areas of:-

   Operational efficiency – reducing the ongoing cost of CO_2 storage operations.

   - Many highly depleted gas fields may require heating of the CO_2 early in their injection cycle to manage the phase of CO_2 in the wells. Further work is required to find alternative solutions to the phase management challenges of highly depleted gas fields Further work is also required to improve the understanding of how caprock strength recovers during re-pressurisation. This may come from detailed study of seasonal natural gas storage sites.

   Storage Efficiency – optimising the amount of safely stored CO_2 that can be held for each square kilometre of any storage site.

   - Low dip open saline aquifer systems have low storage efficiencies. Improved cost effectiveness may be achieved through improving these efficiencies through consideration of CO_2 plume steering. Selective water - alternating CO_2 (WAC) injection should also be considered in Open Saline aquifers to optimise storage efficiency and should be investigated further.
   - Bunter aquifer closures would benefit from regional evaluation of salinity changes, halite diagenesis, aquifer behaviour and pressure evolution due to production at nearby gas fields. Furthermore, the hydrocarbon filling histories of nearby gas fields may also resolve questions regarding the evolution of the formation water salinity and the risk of halite as a potential reservoir quality limiting cement.

Industry and public confidence – further develop stakeholder confidence in the technologies used to plan, operate and monitor safe CO_2 storage sites

- A formalised CO_2 Storage Resource Classification is required to establish a common language regarding the maturity of CO_2 storage resources between developers and other stakeholders.

Together these activities will contribute strongly to delivering the best chance of early mobilisation and delivery of CCS and offshore CO_2 storage in the UK.

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