Project: ACT Acorn Feasibility Study

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Document Summary

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The ACT Acorn consortium is led by Pale Blue Dot Energy and includes Bellona Foundation, Heriot-Watt University, Radboud University, Scottish Carbon Capture and Storage (SCCS), University of Aberdeen, University of Edinburgh and University of Liverpool.
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1.0 Executive Summary

The East Mey CO_{2} storage site and corresponding development plan offers a second low-cost, flexible and scalable storage solution for the Acorn CCS Project.

The main objective of this East Mey CO_{2} Storage Site storage development plan (SDP) was to summarize the site characterisation of the Mey Sandstone in the Central North Sea and develop an understanding of its suitability as a CO_{2} storage solution for the Acorn CCS Project.

The East Mey site was selected from one of 113 identified sites as one of the best candidates to deliver the CO_{2} storage requirements of the Acorn CCS project.

The work undertaken for the ACT Acorn research study has found that the East Mey storage site offers:

- **Significant Storage Resource** and injectivity potential due to high quality reservoir properties.
- **Secure Storage.** East Mey has a demonstrated working caprock, which is the primary caprock for several large hydrocarbon fields in the Central North Sea. As a mature oil producing reservoir, current well abandonment standards are designed to eliminate the escape of oil and gas from the Mey. This is helpful in retaining high CO_{2} integrity.
- **Access to Data.** Since hydrocarbon fields exist within the Mey formation, there is both plentiful high quality reservoir data and good access to it. This includes reservoir and caprock core and dynamic data such as reservoir pressure variation during production.
- **De-risked Aquifer Development.** The development site location can be focussed upon a location close to a depleted oilfield. This provides additional structural trapping security and containment for

Phase 1 development consists of 200kT/yr injected via one dual completion subsea well, starting in 2023 and is readily scalable to more than 5MT/yr with additional wells.

The base case for transportation is via 181km of the existing redundant 240km 30” Miller Gas System (MGS) pipeline from St Fergus plus and additional new 27km pipeline.

An ambitious programme can achieve Final Investment Decision in 2020 and first injection in 2023.

A capital investment of £372 million is estimated for the scalable offshore transport and storage (including £150m for a new umbilical and almost £100m of contingency)
buoyancy injected CO₂ as well as residual tapping in the body of the underlying aquifer.

The proposed storage complex for the East Mey storage site covers an area of 1,124km², in the Central Graben of the North Sea, extending from west of the MacCulloch field, to east of the Balmoral field in the Central North Sea and to the south of the Fladen Ground Spur, approximately 180km from St Fergus. This is illustrated in Figure 1-1 (adapted from Fig 14.9b in Ahmadi et al (2003)).

Figure 1-1: Location Map of the East Mey CO₂ storage complex
Figure 1-2: Depth Map of the Top Mey

The Mey Sandstone Member belongs to the Lista Formation, Montrose Group, of Selandian to Thanetian age (Paleocene) and typically consists of stacked units of fine-to medium-grained or locally coarse-grained marine sandstone with common mudstone and some chalk clasts in its lower intervals. The sand bodies were deposited as high-density gravity or debris flow deposits, with the whole section 450m thick on average, and present in the entire storage polygon.

The high quality Mey Sandstone porosities range from 17-33% with permeabilities from 16mD to 10D.

Secure vertical containment is provided by the already extensive Lista Shales which are a proven seal for multiple Paleocene hydrocarbon fields in the Central North Sea, including the Balmoral, MacCulloch, Brenda and Donan fields, which are near the injection site. The caprock is about 75m thick across the storage site and the shale-dominated overburden covers the reservoir entirely. Minor faults within the upper section of the primary caprock are found dispersed across the entire East Mey area, but the fault density is highest in the north, many kilometres away from the injection site.

The subsurface geology of the East Mey area has been studied using a 3D seismic (PGS, 2015) and well-log data (UK Oil and Gas Authority, 2018). Three horizons were interpreted: Top Balder, Top Mey, Figure 1-2, and Top Ekofisk. The Top Mey Sandstone was challenging to interpret due to the lack of impedance contrast with the overlying shale.

A static model was built for the East Mey site, covering an area of 1,067km², using the zonation in the well correlation. No faults were included in the static modelling as only minor faulting was identified in the seismic interpretation. The model includes 90 layers, proportional to the zonation of the Mey Sandstone, and a total of 66,717,450 grid cells.

The dynamic model was built as a compositional simulation model with three components (pure CO₂ component, light hydrocarbon component and heavy hydrocarbon component) to ensure manageable run times. The model was calibrated against reported pressure and temperatures from hydrocarbon fields within the storage complex. The dynamic modelling results identified no major challenges for injection into the Mey Sandstone. An important assumption made in this study was that the intra reservoir shale layers are perfectly impermeable, but not fully continuous. Shale layers have an important effect on limiting free vertical buoyancy driven CO₂ migration and could act as effective local traps storing part of the CO₂ and increasing storage efficiency. Uncertainty analysis shows that increasing the shale layer permeability reduces storage capacity.
underneath the shale layers and allows easier vertical migration of CO₂ towards the roof of the reservoir underneath the caprock.

The basis for the development plan for Phase 1 is an assumed CO₂ supply of 200kT/yr to be provided from the shore terminal at St. Fergus commencing in 2023. CO₂ will be transported offshore in dense-phase through 181km of the existing 240km 30” MGS pipeline from St. Fergus, plus an additional 27km flowline to an injection site. Phase 1 injection will be via a single subsea injection well with a dual completion which can provide injection rates from 0.1kT/yr to 2MT/yr, making it suitable for use during low rate commissioning and for higher rates during later phases of the project without further well intervention. Future potential build out scenarios were also modelled, with rates up to 5MT/yr using additional wells and a storage resource of 152MT safely contained within the East Mey CO₂ storage site storage complex for 1000 years after injection ceases. The 152 MT represents a CO₂ supply scenario of 5 MT/yr as part of “Phase 3”, however up to 500 MT of CO₂ has been modelled to be safely contained within the East Mey storage site.

There are two CO₂ storage site options for the Acorn CCS Project. At present the East Mey Site is second behind the primary storage site in the Captain Sandstone near to the Atlantic gas field. As shown in Figure 1-3, the development schedule has 5 main phases of activity after this ACT study. Concept, Front End Engineering and Design (FEED), appraisal and contracting activities will commence just over 2 years prior to the final investment decision (FID) in 2020. The capital intensive activities of procurement and construction follow FID (Final Investment Decision) and take place over a 2.5 year period. First injection is forecasted to take place in late 2023.

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<th>2020</th>
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*Figure 1-3: Acorn CCS Project Schedule*

In a scenario where the East Mey site leads the development, the Phase 1 offshore transportation and injection infrastructure is estimated to require a capital investment of £372 million. When including the onshore plant this increases to £472 million. The capital costs are summarised in Table 1-1.
### Table 1-1: Capital Expenditure

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<th>Contingency (£M)</th>
<th>Gross Cost (£M)</th>
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<td>117.5</td>
<td>471.5</td>
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</table>

Note: FEED – Front End Engineering and Design; MMV – monitoring, measurement and verification, FID – Final Investment Decision.
2.0 Introduction to ACT Acorn

2.1 ACT Acorn Overview

ACT Acorn, project 271500, has received funding from BEIS (UK), RCN (NO) and RVO (NL), and is co-funded by the European Commission under the ERA-Net instrument of the Horizon 2020 programme. ACT grant number 691712. ACT Acorn is a collaborative project between seven organisations across Europe led by Pale Blue Dot Energy in the UK, as shown in Figure 2-1.

Figure 2-1: ACT Acorn consortium partners

The research and innovation study addresses all thematic areas of the ACT Call including ‘Chain Integration’. The project includes a mix of both technical and non-technical innovation activities as well as leading edge scientific research. Together these enable the development of the technical specification for an ultra-low-cost, integrated CCS hub that can be scaled up at marginal cost. It will move the Acorn development opportunity from proof-of-concept (TRL3) to the pre-FEED stage (TRL5/6) including iterative engagement with relevant investors in the private and public sectors.

Specific objectives of the project are to:

1. Produce a costed technical development plan for a full chain CCS hub that will capture CO₂ emissions from the St Fergus Gas Terminal in north east Scotland and store the CO₂ at an offshore storage site under the North Sea
2. Identify technical options to increase the storage efficiency of the selected storage site based on scientific evidence from geomechanical experiments and dynamic CO₂ flow modelling and through this drive scientific advancement and innovation in these areas.
3. Explore build-out options including interconnections to the nearby Peterhead Port, other large sources of CO₂ emissions in the UK region and CO₂ utilisation plants
4. Identify other potential locations for CCS hubs around the North Sea regions and develop policy recommendations to protect relevant
infrastructure from premature decommissioning and for the future ownership of potential CO₂ stores.

5. Engage with CCS and low carbon economy stakeholders in Europe and worldwide to disseminate the lessons from the project and encourage deployment of key learnings.

CCS is an emerging industry. Maturity improvements are required in the application of technology, the commercial structure of projects, the scope of each development and the policy framework.

The key areas of innovation in which the project will seek insights are summarised in Figure 2-2.

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<th>Policy recommendations</th>
<th>Societal impact</th>
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<td>Just transition to regional decarbonisation</td>
<td>Perceptions and acceptance</td>
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<td>Geomechanics and rock strength</td>
<td>Decommissioning hydrocarbon infrastructure</td>
<td>Replication around the World</td>
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<tr>
<td>Site selection &amp; evaluation</td>
<td>Infrastructure re-use for CO₂ activity</td>
<td>Life-cycle analysis</td>
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**Figure 2-2: Key areas of innovation**

The project activity has been organised into 6 work packages as illustrated in Figure 2-3. Specific areas being addressed include; regional CO₂ emissions; St Fergus capture plant concept; CO₂ storage site assessments and development plans; reservoir CO₂ flow modelling, geomechanics; CCS policy development; infrastructure re-use; lifecycle analysis; environmental impact; economic modelling; FEED and development plans; and build out growth assessment.

The project will be delivered over a 19-month period, concluding on the 28th February 2019. During that time, it will create and publish 21 items known as **Deliverables**. Collectively these will provide a platform for industry, local partnerships and government to move the project forward in subsequent phases. It will be driven by business case logic and inform the development of UK and European policy around infrastructure preservation. The deliverables are listed in Table 2-1.
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<td>D17 Feeder 10 Business Case</td>
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<td>2) Site Screening &amp; Selection</td>
<td>D03 Basis of Design for St Fergus Facilities</td>
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<td>4) Full Chain Business Case</td>
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<td>D20 Publishable Final Summary Report</td>
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Table 2-1: ACT Acorn Milestones and Deliverables
The Consortium includes a mix of industrial, scientific and CCS policy experts in keeping with the multidisciplinary nature of the project. The project is led by Pale Blue Dot Energy along with University of Aberdeen, University of Edinburgh, University of Liverpool, Heriot Watt University, Scottish Carbon Capture & Storage (SCCS), Radboud University and The Bellona Foundation. Pale Blue Dot Energy affiliate CO₂DeepStore are providing certain input material.

### 2.2 Acorn Development Concept

Many CCS projects have been burdened with achieving “economies of scale” immediately to be deemed cost effective. This inevitably increases the initial cost hurdle to achieve a lower lifecycle unit cost (be that £/MWh or £/T) which raises the bar from the perspectives of initial capital requirement and overall project risk.

The Acorn development concept uses a Minimum Viable Development (MVD) approach. This takes the view of designing a full-chain CCS development of industrial scale (which minimises or eliminates the scale up risk) but at the lowest capital cost possible, accepting that the unit cost for the initial project may be high for the first small tranche of sequestered emissions.

Acorn will use the unique combination of legacy circumstances in North East Scotland to engineer a scalable full-chain carbon capture, transport and offshore storage project to initiate CCS in the UK. The project is illustrated in Figure 2-4 and seeks to re-purpose an existing gas sweetening plant (or build a new capture facility if required) with existing offshore pipeline infrastructure connected to a well understood offshore basin, rich in storage opportunities. All the components are in place to create an industrial CCS development in North East Scotland, leading to offshore CO₂ storage by the early 2020s.

*Figure 2-4: A scalable full-chain industrial CCS project*
A successful project will provide the platform and improve confidence for further low-cost growth and incremental development. This will accelerate CCS deployment on a commercial basis and will provide a cost effective practical stepping stone from which to grow a regional cluster and an international CO₂ hub.

The seed infrastructure can be developed by adding further CO₂ capture points such as from hydrogen manufacture for transport and heat, future CO₂ shipping through Peterhead Port to and from Europe and connection to UK national onshore transport infrastructure such as the Feeder 10 pipeline which can bring additional CO₂ from emissions sites in the industrial central belt of Scotland including the proposed Caledonia Clean Energy Project, CCEP. A build out scenario for Acorn used in the 2017 Projects of Common Interest (PCI) application is included as Figure 2-5.

Pale Blue Dot Energy is exploring various ways and partners to develop the Acorn project.

*Figure 2-5: Acorn build out scenario from the 2017 PCI application*
3.0 Scope and Objectives

3.1 Purpose

The purpose of the ACT Acorn Project Deliverable D08 East Mey CO2 Storage Site Development Plan (D08) is to document a coherent storage development plan for the site which represents either an alternative or addition to the Captain Sandstone site.

3.2 Scope

The East Mey site was selected from one of 113 as part of site selection work carried out for the ACT Acorn Project (Pale Blue Dot Energy, 2018). This Storage Development Plan pulls together the in-depth work that has been undertaken on the East Mey site to confirm its suitability as a CO2 store.

The D08 scope includes:

- Learnings from other relevant projects
- Data analysis
- Seismic interpretation
- Petrophysical analysis
- Geological setting
- Geological model build
- Dynamic model build
- Injectivity and storage resource assessment
- Injectivity performance over time
- Integrity assessment, seal and cap rock description
- Proposed definitions for Storage Complex & Storage Site
- Risk register
- Uncertainty and risk analysis
- Leakage scenarios workshop
- Shallow seismic pre-feasibility assessment
- Measurement, monitoring and verification plan
- Infrastructure requirements and cost estimate
- Well design and cost estimates
- Decommissioning
- Outline development plan and budget
- Conclusions and recommendations for further work.

In parallel, geomechanics work has been carried out on the East Mey site, which is attached to this Storage Development Plan as Annex 9: East Mey Geomechanics. The geomechanics work has been referred to where appropriate throughout the text.

Any assumptions made during this scope of work have been explicitly stated throughout the text.
4.0 Site Characterisation

4.1 Geological Setting

The East Mey Storage Site was selected as part of the site selection works described in Deliverable 5 of this project (Pale Blue Dot Energy, 2018). The East Mey Storage Site area (East Mey hereafter) targets a Paleocene sandstone interval called the Mey Sandstone Member as a potential storage reservoir. It is an extensive open aquifer system that extends over the Central and Northern North Sea, covering the Outer Moray Firth, Central Graben and the Viking Graben, Figure 4-1 – adapted from Fig 14.9b in Ahmadi et al (2003), the same as Figure 1-1) and in some areas also constitutes a significant proven petroleum play.

The Mey Sandstone Member belongs to the Lista Formation, Montrose Group, of Selandian to Thanetian age (Paleocene). The Mey Sandstone member is equivalent to the Andrew, Balmoral and Glamis members that are referred to in older nomenclature (Mudge & Copestake, 1992). They typically consist of stacked units of fine-to medium-grained or locally coarse-grained sandstone with common mudstone and some chalk clasts in its lower intervals. The sand bodies were deposited as high-density gravity or debris flow deposits.

The East Mey province as defined here stretches over more than 1,124km$^2$ in an elongated NW-SE direction polygon, located some 20km away from the UK-Norway North Sea border. The Mey Sandstone Member hosts several hydrocarbon accumulations, including 10 located within the East Mey area, Figure 4-2: Balmoral, Blenheim, Bladon, Burghley, Beauly, Brenda, Nicol, MacCulloch, Donan, and 15/20b-11. Three more fields, Blair, Glamis and Stirling, are also located in the East Mey area but hosted in deeper formations, e.g. Stirling sits in the Devonian. The Mey Sandstone Member is included in the CO$_2$Stored list of potential storage formations compiled by BGS (www.CO$_2$stored.co.uk).
4.2 Site History and Database

4.2.1 Geological Summary

The East Mey storage site development area encompasses an open saline aquifer system with several associated oil fields. The top of the reservoir structure dips regionally to the south east at approximately 1.5 - 6 degrees. The limits of the East Mey area within the major Mey Sandstone Member for this study was based simply upon the distance to the Miller Gas System pipeline in its potential role as a critical piece of early enabling infrastructure. This was subsequently refined using data availability (well-log and seismic) and presence of hydrocarbon fields. The target area is therefore a hybrid design from both
technical and commercial play elements. The Mey Sandstone itself was selected because of its very suitable geological characteristics for the storage of CO₂, such as its significant capacity, excellent reservoir quality (high injectivity, clean sands) and the presence of an effective caprock, that has been successful in trapping hydrocarbon fluids trapped over large periods of time (Pale Blue Dot Energy, 2018).

The East Mey area is located to the south and west of the Fladen Ground Spur, a north-south trending elongate extension of the East Shetland Platform, composed of Devonian continental rocks which locally separates the Witch Ground Graben to the west, the South Viking Graben to the east and the Fisher Bank basin to the south (Gambaro & Currie, 2003). These rifting structures originated during Cimmerian orogeny in the Late Triassic (Tonkin & Fraser, 1991). The Late Jurassic organic-rich Kimmeridge Clay Formation is the source rock for the hydrocarbons in the Balmoral (Paleocene), Glamis (Jurassic) and Stirling (Devonian) oil fields (Tonkin & Fraser, 1991).

During the Cenozoic, the Orkney-Shetland Platform was uplifted. This generated an east-direction drainage pattern, where turbiditic currents deposited large volumes of sand and mudstone into the basin in different major submarine fans (Gambaro & Currie, 2003). The primary target reservoir formation belongs to the Mey Sandstone Member, Figure 4-4, which forms one of the Palaeogene turbiditic cycles of the Central North Sea (Mey Cycle). It forms part of the Montrose Group, which sits stratigraphically above the Cretaceous to Early Danian Chalk Group. The Montrose group is composed of the Maureen and Lista Formations (Kilhams et al. 2012). Within the Lista Formation, the Mey Sandstone Member is formed by four main Tertiary sequences (T) separated by maximum flooding surfaces, T40 within L1, T50 and T55 within L2 and T60 within L3, Figure 4-3. These T sequences represent potential periods of sand input into the basin (Kilhams, Hartley, Huuse, & Davis, 2012).
4.2.2 Hydrocarbon Exploration

Most of the North Sea Paleocene oilfields have reservoirs formed by deep-water fan systems. The Mey Sandstone Member is a sand rich and laterally extensive fan system, with widespread channelling within deep water turbidites. These channels amalgamate in some places and form large areas with uniform reservoir properties, but other channels can have relatively high lateral variation. Nevertheless, the Mey Sandstone bears excellent reservoirs with good connectivity, high porosities (17-33%) and permeabilities (16mD to 10D). There are distinct porosity changes from proximal to distal areas, as porosity is dominated by grain size. They may contain minor depth related diagenesis, but most traps had formed and were charged prior to cementation. There is documented existence of thin intra-reservoir shales that can be laterally extensive and form barriers to flow. A sensitivity case investigating shale transmissibility was run as part of the dynamic modelling in Section 4.6.7.9.

The East Mey site area contains 13 hydrocarbon fields, according to the UK Oil and Gas Authority, Figure 4-5. A review of the characteristics of the most relevant fields is presented below.

4.2.2.1 Balmoral Field

This section provides a summary of the Balmoral Field, taken from Tonkin & Fraser (1991).

The Balmoral Field lies within UK blocks 16/21a, 16/21b and 16/21c, 225 kilometres from the northeast Scottish coast. It started operation during the mid 1970’s and is currently active. Balmoral is elongated in a northwest to southeast orientation with a length of 10.5km and a width of 3.2km at the widest point (net area: 13km^2). The reservoir formation is the Andrew Sandstone (Mey Sandstone member), located at 2,104m at the crest of the reservoir, and with a thickness...
of 170-260m. The average porosity is 15%, with permeability ranging from 20-3300mD. The hydrocarbon trap is structural, consisting on a drape over a deep Devonian horst block.

Balmoral Field Reservoir Lithologies: Andrew Formation - amalgamated massive sandstone units with minor sections of interbedded mudstones and sandstones – fine to medium-grained, poorly to moderately sorted. Four units in total. Friable Sand (Unit F): poorly consolidated fine- to medium-grained sandstones, lacks quartz overgrowths, has abundant grain coating clays; 0-300ft thick. Porosity 20.4-28.4%; permeability 20-700 mD. Contains lenses of calcite-cemented sandstone (‘doggers’), which act as localised barriers to vertical flow. Main Sand (Unit M) and Upper Sand (Unit U): series of stacked channel fill sands (1-2ft thick) with minor channel abandonment claystones. Porosity 17.4-27.7%; permeability up to 3300mD. Shale Unit (S1): thin but laterally extensive claystones up to 10ft thick, separates Units U and M vertically. Forms local vertical permeability barriers, but sufficient channel downcutting from Unit U to Unit M to provide sand-sand contacts. Total thickness of Units U, S1 and M varies from 35-140ft. Best reservoir properties occur in the central part of the field, decreases to flanks. All wells sample all units. The ultimate recovery of the Balmoral field is 105MMstb (Ahmadi, et al., 2003).

4.2.2.2 Blenheim Field

This summary of the Blenheim Field is taken from Dickinson, Waterhouse, Goodall & Holmes (2001).

Blenheim is a northerly extension of Balmoral, with a similar oil water contact. The reservoir sequence in the Blenheim area belongs to the deep water marine Mey sandstone (Lista Formation), subdivided in nine lithofacies (four sand dominated, two mud dominated and one mixed facies) by means of biostratigraphic methods. The average reservoir porosity is 28.1%, with horizontal and vertical permeabilities of 279 and 206mD, respectively. The trap is a four-way dip-closed structure. Above the Mey, there is 7000ft of mud and siltstones, interrupted only by the Balder tuff/mudstone and thin Gridstone Member (Horda). Over the central and east part of the Field, the seismic interpretation of the Top Mey Sandstone event is unambiguous; on the western
flank the reflection becomes ambiguous and the event splits in two. The ultimate recovery of the Blenheim field is 20MMstb (Ahmadi, et al., 2003).

4.2.2.3 MacCulloch Field

This summary of the MacCulloch Field is taken from Gunn, Macleod, Salvador & Tomkinson (2003).

The MacCulloch Field is a four-way dip closure of 13.5km² area. The reservoir unit is the upper Balmoral Sandstone (Mey Sandstone member), located at 1830m and deposited as massive submarine debris flows and stacked channels and levees. The reservoir quality is good, with an average porosity of 28% and permeability of 200mD-2D. The reservoir contains sparse faults with minor significance (20-40ft throw). The overlying Sele Formation consists of basinal mudstones and marine shales (seal of the field). The Forties Sandstone is absent in this area. The seismic mapping of the Balmoral Sandstone is often problematic due to its low reflectivity and the complex stratigraphic relationship at this level. The ultimate recovery of the MacCulloch field is 58MMstb (Ahmadi, et al., 2003).

4.2.3 Seismic Database

The seismic 3D dataset used for the evaluation of East Mey was the PGS UK CNS Mega Survey:

- Survey: MC3D_NSEA (CNS)_MEGA (UK Sector)
  - Final Merged Migration (53 Tiles)

The data were supplied as SEG-Y on a USB hard drive, the survey datum and map projections can be found in Table 4-1. The tiles of SEG-Y data that were used for the East Mey site selection and evaluation can be found in Table 4-2.

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*Table 4-1: SEG-Y Survey Datum and Map Projections*

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<td>SEG-Y</td>
<td>F06</td>
<td>27395002</td>
<td>25001-30000</td>
<td>120001-124000</td>
</tr>
<tr>
<td>MC3D_NSEA_MEGA_F07</td>
<td>SEG-Y</td>
<td>F07</td>
<td>27395002</td>
<td>30001-34657</td>
<td>120001-124000</td>
</tr>
<tr>
<td>OS0456_MC3D_NSEA_A_MEGA_G06_MAR2014</td>
<td>SEG-Y</td>
<td>G06</td>
<td>27395002</td>
<td>25001-30000</td>
<td>120001-128000</td>
</tr>
<tr>
<td>OS0457_MC3D_NSEA_A_MEGA_G07_MAR2014</td>
<td>SEG-Y</td>
<td>G07</td>
<td>27395002</td>
<td>30001-32923</td>
<td>120001-128000</td>
</tr>
</tbody>
</table>

*Table 4-2: SEG-Y Tiles for East Mey Storage Site Evaluation*
4.2.4 Wells

Table 4-3 shows a summary of the well data used in the characterisation of the East Mey Storage Site (location in Figure 4-6). The data were downloaded from CDA (UK Oil and Gas Authority, 2018). The wells were selected based on the following aspects: the availability of digital well-log data; the appropriate geographical distribution within the storage area; and the preference for vertical wells instead of deviated wells. A full list of the data available in each well can be found in Annex 1: Data Inventory.

<table>
<thead>
<tr>
<th>Drilling purpose</th>
<th>Well list</th>
</tr>
</thead>
<tbody>
<tr>
<td>Appraisal</td>
<td>15/20a-6, 15/24b-5, 15/24b-6, 15/25b-10, 15/25b-8, 15/25e-11, 16/21a-15, 16/21a-20, 16/21b-5</td>
</tr>
<tr>
<td>Development</td>
<td>16/21a-10, 16/21a-13, 16/21a-2, 16/21a-6, 16/21a-8, 16/21b-14, 16/21b-21, 16/21b-4A</td>
</tr>
<tr>
<td>Exploration</td>
<td>15/19-1, 15/19-2, 15/19-3, 15/19-4, 15/19-5, 15/19-6, 15/19-7, 15/19-8, 15/19c-11, 15/20-1, 15/20-2, 15/20a-10, 15/20a-4, 15/20a-5, 15/20a-7, 15/20a-8, 15/20a-9, 15/20b-18, 15/24a-2, 15/24a-4, 15/24b-3, 15/25a-2, 15/25b-1A, 15/25b-3, 15/25b-7, 16/16a-3, 16/16b-1, 16/16b-4, 16/21-1, 16/21a-18, 16/21a-23, 16/21b-9, 16/21d-28, 16/21d-36</td>
</tr>
</tbody>
</table>

Table 4-3: List of Wells Used in the Geological Characterisation of East Mey

4.2.5 Literature Review

The literature review on the East Mey site considered 11 pieces of work, summarised in Table 4-4. The work reviewed includes a book chapter from the Millennium Atlas (Ahmadi, et al., 2003), an online database on CO2 storage sites (British Geological Survey, 2018), and nine scientific articles.

The nine research articles reviewed in this section were selected according to their relevance to the Acorn Project. They all address studies carried out in the East Mey Sandstone or related strata and include detailed studies about hydrocarbon fields located in the East Mey area.

The lithostratigraphic nomenclature of the Paleocene formations has changed substantially in the last decades (see Mudge and Copestake, 1992; Ahmadi et al., 2003; and Kilhams et al., 2012); the review described in Ahmadi et al., (2003) is used as the lithostratigraphic standard for this work and refer to other nomenclatures only if necessary to clarify concepts.
The East Mey storage site is in the Mey Sandstone Member (MSM), and belongs to the Lista Formation, Montrose Group, Figure 4-4. The Lista Formation is Selandian to Thanetian age. It usually overlies Maureen Formation and is overlaid by the Sele Formation (Moray Group) and extends over the Central and Northern North Sea, Figure 4-1. The Lista Formation consists of non-calcareous, blocky, grey mudstones interbedded with sandy, high-density, gravity or debris flow deposits (net to gross of 35%). The average thickness is usually over 600m, with maximum thickness in the Outer Moray Firth Basin. Up to 19 Paleocene fields have Lista Formation sandstones as reservoir, with seals in hemipelagic shales deposited during higher-frequency transgressions.

The MSM extends over the Outer Moray Firth Basin and the Central Graben. It is an equivalent to the Andrew, Balmoral and Glamis members (Mudge & Copestake, 1992). The Mey Sandstone typically consist of stacked units of fine- to medium-grained or locally coarse-grained sandstone with common mudstone and chalk clasts. In the Outer Moray First and Central Graben, the MSM subdivided locally at dark green-grey tuffaceous sandstone (called Glamis Member or Balmoral Tuffite unit) at the base of Balmoral Sandstone unit – it separates the Andrew sandstone at the base and the Balmoral Sandstone at the top of the lithostratigraphic section.

The depocenter of the Andrew Sandstone is in the Central Graben, whereas the Balmoral Sandstone depocenter is found in the Outer Moray Firth to Central Graben.

4.2.5.1 Ahmadi et al., 2003 (Millennium Atlas)

Ahmadi et al., (2003) forms Chapter 14 in the Millennium Atlas, a comprehensive volume that describes the geology of the Central and Northern North Sea. This chapter summarises the geological history, properties and reservoirs of the Paleocene in this region.

4.2.5.2 CO2 Stored

The CO2 Stored project (www.CO2stored.co.uk) is the UK CO2 Storage Evaluation Database, hosted and developed by the British Geological Survey (BGS) and The Crown Estate. The CO2 Stored database provides an overview of 574 potential CO2 storage sites around offshore UK and contains information about the geological and storage characteristics, and potential risk and economic cost of the CO2 storage sites. The whole Mey Sandstone Member is described as one site in the CO2 Stored database.

4.2.5.3 Dickinson et al., 2001

In this article, Dickinson et al. (2001) introduce the Blenheim Field, a small oil field discovered in 1990 and located on the western flank of the Fladen Ground.
Spur (FGS), between Balmoral and Donan fields, approximately 230km northeast of Aberdeen. The article focuses on the appraisal of the field with emphasis on the analysis of well designs, high-resolution bio-stratigraphic analysis and drilling and steering in appraisal wells.

4.2.5.4  *Fraser & Tonkin, 1991*

The authors describe the Glamis oilfield, (UK Block 16/21a), focusing on the exploration and development history, reservoir conditions and lithologies. The Glamis oilfield is located to the southwest of the East Mey area.

4.2.5.5  *Gambaro & Currie, 2003*

Gambaro and Currie describe and review the Balmoral, Glamis Stirling Fields (UK Block 16/21).

4.2.5.6  *Gunn et al., 2003*

In this article, Gunn et al. (2003) introduce the MacCulloch Field, an oil field located in the on the northern flank of the Witch Ground Graben area, approximately 250km northeast of Aberdeen. The article focuses on the exploration history and on the petroleum geology, including a description of the structure, stratigraphy, trap, reservoir and the hydrocarbons.

4.2.5.7  *Kilhams et al., 2012*

This paper presents an integrated seismic, petrophysical and core facies study of the Mey Sandstone Member of the Central North Sea Lista Formation. The detailed mapping from seismic data, wells and core examples allows distinct axial and lateral fairways of turbidite flows to be defined which show distinct similarities and differences with the distribution of sandstones within the overlying Sele Formation.

4.2.5.8  *Mudge & Copestake, 1992*

The authors present a revised lithostratigraphy for the Lower Paleogene in the Outer Moray Firth, which includes the Montrose Group and the Lista Formation, to which the Mey Sandstone Member belongs. They used wireline log and biostratigraphic data to produce their lithostratigraphic revision, which redefines the Montrose Group and adds new members to the Lista Formation, such as the Balmoral Member.

4.2.5.9  *Robertson et al., 2013*

In this article, Robertson et al. describe the pressure system of the post rifting sediments in the UK, with a focus on the Sele and the Horda Sediments.

4.2.5.10  *Stewart et al., 1994*

Stable isotopic (oxygen and hydrogen) and petrographic data have been used to interpret conditions for the formation of authigenic kaolinite within Lower Paleocene sands, Central North Sea. The authors used cores acquired from wells 15/20a-4 and 16/28-6.

4.2.5.11  *Tonkin & Fraser, 1991*

Tonkin and Fraser describe the Balmoral Field, (UK Block 16/21), focusing on the exploration and development history, reservoir conditions and lithologies. The Glamis oilfield is in the central-southeast part of the East Mey area.
4.3 Storage Stratigraphy

A summary of the stratigraphy in the East Mey area is shown in Figure 4-7, adapted from Ahmadi et al. (2003).

![Stratigraphy Diagram]

**Ekofisk**

The Ekofisk formation forms the top of the Late Cretaceous to Early Paleocene Chalk Group. It is typically formed by hard, white, pale grey to beige limestones and pelagic chalks (Surlyk, 2003). Some areas present fine to medium grained sandstones, usually in areas close to the basin margins or in intra-basin highs (Surlyk, 2003). The transition to the overlying siliciclastic sediments is often abrupt, with reworked chalk and sandstone deposits (Thomas, 2015). The combined thickness of the Chalk Group sediments reaches up to 185m in the Balmoral Field area. (Gambaro & Currie, 2003).

**Montrose Group**

These Paleocene deposits are divided into the Maureen and Lista Formations, the latter containing the target reservoir-seal system for this project.

**Maureen Formation**

The Maureen Formation overlies the Chalk Group and is widely distributed in the Central Graben. It is comprised predominantly of amalgamated gravity flow sands interbedded with siltstones and reworked basinal and slope carbonates (chalks) (Ahmadi, et al., 2003). The base of the Maureen is marked by a thin but extensive marl layer above the Ekofisk.

**Lista Formation**

The Lista Formation is comprised largely of grey mudstone deposited in a marine basin or outer shelf environment with interbedded gravity flow fine to medium-grained sandstones. These sandstones deposits are developed across the Outer Moray Firth and Central Graben, Figure 4-1. The sandstone units have received different names in the past (Andrew, Glamis or Lower Balmoral and Upper Balmoral Sandstones) (Mudge & Copestake, 1992), but since their
distribution is not uniform, and they have been termed as a single unit, Mey Sandstone (Knox, 1992). At the top of the Lista Formation, the Lista shale is present within the East Mey area, forming an effective caprock for the Paleoocene fields present, Figure 4-8 (Gambaro & Currie, 2003) (Gunn, Macleod, Salvador, & Tomkinson, 2003) (Dickinson, Waterhouse, Goodall, & Holmes, 2001).

**Moray Group**

In this area, the Montrose Group is locally overlain by a thin sandstone member, the Forties Sandstone, deposited with a NW-SE oriented fan system, which increases in thickness towards the south and the west towards the Forties oilfield (Robertson, 2013). The Forties sandstones are interbedded with medium to dark grey carbonaceous, pyritic, laminated mudstones (Ahmadi, et al., 2003).

The Eocene succession includes the interbedded tuffs and mudstones of the Balder Formation. The lower unit, called the Balder Tuff, presents a strong seismic response and well log marker, observable across the entire East Mey area.

**Oligocene to present day**

The sedimentation above the Paleocene sediments consist predominantly of deep marine mudrocks, with localised channel sands and turbidity flows. The sequence is 1500-1800m thick, providing sufficient depth of burial to the Kimmeridge Clay in the basin centres, for maturation and oil generation, starting from the Oligocene (Gambaro & Currie, 2003).

The early Oligocene to lower Miocene sediments are represented in the study area by the Lark formation. This formation, which has been interpreted in several wells, consists of brown to grey mudstones. It is widespread over the North Sea and can often be traced easily on seismic data in the study area. The Skade and Vade formations consist of deltaic and shallow marine sand and are embedded in the mudstones of the Lark formation. Neither of the Skade and the Vade formations has been named in the studied wells in the East Mey area.

The continuous and symmetrical deposition of mud-dominated sediments continued after the Miocene uplift event. No hydrocarbon fields have been found in the stratigraphy pointing to the effectiveness of the underlying primary caprock system. However, some shallow gas pockets are a potential hazard for drilling campaigns, (Fyfe, et al., 2003). Shallow fluid migration pathways such as pockmarks and injectites are common. Younger Pliocene rocks are a continuation of the underlying Miocene mud-rich sediments, with increased abundance of sand-dominated mud, and local sand layers up to 20m thick (Gatliff, et al., 1994). The youngest sediments in the central North Sea are mud-dominated glacial deposits.

### 4.4 Seismic Characterisation

#### 4.4.1 Database

The seismic dataset used in the seismic characterisation of the East Mey area is the PGS Central North Sea MegaSurvey (PGS, 2015). The seismic volume was created from four pre-stack time migrated cubes (G6, G7, F6 and F7), North and South respectively, that cover the East Mey polygon, Figure 4-8. The areal coverage is complete in the storage complex polygon (by polygon design), but there is no seismic data in the area located to the southwest and to the north of the East Mey area.
These boundaries were chosen as practical limits for the East Mey storage complex. The south and east limits were selected according to the distance to the Miller Gas System pipeline (see D05 the site selection report (Pale Blue Dot Energy, 2018)). The dataset has a 12.5x12.5m bin size. The dominant frequencies range from 10-30Hz, Figure 4-9, with an approximate vertical resolution of 31m at the target formation depth. The polarity of the seismic data were determined by extracting the statistical wavelet from the dataset, featuring SEG normal polarity with a peak (blue on seismic sections) representing an increase in acoustic impedance and a trough (red on seismic sections) representing a decrease in acoustic impedance. The phase of the wavelet is almost zero phase, meaning that the changes in acoustic impedance can be correlated with changes in seismic amplitude almost directly (a change in acoustic impedance at a formation interface being represented by either a peak or a trough).

**4.4.2 Horizon Identification**

The well-log data were used to identify the main horizons interpreted in the seismic dataset. Checkshot surveys acquired during the drilling of the wells provide velocity data allowing the well-log data (in depth) to be tied with the seismic data (acquired in two-way travel time - TWT). Synthetic seismograms were then created using these time-depth relationships together with sonic and density logs. These synthetic seismograms allowed modelling of the seismic response of the rocks to a seismic pulse at the well locations, and enabled matching with the seismic data at that position. This process provided accurate
positioning of the different seismic reflectors with respect to the geological formations interpreted in the wells.

Eleven synthetic seismograms were created using density and sonic logs for the wells 15/19-2, 15/19-3, 15/20a-10, 15/20a-6, 15/20a-9, 15/24b-3, 15/25a-2, 15/25b-1A, 16/16a-3, 16/21a-8 and 16/21b-14, Figure 4-10. The synthetic seismograms were generated using a wavelet extracted using a statistical method, that uses average auto-correlation from many traces to provide a characteristic approximation of spectral information and the signal-to-noise ratio. This wavelet was then convolved with the reflection coefficient profile, calculated using the density and sonic log in each well, Figure 4-11. The synthetic seismograms generated generally showed a good match with respect to seismic data, although some discrepancies exist. Spikes in well data introduced uncertainties to the seismic-to-well tie. Nevertheless, the synthetic seismograms provided valuable information and high confidence in horizon identification on the seismic images with respect to the well data.

The interpreted horizons were the Seabed, Top Balder Formation, Top Mey Sandstone (top of the reservoir) and Top Ekofisk formation (base of the reservoir), hereby called “Top Balder”, “Top Mey” and “Top Ekofisk”. The synthetic seismogram study also helped to evaluate the seismic response of the interpreted geological formations, Table 4-5, examples of the interpretation in a seismic line can be found in Figure 4-12 to Figure 4-13.

<table>
<thead>
<tr>
<th>Horizon</th>
<th>Pick criteria used</th>
<th>Pick Quality</th>
</tr>
</thead>
<tbody>
<tr>
<td>Seabed</td>
<td>Troughs</td>
<td>Very good</td>
</tr>
<tr>
<td>Top Balder</td>
<td>Peaks</td>
<td>Good</td>
</tr>
<tr>
<td>Top Mey</td>
<td>Troughs</td>
<td>Fair - Poor</td>
</tr>
<tr>
<td>Top Ekofisk</td>
<td>Peaks</td>
<td>Good</td>
</tr>
</tbody>
</table>

*Table 4-5: Interpreted Horizons, Pick Criteria and Pick Quality*
Figure 4-11: Example of Synthetic Trace Generation for the Well 16/21a-8 and Fit to the Seismic Data
Figure 4-12: Southeast-Northwest Seismic Profile with Interpreted Horizons
Figure 4-13: Southwest-Northeast Seismic Profile Crossing the Blair and Balmoral Fields
4.4.3 Horizon Interpretation

The seismic interpretation was conducted using a combination of seismic reflectivity and attribute volumes (variance, RMS and spectral decomposition). The objective of this process was to generate the depth surfaces that will constitute the framework for the Static Model of East Mey.

Four horizons were interpreted across the 3D seismic dataset, from Seabed to the top of the Ekofisk Fm. The Seabed was entirely autotracked, based on its clear seismic signal. Top Balder and Top Ekofisk were picked on a broad seed-grid (every 20 inlines/crosslines) and then autotracked. The Top Mey required a denser grid, particularly in the areas between structural highs, in the southeast, northeast and northwest corners, but autotracking worked well in the central part of the East Mey polygon.

The horizons were gridded at 50x50m grid increment, using a convergent interpolation algorithm. The resultant time maps are shown in Figure 4-14 to Figure 4-17, with the potential location of the injection well G1 marked in the maps. The 3D surface maps were smoothed in the TWT stage before depth conversion. The seismic horizons interpreted in the East Mey area are described below.

Seabed – This event is a high-amplitude continuous peak (blue in the seismic image), representing an increase in acoustic impedance at the seabed. The Seabed horizon was picked using manually-seeded 3D autotracking, and the excellent quality of the pick resulted in high confidence in the interpretation. There is a slight decrease in depth towards the east of the area, Figure 4-14.

Top Balder – The Top Balder is characterised by a high amplitude trough, representing a decrease in acoustic impedance, e.g. southwest side of Figure 4-13. The Top Balder surface dips towards the southeast, with average dips of 2-5°. This layer is characterised by a high density of small-scale faulting in the north western third of the study area. These faults form channel-like structures dividing the structure in polygonal blocks. This issue is more clearly observed in the map of variance built using Petrel's attribute analysis software, Figure 4-18. The high density of these collapse structures (Ahmadi, et al., 2003) present in the area prevented their manual interpretation. However, these structures seem to affect only the Top Balder surface, and not the underlying sediments.
Top Mey – The Top Mey is characterised by a fluctuating amplitude trough, which presents a relatively highly variable pick quality. This pick quality is remarkably reduced in the north and southeast areas of the polygon, as suggested by the inability of the autotracking software to identify the horizon in these areas, Figure 4-19. The surface dips to the southeast, with slightly greater angles (3-7° on average) than in the Top Balder surface. The faulting interpreted in the Top Balder is not observed in this horizon. Figure 4-20 shows the thickness of the Mey Sandstone, calculated by subtracting the Top Mey from the Top Ekofisk surface. These thickness maps show a general increase in thickness towards the east, with two thickness highs at the northeast and southeast areas. The thickness of this layer reaches 700m in the northeast high, and pinches out in the northwest, and is 450m thick on average. The oil fields are not located in the areas of greatest thickness, suggesting that sand availability in the reservoir is not a constraint for the development of hydrocarbon accumulation.

Top Ekofisk – The Top Ekofisk (base of the target reservoir) shows a different architecture than the rest of the interpreted surfaces, with the southwestern half being relatively flat, having a dip of c. 2.5° to the South, and with a moderate increase in depth towards the east and the northeast, Figure 4-17. Although not interpreted in detail in this work, the seismic image shows the Ekofisk Formation pinching out towards the northeast, Figure 4-13, because of the rise of the underlying basement layers, corresponding to the regional structure called the Fladen Ground Spur.
**Figure 4-17: Depth Map of the Top Ekofisk (Base of the Reservoir)**

**Figure 4-18: Variance Map of the Top Balder**
4.4.4 Faulting

The faults present in the study area are mainly located to the north and west of the main area of interest for an East Mey storage site, and can be interpreted, with most confidence, in the Top Balder surface, Figure 4-18). The scale of these faults is small, with maximum vertical offsets of 15-20ms observed. These structures have been interpreted as collapse structures formed by differential...
compaction of the brittle tuffs overlying the Forties channels (Ahmadi, et al., 2003).

There is evidence of faulting affecting the Ekofisk layer and partially the Mey Sandstone, mainly in areas related to the existence of structural traps for hydrocarbons (e.g. the fault near the Lochranza field in Figure 4-13) (Gambaro & Currie, 2003) (Gunn, Macleod, Salvador, & Tomkinson, 2003).

### 4.4.5 Depth Conversion

The depth conversion was carried out by using a velocity model extracted from the data available from the wells in the area. First, the time-depth pairs from the checkshot data for all the wells in the area were plotted together, Figure 4-21a. This allowed evaluation of the dispersion of the velocity field in the area, as well as detection of poor-quality data. The dispersion of the data in the plot is small, indicating that there are no major velocity changes in depth and that a relatively simple velocity function could fit the data and provide a good depth conversion.

The velocity model was built using a velocity function calculated from the TWT seismic interpretation. Figure 4-21 shows a plot with the true-vertical depth (TVD) of the three main horizons (Balder, Mey and Ekofisk) interpreted in the well data versus the TWT of these surfaces at the well-head location. This allows estimation of a time-depth relationship between the well and the seismic data, by calculating the equation corresponding to the regression curve that fits best these time-depth pairs (light blue line in Figure 4-21 b). This equation is best fitted to the Top Mey values (pink squares), as the Top Balder (light blue squares) lie slightly above and the Top Ekofisk (dark blue) slightly below the regression curve. The velocity function used is:

\[ y = -0.0001x^2 + 0.83x + 25.254 \]

Where \( x \) is the TWT (in milliseconds) and \( y \) is the TVD (in metres). This results in an approximate average velocity of 2100m/s for the interval from sea level to the Top Mey surface.

*Figure 4-21: Time-Depth Graphs from (a) the Checkshot Data; (b) the Interpreted Horizons at the Crossing with Each Well*

The three TWT-interpretated surfaces were depth-converted using the velocity function. A quality-control was performed in the resulting depth surfaces by subtracting the depth of the surfaces at the location of the wells with the formation tops interpreted in the wells, to obtain the residual differences Figure 4-22. These residuals were converted into three surfaces by using a spherical
kriging interpolation algorithm. The values of these surfaces were subtracted to the three different depth-surfaces to tie them to the well data. The result are three depth-converted surfaces that honour the formation tops interpreted in the well-log data (residuals < ±1m).

![Image](residual-differences-histogram-three-surfaces.png)

**Figure 4-22: Residual Differences Histogram of the Three Surfaces**

### 4.4.6 Seismic Attributes

Seismic attribute analyses are based on measurable properties of the seismic data, that can be extracted at specific times or time windows, and that can image features that are not achievable through interpretation of conventional seismic data, (Chopra, 2007). In this study, amplitude and spectral decomposition-based attributes are used to aid in the subsurface characterisation of the East Mey area. Three attributes were studied: Variance, RMS amplitude and Spectral Decomposition. The variance attribute was extracted to identify lateral trace discontinuities, as it enhances faults and channel margins, such as in the example in Figure 4-18. The RMS amplitude analysis helps in identifying the distribution of sands, which feature high amplitudes compared with shale-dominated sediments. The Spectral Decomposition (SD) allowed the analysis of the amplitude response at different frequencies, which helps with the channel mapping and provides information about bed thicknesses and local lithology changes. These attributes can be combined using co-rendering, which allows the plotting of two or more attributes simultaneously for interpretation. An example of this analysis can be observed in Figure 4-23, that shows a co-rendering of Variance and SD at four different TWT across the Mey Sandstone Member. Up to four different channels and their fills are identified with this combination of attributes, where the margins are defined by the Variance attribute and the SD provides a proxy for the sand distribution in the channel, overbanks and lobes, as well as lithology variations or heterogeneities within the fills.

The seismic attribute assessment works, together with the interpretation of the conventional seismic image data allowed the mapping of major structures and constraints on the depositional environment of the Mey sediments in the East Mey area. The mapped sediments correspond to a shelf slope complex composed of sinuous sand/mud filled channels, levees and lateral/frontal splays for the upper Mey Sandstone (channel dominated), and lobes for the lower Mey Sandstone (fan lobe/sheet dominated). These structures may play a role in the preferential migration of the injected CO2. Early investigation of seismic attributes within the Mey Sandstone has provided encouragement that more detailed information on reservoir architecture may be extracted in the future. This should be considered in future work programmes.
Figure 4-23: Co-rendering of Variance and SD at Four Different Time Slices Within the Mey Sandstone Member
4.4.7 Conclusions

The subsurface geology of the East Mey area has been studied using a 3D seismic (PGS, 2015) and well-log (UK Oil and Gas Authority, 2018) data. The quality of the seismic data allowed the interpretation of the three targeted formations (Top Balder, Top Mey and Top Ekofisk formations), with a slightly greater difficulty in the case of the Top Mey, which corresponds to the top of the target reservoir.

The target reservoir is a relatively thick deep water marine sandstone (450m on average), present over the entire storage polygon. The shale-dominated overburden covers the reservoir entirely. Faults are found dispersed in the entire East Mey area, but the fault density increases towards the north of the area. The interpreted channel structures may constitute preferential pathways for the migration of the injected CO₂.

4.5 Geological Characterisation

4.5.1 Primary Store

4.5.1.1 Depositional Model

The Paleocene Mey Sandstone interval has been a prolific petroleum producing reservoir in the North Sea from a number of different fields. The distribution of these accumulations within the basin is significantly controlled by the vertical connectivity through the Paleocene to Eocene deep marine clastic sequence, with the petroleum accumulations invariably occurring within the youngest stratigraphic interval of sandstone. In this area, the younger Eocene Forties sandstone is either not developed or only poorly developed and so the underlying Mey sandstone is the primary Cenozoic petroleum play. This basic observation points to the effective nature of the overlying Paleocene and Eocene deep-water mudstone interval as a caprock for the storage complex.

The stratigraphic nomenclature of the target storage interval in the Montrose and Moray Groups in this area has evolved significantly during the period of exploration of the play. This is well described within the Millennium Atlas (The Millenium Atlas Co., 2002). The effect of this evolution renders the Operator formation picks noted within the released composite logs as unreliable since they were all made at different times and linked to different stratigraphic key references. As a result, the target storage reservoir is variably called Andrew Formation, Mey Sandstone, Forties Sandstone, Montrose Sandstone and Balmoral Sandstone. The nomenclature reference here is Figure 14.12 of the Millennium Atlas (The Millenium Atlas Co., 2002).

The overall depositional environment for the sequence is a clastic deep-water marine system with shallow water to the east and north and deeper water to the south and west. Sea level fluctuations during the period resulted in either more or less sand being introduced into the basin area. High density mass flows brought coarse sediment from the shelf area into deeper water during periods of lower relative sea level. During periods of high sea level the basin was started of coarse sand material and accumulated thick intervals of mudstone.

The sand flows were delivered into the basin through distinct wide channelized systems. These resulted in thick sand sequences. Away from these systems, sandstones are thinner with more interbedded mudstones. Within the channelised belts, the pelagic muds deposited in between the mass flow deposits are often thin and even removed by erosion of the subsequent flow. This provides the essential vertical connectivity through the interval.
In detail the reservoir stratigraphy developed in this project is heavily guided by an excellent publication by Gambaro and Currie on the Balmoral Field (Gambaro & Currie, 2003). Other good extensions to this work were published for the adjacent fields including Blenheim, MacCulloch and Donan. Examination of the RFT data from the exploration history of the area during petroleum production provides strong evidence for a highly connected common aquifer between these fields (Section 4.7.1.2).

The primary injection site has been selected based on a simple “common risk elements” approach. Specifically, this involved:

1. Distance to MGS pipeline less than 50km
2. Specific 3D seismic data coverage
3. Specific well data coverage
4. Downdip location with acceptable reservoir quality.

Note that there were no essential criteria to inject within a structural closure, however a well-defined structural watershed which might guide any migration at the top of the reservoir was considered.

These criteria pointed to a primary injection location just to the east of the Balmoral field. Here the Mey Sandstone is 167m (550ft) to 259m (850ft) thick and comprises thickly bedded sandstones. Throughout the section there are thin pelagic mudstones present. These create localised baffles to vertical flow, but since the mudstones are thin, they are often not present everywhere. This is evidenced by reservoir pressure information during petroleum production. They are however the result of extensive events created at periods. This architecture presents a high-quality reservoir with local vertical baffles, but strong overall vertical and lateral hydraulic connectivity. This is advantageous for CO$_2$ storage since it supports rapid pressure dissipation to prevent overpressuring at injection wells, but also encourages effective hold up of CO$_2$ as it migrates away from the injection point, both of which improve the storage efficiency.

Detailed facies descriptions are available from Gambaro and Currie (Gambaro & Currie, 2003). In summary there are four primary rock fabrics or lithofacies present:

1. Hemi pelagic mudstones. These are green to grey mudstones with some mica that often show evidence of having been burrowed by sea floor fauna. These intervals can be identified readily on logs by their high gamma ray and shale content and were deposited during periods of quiet deposition as mud slowly settled from the water column during periods of high sea level.
2. Shaley sandstones. These are often thin bedded sandstones which have a significant amount of shale entrained within them. In detail they are the result of small low density turbidite flows which deposit a thin sandy interval with an upward fining nature and a mudstone top. Again, these intervals can be identified from wireline logs.
3. Clean sandstones. These are the primary reservoir intervals and present as thick almost structureless sandstone beds which were deposited suddenly and repeatedly by mass submarine flow deposits or land slips which move sand from the shelf area down slope towards the basin centre. These were most frequent during periods of low sea level when the shelf itself was exposed and reworked by waves and storms. These intervals are typically clean with little mud and have porosities of around 25% and permeabilities sometimes in excess of 1 Darcy. They are referred to as high density turbidites.
4. Cemented clean sandstones. Where high density turbidites also entrain significant biogenic material such as shell debris, they can contain a proportion of carbonate content. This carbonate is remobilised during early burial and diagenesis and reprecipitated in the highest quality intervals or around other shell material. These intervals are thin, easy to identify on wireline logs due to their low shale and gamma ray response and their low porosity. Typically, they are of limited lateral extent in these formations.

Gambaro and Currie also discuss a diagenetic friable zone which occurs within the oil column of the Balmoral field (Gambaro & Currie, 2003). The “friable zone” in Balmoral actually has reduced permeability despite its lack of cementation. Here the sandstones have been “frozen” on their diagenetic path by the early emplacement of petroleum. This preserved early diagenetic clays and prevented subsequent quartz overgrowths. This fabric has not been characterised in this study as the oil column volume represents only a small fraction of the target pore space. The friable sands are only present in the oil column and the oil columns in the area are not connected. As a result, the implications are not significant for CO₂ migration.

The reservoir correlation developed here was extended from that presented by Gambaro and Currie (Gambaro & Currie, 2003). It is important to note that without detailed high resolution biostratigraphy, the correlation of thin shale intervals between wells is problematic and subject to significant uncertainty. Furthermore, the thickness of both sands and shale intervals is variable and this cannot be reliably used to aid correlation. As a result, the correlation developed represents a single scenario amongst many possibilities. The important issue is that it captures the overall hydraulic and flow architecture such that the dynamic model which will be based upon it will respond to injection in a similar way to the real reservoir.

The reservoir layering has been adopted to include higher definition near to the top of the reservoir where the CO₂ will be migrating towards, whilst having thicker layers towards the base of the reservoir. Wherever possible, boundaries between defined reservoir layers are selected at specific shale to sand boundaries, for example Zone C2 and Zone B is always a sandstone overlying a shale interval.

A sample correlation across the area is presented in Figure 4-24. This has a datum at the Top Mey Sandstone. Overall there is a trend of increasing sand content in the upper parts of the interval, with the thicker shale packages confined to the lower parts of Zones B and A. The correlation was developed using open hole log data and is displayed here with reference to a set of derived log curves computed from the original CDA log data. These are from left to right:

1. Vshale – the proportion of shale within the formation computed from a combination of gamma ray and nuclear logging tool responses.
2. Net Flag – this is a binary 1 and 0 flag to describe where the formation has less than 25% shale content and a porosity of more than 10%
3. PHIE – this is the effective porosity calculated from nuclear and sonic logging tool responses and corrected for shale content. It described the proportion of the formation which is pore space and potentially capable of hosting injected CO₂.
4. KMD – this is the permeability of the formation. This is not measured by logging tool but is developed using a relationship between porosity and permeability in core rock samples which is then applied
to the porosity measurements from logs (PHIE). During the analysis three curves were calculated (low, mid and high) to capture the range of uncertainty resulting from this estimation process.

5. FAC – finally this represents the code for the rock fabric or facies type.
   (a) 1 is high density turbidite sandstone
   (b) 2 is cemented high density turbidite sandstone
   (c) 3 is low density turbidite sandstone
   (d) 4 is hemipelagic shale
Figure 4-24: East Mey area well correlation
4.5.1.2 Rock and Fluid Properties

The database used for the petrophysical analysis was based on log data from 45 wells and core analyses for 17 wells, both from the CDA database. Most well log data were available as digital LAS or LIS files and the core analysis reports were digitised into excel. Wells with poor or incomplete data were discarded from the study. The well data were loaded into ‘Interactive Petrophysics’ (IP, Lloyd’s Register software) and quality controlled. Depths were converted to metres and the target study area was over the Paleocene formations. The core data were converted to ASCII, loaded into IP and depth shifted to the logs. Formation tops (provided by the well correlation – discussed in Section 4.5.1.1) were also loaded in.

The evaluation of rock properties is discussed in more detail in Annex 6: Petrophysics Report, including Computer Processed Interpretation (CPI) plots for each well analysed during the petrophysical interpretation. Note that the input curves have been provided under a CDA licence agreement and therefore are not reproduced in this report.

A summary of the work flow is shown in Figure 4-25.
A simple model was used to evaluate Effective Porosity and Shale Volume from Nuclear and Sonic logs, which show results that are consistent with, and within the uncertainty range of, the Core Analyses.

Porosity was calculated for each well, including a Shale Volume and Net Flag. A correction to core and log porosity was provided to incorporate the effect that overburden stress has on core porosity measurements.

Permeability prediction was a preliminary study and a thorough study is recommended for the next phase of the project, one that includes integration of all static and dynamic data, including electric logs, conventional and special core analyses, wireline formation tests and formation well tests. Among the methods investigated for permeability, the Coates function is observed to provide results broadly more consistent with core data.

More details on the workflow of the porosity and permeability prediction for the wells is described in Section 4.5.4 and in Annex 6: Petrophysics Report.

4.5.1.3 Relative Permeability and Capillary Pressure
See Section 4.6.7.3, which summarises the Dynamic Modelling work undertaken and presents a discussion on relative permeability.

4.5.1.4 Geomechanics
A study of direct measurement of rock strength using core samples retrieved during hydrocarbon exploration and development was performed on wells 16/21a-13 and 16/21a-20, with the full report in Annex 9: East Mey Geomechanics.

The key outcomes are:

1. The East Mey Storage Site lithologies are appropriate for the injection and storage of CO₂. The Mey Sandstone is highly porous and transmissible. Its bulk mineralogy is stable under CO₂-rich conditions making it ideal for receiving and containing the proposed quantities of CO₂, 152MT (5MT/yr injection rate) for storage for a minimum of 1000 years after cessation of injection. The proposed injection pressures of 44.5-160bara can be accommodated by the lithologies without rock failure and disaggregation.

2. The Mey Sandstone mineral composition has been assessed. The sandstone is moderately to poorly sorted, with a homogenous structure and high porosity (conventional core analysis average 24.3%).

3. The Mey Sandstone shows little direct evidence of mechanical compaction, with features such as intergranular microcracks in quartz/feldspar grains, comminution and cataclastic flow are rarely present.

4. The Mey Sandstone has a low tensile strength. The highest porosity samples have the lowest tensile strength. The high average porosity is the result of the low degree of cementation of the East Mey sandstone.

5. Hydrostatic overconsolidation tests on the Mey Sandstone have shown that permanent, inelastic hydrostatic compaction is achieved at effective pressures of 1480bara. Once hydrostatic compactive yield is achieved, the rock strengthens with further reduction of porosity.

6. If, during CO₂ injection, the fluid pressures exceeds the least principal stress and/or the tensile strength of the rock, tensile fracturing (hydraulic fracturing) may occur, (Zoback, 2007). This pressure/stress threshold for fracture is known as the formation
fracture pressure and may be overcome if the rate of fluid flow into the formation away from the injection site is exceeded by the fluid supply. Such a situation would allow pore fluid pressure to build, resulting in stresses that may deform the rock. The fracture gradient is the pressure/stress gradient required to fracture the rock at a given depth, this increases with depth due to increasing overburden pressure, (Schlumberger, 2018). There is currently no consensus in the petroleum industry on the calculation of the fracture gradient; some use the least principal stress gradient, and others the maximum leak-off pressure gradient (fracture breakdown pressure gradient) or the fracture initiation pressure gradient, (Zhang & Yin, 2017). Knowledge of the tensile strength of the rock in a formation gives us a further constraint on the fracture gradient when used in conjunction with the least principal stress and formation pressure test results.

7. As the Mey Sandstone is friable and poorly cemented, fracturing will likely be accompanied by extensive disaggregation of the wellbore. This disaggregation may hamper injection as porosity and thus permeability is lost around the injection (depth) interval where loose material accumulates. Therefore, keeping fluid injection pressures below this threshold, i.e. the fracture gradient, is required to maintain injectivity.

4.5.1.5   Geochemistry

Geochemically, the predominantly homogenous, quartz-rich mineralogy of the Mey Sandstone is unlikely to undergo much CO₂-rock interaction during injection and storage operations. The minerals most susceptible to alteration, such as plagioclase, K-feldspar, carbonates and clay minerals form a minor proportion of the rock (<20% in total) and are evenly disseminated throughout, that even if full dissolution was to take place of these susceptible minerals the overall integrity of the quartz grain-grain framework will be unlikely to be compromised.

Additionally, experimental work on the mechanical effect of CO₂ injection on simulated reservoir sands, performed by Hangx et al., (2010), has shown that the presence of CO₂ seems to inhibit stress corrosion and microcracking in both quartz and feldspars, due to the acidification of the pore fluid. As such, on the timescales of injection and storage, CO₂-rock chemical interactions within the Mey Sandstone reservoir should prove to be negligible and will not hinder CO₂ storage activities.

4.5.2   Primary Caprock

4.5.2.1   Depositional Model

The Lista Formation is comprised largely of grey mudstone deposited in a marine basin or outer shelf environment with interbedded gravity flow fine to medium-grained sandstones. At the top of the Lista Formation, the Lista shale is present over the East Mey area, with a thickness of about 75m, forming an effective caprock for the Paleocene fields present.

4.5.2.2   Geomechanics

The Lista Shale caprock mineral composition has been assessed. The shale caprock has a suitable mineralogy and geomechanical character for long-term CO₂ storage.

These shales are finely laminated with low porosity and provide the required barrier for secure storage of CO₂ within the sandstone.

The Lista Shale tensile strengths are typical for shales and vary according to the orientation of the principal stresses to the rock structure.
The Lista Shale is composed of very fine-grained clay minerals, with an average composition of smectite (25.25%), kaolinite (4.00%), and chlorite (2.25%) with fine-grained quartz (38.50%), plagioclase (9.75%) and K-feldspar (6.00%) grains, average mineral proportions determined from XRD analyses. These shales are generally finely laminated, with lamina typically with a thickness of 500-1000μm and contain increasing amounts of quartz, plagioclase and K-feldspar grains as it transitions into the underlying Mey Sandstone and overlying Forties Sandstone.

The Lista Shale caprock has a variable character. Generally, the shales are typified by increases in the gamma ray, compressional sonic and density logs, compared to the Mey Sandstone, with substantial variation within the shale horizons themselves.

### 4.5.2.3 Geochemistry

The Lista Member shale caprock, due to its high swelling clay content, may be vulnerable to either CO₂ adsorption/swelling or dewatering, the former increasing caprock integrity via closure of leakage pathways while the former may facilitate CO₂ penetration into the caprock as progressive dewatering of the swelling clay takes place.

### 4.5.3 Secondary Store

The role of a secondary storage site in any CCS development is to be available to hold any CO₂ that migrates out of the primary storage site and through the primary containment system. “Plan A” is therefore that the secondary storage site will never be used. Nevertheless, as part of the routine security assessment, the identification of these potential secondary storage reservoirs is important. A potential secondary storage reservoir for the East Mey storage site are the Eocene sandstones with their overlying secondary caprock of Eocene shales. Elsewhere in the North Sea, these sand intervals are proven hydrocarbon plays for oilfields such as Alba and Chestnut.

#### 4.5.3.1 Depositional Model

The Eocene succession includes the interbedded tuffs and mudstones of the Balder Formation. The lower unit, called the Balder Tuff, presents a strong seismic response and well log marker, observable across the entire East Mey area.

The tectonic history of the Eocene formations is a continuation of the Paleocene post-rift subsidence controlled by the thermal relaxation of the pre-existing Mesozoic rift structures (Jones, et al., 2003). The rocks are mainly clay-rich mudstones with minor sand input compared to the large, extensive Paleocene submarine fans. However, the main source of depositional material remained similar and derived from the western Scottish Highlands and the East Shetland Platform. The maximum thickness of the Eocene succession is below 800m in the Central Graben. At the end of the Eocene, the stress orientation in the North Sea changed to east-west extension and the Eocene depositional pattern changed to more sediment influx from Scandinavia, (Le Pichon, Bergerat, & Roulet, 1988; Kooi, Cloetingh, & Remmelts, 1989).

Generally, Eocene reservoir sands are of good reservoir quality and interpreted as deep-marine deposits such as turbidites, debris flows and slumps, (Jones, et al., 2003). In the study area, the Eocene stratigraphy is dominated by shale-rich homogenous sediments between the fractured Balder formation and the...
Eocene–Oligocene boundary where shale rocks show extensive polygonal faulting. Reservoir sands recognised and classified while drilling are the Belton and Brodie sands and the shallower Thet sand in licence blocks 15/19, 15/24 and 15/25 and the Grid sand in block 16/21, Figure 4-26. Several unnamed sand layers in older wells are also present. Eocene reservoir sands are of various thickness and present in almost all wells, but the lateral correlation and extent remains difficult to interpret.

In Figure 4-26 the sequence is mud-dominated with occasional sands. The well is a good representation for the stratigraphy of the East Mey area.
4.5.4 Static Modelling

One static model has been built for the East Mey area – the Primary Static Model. This has been developed over an area which includes the East Mey injection site. The purpose of this model is to feed into the dynamic modelling work.

4.5.4.1 Primary Static Model

Grid Definition

The static model incorporates the Paleocene Mey sandstone. Maps of the input depth horizons for Top Mey and Top Ekofisk within the site area are shown in Figure 4-16 and Figure 4-17 respectively.

The static model area is approximately 1067km² (43km x 24km), with the coordinates of the model boundaries:

X Min 357950.78  X Max 400800.78
Y Min 644682.61  Y Max 648973.61

Reservoir modelling has been carried out using Petrel v2017.

Reference system used ED50 (UTM31).

The static model extends from the Top Mey Sandstone down to the Top Ekofisk. The primary seal for the reservoir is the Lista Shale.

The reservoir stratigraphy of the model is in Table 4-6 and is based on the Mey sandstone zonation that was defined for the well correlation.

The Top Mey and Top Ekofisk depth horizons were created from the depth converted seismic interpretation (discussed in Section 4.4.3). The zonation within the Mey Sandstone was generated by building down from the Top Mey sandstone using an isochore map derived from the well log interpretation.

The upper boundary of the model is the top of Zone E, this is impermeable and is represented in the model by a single layer.

No faults have been included within the static model as only minor faults were interpreted in the seismic interpretation in the vicinity of the injection site and they are not expected to provide any barriers to flow.

A cross section through the structure showing the different zones and layering within the model is shown in Figure 4-27.

The static model grid was built with grid cells of 50m x 50m in the X, Y direction, the same resolution as the seismic surfaces from which they were created. This results in 857 and 865 cells in X and Y directions (“Ni” and “Nj”, respectively).

Proportional layering has been used for all zones. The number of layers has been selected in order to effectively model the geological heterogeneity seen in the well data, including 90 layers. Table 4-6 shows the number of layers for each zone in the static model. As a result, the entire static model grid has 66,717,450 grid cells.
<table>
<thead>
<tr>
<th>Horizon</th>
<th>Zone</th>
<th>Source</th>
<th>Number of Layers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Top Mey (E2)</td>
<td>Mey Sst</td>
<td>Direct seismic interpretation and depth conversion</td>
<td>12</td>
</tr>
<tr>
<td>D2</td>
<td>Mey Sst</td>
<td>Built down from the Top Mey using well derived isochore</td>
<td>6</td>
</tr>
<tr>
<td>D1</td>
<td>Mey Sst</td>
<td>Built down from the Top Mey using well derived isochore</td>
<td>12</td>
</tr>
<tr>
<td>C2</td>
<td>Mey Sst</td>
<td>Built down from the Top Mey using well derived isochore</td>
<td>12</td>
</tr>
<tr>
<td>C1</td>
<td>Mey Sst</td>
<td>Built down from the Top Mey using well derived isochore</td>
<td>18</td>
</tr>
<tr>
<td>B</td>
<td>Mey Sst</td>
<td>Built down from the Top Mey using well derived isochore</td>
<td>21</td>
</tr>
<tr>
<td>A</td>
<td>Mey Sst</td>
<td>Built down from the Top Mey using well derived isochore</td>
<td>9</td>
</tr>
<tr>
<td>Top Ekofisk</td>
<td>Ekofisk Fm</td>
<td>Direct seismic interpretation and depth conversion</td>
<td></td>
</tr>
</tbody>
</table>

Table 4-6: Stratigraphy, zonation and layering for East Mey static model

![Cross section showing the 3D grid at well 16/21b-14](image)

**Figure 4-27: Cross section showing the 3D grid at well 16/21b-14**

<table>
<thead>
<tr>
<th>Member</th>
<th>Allocated number of layers</th>
</tr>
</thead>
<tbody>
<tr>
<td>E</td>
<td>12</td>
</tr>
<tr>
<td>D2</td>
<td>6</td>
</tr>
<tr>
<td>D1</td>
<td>12</td>
</tr>
<tr>
<td>C2</td>
<td>12</td>
</tr>
<tr>
<td>C1</td>
<td>18</td>
</tr>
<tr>
<td>B</td>
<td>21</td>
</tr>
<tr>
<td>A</td>
<td>9</td>
</tr>
<tr>
<td>Sum</td>
<td>90</td>
</tr>
</tbody>
</table>

Table 4-7: Allocated number of layer for each member in static model
4.5.4.2 Property Modelling

The East Mey storage complex is formed by a high quality, sand rich and laterally extensive fan system, with widespread channelling, deposited as deep water turbidites primarily from the northwest. The Mey Sandstone bears excellent reservoirs with good connectivity, high porosities (17-33%) and permeabilities (16mD to 10D).

Mey Sandstone

The Mey Sandstone is formed by amalgamated turbiditic flow sand channels with interbedded shale baffles and occasional carbonate cemented sand lenses. The sand bodies are laterally extensive and at least seven sand units have been interpreted in the study area. The presence of thin shales and cemented layers may act as baffles to vertical flow and therefore control the migration of the CO\textsubscript{2} plume. A facies model has been built to ensure that these variations in the Mey Sandstone can be captured within the static and the dynamic model.

The reservoir quality of the Mey Sandstone has been modelled using well based interpolation of zone average properties (net-to-gross (NTG), porosity, permeability). The available data were loaded into a dedicated database in ‘Interactive Petrophysics’ (IP, Lloyd’s Register software). Log data available in LAS or LIS format were loaded and quality controlled.

4.5.4.3 Facies Log Interpretation

A lithology log at the wells has been generated using the well log data processed in Petrel. Four depositional facies using Vshale and porosity (PHIE) have been interpreted from the well logs. Table 4-8 shows the facies interpreted and the Vshale and PHIE cut-off values used.

<table>
<thead>
<tr>
<th>Facies</th>
<th>Depositional environment</th>
<th>Vshale</th>
<th>PHIE</th>
<th>N/G</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clean sand</td>
<td>High density turbidite</td>
<td>≤ 0.15</td>
<td>&gt;0.1</td>
<td>Net</td>
</tr>
<tr>
<td>Muddy sand</td>
<td>Low density turbidite</td>
<td>&gt; 0.15</td>
<td>&lt;0.25</td>
<td>Mixed net/ non net</td>
</tr>
<tr>
<td>Cemented sand</td>
<td>High density turbidite -- cemented</td>
<td>≤ 0.15</td>
<td>≤ 0.1</td>
<td>Always non net</td>
</tr>
<tr>
<td>Shale</td>
<td>Shale</td>
<td>&gt;0.25</td>
<td>-</td>
<td>Always non net</td>
</tr>
</tbody>
</table>

Table 4-8 Facies interpreted from Vshale and PHIE logs

Facies logs have been calculated for 40 wells, which have been used as controls for the facies modelling: 15/19- 1, 15/25b- 7, 16/16a- 3, 16/16b- 4, 16/21- 1, 16/21a- 10, 16/21a- 13, 16/21a- 15, 15/25b- 3, 16/21a- 2, 16/21a- 23, 16/21a- 6, 16/21a- 8, 16/21b- 14, 16/21b- 21, 16/21b- 4A, 16/21b- 9, 16/21a- 20, 15/25b- 1A, 15/24b- 6, 15/24b- 5, 15/19- 2, 15/19- 3, 15/19- 4, 15/19- 5, 15/19- 7, 15/19- 8, 15/19c- 11, 15/20- 1, 15/20- 2, 15/20a- 10, 15/20a- 4, 15/20a- 5, 15/20a- 6, 15/20a- 7, 15/20a- 9, 15/24a- 2, 15/24b- 3, 16/21d- 28, 16/21d- 36

An example of the facies log is shown in Figure 4-28.
4.5.4.4 Facies Modelling

Four depositional facies (which were interpreted from the well logs) were modelled across the Mey Sandstone: clean sand, muddy sand, cemented sand and shale, Table 4-8. The regional geology (Ahmadi, et al., 2003) as well as the interpreted seismic data define the depositional environment as an amalgamation of sand channels within basin shales deposited within an approximate NW-SE direction. Hence, the orientation of the axis of deposition in the model has been aligned with this depositional direction, approximately NW – SE (330°).

The facies were first upscaled for each well to the resolution of the static model and were then populated within the model. Facies were upscaled using the most frequent facies type observed in the entire vertical grid block volume.

The vertical and horizontal distribution of different facies within the model was undertaken using sequential indicator simulation method and using a spherical variogram. Facies were populated for each zone individually within the range observed at each well for the respective zones. The properties of the variogram used for 3D facies population has also been illustrated in Table 4-9.

A view of the top layer of the final facies model (Zone E) is shown in Figure 4-29 and a cross section through the final facies model is shown in Figure 4-30.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Major direction anisotropy range</td>
<td>5,000m</td>
</tr>
<tr>
<td>minor direction anisotropy range</td>
<td>1,000m</td>
</tr>
<tr>
<td>Vertical direction anisotropy range</td>
<td>3m</td>
</tr>
<tr>
<td>Orientation</td>
<td>330 degrees</td>
</tr>
</tbody>
</table>

*Table 4-9: Variogram parameters used for 3D facies population within the model*
### Table 4-10: Modelled facies proportions final facies model

Table 4-10 shows the comparison between distribution populations obtained from well-logs, upscaled cells and 3D distribution within the model.

<table>
<thead>
<tr>
<th>Model Results</th>
<th>From Well Logs</th>
<th>From Upscaled Cells</th>
<th>From 3D Cells</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clean Sand</td>
<td>52.1%</td>
<td>60.9%</td>
<td>56.7%</td>
</tr>
<tr>
<td>Muddy Sand</td>
<td>4%</td>
<td>2.9%</td>
<td>11.8%</td>
</tr>
<tr>
<td>Cemented</td>
<td>1.3%</td>
<td>0.8%</td>
<td>1.7%</td>
</tr>
<tr>
<td>Shale</td>
<td>38.1%</td>
<td>35.4%</td>
<td>34.3%</td>
</tr>
</tbody>
</table>

**Figure 4-29: Results of depositional and final facies modelling (top view)**
4.5.4.5 Porosity Modelling

17 wells had both porosity logs and core data interpreted, which were used within the site model for the modelling of porosity: 15/19-2, 15/20-1, 15/20a-4, 15/20a-5, 15/20a-6, 15/20a-7, 15/20a-9, 15/24b-3, 15/25b-3, 15/25b-8, 16/21a-13, 16/21a-20, 16/21a-6, 16/21b-4A and 16/21b/9.

The porosity attributes were calculated using the conventional well-log methods (Neutron porosity + Density logs), except in wells with missing or poor quality nuclear logs, where Gamma Ray and Sonic Logs were used instead. The Total Shale Porosity was assumed to be approximately 35%, as broadly estimated from logs and expected for North Sea Tertiary Mudstones, that are known to be saturated with capillary and clay bound water.

Over the Paleocene sands investigated, lithological and fluid effects on Density and Neutron logs are similar in value but opposite, hence averaging the response of the two logs broadly cancels out these effects and provides a fast turnaround and satisfactory estimate of formation porosity, within the expected range of uncertainty. Although the porosity evaluation was not calibrated with respect to the core analyses on a well-by-well basis, the porosity values calculated from well-logs show a good overall match when compared to all core data, Figure 4-31. Differences observed for individual samples are within the expected range of uncertainty due to accuracy of each measurement, depth matching and different resolution.

The core porosity may represent Total or Effective Porosity, depending on the temperature and humidity at which the core samples were cleaned and dried. An overview of the data suggests that different conditions were applied to cores from different wells, and hence a certain degree of inconsistency is observed, particularly over shale intervals. However, Total and Effective Log Porosities are similar over NET reservoir sands and their match with Core Porosity is satisfactory. Core Porosity values plotted in Figure 4-31 are at laboratory ambient conditions, i.e. not corrected for the overburden stress at the reservoir.
depth. Core porosity measurement at overburden stress were available only for eight core plugs of well 15/20a-7. It is assumed that an isostatic stress of 248.2bar (3600 psi) applied to the samples was evaluated from reservoir vertical depth in m and estimates of litho-static and hydro-static stresses of 0.23bar/m and 0.1bar/m (1.0 and 0.45 psi/ft); 2000m * (0.23-0.1) bar/m = 248.2bar.

The Porosity values at Isostatic Stress were converted to equivalent Uniaxial Stress and compared to porosity measured on the same core samples at ambient stress. A correction factor of -5% (0.95 multiplier) was applied to all core porosities and to all calculated porosity profiles, as a broad calibration to core data.

The interpreted PHIE log was then upscaled to the grid scale using arithmetic averages, biased to the final facies’ logs. This ensures that the porosity distribution (mean and standard deviation) for each facies is correct.

Porosity was initially upscaled arithmetically for each well. 3D porosity modelling process, populated porosities within each zone for each facies, constrained to the upscaled range of porosities observed at each well. This ensures that the property distributions (mean and standard deviation) remained correct from the porosity log to upscaled well and then to the final 3D static model. Shales were explicitly assigned with porosity values of 0. The same variogram parameters as was used for facies modelling was also used for 3D porosity modelling, Table 4-10.

A histogram showing a comparison of the porosity from well log input versus the 3D modelled porosity for the entire model is shown in Figure 4-32. Average modelled porosity values by zone are also shown in Table 4-11.

<table>
<thead>
<tr>
<th>Facies</th>
<th>Average porosity (%) (log)</th>
<th>Average porosity (%) (Log-upscaled)</th>
<th>Average porosity (%) (cells)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clean Sand</td>
<td>0.2267</td>
<td>0.2302</td>
<td>0.225</td>
</tr>
<tr>
<td>Muddy Sand</td>
<td>0.1861</td>
<td>0.1923</td>
<td>0.186</td>
</tr>
<tr>
<td>Cemented</td>
<td>0.0695</td>
<td>0.0677</td>
<td>0.043</td>
</tr>
<tr>
<td>Shale</td>
<td>0.1027</td>
<td>0.1004</td>
<td>0.111 (later explicitly set to zero to simulate impermeable shale)</td>
</tr>
<tr>
<td>Overall</td>
<td>0.1815</td>
<td>0.1738</td>
<td>0.1759</td>
</tr>
</tbody>
</table>

Table 4-11: Average modelled porosity values for sand facies
4.5.4.6 Permeability Modelling

The permeability profiles were calculated using a regression of core permeability vs. porosity, including data from the 17 wells with porosity data listed in the previous section. The regression is shown in the cross-plot of Figure 4-33 and it was used to predict permeability in each well, using the calculated effective porosity, before application of a 0.95 correction factor, as input. Minimum and Maximum cases were generated multiplying the base case by factors of 0.2 and 5.0, to capture the spread of all data. Core data represent absolute permeability to air at lab conditions.

Figure 4-32: Histogram of porosity. Comparison between 3D cells and porosity logs

Figure 4-33: Preliminary Core porosity-permeability functions based on all core analyses available

In Figure 4-33, the black line represents the line of the regression equation, the green and red lines represent the min and max cases, which were generated by multiplying the base case by factors of 0.2 and 5.0 in order to capture the spread of all data.
The permeability modelling work also included an investigation of the core ‘poro-perm’ relationships specific to the different sand layers, discriminating different zones and facies quality. The different zones were not interpreted in all of the 17 wells with core data available. Table 4-12 shows the zones with available core analyses in each well (the interpretation in well 15/20-1 is uncertain, and thus it was excluded from the specific permeability works). Core poro-perm relationships were investigated for different groups of zones and it was found that the most consistent results were obtained by discriminating Mey D-E-Sele vs. Mey C sands. Cross-plots in Figure 4-34 and Figure 4-35 show core poro-perm regressions for the Mey D-E-Sele and Mey C sands respectively. The data are colour coded using a VSH cut-off showing that distinction of High (VSH<0.15) and Low (VSH>0.15) Density Turbidites does not indicate clear poro-perm trends.

Figure 4-34: Cross plot of core porosity versus permeability for Mey D-E and Sele sediments

Figure 4-35: Cross plot of core porosity versus permeability for Mey C1-C2 sands
An additional method investigated was the Coates equation (Coates & Dumanoir, 1973) which predicts permeability as a function of porosity and irreducible water saturation. This method required some assumptions as precise evaluation of water saturation was not available. A quick-look evaluation of water saturation in wells with hydrocarbon columns suggested that at 30% porosity the irreducible water saturation (SWirr) is as low as 10%. It was then assumed that SWirr increases linearly as a function of decreasing porosity, up to 60% SWirr at 10% Porosity: the NET cut-off. The Coates equation and the assumed relationship between Bound Volume of Water and Porosity are shown in Figure 4-35. Here below is the Coates Permeability equation obtained, where C is a formation coefficient. The value of C = 0.22 was found to give the best match to core data.

\[ K_{ah} = \left( \frac{\text{PHIE}_{c}}{0.22} \right)^2 \times (1 - (0.075 - 0.15 \times \text{PHIE}_{c})) / (0.075 - 0.15 \times \text{PHIE}_{c}) \]

\[ k_{ah} = \left( \frac{\phi_{c}}{0.22} \right)^2 \left( 0.925 - 0.15 \phi_{c} \right) / \left( 0.075 - 0.15 \phi_{c} \right) \]

Equation 4-2

Where \( \phi_{c} \) represents effective porosity multiplied by 0.95 correction factor for calibration to overburden stress corrected core porosity. Using effective porosity is of simpler application in the geological model as it represents the pore volume available to moveable fluids in the sands. Min. and Max. cases were generated by multiplying the Mid case by 0.3 and 3.0 respectively. For the purposes of this early reservoir quality assessment no detailed calibration to the measured rock stress conditions has been attempted. Empirical correction factors have been used. This is an opportunity for future refinement.

The Coates method provided the most consistent results with respect to the core data, Figure 4-38, and it was finally used as input in the static modelling. The effective porosity input was corrected to account for overburden stress using a multiplier of 0.95. Permeability prediction with the Coates equation should be limited to a Maximum value of 10.0 Darcy at ambient conditions, which is the maximum value measurable in most core laboratories. The predicted permeability represents Absolute permeability to Air at lab Conditions and requires further work to be converted to Effective Permeability at Reservoir Conditions, using Klinkenberg, Overburden Stress and Absolute to Effective Permeability corrections. Again, these were not calibrated directly to measured rock stress in this study, but experience in previous studies suggests that the summation of these corrections usually results in a correction factor of 0.5 and that the predicted permeability profiles should be converted to reservoir conditions using this multiplier. This is an opportunity for future refinement.
### Table 4-12: Paleocene sediments zonation and availability of core data for the 17 wells

<table>
<thead>
<tr>
<th>TOPS</th>
<th>15/192</th>
<th>15/20-1</th>
<th>15/20a-10</th>
<th>15/20a-4</th>
<th>15/20a-6</th>
<th>15/20a-7</th>
<th>15/20a-9</th>
<th>15/24b-3</th>
<th>15/25b-3</th>
<th>15/25b-8</th>
<th>15/21a-13</th>
<th>16/21a-2</th>
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<th>16/21b-4A</th>
<th>16/21b-9</th>
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<td>Top Valhall</td>
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</tbody>
</table>
Figure 4-36: Porosity-permeability function using the general core petrophysical function
Figure 4.37: Porosity-permeability function using the zoned core petrophysical function
Figure 4-38: Porosity-permeability function using the Coates petrophysical function
As observed in core data, there is a strong positive correlation between the measured core porosity and core permeability, Figure 4-40. Horizontal and vertical permeability within the sand facies were upscaled using arithmetic averaging, following a Gaussian random function simulation algorithm with a spherical variogram. The correlation lengths in major, minor horizontal directions were set to respectively 5000 and 1000m, and 3m in the vertical direction. Porosity and Permeability population were carried out for each facies within each zone, where the permeability trend was set to follow the porosity trend in the model.

A cross plot of porosity versus permeability for both the measured core data and final modelled data are shown in Figure 4-34 and Figure 4-40.

Permeability was initially upscaled arithmetically for each well. Similar to 3D porosity modelling, 3D permeability modelling populated permeabilities within each zone for each facies, constrained to the upscaled range of permeability obtained at each well. This ensures that the property distributions (mean and standard deviation) remained correct from the original permeability log to upscaled well and then to the final 3D static model. As with porosity, shales were explicitly assigned with permeability values of 0mD. The same variogram parameters as were used for facies modelling were also used for 3D property modelling, Table 4-11.

The average horizontal permeability interpreted from well data is 219.7mD which compares to the average modelled horizontal permeability of 208.63mD. A histogram showing the horizontal permeability for the sand facies is shown in Figure 4-39. Note that as before, shale facies permeability was explicitly set to zero to make them effectively barrier to flow.

Average horizontal permeability values by Facies are shown in Table 4-13.
Figure 4-40: Cross plots of porosity versus permeability modelling results for different facies

Shale facies are consequently assigned with 0 porosity and permeability to illustrate them as baffles to flow.
Derived function: \( \log(kv) = 1.11093 \times \log(kh) - 0.332788 \)

**Figure 4-41:** Cross plot of horizontal versus vertical core permeability (log scales)

<table>
<thead>
<tr>
<th>Facies</th>
<th>Average Kh (well log) (mD)</th>
<th>Average Kh (upscaled well) (mD)</th>
<th>Average kh (3D model) (mD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clean Sand</td>
<td>334.9</td>
<td>349.7</td>
<td>293.6</td>
</tr>
<tr>
<td>Muddy Sand</td>
<td>89.9</td>
<td>95</td>
<td>105.8</td>
</tr>
<tr>
<td>Cemented</td>
<td>79.1</td>
<td>71.9</td>
<td>51.3</td>
</tr>
<tr>
<td>Shale</td>
<td>66.2</td>
<td>65.1</td>
<td>76.6 (explicitly set to zero later)</td>
</tr>
<tr>
<td>All facies</td>
<td>219.7</td>
<td>219.9</td>
<td>208.6</td>
</tr>
</tbody>
</table>

**Table 4-13: Average horizontal permeability values by facies**

The average modelled vertical permeability is 142.8 mD.

**4.5.4.7 Rock and Pore Volumetric**

The East Mey area static model volumes are shown in Table 4-14.

<table>
<thead>
<tr>
<th>Zones</th>
<th>Bulk volume ([*10^6 \text{ m}^3])</th>
<th>Pore volume ([*10^6 \text{ m}^3])</th>
</tr>
</thead>
<tbody>
<tr>
<td>E</td>
<td>16,669</td>
<td>1,871</td>
</tr>
<tr>
<td>D2</td>
<td>18,912</td>
<td>1,551</td>
</tr>
<tr>
<td>D1</td>
<td>33,740</td>
<td>6,432</td>
</tr>
<tr>
<td>C2</td>
<td>38,318</td>
<td>3,162</td>
</tr>
<tr>
<td>C1</td>
<td>54,462</td>
<td>10,744</td>
</tr>
<tr>
<td>B</td>
<td>129,723</td>
<td>18,450</td>
</tr>
<tr>
<td>A</td>
<td>27,574</td>
<td>1,725</td>
</tr>
<tr>
<td>Sum</td>
<td>319,398</td>
<td>43,935</td>
</tr>
</tbody>
</table>

**Table 4-14: Gross rock and pore volumes for the East Mey static model**

**4.5.4.8 Simulation Model Gridding and Upscaling**

To allow for the dynamic modelling studies to be undertaken over the entire East Mey fairway, a fairly large degree of upscaling was carried out. The upscaled numerical model has an area cell size of 400m x 400m compared to 50m x 50m for the static model, additionally the simulation upscaling reduces the run times of the model to more manageable levels. This represents almost 64 times upscaling in the horizontal direction.
The number of cells vertically was also reduced to 36 grid blocks from 93 vertical layers in the static model. In the vertical direction, an upscaling factor of 3 was applied for all members except for the top two members of E and D2 where the upscaling factors were respectively 2 and 1. In total the upscaled model has 363,096 grid blocks comprising $82 \times 123 \times 36$ in each orientations x, y, z. Of which, only 201,092 grid blocks are active.

Both porosity and permeability were upscaled arithmetically. Facies were also upscaled based on the most common facies population found in a given volume of a dynamic grid block. Facies upscaling is an important step toward more accurate representation of the petrophysical properties. It must be noted that removal of shales during upscaling could exaggerate vertical migration and Dietz tongue under the caprock, which implies that the dynamic modelling calculations are conservative.

As with the static model, all the grid blocks with shale facies in the dynamic model were set a porosity and permeability of zero. This aims to make the shale layers barrier to flow in the dynamic model as well. Note that many shale layers disappear because of this degree of upscaling. Figure 4-42 compare facies definition between static and dynamic models i.e. before and after upscaling, Figure 4-43 and Figure 4-44 also compare facies and permeability cross section before and after upscaling between static and dynamic models.
Figure 4-43: Cross section comparing facies between the fine static (top) and the coarse dynamic models (bottom)

Figure 4-44: Cross section comparing permeability field between the fine static (top) and the coarse dynamic models (bottom)
4.6 Injection Performance Characterisation

Phase 1 of the Acorn CCS Project will inject approximately 200kT of CO₂ per year over 15 years reaching a total amount of injected CO₂ of 4.2MT. The rate of CO₂ modelled in the injection performance characterisation is that which is currently available at the St Fergus site and ramps up from 200kT/yr for the first three years, to 281kT/yr thereafter. This CO₂ will be used to kick-start the project as a scalable development.

Additionally, the Acorn CCS Project will seek opportunities to store additional CO₂ as part of a broader regional decarbonisation plan. This will increase the injection rate and the overall scale of the storage project once Phase 1 has commenced. Additional CO₂ storage beyond the 200kT/yr is referred to as Phase 2 and 3.

This chapter describes the well performance modelling for Phase 1 (well design for subsequent phases will be determined later) and the well placement strategy and dynamic modelling for Phase 1 and 3. Full dynamic modelling results are in Annex 2: Dynamic Modelling Report.

4.6.1 Well Performance Modelling

The purpose of well performance modelling is three-fold:

1. to select a suitable injection tubing size;
2. to evaluate some of the factors that may limit injection performance; and
3. to compare this performance with injection targets.

The results from well performance modelling feeds in to the reservoir engineering in the form of “lift curves”, which are then used to define well performance in the reservoir simulation models.

The well engineering aspects of the East Mey CO₂ Storage Site were delivered by Axis Well Technology and the full well engineering report is in Annex 7: Well Design.

4.6.2 PVT Characteristics

In line with Petroleum Experts’ recommendations, the PVT in Prosper was modelled using the Equation of State option using Peng Robinson as the equation of state and enabling the CO₂ density correction implemented by Petroleum Experts for modelling CO₂ injection. The injection fluid was modelled as 100% CO₂ as agreed in the scope of work. The PVT description used is shown in Table 4-15 below.

<table>
<thead>
<tr>
<th>Property</th>
<th>Units</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Critical Temperature</td>
<td>°C</td>
<td>30.98</td>
</tr>
<tr>
<td>Critical Pressure</td>
<td>bara</td>
<td>73.77</td>
</tr>
<tr>
<td>Critical Volume</td>
<td>m³/kg.mole</td>
<td>0.0939</td>
</tr>
<tr>
<td>Acentric Factor</td>
<td>(-)</td>
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</tr>
<tr>
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<td>1.53</td>
</tr>
<tr>
<td>Boiling Point</td>
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<td>-78.45</td>
</tr>
</tbody>
</table>

*Table 4-15: PVT Definition*

CO₂ physical properties that strongly affect tubing flow and hence transport are density (ρ) and viscosity (μ). To test the validity of the Prosper PVT model predicted in-situ CO₂ densities and viscosities were compared with pure component CO₂ properties calculated using the Thermophysical Properties of Fluid Systems from the National Institute of Standards and Technology (NIST)
Comparisons were carried out for a range of temperatures and pressures (temperatures of 4°C to 100°C and pressures of 5bara to 450bara), with the following results:

- Density differs from the NIST calculated value by a maximum of 1.1% with an average of 0.3%.
- Viscosity differs from the NIST calculated value by a maximum of 14.3% with an average of 7.3%.

These results were considered adequate for the purposes of this study.

**4.6.2.1 CO₂ Impurity Sensitivity**

The well and tubing design work has been carried out assuming that the CO₂ is contaminant free. In practice, however, a small amount of other gases may be present in the injection gas. The main effect of this is that the phase envelope, which simplifies to a line in the case of pure CO₂, has a two-phase region and the minimum injection pressures required to ensure single phase liquid injection have to be raised, see Figure 4-45. For small amounts of impurities this shift is minor, but in order to simulate the effect of possible contamination a 10% safety region has been defined around the pure CO₂ phase envelope and this region has been avoided during the well design work.

A further effect of the presence of contaminants is that the fluid viscosity and density will change, which influences the flow behaviour, which should be minor if contaminant content is insignificant.

**4.6.3 Well Performance Modelling**

The purpose of well performance modelling is to help select a suitable injection tubing size, to evaluate some of the factors that may limit injection performance and to compare this performance with injection targets. The results of this modelling are then made available as Lift Curves that are used to model well performance in the reservoir simulation models.

**4.6.3.1 Methodology**

Well modelling was carried out using Petroleum Experts’ Prosper software, which is a leading software for this type of application. All further modelling assumptions are described in the sections below.

**4.6.3.2 Downhole Equipment**

The subsea wellhead is assumed to be in 110m water depth.
Part of the purpose of this study was to discuss a suitable tubing size for the East Mey wells and therefore a set of sensitivity cases was defined on downhole equipment (see section 4.6.3.4).

4.6.3.3 Wellbore Trajectory
Well designs are still to be finalised, but a preliminary well path was designed on the basis that the well should be mostly vertical but deviated to an angle of 50 degrees through the reservoir. Figure 4-46 illustrates the well path used.

![Deviation Survey](image)

*Figure 4-46: East Mey GI-01 – Preliminary Well Path*
4.6.3.4 Temperature Model

Prosper offers three heat transfer models; rough approximation, improved approximation and enthalpy balance.

The rough approximation model estimates heat transfer and hence fluid temperatures from background temperature information, an overall heat transfer coefficient and user-supplied values for the average heat capacity (C_p value) for oil, gas and water. In an application in which accurate temperature prediction is vital this model is considered too inaccurate, especially since it neglects Joule-Thomson effects, which can be vital in predicting the behaviour of a CO_2 injector. For this reason, this model was not considered.

The full enthalpy balance model uses more rigorous heat transfer calculations (including capturing Joule-Thomson effects) and estimates the heat transfer coefficients as a function of depth from a full specification of drilling information, completion details and lithology. However, at the current stage in the design cycle many of the input parameters are still unknown (e.g. mud densities). For this reason, the improved approximation model was chosen for this work. The sole difference between this model and the full enthalpy balance model is that the user supplies reasonable values for the heat transfer coefficient rather than having them estimated from the completion information and lithology. In line with Petroleum Experts recommendations, a uniform heat transfer coefficient of 3BTU/h/ft^2/F (17.04W/m^2/K) was chosen.

For the modelling a seabed temperature of 6°C was assumed and the required background temperature gradient was defined as 6°C at the seabed and reservoir temperature at top perforation depth. Due to the depth of the sea at the East Mey location and the latitude of the site in the North Sea, there is no summer to winter temperature variation expected in this seabed temperature.

Since it is anticipated that CO_2 is conducted to the wellhead through a long (205km) delivery pipeline the temperature of the injection fluid at the wellhead was assumed to be the seabed temperature (6°C)

4.6.3.5 Reservoir Data and Inflow Performance Relationship (IPR)

The estimates on which the IPR modelling is based are summarised in Table 4-16 and Table 4-17 below. Permeability estimates were based on the Petrophysics Report (Annex 6: Petrophysics Report) and other information is as provided in the scope of work.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Unit</th>
<th>Low</th>
<th>Best Estimate</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation Top Depth - Datum</td>
<td>mTVDSS</td>
<td>2216.41</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Formation Gross Thickness</td>
<td>m</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Reservoir Pressure @ Datum</td>
<td>bara</td>
<td>220</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reservoir Temperature @ Datum</td>
<td>°F (°C)</td>
<td>207 (97.22)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Permeability</td>
<td>mD</td>
<td>200</td>
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<td>5000</td>
</tr>
<tr>
<td>Permeability Anisotropy (K_v/K_h)</td>
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<td>-</td>
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<td></td>
</tr>
<tr>
<td>Formation Water Salinity</td>
<td>ppm</td>
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</table>

Table 4-16: East Mey Reservoir Data

<table>
<thead>
<tr>
<th>Parameter</th>
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<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water Depth</td>
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<td></td>
</tr>
</tbody>
</table>

Table 4-17: East Mey Field and Well Data

Using these data three IPR models were defined in Prosper to represent high, medium and low reservoir performance. The drainage area for the well is assumed to be the whole reservoir. Reservoir thickness / perforation interval
sensitivities were constructed by subtracting / adding 10% to the best estimates provided in Table 4-16 above. The parameters used are summarised in Table 4-18 below.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Unit</th>
<th>Low</th>
<th>Medium</th>
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<td>Permeability</td>
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<td>1000</td>
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</tr>
<tr>
<td>Reservoir Thickness</td>
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<tr>
<td>Drainage Area</td>
<td>acres</td>
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<td></td>
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<tr>
<td>Dietz Shape Factor</td>
<td>(-)</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Perforation Interval</td>
<td>m</td>
<td>155.36</td>
<td>172.62</td>
<td>189.88</td>
</tr>
<tr>
<td>Skin</td>
<td>(-)</td>
<td>+20</td>
<td>+10</td>
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</tr>
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</table>

*Table 4-18: East Mey IPR Input Data*

### 4.6.3.6.2 Sensitivity Cases

The sensitivity cases considered are summarised in Table 4-20 below. The injection temperature at the well head is 6°C for all cases.

The high, medium and low reservoir cases are as described in section 4.6.3.5 above.

Single and dual completions were considered. Note, that a 9⅝” casing was assumed and a dual 4½” completion is incompatible with this choice and was therefore not considered. For dual completions it was assumed that only a single string was open for the low-pressure injection case; for the high pressure injection case both strings were considered open.

The minimum tubing head pressure (44.5bara) is the minimum pressure required to ensure single phase liquid injection throughout the tubing. The maximum tubing head pressure (131bara, 130barg) represents the maximum pipeline delivery pressure. Not all tubing choices can achieve injection at the lower injection pressure. Where this is the case the minimum pressure for injection has been calculated.
4.6.3.6.3 Results

Table 4-20 summarises the rates achievable for the various sensitivity cases and Figure 4-47 provides a graphical representation. Prosper uses volumetric flow rates and the conversion to mass flowrate is based on a density of 1.87 kg/m$^3$ at standard conditions. Where the minimum tubing head pressure needed to be raised to achieve injection the calculated figure is highlighted in red.

Figure 4-48 to Figure 4-52 show the pressure and temperature behaviour along the tubing plotted as pressure versus temperature for the various tubing sizes and well head injection pressures. Note that two curves are plotted for each case to illustrate the maximum and minimum tubing head pressures, with suffix “A” referring to the minimum THP (constrained by the phase envelope) and suffix “B” referring to the maximum THP (constrained by the pipeline pressure). The graphs also show the phase boundary with upper and lower safety limits and the various pressure and temperature limits. Figure 4-53 shows a pressure and temperature versus depth profile for a typical injection case.
Figure 4-49: Pressure / Temperature Profiles – 3½” Tubing – Min (A)/Max (B) Tubing Head Pressure

Figure 4-50: Pressure / Temperature Profiles – 2⅞” Tubing – Min (A)/Max (B) Tubing Head Pressure
<table>
<thead>
<tr>
<th>Case</th>
<th>Reservoir Case</th>
<th>Completion</th>
<th>Tubing Size</th>
<th>Max and Min THP (bara)</th>
<th>Rate (MMscf/d)</th>
<th>Rate (MT/yr)</th>
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</tr>
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<td>4½'' (12.6 ppf)</td>
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<tr>
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<td>3½'' (9.2 ppf)</td>
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<td>131.01</td>
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<td>1.014</td>
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<td>3½'' (9.2 ppf)</td>
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</tr>
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<td>3½'' (9.2 ppf)</td>
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</tr>
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<td>2⅞'' (6.5 ppf)</td>
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<tr>
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<td>5.7</td>
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<td>131.01</td>
<td>60.3</td>
<td>1.166</td>
</tr>
</tbody>
</table>

Table 4-20: Rates Achievable by Case for Minimum and Maximum Tubing Head Pressure
The results may be summarised as follows:

- For the Medium Reservoir Case (rounded to nearest 0.01MT/yr):
  - A single 2½" tubing has a range of 0.12 to 0.60MT/yr
  - A single 3½" tubing has a range of 0.25 to 1.01MT/yr
  - A single 4½" tubing has a range of 0.62 to 2.11MT/yr
  - A dual 2½" tubing has a range of 0.12 to 1.19MT/yr
  - A dual 3½" tubing has a range of 0.25 to 2.02MT/yr
  - A dual 2½" and 3½" tubing has a range of 0.12 to (max) 1.61MT/yr
  - A dual 2½" and 4½" tubing has a range of 0.12 to (max) 2.71MT/yr

- Achieving injection rates ranging from 0.1MT/yr to 2.0MT/yr over injection field life with a single completion design will be challenging:
o The larger two tubing sizes (4½” and 3½”) inject more than the required 0.1MT/yr at initial reservoir conditions even if the lowest THP compatible with single phase liquid injection is chosen.

o An initial injection rate close to 0.1MT/yr should be achievable with a 2⅞” tubing. However, the desired upper limit injection rate of 2MT/yr cannot be achieved using a 2⅞” tubing even if a dual string is considered and the shortfall is large (at least 0.81MT/yr). Note, that this figure applies to initial reservoir conditions; once injection is started reservoir pressures will rise and the shortfall will increase further.

• In the modelling, only the dual 3½” tubing (unless the most pessimistic reservoir conditions are considered) and the 4½” tubing can achieve a target rate of 2MT/yr under initial reservoir conditions. However, neither provide an option for the low range of 0.1MT/yr.

o Note that it is not currently possible to model dual completions explicitly in Prosper. A workaround is provided, which relies on the user specifying a single string and then providing a multiplier for that string that defines the fraction of total flow going through it. Prosper then grosses up this flow contribution to total flow for all remaining calculations (e.g. the IPR calculations). For a dual completion consisting of two identical tubing strings the multiplier is easy to define as 0.5. For mixed dual completions this is more complex and Petroleum Expert’s GAP software, in which dual completions can be defined and evaluated rigorously, should be used. It is hence recommended that a full evaluation of a dual completion is performed in GAP.

• Though not explicitly modelled a dual completion consisting of a 3½” tubing string and a 2⅞” tubing string will not achieve the 2MT/yr target because the target exceeds the sum of what these two strings can achieve as single completions (at best 1.61MT/yr) and this acts as an upper bound on what the dual string can achieve.

• A dual completion consisting of a 2⅞” tubing string and a 4½” string does appear to achieve the target injection range. The combined injection rate will be less than the sum of the two individual strings but will achieve the target 2MT/yr since the 4½” string is able to achieve this target on its own.

  o Note that a dual completion consisting of a 2⅞” and a 4½” tubing string is not commonly run and will provide challenges for well design (potentially requiring an increase in casing size to 10-3/4” and modifications to existing subsea tree designs) but is considered technically achievable.

• Beyond the inability to achieve the extended target range of injection rates in most cases none of the tubing options considered violate any of the restrictions specified, including:

  o Temperature limits: A fluid temperature of 0°C is not reached by any of the scenarios considered.
  o Fracture Limits: This limit is not reached by any of the cases considered.
  o Phase changes to the gas phase are avoided (though the fluid may be supercritical at the injection point for some low rate cases, which is not considered an issue).
Vertical Lift Performance Curve Generation

Vertical lift performance (VLP) curves were generated for three different completion options:

- 2⅞" single tubing string
- 3½" single tubing string
- 4½" single tubing string

To allow sensitivities to injection pressure limits and other quantities to be run in Eclipse without extrapolation, the curves were generated for pressures and rates that were adjusted to Eclipse requirements. Note that the VLPs are based on (gas) rates at standard temperature and pressure for compatibility with Eclipse.

Input parameters were as follows:

- For the 2⅞" single string
  - Tubing Head Pressures: 645psia (44.5bara) to 2000psia (137.9bara) in 10 steps
  - Gas Rates: 2.5 Mscf/d (0.05MT/yr) to 47.5Mscf/d (0.92MT/yr) in 20 steps
- For the 3½" single string
  - Tubing Head Pressures: 645psia (44.5bara) to 2000psia (137.9bara) in 10 steps
  - Gas Rates: 2.5Mscf/d (0.05MT/yr) to 8Mscf/d (1.55MT/yr) in 20 steps
- For the 4½" single string
  - Rates: 2.5Mscf/d (0.05MT/yr) to 160Mscf/d (3.09MT/yr) in 20 steps

The performance envelopes of the well are shown in Figure 4-54 to Figure 4-56 below. It was ensured that for all points shown on the curves dense phase injection was maintained throughout the tubing and that the temperature limit of 0°C was not broken.
Figure 4-54: Performance Envelope – 2¾” Single Tubing String
Figure 4-55: Performance Envelope – 3½” Single Tubing String
Figure 4-56: Performance Envelope – 4½” Single Tubing String
4.6.4 Injectivity and Near Wellbore Issues

4.6.4.1 Halite

*Halite formation is considered to pose a low risk to injectivity*

When CO₂ is injected into formations containing saline brine, the majority of the brine will be pushed away from the wellbore by the injected CO₂. However, some brine will remain in pores and adhering to rock matrix. As CO₂ and water are miscible, CO₂ will absorb the water. However, the salt in the brine is not soluble in CO₂, thus precipitating the salt out of solution as halite. In other words, the near wellbore is dehydrated (water removed), leaving the salts behind. The volume of solid salt crystals produced depends on brine salinity, residual brine volume (left after the ‘sweep’ of CO₂), interactions at the CO₂ flood front and the propensity of the brine to re-saturate the near wellbore during shut-in periods. Capillary pressure also plays a part in re-saturation but is likely to be masked by CO₂ buoyancy effects (CO₂ rising in the fluid column, allowing brine to recharge from below). As the re-saturation will depend on the number and length of shut-ins, predictions of actual salt precipitation volumes are not possible at this stage.

However, on the assumption that the current brine contained within the Mey Sandstone is relatively low salinity (72,000ppm), there is a possibility that near wellbore permeability will remain unchanged by dehydration.

Halite will only become an issue if the halite crystals are mobilised and form bridges / plugs in the matrix rock pore throats. This is considered unlikely in this low salinity system.

The effect of halite precipitation can be mitigated by ‘washing’ the near wellbore with fresh (or relatively low salinity) water. The wash water dissolves the salt and carries it away from the near wellbore region, where the effects of permeability reduction have most impact. However, as the halite risk for Mey is currently considered to be low, the addition of wash water facilities for these operations is not considered necessary. The residual risk therefore remains very small.

4.6.4.2 Thermal Fracturing

*Thermal Fracturing is considered to pose a low risk to injectivity, however more work is required to assess its impact on containment*

The temperature of the CO₂ stream injected into the Mey well is likely to be close to the sea bed temperature of ~6°C due to the long subsea pipeline. Using this value for wellhead temperature, the CO₂ bottom hole temperature (at the point of injection into the reservoir) is likely to be at approximately 20-50°C (dependent on rate and pressure), which is significantly lower than the expected ambient reservoir temperature (97°C). This will result in a reduction in reservoir temperature in a limited region close to the wellbore. This drop in temperature will have an effect on the near wellbore stresses and will make rock more liable to fracture (tensile failure). The effect of this thermal effect on the frac pressure has not been investigated in this report. The applied safety margin (10%) on frac pressure and a stand-off from injection point to cap rock will provide some security with respect to cap rock fracturing and containment issues. Furthermore, the effect of increasing frac pressure with increased pore pressure (pore pressure increases throughout the injection period) has not been taken into consideration when defining fracture limits, and this is likely to have a countering effect to the potential for thermal effects on frac pressure. It is recommended that these issues be reconciled in the pre-FEED stage.

4.6.4.3 Sand Failure

*Some sand failure is considered likely and sand screens are recommended*
As with water injection wells, there is a potential for sand failure in CO₂ injection wells. The principal causes of this are similar:

- Flow back (unlikely to occur in CO₂ injection wells without some form of pre-flow pad)
- Hammer effects during shut-in
- Cyclic stressing (applied during injection and released during shut-in)
- Downhole crossflow during shut-in (from and to formation zones with different charging profiles)
- Well to well crossflow during shut-in (if individual wells are charged to different pressures and surface valves are left open, allowing cross-flow via injection manifold)

The effects of sand failure are that near wellbore injectivity can be reduced (failed sand packs the perforation tunnels or plugs the formation) or the well can be filled with sand (reducing injectivity and potentially plugging the well completely).

The pre-requisite for sand failure is that the effective near wellbore stresses exceed the strength of the formation. This is unlikely in a CO₂ injection well on a continuous basis, but pressure spiking (Hammer effect) can cause intermittent rock failure, with the other process mentioned above contributing to the production of sand.

The in-situ stresses at the wellbore wall, while predominantly a function of the overburden and tectonic forces will vary dependent on the trajectory (deviation and azimuth) of the proposed wellbore. So, while field wide values can be generalised, the specifics of the well can impact on the required conditions for failure of the formation.

The strength of the formation can be estimated in several different ways based on a range of other properties including its age, permeability and log data. In addition, several qualitative indications of relatively high or low strength can be gained during drilling including rate of penetration and inspection of drill cuttings. In the offset wells the rates of penetration in the Mey sandstone were quite high and the drill cutting were often described as "friable" and "poorly cemented" these all suggest relatively low rock strength. Hence it is recommended that the well design does include sand control in the form of stand-alone sand screens (SAS). More detail on the laboratory work to estimate formation strength from core materials is included in Annex 9: East Mey Geomechanics.

To provide some offset from the caprock penetration point to the first injection point through the sand screens, it is recommended that the 9½" shoe is set at least 40ft into the top of the Mey sandstone, and that a further joint of blank pipe with annular isolation is set above the screens.

More detailed work to confirm the suitability of standalone screens for the well will be required once the well trajectory and injection scheme parameters are better defined and, if possible, more offset data reviewed.

4.6.5 Transient Well Behaviour

In the modelling of the injection to the Mey sandstone, it was assumed that CO₂ would remain in liquid or dense phase in all injection scenarios, providing minimum rates of injection were achieved. However, if the wells are shut-in at surface, the tubing head pressure (THP) may drop below critical pressure and CO₂ will boil off into the gas phase. This will generate significant temperature drops and create a two phase scenario when the well is re-started. These effects are transient but have significant impact on well design (temperature resilience).
4.6.5.1 Shut-in at Surface with a Full Column of \( \text{CO}_2 \) in the Well

With a surface shut-in, the pressure at the top of the well, below the shut-in point, falls to below the phase boundary (may not occur after prolonged injection if reservoir pressure has increased sufficiently), so gas will evolve, leading to significant cooling (and gas slugging when injection starts up again). When injection starts again, the pressure will be low at the wellhead at the top of the \( \text{CO}_2 \) column and there will be a short transitional period of high pressure liquid entering a low pressure gas environment, leading to further cooling effects.

The transient pressure effects of a surface shut-in could be modelled using a simulator such as OLGA, for example. This would give a better prediction of the maximum and minimum pressures in the wellbore and highlight if the pressure variations (for example, the ‘water hammer’ effect) cause problems at the sand face.

If significant issues are identified, a possible solution to transitional effects is to add a deep-set shut-in valve to the completion. The deep-set valve would act as the primary shut-in. Note that a combined deep-set shut-in valve / choke valve could provide the solution to the variable rates (high injection range) required for this development, and further investigation of this solution is recommended in the pre-FEED stages.

4.6.5.2 Alternative Solution to Transient Effects

Shut-in closer to the formation reduces the hydrostatic head of \( \text{CO}_2 \) acting on the formation and removes the risk of damaging pressure pulses (‘water hammer’ effect) affecting the sand face integrity. After shut-in the well could be left with the \( \text{CO}_2 \) supply pressure applied (above the barrier valve) and therefore mitigate cooling effects at the wellhead on restart. The pressure differential across the downhole valve will be minimal and cause no problematic transitional effects on restart. Some OLGA modelling would be required to determine the minimum depth of shut-in and a suitable valve specified.

For the purposes of this work, it is assumed that a suitable mechanism is available to perform the downhole shut-in function. Transient effects are therefore mitigated. However, further work is required in the pre-FEED and FEED stages to substantiate this approach, or to provide alternate solutions. In all cases, well design should reflect the potential for very low temperatures should these mitigations fail.

4.6.6 Safe Operating Envelope Definition

With respect to \( \text{CO}_2 \) injection, safe operating limits are those that allow the continuous injection of \( \text{CO}_2 \) without compromising the integrity of the well or the geological store. Since wells are designed to cope with the expected injection pressures and temperatures, the primary risk to integrity is uncontrolled fracturing of the formation rock, leading to an escape of \( \text{CO}_2 \) through the caprock (adjacent to the wellbore or at a point anywhere in the storage complex). The pressure at which fractures can propagate through formation rock is called the frac pressure and is usually defined as a gradient, as it varies with true vertical depth.

In order to prevent \( \text{CO}_2 \) leaking from a storage complex, fractures in the caprock need to be avoided. This can be done by limiting the pressure to which the caprock is exposed, in both the near wellbore and the storage site complex as a whole. The pressure limit at any one point depends on the caprock properties, including strength, elasticity and thickness. Given that there is always uncertainty in rock properties as you move away from ‘control’ wells, and that caprock properties are generally not measured and documented to the same degree as permeable formation rock, there is a high degree of uncertainty.
surrounding caprock fracture initiation pressures and the vertical extent of any resulting fracture (fully penetrating or partially penetrating). For this reason, this study has used the permeable formation frac pressure as the pressure limit (which, in the overwhelming majority of cases considered for CO₂ storage, is lower than the caprock frac pressure) rather than that of the caprock itself. This provides a conservative approach, and also allays concerns over the concentration of cold CO₂ at high pressure that might be delivered to the caprock boundary through frac propagation in the target formation. A further safety margin of 10% is taken from the estimated formation frac pressure to allow for variations (and unknowns) within the formation rock properties.

A further risk to well integrity and the well injection performance is the poor understanding of operating a CO₂ injection well close to the gas / liquid phase boundary. Due to the characteristics of CO₂, changes in phase can be accompanied by significant changes in temperature as well as flow performance (pressure drops due to friction within the wellbore). Across the phase boundary, CO₂ is boiling and condensing, making it an extremely complex system to model, from both a temperature and flow perspective. This complexity introduces significant uncertainty.

4.6.6.1 Fracture Pressures

An initial reservoir fracture gradient of 0.80psi/ft (~0.18bar/m) was provided by SCCS; however, for all well design a safety margin of 10% has been used resulting in a fracture pressure of 0.72psi/ft being used in the well design process. This safety margin should be sufficient to account for local variations and uncertainties.

4.6.6.2 Phase Envelope

In order to minimise the risk associated with the uncertainty introduced by operating wells across a phase boundary, all injection will be limited to single phase. With the pore pressure in the Mey Sandstone (220bara) being above the critical point for CO₂ (74bara), injection will be limited to liquid (below critical temperature) or dense phase (above critical temperature). CO₂ will be delivered to the injection sites in liquid phase, with assumed pipeline operating pressures of up to 130barg.

4.6.7 Dynamic Modelling

The following section contains a summary of the dynamic modelling work that was undertaken for the East Mey storage site. For the full modelling report, refer to Annex 2: Dynamic Modelling Report.

In this study, CO₂ storage in the South East region of the East Mey fairway, east of the Balmoral oil field is considered, mainly because of the results observed in Annex 3: Strategies for Increasing Storage Efficiency. Simulation was conducted over the entire East Mey area.

4.6.7.1 Structural Grid and Reservoir Modelling

Table 4-21 shows the properties of the East Mey reservoir model. The dynamic model is an upscaled version of the static model and is suitable for undertaking numerical simulations.
<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Pressure @ datum</td>
<td>216.8bar (3145psi) at 2148.8m (7050ft) TVDSS</td>
</tr>
<tr>
<td>Temperature @ datum</td>
<td>79.2°C (207°F)</td>
</tr>
<tr>
<td>Rock Compressibility</td>
<td>5.5764×10⁻⁵ (1/bar)</td>
</tr>
<tr>
<td>Brine Salinity</td>
<td>72,000ppm</td>
</tr>
<tr>
<td>Porosity</td>
<td>1%-32%</td>
</tr>
<tr>
<td>Permeability horizontal</td>
<td>0mD (shale layers)-3200mD</td>
</tr>
<tr>
<td>$k_v/k_h$ ratio</td>
<td>0.5</td>
</tr>
<tr>
<td>Grid Dimensions</td>
<td>82×123×36</td>
</tr>
<tr>
<td>Number of Cells</td>
<td>201,092 (active)</td>
</tr>
<tr>
<td>Cell size (L x W)</td>
<td>400m×400m</td>
</tr>
<tr>
<td>Cell Thickness</td>
<td>9.54m (average)</td>
</tr>
</tbody>
</table>

Table 4-21: Major paramters of the East Mey model

The East Mey model is bounded between the Mey and Ekofisk horizons interpreted as part of the seismic work. The model consists of six individual regions in accordance with incorporated hydrocarbon fields as further described later. Five of these regions illustrate the existing hydrocarbon fields in East Mey and the remaining one (blue) represents the residual area of East Mey. Figure 4-57 shows these regions.
Figure 4-58: Geometry of the East Mey site; there is 1° tilt in the entire East Mey structure.

Figure 4-58 shows an aerial view of the East Mey model along with a distance indication from the shallowest to the deepest part of the structure. The storage site is tilted, with the tilt in the entire East Mey structure less than 1°. However, there are greater local tilts as a result of local structures.

Vertically, the model is subdivided into seven zones based on petrophysical characterisation, see Section 4.5.4. Figure 4-59 shows a cross section between wells in the storage site. Figure 4-60 illustrates the identified zonation between these five wells in the East Mey fairway. Table 4-22 illustrates the allocated numbers of grid blocks vertically along with the available pore volume in each individual zone.

Figure 4-59: Location of the cross section between wells 15/19-2 and 16/21b-4A
Figure 4-60: Cross section between wells 15/19-2 and 16/21b-4A, Figure 4-59, showing seven discrete members.

Table 4-22: Volumetric properties of each East Mey formation member

The reservoir thickness varies across the site. The reservoir interval is thicker toward west and centre and becomes thinner toward east and south east. Figure 4-61 shows a thickness map of the East Mey site.
An important feature for CO₂ storage at East Mey is the presence of shale layers in the storage site which limits free vertical buoyancy driven CO₂ migration within the site during and post injection. These shales layers are, however, not extensive and do not create disconnected hydrodynamic regions. However, their presence could affect the CO₂ distribution within the site. The shale layers limit free vertical CO₂ migration and promote its lateral distribution which is discussed further later in Section 4.6.7.8. Figure 4-62 shows a cross section of the storage site between the same 15/19-2 and 16/21b-4A wells described before. The correlation between shale layers and permeability fields can be best observed in Figure 4-62.

The shale facies in this study are assumed to be completely impermeable. Sensitivity analysis did, however, show that a very small transmissibility across the shale layers could affect CO₂ storage and ultimate plume distribution underneath the caprock.
4.6.7.2 PVT Management within Eclipse

A compositional fluid model was used for CO₂ storage modelling in the East Mey Fairway. Table 4-23 shows details of the fluid model constructed for this study. Three components were used to enable manageable simulation runtimes. Injected CO₂ was represented with pure CO₂ component defined in the Eclipse 300 components library, i.e. there is no impurity in the injection stream. There is one light hydrocarbon component and one heavy component. The combination of light and heavy components approximately generates the oil properties (density and viscosity) observed broadly at the Balmoral field, i.e. a density and viscosity of 703.5kg/m³ (43.9lb/ft³) and 0.61cP respectively. (CDA data for well 16/21-1). It was observed in the Acorn/Captain X modelling study that the use of a compositional model makes a significant difference to the modelling results compared to a black oil model because of the correct representation of the mixing effect of injected CO₂ with the light gas remaining in the Atlantic and Cromarty gas fields. In the East Mey storage site, there is no gas field, however, compositional simulation will be used allowing for correct identification of any compositional effects.

The Peng-Robinson Equation of State (EOS) was used to simulate PVT properties of the injected CO₂ and other hydrocarbon components. The CO₂SOL model of Eclipse 300 (Schlumberger, 2014) was used to replicate the interaction between brine and CO₂, i.e. CO₂ dissolution in brine and consequent brine density increase.

The brine salinity was 72,000ppm similar to that reported at the Balmoral field. The brine pressure gradient is set to 0.1bar/m (0.445psi/ft), the reported water gradient observed at the East Mey site obtained by compiling RFT (repeat formation tester) results over the entire structure. Brine viscosity was approximated at the ambient Balmoral reservoir conditions using appropriate correlations.

<table>
<thead>
<tr>
<th>Component</th>
<th>CO₂</th>
<th>C₁N₁</th>
<th>C₂⁺</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pₑ (bar)</td>
<td>73.8</td>
<td>45.9</td>
<td>19.9</td>
</tr>
<tr>
<td>Tₑ (°C)</td>
<td>31.6</td>
<td>-83.7</td>
<td>646.7</td>
</tr>
<tr>
<td>Ω (acentric factor)</td>
<td>0.225</td>
<td>0.013</td>
<td>0.511</td>
</tr>
<tr>
<td>Vₑ (m³/kg-mole)</td>
<td>0.094</td>
<td>0.098</td>
<td>0.638</td>
</tr>
<tr>
<td>Vₑ-visc (m³/kg-mole)</td>
<td>0.094</td>
<td>0.098</td>
<td>0.692</td>
</tr>
<tr>
<td>Mₑ</td>
<td>44.01</td>
<td>16.26</td>
<td>160.84</td>
</tr>
</tbody>
</table>

*Table 4-23: Details of the fluid model used for East Mey CO₂ storage modelling*

4.6.7.3 Relative Permeability

There is limited SCAL (special core analysis laboratory) analysis in the CDA data over the East Mey area, particularly with regard to gas-water systems. Only seven wells have SCAL data with relative permeability measurements out of which only three wells have gas relative permeability experiments. Table 4-24 compiles all the gas relative permeability measurement from CDA data. Notably, none of the experiments are from the Paleocene interval. Additionally, there is no imbibition relative permeability measurement for gas phase, which means CO₂ trapping behaviour at East Mey remains unknown.
Table 4-24: Gas relative permeability measurements over the storage area. $k_{rg}$ are normalised to initial $k_{ro}=1$ or $k_{rw}=1$ depending on the experiment.

In Table 4-24 the sample depths are withheld to comply with the CDA licence.

Similar to Williams, et al. (2013) and in the absence of relative permeability data, we have assumed that the gas-water relative permeability and trapping properties are similar to those reported for the Viking No 2 formation, (Burnside & Nayer, 2014). Relative permeability was described by a Corey power law equation, illustrated in Figure 4-63. Hysteresis was only considered in the gas phase. No hysteresis effect was considered for the water phase as it is regarded as the wetting phase with a much lower hysteresis effect.

Sensitivity analysis will, however, be undertaken to capture uncertainty for this critical data. This will be addressed later in Section 4.6.7.9 for uncertainty analysis.

4.6.7.4  Pressure Constraints

As with Williams, et al. (2013) an estimate of 0.181bar/m (0.8psi/ft) reported was initially assumed for rock fracture pressure for the entire East Mey structure. This is consistent with the results from the geomechanical study (Annex 9: East Mey Geomechanics). A safety margin of 10% was, however, incorporated in this figure resulting to actual 0.163bar/m (0.72psi/ft) rock fracture gradient considered for this study. This critical number was used to monitor pressure at the injection wells in addition to the shallowest depth where plume could migrate. At no point should pressure exceed the fracturing pressure.
The rock compressibility is not a critical input parameter for CO₂ storage in the East Mey since the site has no physical boundaries and is in free communication with the much larger body of aquifer at its periphery. This extensive regional aquifer was seen during production of the Balmoral field (Gambaro & Currie, 2003) and can also be seen in Figure 4-92, where the initial pressures of the fields lie along the same gradient, even though production is initiated at different times. A value of $3.8386 \times 10^{-6}$ (1/psi) was selected for rock compressibility over the East Mey fairway as with Williams, et al. (2013).

### 4.6.7.5 Well Modelling

The well modelling was completed separately and after the dynamic modelling by Axis Well Technology, Section 4.6.7.8. Thus, no VFP (Vertical Flow Performance) curves were supplied and so only bottom hole pressures are reported for injection wells used for this study.

### 4.6.7.6 Model Calibration

The East Mey model was initialised with reservoir pressure and temperature observed broadly at the Balmoral field at the time of exploration, Table 4-21. The initial pressure was set to 216.8bar (3145psi) at 2148.8m (7050ft) TVDSS, since this field has the largest accumulation and is very close to the location of the injection site in the south east of the East Mey area. The model was initialised at 1986, the point at which production from the Balmoral field was started. This datum pressure has been applied to all the six model regions discussed above, Figure 4-57. Note that all the six regions are hydrodynamically in communication. Figure 4-64: shows the temperature gradient observed in the storage site. Inspection of temperature data in this figure shows that there is a slight temperature gradient of 3.08°C/100m (1.69°F/100ft) from 79.4°C (175°F) in the MacCulloch field (shallowest) to 118.9°C (246°F) in the Stirling Field (deepest). Despite this, the model will be initialised at isothermal temperature of 97.2°C (207°F) observed at Balmoral field. Water and CO₂ properties and their interaction are not significantly sensitive to temperature variation observed in the fairway. This allows an isothermal model to be used. Sensitivity analysis was, however, conducted to investigate the impact of model temperature on CO₂ storage characteristics in East Mey.

All the oil existing in the other five hydrocarbon fields is defined as having similar properties to the Balmoral field. This is a reasonable assumption for the purpose of this modelling study as all these fields have light oil with a similar composition. Additionally, three of these fields are far from the injection site located south east of the East Mey fairway. More refined studies might be undertaken in future should the composition difference between these oil fields need to be considered.

![Figure 4-64: Observed temperature gradient in the East Mey area](image-url)
A high level calibration was performed for this modelling study. Detailed calibration is not possible mainly because large cells have been used in the modelling which limits accurate saturation calibration prior to CO₂ injection. Attention was made only to calibrating two critical aspects of the model; the pressure footprint and the remaining hydrocarbon left in the fields with Mey Sandstone oil accumulations, prior to CO₂ injection. Although these two aspects are coupled in that oil production can affect the pressure footprint, they were decoupled, and a different approach has been taken, by calibrating each of them separately.

Many years of oil production from the incorporated oil fields caused their remaining oil volume to reduce compared to the initial oil in place at the time of their exploration; this needed to be correctly taken into account before undertaking the CO₂ modelling.

A rather simple approach was undertaken here. The remaining oil in place for the Balmoral and Blenheim fields which are closer to the injection site were approximated by subtracting the cumulative oil production, (Oil and Gas Authority, 2018), from their initial oil in place reported in the literature, (Gambaro & Currie, 2003). The remaining oil was then corrected by adjusting the respective oil-water contact for either of these two fields.

For the other three remaining fields, no adjustment was made regarding their remaining reserves at the time of CO₂ injection, as they are far from the storage site with minimal impact on CO₂ storage. Accordingly, no adjustments were made for their oil water contact (OWC). Table 4-25 shows the corresponding OWC for each field incorporated in the storage area.

It is acknowledged that this strategy would not reproduce the accurate oil saturation distribution within hydrocarbon fields prior to CO₂ injection, however, it is considered sufficient for the purpose of this modelling study. The reason for this is that the injected CO₂ plume is unlikely to reach these fields in significant volumes and change their water saturation. The key focus is the impact on pressure arising from the petroleum production process.

<table>
<thead>
<tr>
<th>Field Name</th>
<th>Region Number</th>
<th>Corresponding oil water contact (OWC)</th>
</tr>
</thead>
<tbody>
<tr>
<td>East Mey Fairway</td>
<td>1</td>
<td>100m (above structure)</td>
</tr>
<tr>
<td>MacCulloch</td>
<td>2</td>
<td>1900m</td>
</tr>
<tr>
<td>Donan</td>
<td>3</td>
<td>1974m</td>
</tr>
<tr>
<td>Brenda</td>
<td>4</td>
<td>2072m</td>
</tr>
<tr>
<td>Blenheim</td>
<td>5</td>
<td>2125m (corrected)</td>
</tr>
<tr>
<td>Balmoral</td>
<td>6</td>
<td>2138m (corrected)</td>
</tr>
</tbody>
</table>

Table 4-25: The OWC for each of the fields incorporated in the East Mey fairway

Figure 4-66 shows the reported initial pressure in a few fields in the East Mey fairway. It can be observed that the initial pressures of the fields follow nearly the same gradient although production was initiated at different times, Figure 4-65, which suggests the presence of a strong aquifer at the periphery of the storage site that provides sufficient pressure support allowing the natural water pressure gradient to be maintained over time. The pressure gradient observed in this figure is approximately 0.0988bar/m (0.437psi/ft) which is very close to the assumed water column density of 0.1bar/m (0.445psi/ft) compiled from RFT data.
The pressure in the East Mey fairway has been recorded by several RFT measurements over time. Table 4-26 shows the chronological order of all the collected RFT data in the storage area. RFT data have been used as a matching parameter for pressure calibration and to calculate the likely size of the connected aquifer around the model. There are 31 wells with reported RFT data in the storage area, collected between 1981 and 2010, though only those RFT data collected after 1986, the year at which model initialises, were used. Figure 4-67 shows the distribution of these wells over the East Mey fairway.

![Figure 4-65: The operational time frame for each of the hydrocarbon fields within the fairway](image1)

![Figure 4-66: Measured pressure gradient in different fields in the storage area](image2)
To calibrate the pressure, first, the full history of fluid injection (water) and fluid withdrawal (water and oil) were loaded in the model, (Oil and Gas Authority, 2018). However, as mentioned the remaining oil in place for each of these fields is already fixed. Therefore, it is assumed that no oil production will be undertaken during pressure calibration. Instead the voidage created by oil production is matched with equivalent water production at respective reservoir conditions and is produced accordingly. Again, this means that the volume of oil left after abandonment will not be affected as a result of the pressure calibration process.

### Figure 4-67: Distribution of wells with RFT data over the East Mey fairway

<table>
<thead>
<tr>
<th>Well</th>
<th>Year of Collection</th>
<th>Well</th>
<th>Year of Collection</th>
</tr>
</thead>
<tbody>
<tr>
<td>16/21b-4A</td>
<td>1981</td>
<td>15/20a-9</td>
<td>1990</td>
</tr>
<tr>
<td>16/21b-5</td>
<td>1982</td>
<td>16/21a-20</td>
<td>1990</td>
</tr>
<tr>
<td>16/16b-1</td>
<td>1982</td>
<td>15/20a-10</td>
<td>1990</td>
</tr>
<tr>
<td>16/21a-8</td>
<td>1983</td>
<td>16/21b-21</td>
<td>1990</td>
</tr>
<tr>
<td>16/21b-9</td>
<td>1983</td>
<td>15/24b-5</td>
<td>1991</td>
</tr>
<tr>
<td>15/25b-1A</td>
<td>1984</td>
<td>16/16b-4</td>
<td>1991</td>
</tr>
<tr>
<td>15/19-4</td>
<td>1984</td>
<td>15/24b-6</td>
<td>1992</td>
</tr>
<tr>
<td>16/21a-13</td>
<td>1984</td>
<td>15/19-7</td>
<td>1995</td>
</tr>
<tr>
<td>15/19-5</td>
<td>1986</td>
<td>15/25b-7</td>
<td>2004</td>
</tr>
<tr>
<td>15/25a-2</td>
<td>1988</td>
<td>15/25b-8</td>
<td>2004</td>
</tr>
<tr>
<td>16/16a-3</td>
<td>1988</td>
<td>15/25b-10</td>
<td>2004</td>
</tr>
<tr>
<td>16/21a-18</td>
<td>1989</td>
<td>15/25e-11</td>
<td>2004</td>
</tr>
<tr>
<td>15/24a-4</td>
<td>1990</td>
<td>16/21d-36</td>
<td>2008</td>
</tr>
<tr>
<td>15/20a-5</td>
<td>1990</td>
<td>15/20b-18</td>
<td>2010</td>
</tr>
<tr>
<td>15/20a-7</td>
<td>1990</td>
<td>15/19c-11</td>
<td>2010</td>
</tr>
<tr>
<td>15/25b-3</td>
<td>1990</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Table 4-26: Summary of compiled RFT data in the storage area**
Fluid production and injection was not distributed between the actual number of producer or injectors used at that respective field. Instead, all the observed fluid production or injection was conducted using only one synthetic injector or producer which injects or produces fluid (water) from only below the OWC at each field. Note that the aim is fairway scale pressure calibration over the entire East Mey area and not an oilfield scale accurate pressure calibration. Figure 4-68 shows the calibrating wells used to conduct injection and withdrawal for each field.

![Calibrating wells used to conduct production or injection for the fields located in the fairway area](image)

Calibration started in 1986 and the difference between recorded RFT and simulated RFT was noted for each well observed in Table 4-26. The size of the aquifer was then varied until the overall difference between observed and simulated RFTs became minimal. Figure 4-69 shows comparison between simulated and imported RFT data for two sample wells. The impact of the aquifer on the simulated RFT data in these two wells can be observed. Figure 4-70 also compares the pressure footprint with and without the numerical aquifer for a few wells. The difference between the two models can be observed.

Pressure calibration showed that the pore volume and permeability of the connected (numerical) aquifer around the East Mey are respectively 152km$^3$ and 1000mD. This numerical aquifer has been added around the periphery of the model. These properties of the aquifer are considered final and no further sensitivity analysis was undertaken in this regard. Thus, there is a very large and well-connected aquifer, hydraulically connecting the hydrocarbon fields and therefore the broader Mey Sandstone. This implies that significant overpressuring during injection operations is unlikely.
4.6.7.7 Storage Modelling Philosophy

4.6.7.7.1 CO₂ Supply Profile

Depending on CO₂ availability, three CO₂ injection scenarios are envisaged for injection in East Mey, Figure 4-71. Modelling results are presented for these injection scenarios. The details of the supply scenarios have been illustrated in the ACT Acorn CO₂ Supply Options report (Pale Blue Dot Energy, 2017) and are:

- **Phase 1 – Minimum Viable Development Case (Scenario 1):**
  - ~200kT/yr from part of the current St Fergus emissions, injected via one subsea injection to an injection site in the East Mey storage site, starting in 2023.
Phase 2 – 64MT Case (Scenario 2): Emissions include those in the Scenario 1, plus those from a potential build-out scenario, including CO₂ captured from hydrogen generation and importation of CO₂ via Peterhead Harbour (from shipping), with a maximum injection of 2.7MT/yr.

Phase 3 – 152MT Case (Scenario 3): A supply rate capped at 5MT/yr (259mmscfd) via four injection wells at different injection sites. Emissions include those in the Base Case, plus those from a potential build-out scenario, including CO₂ captured from hydrogen generation, importation of CO₂ via Peterhead Harbour (from shipping) and importation of Grangemouth emissions via the Feeder 10 pipeline to St Fergus.

A further case looking at 500MT with an injection rate of 5MT/yr was also investigated.

The injection inventories presented here, which range from 4.2MT to 152MT and even 500MT, do not represent the ultimate storage resource potential within East Mey. The evaluation of this ultimate potential is not part of this study.

Figure 4-71: CO₂ supply scenarios envisaged for Acorn project

4.6.7.2 Well Number and Placement

Between one and four wells will be required for CO₂ injection at East Mey, depending on the CO₂ injection profile. Wells were positioned at the south east of the model at deep locations. Figure 4-72 schematically shows the well placement adopted in this study. The cross section depicted between the four wells in this figure is used to demonstrate results. Table 4-27 shows the coordinates of these wells.
The work undertaken and reported in Annex 2: Dynamic Modelling Report confirmed that the best injection location is at the south east of the model where the fairway is at its thinnest. Injecting CO$_2$ in the south east region of the model ensures injecting at as high a pressure as possible before fracturing the rock. Injecting at this location also ensures having enough distance from the injection site to the Northern boundary of the fairway which maximises storage capacity and increases the security of storage. The spacing between wells is approximately 4km ensuring minimum pressure interference between them upon CO$_2$ injection, but also probably requiring dedicated surface drilling locations.

<table>
<thead>
<tr>
<th>Well Number</th>
<th>Latitude</th>
<th>Longitude</th>
<th>Single/Dual</th>
<th>Top (m)</th>
<th>Fracture pressure (bar)</th>
</tr>
</thead>
<tbody>
<tr>
<td>G1</td>
<td>58°14'9.3082&quot;N</td>
<td>1°11'39.3088&quot;E</td>
<td>Dual bore</td>
<td>2217</td>
<td>361</td>
</tr>
<tr>
<td>G2</td>
<td>58°12'0.9028&quot;N</td>
<td>1°11'51.2130&quot;E</td>
<td>Single bore</td>
<td>2202</td>
<td>359</td>
</tr>
<tr>
<td>G3</td>
<td>58°14'20.1235&quot;N</td>
<td>1°07'25.8681&quot;E</td>
<td>Single bore</td>
<td>2146</td>
<td>350</td>
</tr>
<tr>
<td>G4</td>
<td>58°16'18.2580&quot;N</td>
<td>1°05'44.8411&quot;E</td>
<td>Single bore</td>
<td>2158</td>
<td>351</td>
</tr>
</tbody>
</table>

Table 4-27: Coordinates of the injection wells

4.6.7.3 Development Strategy

The cessation of production (CoP) data reported by Wood Mackenzie for the five incorporated fields in this modelling suggests that production from the Donan and Brenda fields will continue until 2020 and 2021 respectively. Blenheim was abandoned in 2000. The CoP date for Balmoral and MacCulloch fields are 2021 and 2020 respectively, (Wood MacKenzie, 2015). However, inspecting the actual production data from the OGA suggests that production from these fields is likely to terminate much earlier. The last production figure for Balmoral is reported to be September 2017. There is no reported production.
for MacCulloch after 2015. Therefore, for this modelling, these fields are considered abandoned in 2018 and 2016 respectively. Figure 4-73 shows production from Balmoral and MacCulloch.

Figure 4-73: Production profile for Balmoral and MacCulloch fields

The last recorded productions are 2017 for Balmoral and 2015 for MacCulloch (images from OGA website)

CO₂ injection in East Mey starts in 2022 or 2023, depending on the CO₂ injection profile. The simulation is then extended 1000 years post injection to monitor the movement of the CO₂ plume for all the CO₂ injection scenarios. This is to provide assurance regarding the security of storage and the status of plume mobility post injection.

In all scenarios the dynamic model has assumed full perforation of the Mey Sandstone.

4.6.7.7.4 Well Injectivity Potential

Well injectivity is generally good to excellent in the storage site. No wells are limited by the fracture pressure at their chosen injection rate, assuming the considered fracture gradient of 0.163bar/m (0.72psi/ft). However, should a lower fracture pressure be assumed, the injectivity potential will be reduced accordingly. This will necessitate addition of new wells or drilling horizontal wells to increase their injectivity potential.

4.6.7.8 Dynamic Modelling Results

This section summarises the results for Phase 1 (4.2MT) and Phase 3 (152MT). Please see the full dynamic modelling report in Annex 2: Dynamic Modelling Report for the results of the Phase 2 case (63MT).

Additional discussion and sensitivities are presented for the Phase 3 152MT case.

One additional case was run to understand the possible dynamic storage resource of the East Mey site, where the 5MT/yr injection rate was extended for 100 years, with 500MT injected via four wells. The results of this imply that under realistic storage conditions with the site hosting multiple injection sites, a few gigatonnes of CO₂ could be stored in the East Mey fairway. Please see Annex 2: Dynamic Modelling Report for further detail on this case.

4.6.7.8.1 Phase 1 results (4.2MT scenario)

The lowest volume CO₂ injection profile depicted in Figure 4-71 will be injected using the only injection well required for this scenario (G1). Figure 4-74 shows the CO₂ plume at the end of simulation, Year 3040. This is the smallest CO₂ inventory with a small CO₂ plume and the storage is not limited by either plume migration or pressure responses. CO₂ enters the Balmoral field at 2070 by which time the field has already been abandoned.

Figure 4-75 shows trapping of CO₂ by different trapping mechanisms at the end of CO₂ injection (Year 2040) and 1000 years later (Year 3040). All the injected CO₂ becomes effectively trapped and no CO₂ remains mobile 1000 years after
injection. The plume is considered mobile if its migration velocity is larger than 10m/year, otherwise it is assumed trapped.

Figure 4-74: The extent of the CO₂ plume 1000 years after injection for the Phase 1 (4.2MT) CO₂ supply scenario

Figure 4-75: Fraction of CO₂ trapped by different trapping mechanisms for the Phase 1 (4.2MT scenario) after injection (left) and 1000 year later (right)

4.6.7.8.2 Phase 3 results (152.4MT scenario)

Four injection wells will be required for the largest CO₂ injection scenario (Phase 3). Table 4-28 shows the individual well injection profiles. This scenario is the maximum CO₂ scenario considered in this study. Most of the understanding of large scale CO₂ injection in East Mey is derived from this scenario.

<table>
<thead>
<tr>
<th>Year</th>
<th>G1 (MT/yr)</th>
<th>G2 (MT/yr)</th>
<th>G3 (MT/yr)</th>
<th>G4 (MT/yr)</th>
<th>Sum (MT/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2022</td>
<td>0.7</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.7</td>
</tr>
<tr>
<td>2023-2024</td>
<td>0.9</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.9</td>
</tr>
<tr>
<td>2025-2029</td>
<td>1.6</td>
<td>1.2</td>
<td>1.2</td>
<td>0</td>
<td>4.0</td>
</tr>
<tr>
<td>2030-2059</td>
<td>1.7</td>
<td>0.8</td>
<td>0.8</td>
<td>1.7</td>
<td>5</td>
</tr>
<tr>
<td>Sum (MT)</td>
<td>54.7</td>
<td>26.8</td>
<td>26.8</td>
<td>44.2</td>
<td>152.4</td>
</tr>
</tbody>
</table>

Table 4-28: Individual well injection profiles for the Phase 3 (152.4MT) scenario
Figure 4-76 and Figure 4-77 show the extent of the CO₂ plume after injection termination (Year 2056) and 1000 year later. The plume has propagated to both Balmoral (during injection) and Blenheim (1000 years later). As before Figure 4-78 shows trapping of CO₂ by different trapping mechanisms at the end of CO₂ injection (Year 2056) and 1000 years later (Year 3056). Only 1% of the injected CO₂ will remain mobile while the rest will be effectively trapped by either of trapping mechanisms.
Figure 4-79 shows the bottomhole pressure for each of the injectors used in this scenario. With a fracture gradient of 0.163bar/m (0.72psi/ft), operational bottomhole pressure did not exceed the respective fracturing pressure in any of the wells. However, care must be taken during initial injection to eliminate short periods of high bottomhole pressure as experienced by G2 and G3 at the time of well opening. This is expected to be manageable through injection operation. At all other times, the bottomhole pressures for all injectors all well below the fracturing pressure.

Figure 4-79: Profile of bottomhole pressures for injectors G1 to G4 under the for the Phase 3 (152.4MT) supply scenario

Figure 4-80 shows the ratio of observed pressure to fracture pressure within the plume at the time of injection termination. A ratio larger than 1 implies that the observed pressure is larger than corresponding fracture pressure at that grid block causing rock failure. Apart from the periphery of G4, at other points within the plume, the ratio is well below 1.

These results imply that pressure response is not critically important for CO₂ storage in East Mey as the site is connected to a significant body of aquifer at its periphery where pressure can dissipate during and after injection.

Figure 4-80: Fracture pressure within the plume at injection termination for the Phase 3 (152.4MT) supply scenario

A ratio of 1 implies that the observed pressure is larger than the corresponding fracture pressure at that grid block, which would cause rock failure. All ratios in this figure are below 1 so are within the safety margin.
4.6.7.8.3 Discussion of Results

This section presents a discussion of the results from the Phase 3 CO₂ supply scenario (152.4MT) dynamic modelling work.

CO₂ Storage Characteristics at East Mey

Figure 4-81 shows the injection profile into each individual zone during CO₂ injection. As shown, the vertical injection profiles are not identical in each individual zone. It can be seen that certain zones, particularly, zones C and D, take the majority of injected CO₂ as their petrophysical properties are better.

During and post injection the displacement is gravity-dominated and controlled by the extent of impermeable shale layers; CO₂ migrates underneath a disconnected shale layer as long as it continues and then flows to an upper sandstone layer. This process continues until injected CO₂ arrives underneath the storage caprock or has been trapped locally underneath a discrete shale layer. The presence of shale layers acts as a local trap in that they can retain a large fraction of the injected CO₂ and limit vertical buoyancy driven CO₂ migration underneath the caprock. This could increase the security of storage.

Figure 4-82 shows the CO₂ plume, this time with filtered cells. It can be seen in Figure 4-82 that an integrated complete CO₂ plume has not been formed on top of the model and that the CO₂ plume underneath the caprock is in fact disconnected.

Figure 4-83 compares gas (CO₂) saturation profiles respectively after CO₂ injection at 2056 and 1000 years later in a cross-section made across the four injectors (G1 to G4) shown in Figure 4-81. Comparison of Figure 4-83 and Figure 4-62 shows there is strong correlation between the gas saturation profiles and the distribution of shale layers. The distribution and properties of the shale layers have an important impact on the CO₂ distribution and the extent of the plume, both during and post injection.

As highlighted in the static modelling upscaling section (4.5.4.8), the removal of shales during upscaling could exaggerate vertical migration and Dietz tongue under the caprock, which implies that the dynamic modelling calculations are conservative.
Although shale layers promote lateral CO₂ migration (distribution) during CO₂ injection, post injection the rate of plume expansion will be small as CO₂ is already trapped underneath the shale layers. Figure 4-84 compares the extent of the plume just after CO₂ injection and 1000 years later. The area of the plume expands by more than 50% only after 1000 years compared to the time of
injection cessation. Comparison of the plume boundaries shows that the relative velocity of plume migration post injection is small. It is less than 2.5m/year toward the north west and around 1.1-1.2m/year towards the west and south west. For comparison, note that during injection, the plume expansion velocity is above 70m/year. This slow migration velocity post injection is due to a combination of small tilt of the East Mey structure and the presence of the shale layers as mentioned earlier.

In this modelling study, we assumed that the shale layers are completely impermeable. Sensitivity analysis, however, showed that transmissibility through the layers affects final CO₂ accumulation underneath the caprock.

**Compositional Effects**

A compositional fluid model was used in this study as per the learning observed in the Acorn storage site CO₂ storage modelling (Pale Blue Dot Energy, 2018). In the latter, it was observed that mixing of injected CO₂ with remaining gas in the Atlantic and Cromarty fields causes parts of the plume to become less dense and it migrates faster towards the northern storage boundaries. This mixing also affects security of storage by otherwise releasing the structurally trapped hydrocarbon gas in the two mentioned structures adding to the overall leakage risk. This is the added risk of releasing the otherwise trapped hydrocarbon by substituting it with injected CO₂, noting that hydrocarbons are more serious greenhouse gases compared to CO₂.

The results observed for CO₂ storage modelling in East Mey show that mixing effects here are not as significant as those observed for CO₂ storage in the Acorn storage site. This is because the remaining hydrocarbon in East Mey (mainly in Balmoral and Blenheim which are closer to the injection wells) is in oil phase rather than at gaseous state. CO₂ entering these fields, immediately dissolves in the remaining oil in these two structures and no immediate free gas phase is initially formed. After sufficient CO₂ dissolution in oil separation occurs and light gas is released into the CO₂ stream. The separated light hydrocarbon gas is, however, immediately trapped by either structural or residual trapping, similar to injected CO₂.

4.6.7.9 **Sensitivity Analysis**

Sensitivity analyses have been undertaken to investigate the uncertainty of several parameters. To enhance understanding, uncertainties were investigated for only the maximum CO₂ supply scenario (152.4MT). Nevertheless, the findings could be inclusive under other supply scenarios.
Relative Permeability

There is significant uncertainty with regard to the choice of relative permeability data used in this study. The chosen set of relative permeability is characterised with a relatively low gas endpoint relative permeability ($k_{rg}$) which could underestimate the plume mobility post injection.

To understand the impact of this uncertainty, a few alternative modelling scenarios were investigated in this study. Table 4-29 shows the properties of the alternate sets. Sensitivity analysis covers the ranges of endpoint gas relative permeability observed in the CDA inventory.

<table>
<thead>
<tr>
<th></th>
<th>$k_{rg}$</th>
<th>$S_{gmax}$</th>
<th>$S_{trap}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base set</td>
<td>0.2638</td>
<td>0.577</td>
<td>0.297</td>
</tr>
<tr>
<td>Set 1 (max $k_{rg}$ end point)</td>
<td>0.664</td>
<td>0.662</td>
<td>0.341</td>
</tr>
<tr>
<td>Set 2 (min $k_{rg}$ end point)</td>
<td>0.164</td>
<td>0.222</td>
<td>0.114</td>
</tr>
<tr>
<td>Captain X Relative Permeability</td>
<td>0.7</td>
<td>0.92</td>
<td>0.3</td>
</tr>
</tbody>
</table>

*Table 4-29: Alternate set of relative permeabilities used for sensitivity analysis*

Figure 4-85 shows that under all envisaged relative permeability data, the extent of CO$_2$ plume is similar. Slight differences in the shape of the plume can be attributed to the end point gas mobility for each relative permeability curve. The higher the end point mobility, the more sensitive will be the expansion of the plume to permeability contrasts. The Set 2 relative permeability curves have the minimum end point gas relative permeability ($k_{rg} = 0.164$) and is, therefore, least sensitive to permeability contrasts; its plume expansion is more stable in that less fingers have been formed in its expanding plume. In contrast, the Captain
X set of relative permeability (Pale Blue Dot Energy & Axis Well Technology, 2016) has the maximum gas end point relative permeability ($k_{rg}=0.7$) and therefore, its plume expansion is more unstable. Nevertheless, CO$_2$ storage and plume expansion are still controlled by properties of shale layers and trapping underneath them controls the lateral movement of CO$_2$ plume.

**Reservoir Temperature**

The base case modelling study was undertaken assuming the initial model temperature of 97.2°C (207°F), the reservoir temperature observed at Balmoral field. There is a temperature gradient across the site as was observed in Figure 4-64: . To investigate the impact of temperature on the modelling results, the model temperature was varied from minimum 79.4°C (175°F) to maximum 118.9°C (246°F) observed in Figure 4-64: and results were compared against the base case modelling studies. Figure 4-86 compares the extent of the plume for the respective 79.4°C (175°F) and 118.9°C (246°F) reservoir temperatures. The blue dashed line in each figure illustrates the extent of the plume in the base case modelling study 97.2°C (207°F). Whilst CO$_2$ mobility slightly changes with temperature, it can be observed that temperature does not have a significant impact on CO$_2$ storage in East Mey and the choice of isothermal model can effectively address the problem.

*Figure 4-86: Comparison of the size of the plume between maximum (top) and minimum observed reservoir temperatures*
The blue dashed line shows the extent of plume under base case reservoir model temperature of 97.2°C (207°F)

Shale Transmissibility

Shale layers have an important effect on limiting free vertical buoyancy driven CO₂ migration and could act as effective local traps storing part of the CO₂. An important assumption made in this study was that the shale layers are perfectly impermeable. To investigate the impact of shale properties on modelling results a few alternate scenarios were investigated. In these scenarios, the shale permeability was increased to 0.01mD, 0.1mD and 1mD, respectively, and the results were compared against the base case scenario. Figure 4-87 compares the extent of the plume among different scenarios. Cross sections between the four wells at the end of simulation (Year 3056) have also been depicted for better comparison, Figure 4-88. Results show that increasing the shale layer permeability reduces storage capacity underneath the shale layers and allows easier vertical migration of CO₂ underneath the caprock. In none of the scenarios is the fracture pressure limit reached anywhere in the reservoir.

Figure 4-87: Impact of transmissibility across the shale layers on the final plume accumulation underneath the caprock
4.6.8 Strategies to Increase CO₂ Storage Efficiency

The following section is a summary of the work undertaken to investigate strategies to increase CO₂ storage efficiency, for more information refer to Annex 3: Strategies for Increasing Storage Efficiency.

CO₂ storage efficiency (SE) is a measure of how efficiently a certain pore volume has been used for CO₂ storage; the larger the parameter, the better the overall utilisation of the storage pore volume. CO₂ can be stored in a supercritical state (free and trapped) or dissolved (in brine and oil). Storage at supercritical conditions is preferred from a storage efficiency perspective, though in terms of security of storage, storage of CO₂ in dissolved conditions is preferred.

In the context of this report, storage efficiency (SE) is described and calculated using the equation below:

\[
SE = \frac{\text{CO₂ inventory after 1000 years at reservoir conditions}}{\text{Total pore volume within the 1000 year plume footprint}}
\]

Equation 4-3

This definition implies that “Storage Efficiency” will be measured only in those areas affected or within the CO₂ plume footprint 1000 years post injection termination and not against the entire site pore volume. This definition also implies that the larger the CO₂ plume (under similar injection quantities), the smaller will be the storage efficiency i.e. a more concentrated CO₂ plume is more desirable in terms of storage efficiency.

Storage efficiency can be maximised as long as the security of storage has not been compromised. In this regard, certain considerations may limit the ultimate storage efficiency;
**CO₂ migration out of the storage complex:** CO₂ as a free supercritical phase should not leave the boundary of the storage complex after a given period of time e.g. 1000 years after the end of CO₂ injection. The reason for CO₂ plume movement and migration in the storage complex is natural forces that are present once injection has been stopped, this could be a natural water drift within the aquifer or buoyancy effects as a result of density difference between water and CO₂. CO₂ migration out of the storage complex may jeopardize the ultimate benefit of CO₂ storage, which is to hold CO₂ from reaching the atmosphere for long enough to eliminate its greenhouse effect.

**The maximum attainable pressure due to CO₂ injection:** the in-situ pressure at any given point within the storage containment should not increase beyond the fracturing pressure at that point. A fracture may create a path for the injected CO₂ to escape from the storage complex. The fracturing pressure is not constant and generally decreases at shallower depths. The critical fracturing pressure due to CO₂ storage is expected to be reached at the shallowest depths.

The East Mey site is an open aquifer storage system not bounded by physical boundaries. Pressure response upon CO₂ injection would not be critically important for this site due to free hydrodynamic communication between the site and its periphery.

### 4.6.8.1 Overview of strategies

Several strategies were investigated to understand their effectiveness toward increasing storage efficiency at East Mey.

For the base case scenario, the wells are assumed to be vertical with continuous injection over the entire interval and into all the zones. To enhance understanding of the storage process at the East Mey site, the 152.4MT scenario has been chosen, though the findings could be inclusive for other scenarios.

The baseline storage efficiency was 7.4%. The strategies are limited to those not affecting the cost and complexity of the project as the philosophy of the Acorn storage project is to initiate CO₂ storage in the North Sea at minimum possible cost and complexity.

The investigated strategies have been divided into several categories depending on the mechanism by which they are expected to be effective. Pressure relief strategies were not addressed. Likewise, carbonated water injection was also discounted, (Shariatipour, Pickup, & Mackay, 2012), as it is not practical for the range of CO₂ injection scenarios envisaged for the Acorn storage project.

### 4.6.8.2 Methodology and results

Figure 4-89 summarises the calculated storage efficiencies for the range of strategies investigated in this study. Apart from maximising the injected CO₂ inventory, none of the investigated strategies are actually effective for enhancing storage efficiency at East Mey compared to the base case (7.4%).
Figure 4-89: Comparison of storage efficiencies among different investigated strategies

The storage efficiency is largely controlled by CO₂ trapping underneath the shale layers and also the buoyancy driven vertical CO₂ migration around the shale layers during and post CO₂ injection. The latter distributes CO₂ within the storage system. Due to the gravity dominated nature of injection, none of the strategies investigated in this report are considered to be significantly more effective than the base case.

Injecting CO₂ downdip can theoretically enhance buoyancy driven CO₂ migration to shallower depths and thus take more advantage of CO₂ trapping underneath the shale layers. However, downdip injection can simultaneously prevent the injected CO₂ reaching the upper most layers. For the same reasons, zonal CO₂ injection was detrimental to storage efficiency. This simply caused a fraction of the storage volume in the top layers to become inaccessible for CO₂ storage, if CO₂ were only injected into a specific zone lower in the structure.

Slanted or deviated wells could bring some benefit in terms of increasing the storage efficiency by exposing injected CO₂ to further storage intervals. However, it does not affect the mechanism by which the plume is distributed within the site. In this case, it was observed that the storage efficiency decreased because of relatively larger well spacing compared to the base case model which caused formation of a larger CO₂ plume. Slanted wells could, however, be effective for increasing the injectivity potential of a well.

WAG was not effective for CO₂ storage in East Mey, since the nature of displacement was not viscosity dominated. This does not allow water cycles to follow CO₂ cycles and bring any improvement. High rate CO₂ injection also cannot bring any improvement at East Mey because even injecting at double the rate does not fundamentally change the flow pattern from gravity to viscous dominated.

Maximising utilisation of available pore volume by deliberately increasing the CO₂ inventory and positioning of the storage site are the only strategies which could enhance storage efficiency at East Mey. Storage at thinner areas of fairway limits the detrimental impact of gravity, allowing for higher storage efficiencies.

There is significant density difference between brine and CO₂ at the injection site. Brine and CO₂ densities at the injection site are 1017.1kg/m³ (63.5lb/ft³) and 602.3 kg/m³ (37.6lb/ft³) respectively which shows almost 40% difference. One effective strategy to increase CO₂ storage efficiency is to increase the CO₂ density to eliminate the density difference between brine and CO₂. Usually, this can be achieved by high pressure CO₂ injection. Results of many years of CO₂ flooding in the United States implies that increasing the operating pressure is an effective strategy for enhancing the CO₂ flow patterns (Brock & Bryan, 1989). However, this strategy is not practical at East Mey because the site is connected to an open aquifer system without physical boundaries which consequently does not allow effective pressure management.
4.6.8.3 **Summary**

Although CO₂ storage in East Mey is gravity dominated, the plume mobility is relatively small. This is mainly because of low tilt angle of the East Mey structure coupled with the existence of many shale layers. Shale layers may promote lateral plume distribution but could simultaneously trap CO₂ underneath.

Due to gravity effects, few strategies enhance the storage efficiency at East Mey. The most viable strategy for enhancing storage efficiency at East Mey is careful well positioning to take maximum advantage of shale layers and the structural trapping offered by them. Careful well positioning should further concentrate the plume given the fact that the plume is not very mobile and could increase storage efficiency accordingly.

Well positioning can also seek out local traps offered by shale layers to take maximum advantage of CO₂ storage under them. The concept is very similar to targeting remaining volume of hydrocarbon left in a conventional hydrocarbon field with deliberate well positioning. The challenge is however, that the exact distribution of these shale layers is not well known within site given the fact that intra well spacing is relatively large and shale layers are below the detectable limits of seismic.

In addition to these strategies, careful storage site selection is an important parameter for enhancing storage efficiency in East Mey. Storage in thinner regions of the site ensures a more viscous and less gravity dominated displacement and could enhance the storage efficiency accordingly.

The results depicted here are based on the final model built after upscaling over the entire East Mey fairway area. As the model is very big, this could have led to the omission of certain geological features because of upscaling and the choice of large cell sizes. It is recommended that a finer modelling study is undertaken near the injection site.

### 4.7 Containment Characterisation

#### 4.7.1 Storage Complex Definition

The East Mey storage complex extends 1,124km², from beyond MacCulloch and Brenda in the west and beyond the Balmoral oil field in the east, Figure 4-90. Currently the storage complex represents the boundaries of the static and dynamic model although it is likely that the boundaries of the storage complex will be reduced and refined going forward.

Vertically, the storage complex is bounded at the bottom by the Top Ekofisk, which sits below the Mey Sandstone, and the Eocene shales, which are the secondary seal and provide an additional barrier between the storage site and the seabed.

Laterally the boundaries are provided by the selection criteria used in the screening process: presence of Mey Sandstone, distance to the MGS pipeline less than 50km; 3D seismic coverage and well data coverage.
The East Mey storage complex is open at all sides, with the Mey Sandstone an extensive formation across the Central North Sea.

The faults present are mainly located to the north and west of the East Mey storage site and are very small scale, with maximum vertical offsets of 15-20ms observed. These structures have been interpreted as collapse structures formed by differential compaction of the brittle tuffs overlying the Forties channels (Ahmadi, et al., 2003).

The base seal is provided by the Ekofisk Chalk Group, which is about 185m thick in the East Mey area and typically formed by hard, white pale grey to beige limestones and pelagic chalks.

There is evidence of faulting affecting the underlying Ekofisk, with partial faulting of the Mey Sandstone, mainly in areas related to the existence of structural traps for hydrocarbons.

4.7.1.2 Hydraulic communication

As a part of the geological assessment of the East Mey area, direct pressure data, such as RFT (Repeat Formation Tester) and MDT (Modular Formation Dynamic Tester), were interpreted to better understand the following:

- The primary store consists primarily of the Mey Sandstone with some minor intervals of Forties Sandstone. Pressure data will reveal the degree of vertical pressure communication between the two formations.
- Horizontal pressure communication within the storage complex will be explored and its impact on pressure dissipation will be discussed.

Data
All 51 wells, interpreted for the East Mey storage development plan, were analysed and pressure data from the Mey, the Forties and the Maureen Sandstones were extracted from 24 wells. As a reference hydrostatic pressure to calculate overpressure, a water gradient of 0.1007 bar/m was selected, which fits well to the observed pressure gradients. Figure 4-91 shows all the overpressure data at their geographical location on the East Mey polygon using a colour code according to the formation the data were taken: Forties reservoir (red), Mey reservoir (yellow) and Maureen reservoir (blue). Also shown are three areas (North, Brenda and Balmoral) which will be analysed in detail.
East Mey storage complex; named fields are of Paleocene age.

Figure 4-92 shows all overpressure data on a timeline with the production time of some of the hydrocarbon fields in the East Mey storage complex. Generally, there is a clear trend towards depletion visible, although some fields also worked with water injection for pressure maintenance during production (grey dashed arrow). The steady decline in pressure over the years is a result of progressive petroleum extraction. Water injection was initially used in Balmoral for pressure maintenance purposes but was abandoned after many years when its effectiveness relative to natural water drive was questioned. This all points to a very significant natural water drive in the area which has been verified by the pressure matching in the simulation model discussed earlier. To this end it is unlikely that CO$_2$ injection will create any issues for rock integrity with good management.

Figure 4-93, shown by blue arrows are the times of operation of the biggest hydrocarbon fields inside the storage complex (data taken from the “Oil and Gas Authority Open Data website”). The dashed blue line for the Donan/Dunbarton field represents a temporary cease in production. There is a steady decline in overpressure (grey dashed arrow). Red – Forties Sandstone; yellow – Mey Sandstone; blue – Maureen Sandstone.

**Vertical Pressure Communication**

The ability to detect vertical pressure communication through a reservoir is a function of duration time of observations. Whilst formations that may reach pressure equilibrium over millions of years may also show distinct pressure boundaries over 10 to 40 years (observational duration) implying very poor pressure communication, even pressure depletion over a period of just a few years across a range of formations to very similar levels in a well is an indicator of strong vertical pressure communication.
Eight wells had pressure data covering at least two Paleocene formations. Of the eight wells, four wells show all pressure data falling on a single hydrostatic parallel gradient, allowing a pressure difference of 0.3 bar or less. Two wells show a cross-formation overpressure difference of between 0.8 and 1.0 bar. Two wells show evidence for a hindered vertical pressure communication and show a difference in overpressure across the formation boundary of 1.9 bar. The wells are located in the northern part of the storage complex and are located right next to each other, showing the same pressure values.

**Local horizontal pressure communication**

The variation of reservoir pressure with time in a producing petroleum province can be a powerful indicator of lateral connectivity. This factor is critical to the ultimate CO₂ storage potential and the injection rate that a reservoir may sustain.

**North:** Figure 4-93 shows the overpressure data of the northern half of the storage complex on a timeline with the activity of the Paleocene hydrocarbon fields. There are no hydrocarbon fields in the far north of the storage complex, but several fields, such as MacCulloch, Donan and Lochranza, are located at the southern part of the northern half. Additionally, the Balmoral field, as the biggest field in the area, has also been added. There is a general trend towards depletion visible across the northern area. Three wells drilled around 1990 show a variation in overpressure gradient of about 1 bar in the Mey Sandstone and 0.8 bar in the Maureen Sandstone in the opposite direction in the North-East of the storage complex. Pressure data taken around 2010 show an overpressure gradient difference of more than 3 bar in the Mey Sandstone between well 15/19c-11 and well 15/20b-18 (Lochranza). There is an indication that pressure depletion is locally restricted; however, considering the fact that Lochranza was under production when 15/20b-18 was drilled. The low pressure measured is likely a result of the drawdown arising from production close to an active well. This may not indicate any lateral pressure compartmentalisation.

**Figure 4-93: Pressure data on a timeline for the northern area.**

In Figure 4-93 the white dashed line on the map indicates a pressure delineation which could be a no flow boundary between two producing areas with good connectivity or a potential real baffle to hydraulic connectivity between 15/19c-11 and 15/20b-18.

**South:** Figure 4-94 shows the overpressure data of the southern half of the storage complex on a timeline with the activity of the Paleocene hydrocarbon fields. The Burghley field is not shown because production started in 2010, years after the latest pressure tests were taken. The majority of the pressure data were taken in the western part of the area and they all show a relatively consistent pressure regime between -0.3 bar and 1.1 bar between 1982 and 1991. The next pressure data were then taken in the Brenda field before production started, and it is likely that the negative overpressure values measured in 2004 were influenced by the production of the neighbouring Balmoral and Beauly fields, of
which the impact of Beauly is probably negligible compared to the much bigger Balmoral field. The two pressure measurements taken in the Balmoral field again indicate a non-equilibrium with the pressure in the western part of the study area. However, the pressure data measured by well 16/21b-4A, before production of Balmoral started, is higher than any of the other overpressure data in the south and hence some degree of compartmentalisation is possible. The negative overpressure measured by well 16/21a-20 in 1990 in the Balmoral field could be due to the drawdown of active Balmoral production wells.

![Figure 4-94: Overpressure data on a timeline for the Southern area](image)

In Figure 4-94 the white dashed line indicates the presence of a pressure baffle which could reduce the pressure conductivity between 16/21b-4A and the more westerly wells.

**Summary**

The overpressure data show a clear trend towards depletion, which is normal for an area under intense hydrocarbon production. Significant vertical cross-formation overpressure differences could only be observed in the North-East, an area not considered for CO₂ injection so far. Additionally, there is little evidence for pressure compartmentalisation in the Paleocene reservoir in the East Mey storage complex. Although some data show lateral changes in overpressure gradients, the low-overpressure areas might be directly related to low pressure zones in the vicinity of an active production well. However, the overpressure from well 16/21b-4A is higher than that of other wells, which could either be an indicator of partial compartmentalisation, or may be due to gauge error on this older well. Most of the overpressure variations can be explained by active production.

**4.7.2 Engineering Containment**

The integrity of the caprock is essential for safe CO₂ storage. Engineering containment risks include the risk of damage to the caprock by fracturing (e.g. from applying excessive pressure during injection) or failure to maintain an effective seal in the wells that penetrate the caprock.

In general, abandonment practices for wells have become more rigorous over time, and so older wells (especially pre-1984) pose a greater potential leakage risk. Wells with hydrocarbon shows drilled in the same formation as the storage site will generally have higher abandonment practices than those which did not encounter hydrocarbons, to ensure no hydrocarbon leakage to the seabed. Where wells are drilled for a deeper target than the storage formation, or have found no hydrocarbons, there is a greater chance that these will have lower abandonment standards to comply with regulations of the day and consequentially potentially fewer barriers between the storage reservoir and seabed.
A review of abandoned wells was carried out, which looked at 51 wells across the storage complex and examined completion and abandonment records, where these existed (Kapeerdoss, 2018).

The abandonment year for the wells reviewed ranges from 1974 to 2012 (over 38 years) and cover a range of abandonment specifications. In general, no wells deemed to have a greater risk were near the injection site and plume footprint, however data for some wells was incomplete or missing. The results of this study indicate that overall abandonment practices in the region are suitable for the geological storage of CO₂. A detailed review of every legacy well will be undertaken prior to final investment decision.

4.7.3 Containment Risk Assessment

A workshop on the containment risk assessment for the subsurface and wells was carried out and the results are discussed in this section. The risk analysis on CO₂ leakage was conducted using a methodology which allows a fast yet precise identification and assessment of relevant leakage scenarios. For this workshop, the term “loss of containment” was used to define any undesired vertical or horizontal flow of CO₂ out of the primary reservoir. The storage site life span is defined as 10,000 years with an operating life of approximately 30 years.

4.7.3.1 Methodology

The risk assessment is based on the “bow-tie” method, defining threats that may trigger a top event occurring, which can subsequently lead to other consequences, Figure 4-95. Instead of threats, 11 leakage scenarios were defined. As the top event, the loss of containment, or leakage, was chosen. Threat barriers and methodologies to reduce the threat, and hence make the top event less likely to occur, were also discussed. Subsequently, potential consequences, dependent on both the pre-defined leakage scenario and on the severity of the loss of containment, were discussed during the consequence analysis.

![Adjusted bow-tie diagram displaying the two main steps of the risk assessment: 1) leakage scenario analysis and 2) consequence analysis](image)

Figure 4-95: Adjusted bow-tie diagram displaying the two main steps of the risk assessment: 1) leakage scenario analysis and 2) consequence analysis

The leakage scenario analysis consists of three steps:

1. Definition of leakage scenarios: Here, all relevant leakage scenarios specific to an open offshore aquifer such as the East Mey storage site are identified and defined. Every leakage scenario leads, by definition, to “loss of containment”.

2. Identification and assessment of features events and processes (FEPs): Every leakage scenario will have generic and specific FEPs, which will either enhance or reduce the likelihood of the “loss of containment” occurring. A detailed discussion of the FEPs and
how they influence the risk of leakage scenarios is the core of the leakage scenario analysis. As a guideline, FEPs from the previous Captain X workshop (sub-area of the Acorn Storage Site) were used.

3. Identification of threat barriers: Threat barriers are active procedures to reduce the likelihood of the loss of containment to happen. They are often specific to the leakage scenario. A quantitative analysis of how much a threat barrier will reduce the risk of a leakage scenario occurring has not been performed. Instead, various threat barriers have been recommended.

The results of the leakage scenario analysis are displayed on a risk matrix to quantify the likelihood and the severity of the leakage scenario occurring.

The likelihoods are in Table 4-30.

<table>
<thead>
<tr>
<th>Score</th>
<th>Likelihood</th>
<th>Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Very Low</td>
<td>about once in 5,000 years</td>
</tr>
<tr>
<td>2</td>
<td>Low</td>
<td>about once in 500 years</td>
</tr>
<tr>
<td>3</td>
<td>Medium</td>
<td>about once in 50 years</td>
</tr>
<tr>
<td>4</td>
<td>Likely</td>
<td>about once in 5 years</td>
</tr>
<tr>
<td>5</td>
<td>Very Likely</td>
<td>about once per year or more</td>
</tr>
</tbody>
</table>

Table 4-30: Likelihood scale used in Leakage Workshop

4.7.3.2 Leakage Scenario Definition

Eleven relevant leakage scenarios have been pre-defined for the East Mey storage site, Figure 4-96. They are subdivided into primary pathways (which are defined to be loss of containment of CO₂ out of the primary reservoir into the adjacent storage unit) and secondary pathways (pathways which define loss of containment beyond primary pathways).

![Figure 4-96: The 11 leakage scenarios considered as relevant for the East Mey storage site](image)

**Primary Pathways**

1. CO₂ migrating through overlying primary seal, the Sele, Lista and Balder Shale, into secondary reservoir, one of the Eocene sandstone reservoirs.
2. CO$_2$ enters abandoned well and leaks to seabed. An abandoned well is defined as one drilled and completed before the CO$_2$ storage operation has started, and the CO$_2$ then leaks vertically to seabed.

3. CO$_2$ enters a modern well, one drilled for this CO$_2$ storage project (injection well, monitoring well, pressure relief well, etc.) or one that has been drilled through a CO$_2$ storage site (e.g. for future petroleum activity) and the CO$_2$ then leaks vertically to the seabed.

4. As 2, but CO$_2$ leaks into the secondary reservoir (Eocene sandstone reservoirs).

5. As 3, but CO$_2$ leaks into the secondary reservoir (Eocene sandstone reservoirs).

6. CO$_2$ leaks by migrating along the primary reservoir formation, the Mey sandstone, out of the storage complex (probably in a north-westerly direction) into shallower areas.

7. CO$_2$ leaks by migrating into depleted, underlying reservoir formations under production via the loss of containment pathways, such as wells.

Secondary Pathways

8. As 1, 4 and 5 but, additionally, CO$_2$ migrates along secondary reservoirs (Eocene sandstones) out of the storage complex.

9. As 1, 4 and 5 but, additionally, CO$_2$ leaks across the secondary seal into the overburden.

10. As 6 and 8 but, additionally, CO$_2$ reaches the seafloor either via a fault crosscutting the primary and secondary reservoir or by migrating all the way along the primary and secondary reservoirs until they reach the seafloor.

11. As 9 but, additionally, the CO$_2$ keeps migrating through the overburden to the seafloor.

4.7.3.3 Consequence Analysis

Consequences are traditionally displayed on the right-hand site of the bow-tie diagram. In the presented method, they are not necessarily directly related to the volume of CO$_2$ to leak out of the primary store, in other words the severity of the top event, but are strongly influenced by the definition of the leakage scenario, for example, referring to Table 4-31, a negligible volume of CO$_2$ could leak from the primary store (low consequence) into the shallow overburden outside the storage complex (medium consequence) and hypothetically there is nationwide media coverage (high consequence). Consequences can be subjective and hence dependent on the interpretation of the outcome of a leakage scenario. The impact of a consequence is not connected to the likelihood of the leakage scenario occurring and so when defining consequences for a leakage scenario with a very low likelihood, it must be assumed that the loss of containment has occurred. The impacts of consequences are displayed on a spider diagram and have three grades: low, medium and high, (Govindan, et al., 2018).

Consequences are described below with the impacts summarised in Table 4-31.

- **Impact of CO$_2$ leak out of the Primary Store**: The loss of containment severity itself has been defined as loss of containment over the storage life span of 10,000 years relative to the CO$_2$ present in the storage site according to the storage plan.

- **Impact on Storage Security**: This consequence is pre-defined in the leakage scenario. It defines where the CO$_2$ leaks to.
- **Impact on Social Acceptance**: This is estimated by the assumed media coverage, such as in print, broadcast or online news outlets, the intensity of the debate after loss of containment has occurred and whether it is present in public discussion. Social concern due to the loss of containment can be one of the main consequences, which not only compromises ongoing projects but also future projects.

- **Impact on the Environment**: This summarises the expected environmental damage on flora and fauna including the seafloor.

- **Impact on Hydrocarbon Industry**: Here, the impact on all aspects of the hydrocarbon industry, such as the production of fields nearby, is assessed.

- **Impact on Costs**: Costs directly related to the loss of containment such as remediation costs, loss of storage license, fines etc.

<table>
<thead>
<tr>
<th>Consequence</th>
<th>Low</th>
<th>Medium</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂ Leak from Primary Store</td>
<td>Negligible CO₂</td>
<td>Less than 10% of CO₂</td>
<td>More than 10% of CO₂</td>
</tr>
<tr>
<td>Storage Security</td>
<td>CO₂ migration out of primary store but remains inside storage complex</td>
<td>CO₂ reaches the shallow overburden (out with the storage complex)</td>
<td>CO₂ reaches the seabed</td>
</tr>
<tr>
<td>Social Acceptance</td>
<td>Not present in public discussion and no media coverage. Covered in the scientific community</td>
<td>Present in the local news; policy and industry are aware</td>
<td>Nationwide coverage, headline news and broad debate in public</td>
</tr>
<tr>
<td>Environment</td>
<td>Minor damage, no threat to the environment</td>
<td>Local damage, certain threat to flora and fauna and, if any, minor restitution required</td>
<td>Widespread damage with major risk for the environment; major restitution required</td>
</tr>
<tr>
<td>Hydrocarbon Industry</td>
<td>Negligible, strategic plans do not need to change</td>
<td>Small to medium adjustments required</td>
<td>Leakage of CO₂ requires a major change in operations including long delays and significant costs</td>
</tr>
<tr>
<td>Costs</td>
<td>Negligible</td>
<td>Up to £10 million</td>
<td>More than £10 million</td>
</tr>
</tbody>
</table>

*Table 4-31: Summary of the range of impacts used in the leakage workshop*

4.7.3.4 **Results and Conclusions**

**Likelihood Analysis**
The following conclusions can be drawn:

- All scenarios with a likelihood of three include potential loss of containment along abandoned wells. The main conclusion of this risk analysis is to carefully investigate the abandoned stage of all wells which might come into contact with the CO₂ plume.

- There is very little known about the nature of the Eocene Sandstones. This scenario requires more research, and a better understanding of the interaction of the CO₂ within the Eocene Sandstones is necessary.

- The loss of containment across geological formations or structures (scenarios 1 and 6), is generally less likely than the loss of containment along wells (scenarios 2, 3, 4, 5 and 7).

- All leakage scenarios using secondary pathways are expected to show rather sporadic, negligible volumes of loss of containment relative to the injected volumes.

Consequence Analysis

Table 4-32 lists a summary of the consequence of all leakage scenarios. The following conclusions can be drawn:

- The scenarios with the greatest consequence relate to CO₂ reaching the seabed (scenarios 2, 3, 10 and 11). Some of the consequences might involve penalties, loss of EUAs, environmental damage and remediation costs.

- The scenarios with the lowest consequences are when CO₂ remains within the storage complex, does not impact other subsurface users and does not require costly remediation. Scenario 7 has the lowest overall consequences for these reasons.

- The greatest cost relates mainly to any remediation that would be required and any fines for loss of containment that may be incurred.

- Storage integrity is directly determined by the definition of the leakage scenario. If the CO₂ remains in the storage complex or leaves the storage complex downwards or sideways without migrating into shallower formations, the consequence is "low" by definition. If CO₂ leaks to the seafloor, the consequence is "high".

- Public acceptance is in some ways connected to storage integrity but is more sensitive. Clearly, leakage to the seafloor will have the greatest impact on public acceptance. However, leakage into shallower formations, above the storage complex, will be a concern for the public even though the CO₂ all remains subsurface.

- Environmental damage only occurs when CO₂ reaches the seafloor. No scenario predicts notable volumes of CO₂, relative to the amount of injected CO₂, reaching the seafloor and, generally, only local damage is expected.

- The remediation of a loss of containment of CO₂ via a well, whether it is abandoned or a new well, is a worst-case scenario and is technically challenging. CO₂ leaving the storage complex
horizontally will likely require additional monitoring and may lead to a change of the storage project including appropriate remediation attempts to limit further CO₂ flow. If the CO₂ reaches the surface due to leakage scenarios 10 or 11, a wide range of remediation strategies are needed. However, leakage to the surface (Scenario 11) along geological formations can be avoided by remediation strategies to lower the impact of deeper leakage scenarios (scenarios 1, 4, 5 and 9).

The impact of loss of containment of CO₂ on the hydrocarbon industry is generally low in most scenarios. Appropriate care should be given to any future hydrocarbon development wells penetrating a CO₂ storage site e.g. drilling a deeper target (e.g. discussed in scenarios 3 and 5).
Monitoring, measurement and verification (MMV) of any CO₂ storage site in the United Kingdom Continental Shelf (UKCS) is required under the EU CCS Directive (The European Parliament And The Council Of The European Union, 2009) and its transposition into UK Law through amendments to the Energy Act 2008 (Energy Act, Chapter 32, 2008) in 2010 and 2011. A comprehensive monitoring plan is an essential part of the CO₂ Storage Permit.

A list and description of the offshore technologies was pulled together for the ETI SSAP Captain X Storage Development Plan and is in Annex 5 - MMV Technologies, (Pale Blue Dot Energy & Axis Well Technology, 2016). The list of technologies was summarised from two reports, (National Energy Technology Laboratory, US Department of Energy, 2012) and (IEAGHG, 2015). Many technologies which can be used for offshore CO₂ storage monitoring are well established in the oil and gas industry.

### Table 4-32: Summary of consequence impact of all leakage scenarios

<table>
<thead>
<tr>
<th>Consequence</th>
<th>Scenario 1</th>
<th>Scenario 2</th>
<th>Scenario 3</th>
<th>Scenario 4</th>
<th>Scenario 5</th>
<th>Scenario 6</th>
<th>Scenario 7</th>
<th>Scenario 8</th>
<th>Scenario 9</th>
<th>Scenario 10</th>
<th>Scenario 11</th>
</tr>
</thead>
<tbody>
<tr>
<td>Volume of CO₂ lost</td>
<td>Medium</td>
<td>Medium</td>
<td>Medium</td>
<td>Medium</td>
<td>Medium</td>
<td>Medium</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
</tr>
<tr>
<td>Storage integrity</td>
<td>Low</td>
<td>High</td>
<td>High</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
<td>Medium</td>
<td>High</td>
<td>High</td>
<td>High</td>
</tr>
<tr>
<td>Public acceptence</td>
<td>Medium</td>
<td>High</td>
<td>High</td>
<td>Medium</td>
<td>Medium</td>
<td>Low</td>
<td>Medium</td>
<td>Medium</td>
<td>High</td>
<td>High</td>
<td>High</td>
</tr>
<tr>
<td>Environmental damage</td>
<td>Low</td>
<td>Medium</td>
<td>Medium</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
<td>Medium</td>
<td>Medium</td>
<td>Medium</td>
</tr>
<tr>
<td>Cost</td>
<td>Medium</td>
<td>High</td>
<td>High</td>
<td>High</td>
<td>High</td>
<td>Low</td>
<td>High</td>
<td>Medium</td>
<td>High</td>
<td>High</td>
<td>High</td>
</tr>
<tr>
<td>Hydrocarbon industry</td>
<td>Low</td>
<td>Low</td>
<td>High</td>
<td>Low</td>
<td>High</td>
<td>Low</td>
<td>Medium</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
</tr>
</tbody>
</table>

**4.7.4 MMV Plan**

The outline corrective measures plan (CMP) discussed in Section 4.7.4.3 has been kept consistent with previous work on the Acorn Storage Site. For more detail, including about the purposes of monitoring and the different monitoring phases and domains, please refer to the ETI SSAP Captain X Storage Development Plan, (Pale Blue Dot Energy & Axis Well Technology, 2016).

Additional work will be carried out in the Concept and FEED phases to further refine and update the MMV plan, including detectability thresholds, spatial sampling and finalisation of timing.

#### 4.7.4.1 Mey Sandstone seismic response of CO₂

The Mey Sandstone was identified as a potential secondary containment formation for the Goldeneye CO₂ Storage Site (which was in the Captain Sandstone Formation) and therefore heavily studied during the FEEDs for the Peterhead CCS Project and Longannet CCS Project.
During that extensive work programme, the team built both 1D (Shell, 2011) and 3D (Shell, 2014) forward models to investigate the detectability of CO$_2$ within the Mey Sandstone.

The results show that in the area over the Goldeneye site, the seismic response of the Mey Sandstone is very strong for CO$_2$ saturations of greater than 10%, with acoustic impedance changes of almost 30% and CO$_2$ saturations of 2% possibly still detectable. The 3D forward model also showed that the shale layers within the Mey Sandstone do not unfavourably affect CO$_2$ plume detection.

The depth of the Mey Sandstone model studied in the Goldeneye FEED was 1200m, whereas the depth of the East Mey storage site is around 2200m. At shallower depths CO$_2$ is more compressible and so it is likely that the response at the deeper East Mey site will be less pronounced.

The seismic response of CO$_2$ in the Forties Sandstone (which is slightly younger than the Mey Sandstone) was also studied as part of the ETI Strategic UK Storage Appraisal Project (ETI SSAP). Here, the depth was ~2680m, with a porosity of 16-18% and a seismic response was detected in the forward model. The porosity of the Mey Sandstone in the East Mey area ranges from 17-33%.

It is recommended that additional seismic detectability work is carried out over the East Mey area during future work programmes.

It is also recommended that the seismic response of CO$_2$ in the overlying Eocene shales (secondary containment) is carried out during Concept and FEED.

4.7.4.2 Outline Base Case monitoring plan

Since the volumes injected in Acorn Phase 1, which start at 200kT/yr, are small, the current plan is for 1 x baseline 3D seismic survey to be carried out prior to injection and 1 x 4D seismic survey to be carried out once injection has ceased. If subsequent project development phases are sanctioned, with greater injection rates, the MMV plan will be updated during development planning.

1 x well intervention is planned for Phase 1 and a wireline logging suite will be run at this time to provide additional data for monitoring.

A dedicated monitoring (observation) well is not thought to be necessary or valuable for monitoring the East Mey injection site at this time. Since the area of the plume footprint is large, selecting one observation point that is relevant would be challenging. In addition, since the Mey Sandstone is an open aquifer site, it is anticipated that the injection pressure will dissipate shortly after shut in. Therefore, any pressure measurement in the injection wells should be representative of the greater storage site.

A distributed temperature sensor (DTS) and pressure and temperature (P/T) gauges are planned for the injection well. These will provide continuous data throughout injection.

The frequency and spatial distribution of side scan sonar and sampling of both seabed and water column will be decided during FEED.

Before the site can be handed back to OGA, confidence that the plume has stabilised must be demonstrated. Due to the uncertainties that exist over plume migration, (please see Section 4.6.7.8 for a discussion on CO$_2$ plume migration), it may be that the post-closure injection phase is extended beyond 20 years, with more extensive monitoring during this time. The post-closure monitoring period has been kept at 20 years but noting that this could be extended. Annual MMV reporting to the Oil and Gas Authority (OGA) will include information about site performance and may include commentary around any site-specific monitoring challenges that have occurred, which could include uncertainties.
over plume stabilisation. An on-going dialogue with OGA will be key to managing this uncertainty.

Figure 4-98 maps the selected technologies to the leakage scenarios discussed in Section 4.7.3.

### 4.7.4.3 Outline corrective measures plan

The corrective measures plan will be deployed if either leakage or significant irregularities are detected from the MMV plan data. Examples of significant irregularities and their implications are shown in Table 3-32.

Once a significant irregularity has been detected, additional monitoring may be carried out to gather data which can be used to more fully understand the irregularity. A risk assessment should then be carried out to decide on the appropriate corrective measures to deploy, if any. It may be that only further monitoring is required.

For the leakage scenarios discussed in Section 4.7.3 and mapped to MMV technologies in Figure 4-98, some examples of control actions and remediation options are shown in Table 4-33.
<table>
<thead>
<tr>
<th>Leakage Scenario and Number</th>
<th>Monitoring Technology</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Seabed sampling, ecosystem response monitoring, geochemical analyses of water column</td>
</tr>
<tr>
<td>Overburden</td>
<td>1 Primary reservoir to secondary reservoir</td>
</tr>
<tr>
<td></td>
<td>4 Primary reservoir to secondary reservoir via abandoned well</td>
</tr>
<tr>
<td></td>
<td>5 Primary reservoir to secondary reservoir via modern well</td>
</tr>
<tr>
<td></td>
<td>8 Lateral movement out of secondary reservoir after 1/4/5</td>
</tr>
<tr>
<td></td>
<td>9 Out of primary reservoir into overburden after 1/4/5</td>
</tr>
<tr>
<td>Seabed</td>
<td>2 Primary reservoir to seafloor via abandoned well</td>
</tr>
<tr>
<td></td>
<td>10 Vertical movement to seafloor after 6 and 8</td>
</tr>
<tr>
<td></td>
<td>3 Primary reservoir to seafloor via modern well</td>
</tr>
<tr>
<td></td>
<td>11 Vertical movement from overburden to seafloor after 9</td>
</tr>
<tr>
<td>Lateral</td>
<td>6 Lateral movement out of primary reservoir</td>
</tr>
<tr>
<td>Underburden</td>
<td>7 Vertical movement into underlying reservoir</td>
</tr>
</tbody>
</table>

Figure 4-98: Leakage Scenario Mapping to MMV Technology
<table>
<thead>
<tr>
<th>Leakage Scenario and Number</th>
<th>Overburden</th>
<th>Seabed</th>
<th>Lateral</th>
<th>Underburden</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1</td>
<td>2</td>
<td>6</td>
<td>7</td>
</tr>
<tr>
<td></td>
<td>Primary reservoir to secondary reservoir</td>
<td>Primary reservoir to seafloor via abandoned well</td>
<td>Lateral movement out of primary reservoir</td>
<td>Vertical movement into underlying reservoir</td>
</tr>
<tr>
<td></td>
<td>Investigate irregularity, assess risk, update models if required, increased monitoring to ensure under control</td>
<td>Stop injection, investigate irregularity via additional monitoring at seabed and acquisition of shut-in reservoir data, assess risk, update models</td>
<td>Investigate irregularity, assess risk, update models if required, increased monitoring to ensure under control</td>
<td>Investigate irregularity, assess risk, update models if required, increased monitoring to ensure under control</td>
</tr>
<tr>
<td></td>
<td>Increased monitoring to ensure under control (CO₂ should be trapped by additional geological barriers in the overburden)</td>
<td>Re-entry into an abandoned well is complex, difficult and has a very low chance of success. A relief well would likely be required.</td>
<td>If injection well - replacement of damaged well parts (e.g. tubing or packer) by workover. Worst case scenario would be to abandon the injection well. If P&amp;A well - a relief well may be required.</td>
<td>If injection well - replacement of damaged well parts (e.g. tubing or packer) by workover. Worst case scenario would be to abandon the injection well. If P&amp;A well - a relief well may be required.</td>
</tr>
<tr>
<td></td>
<td>4</td>
<td>10</td>
<td>6</td>
<td>7</td>
</tr>
<tr>
<td></td>
<td>Primary reservoir to secondary reservoir via abandoned well</td>
<td>Vertical movement to seafloor after 6 and 8</td>
<td>Lateral movement out of secondary reservoir after 1/4/5</td>
<td>Vertical movement from overburden to seafloor after 9</td>
</tr>
<tr>
<td></td>
<td>Investigate irregularity, assess risk, update models if required, increased monitoring to ensure under control</td>
<td>Investigate irregularity via additional monitoring at seabed and acquisition of shut-in reservoir data, assess risk, update models</td>
<td>Investigate irregularity, assess risk, update models if required, increased monitoring to ensure under control</td>
<td>Stop injection, investigate irregularity via additional monitoring at seabed, assess risk</td>
</tr>
<tr>
<td></td>
<td>Increased monitoring to ensure under control</td>
<td>Increased monitoring to ensure under control</td>
<td>Continued monitoring, licence additional area as part of Storage Complex if required.</td>
<td>Increased monitoring to ensure under control</td>
</tr>
<tr>
<td></td>
<td>5</td>
<td>3</td>
<td>11</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Primary reservoir to secondary reservoir via modern well</td>
<td>Primary reservoir to seafloor via modern well</td>
<td>Vertical movement from overburden to seafloor after 9</td>
<td>Vertical movement out of primary reservoir</td>
</tr>
<tr>
<td></td>
<td>Stop injection, investigate irregularity, acquire additional shut-in reservoir data, update models</td>
<td>Stop injection, shut in the well and initiate well control procedures, investigate irregularity via additional monitoring at seabed and acquisition of shut-in reservoir data, assess risk, update models</td>
<td>Stop injection, investigate irregularity via additional monitoring at seabed, assess risk</td>
<td>Investigate irregularity, assess risk, update models if required, increased monitoring to ensure under control</td>
</tr>
<tr>
<td></td>
<td>Replacement of damaged well parts (e.g. tubing or packer) by workover. Worst case scenario would be to abandon the injection well.</td>
<td>Replacement of damaged well parts (e.g. tubing or packer) by workover. Worst case scenario would be to abandon the injection well.</td>
<td>If injection well - replacement of damaged well parts (e.g. tubing or packer) by workover. Worst case scenario would be to abandon the injection well. If P&amp;A well - a relief well may be required.</td>
<td>Continued monitoring, licence additional area as part of Storage Complex if required.</td>
</tr>
<tr>
<td></td>
<td>8</td>
<td>9</td>
<td>11</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Lateral movement out of secondary reservoir after 1/4/5</td>
<td>Primary reservoir to overburden after 1/4/5</td>
<td>Vertical movement from overburden to seafloor after 9</td>
<td>Vertical movement out of primary reservoir</td>
</tr>
<tr>
<td></td>
<td>Investigate irregularity, assess risk, update models if required, increased monitoring to ensure under control</td>
<td>Investigate irregularity, assess risk, update models if required, increased monitoring to ensure under control</td>
<td>Investigate irregularity via additional monitoring at seabed, assess risk</td>
<td>Investigate irregularity, assess risk, update models if required, increased monitoring to ensure under control</td>
</tr>
<tr>
<td></td>
<td>Increased monitoring to ensure under control (CO₂ should be trapped by additional geological barriers in the overburden)</td>
<td>Increased monitoring to ensure under control (CO₂ should be trapped by additional geological barriers in the overburden)</td>
<td>Continued monitoring, licence additional area as part of Storage Complex if required.</td>
<td>Continued monitoring, licence additional area as part of Storage Complex if required.</td>
</tr>
</tbody>
</table>

Table 4-33: Outline Corrective Measures Plan
4.7.5 Shallow Overburden Definition

The overburden is a key part of the containment system but is often overlooked by standard oil and gas data acquisition due to the absence of commercial hydrocarbon accumulations. Potential CO₂ storage sites such as East Mey can always benefit from improved overburden definition and there are a range of ways to address this including:

1. High frequency shallow seismic
2. Seismic data processing to boost the high frequency content in the overburden
3. Seabed seismic site surveys

A paper on the potential for high frequency seismic to support this improvement is included in Annex 5: Shallow Seismic Feasibility.
5.0 Appraisal Planning

Appraisal Drilling: Whilst some uncertainties will always remain regarding the subsurface reservoir and caprock properties, the Geomechanical research undertaken for the East Mey storage site has provided additional insights (Annex 9: East Mey Geomechanics). Any remaining uncertainties are not considered significant enough to currently justify the expense of an additional appraisal well. In addition, the East Mey area has undergone hydrocarbon exploration and extraction since the early 1970s, with extensive drilling, logging, coring, testing, the results of which are mostly available through the CDA database. Hydrocarbon production indicates that there is strong hydraulic connectivity across the Mey Sandstone with pressure support from a large regional aquifer and RFT data confirming this. Therefore, no appraisal well is required for injection testing.

Seismic Acquisition: The PGS MegaSurvey used for the interpretation over the East Mey CO₂ Storage Site does not include “offset or angle stacks” which might improve the quality of data in some of the more challenging areas of interpretation. As described in the site characterisation section, the Top Mey Sandstone is a poor seismic reflector due to a lack of impedance contrast between it and the overlying shale. Over most of this area the event is indeed the top of the Mey Sandstone since the overlying Forties sandstone is largely absent. There are some parts of the area where a thin Forties sandstone present also complicates the direct imaging of the Top Mey Sandstone further. This feeds into a depth conversion uncertainty and therefore uncertainty in the Top East Mey structure map and ultimate plume migration. It is recommended that stochastic modelling of the uncertainty in the top structure map is carried out.

It is also recommended that a modern rock physics study and seismic acquisition modelling study is completed to confirm whether the imaging at Top East Mey can be improved upon before a decision is taken to acquire new seismic. This should also be revisited to check the performance of a new survey in tracking plume migration. The final investment decision on the project is not currently considered dependent on acquisition of a new seismic survey which might be follow later as a baseline survey before injection.

Pipeline Pigging: For East Mey, the base case for CO₂ transportation is from the St Fergus gas terminal to the East Mey Storage Site is re-use of the Miller Gas System (MGS) pipeline, which connects the Miller Field with the St Fergus Gas terminal. The MGS was constructed to handle CO₂ and water vapour laden natural gas as hydrocarbons produced in the Miller field area contained significant proportions of dissolved CO₂. The Miller pipeline had a design life of 20 years and was in service for 15 years before being taken out of use.

Uncertainty exists over particulates (rust, organics and produced sand) residing in the Miller pipeline, which could be a risk to injection. A pipeline pigging (cleaning) programme will reduce the initial particulate loading but there may still be a risk around long-term damage from continuous corrosive products. Investigation of solutions should be carried out during FEED, including options for subsea filtration systems. The pipeline conditioning programme will be established once the pipeline pigging run has been completed and the results assessed.

Other Appraisal Activity: Further modelling work is recommended which is fully calibrated to well by well production and pressure data from the operators
of nearby fields, the most relevant being Balmoral, Stirling, Blenheim, Brenda, and MacCulloch. It is also recommended to update the dynamic model to incorporate the results of the geomechanical rock study and refine the resolution of the model.

In addition, complete well abandonment records should be sought from Operators as not all abandonment records are on the CDA database. It is also important to work closely with all petroleum operators in the area to ensure that wells are abandoned to maintain maximum subsurface integrity in the light of a potential future CO₂ storage development. This is required to eliminate any further degradation of engineered containment risk introduced through well abandonment operations.

A more detailed discussion of the development uncertainties can be found in section 6.9.
6.0 Development Planning

6.1 Description of Development

A single subsea well tied back to St Fergus via the existing Miller Gas System (MGS) pipeline is the most technically robust methodology and cost-effective solution over the life of the project for developing the East Mey storage site.

The subsea well would be drilled from a semi-submersible drilling rig using thoroughly understood oil and gas drilling technology and the well will be completed with CO$_2$ compatible tubing.

The MGS pipeline is a 240km long, 30” pipeline that was used for transporting the CO$_2$ rich, natural gas from the BP Miller platform to St Fergus. The Miller platform ceased operations in 2007 and the pipeline has been operated under an Interim Pipeline Regime since 2009. The East Mey storage site sits approximately 180km out from St Fergus along this pipeline, Figure 6-1, and is 20-30km to the south east of the nearest point on the pipeline, Figure 6-8: MGS pipeline and East Mey wells. Figure 6-8 also shows further detail of this tie in to the initial injection well at the storage site.

Figure 6-1: Overview map showing section of MGS used in the development (blue), the end of which represents the tee point, (Oil and Gas Authority, 2018)

The base case is for the control, power and chemical requirements of the development will be provided by a 205km long umbilical from St Fergus, with control and monitoring of the well performed from St Fergus. This is perhaps the single most expensive component of this development. Alternatives should be developed for delivering these services without this umbilical. The CO$_2$ capture and compression facilities would also take place in St Fergus, capturing CO$_2$ emissions from processes at the St Fergus national gas facilities.
6.2 CO₂ Supply Profile

As indicated previously in the Storage Development Plan, the assumed initial supply rate for the reference case, Phase 1, starts at 200kT/yr in 2023 from the St Fergus terminal, delivered via one injection well. The profile is shown in Figure 6-3 as Scenario 1, with the reference case resulting in a cumulative injection of 4.2MT CO₂ over 17 years. For the dynamic modelling, the range of possible injection rates for one well was explored, up to 1.5MT/yr.

The ACT project deliverable D02 CO₂ Supply Profile, (Pale Blue Dot Energy, 2017), explored several possible CO₂ supply scenarios, based on possible future build-out of the Acorn CCS Project to include emissions from central Scotland and importation of CO₂ via ship to Peterhead port. These have been modelled for the Acorn CO₂ storage site and are described below and shown in Figure 6-3:

- **Phase 1 – Minimum Viable Development Case (Scenario 1):** ~200kT/yr from part of the current St Fergus emissions, injected via one subsea injection well at the East Mey injection site, starting in 2023.
- **Phase 2 – 64MT Case (Scenario 2):** Emissions include those in the Base Case, plus those from a potential build-out scenario, including CO₂ captured from hydrogen generation and importation of CO₂ via Peterhead Harbour (from shipping, e.g. from Teesside, Norway or Netherlands), with a maximum injection of 2.7MT/yr.
- **Phase 3 – 152MT Case (Scenario 3):** A maximum supply rate scenario of 8.6MT/yr, but capped to 5MT/yr (259mmscfd), commencing at the end of 2022 with 700kT/yr and reaching the capped point in 2030. This scenario involves St Fergus emissions including those from hydrogen generation, importation of CO₂ via Peterhead Harbour and importation of Grangemouth emissions via the Feeder 10 pipeline.
6.3 Well Development Plan

The well engineering aspects of the East Mey storage site were provided by Axis Well Technology, (Axis Well Technology, 2018).

For the Acorn CCS Project, the most economical development strategy is a single well subsea development with a completion designed to meet the proposed injection profile. The advantage of a subsea well over a platform well is that it does not require expensive substructure and it therefore carries considerably lower capital costs for single well projects. Limited maintenance is expected on the well during its lifetime and therefore the cost savings of a subsea development over a platform can be considerable. Restricting the well angle to less than 60 degrees inclination will allow well interventions to be performed using LWIV (Light Well Intervention Vessel) and wireline.

The subsea well will be drilled by a semi-submersible drill rig. This technology is well understood in the oil and gas sector and is readily available.

For a CCS development, the primary risks from a single subsea well development are filtration and single-well downtime risk.

**Filtration** - For some injection wells, the removal of fine particulates from the injection stream can be critical. If this is not done, then it can lead to a rapid degeneration of injectivity as the rock pore throats are plugged with fines. Platform wells can incorporate a filter pod on the upstream injection line, removing any particulates carried from the pipeline. These filters can be replaced or cleaned out on a regular basis. At present, there is no equivalent subsea filter system. Particulate debris remains a residual risk for subsea wells and therefore for the project. A pipeline pigging (cleaning) programme may reduce the initial particulate loading but is unlikely to prevent long term damage from continuous corrosion products. It is recommended this is explored more fully in the concept work and has been assumed that cleaning and inspection pigs are run every 5 years. It should also be noted that the Snøhvit CO₂ injection project is operating successfully for several years now using a subsea injection well at the end of a 152km long subsea pipeline.

**Sand Failure** – Some sand failure is considered likely and sand screens are recommended. As with water injection wells, there is a potential for sand failure in CO₂ injection wells. The principal causes of this are similar:

- Hammer effects during shut-in
- Cyclic stressing (applied during injection and released during shut-in)
- Downhole crossflow during shut-in (from and to formation zones with different charging profiles)

The effects of sand failure are that near wellbore injectivity can be reduced (failed sand packs the perforation tunnels or plugs the formation) or the well can be filled with sand (reducing injectivity and potentially plugging the well completely). In order to provide some offset from the caprock penetration point to the first injection point through the sand screens, it is recommended that the 9¾” shoe is set at least 40ft into the top of the Mey sandstone, and that a further joint of blank pipe with annular isolation is set above the screens.

**Downtime** - Should the well suffer any problems, including temporary or permanent plugging issues, integrity issues or control issues, the well may need to be shut-in for a period. As a single-well development (no redundancy), this means that no injection could take place in this scenario.

For this subsea well, the wellhead will be located close to the reservoir injection point. This means a lower cost vertical well can be drilled. It is however preferred that well profile through the Mey sands is at ~50° inclination to increase reservoir contact and to provide some offset of the point of injection from the caprock penetration point. A modest build rate of 2° per 30m has been assumed to achieve a 50° angle through the reservoir, Figure 6-4. This results in a kick off point below the 13¾” casing shoe at around 1,500m TVDSS and a lateral offset of around 330m at top Mey sandstone. Note that no drilling engineering has been done to optimise the kick-off point. There is however confidence that this well profile can be delivered successfully based on offset information in the area.

*Figure 6-4: Well profile to the reservoir*
6.3.1 Well Design

6.3.1.1 Well Construction

The preliminary reservoir target shown in Table 6-1 was used for the well design.

<table>
<thead>
<tr>
<th>Target Name</th>
<th>TVDSS (m)</th>
<th>UTM North (m)</th>
<th>North UTM (m)</th>
<th>East UTM (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>GI-01 Top Mey</td>
<td>2,216.43</td>
<td>6,456,397</td>
<td>393,974.4</td>
<td></td>
</tr>
</tbody>
</table>

*Table 6-1: Preliminary well location used in well design*

The G-1 Injector Well Basis of Design can be summarised as follows:

- The G-1 subsea injector well will be at 50° through the Mey sands target formation.
- The G-1 well will consist of 30" conductor, 13¾" surface casing and 9¾" production casing based on other offset data in the area.
- A 6" Sand screen completion will be run to prevent sand failure.

6.3.1.2 Well Completion

**Lower Completion:**

The lower completion would consist of 6" standalone sand screens. Any shale sections can be isolated by blank pipe (with or without external isolation packers). This will allow the formation sands to ‘relax’ and form a pack around the screens. Open hole gravel pack could be considered, but as it is a more expensive and technically complex installation operation, it is felt that the risk of poor clean-up or inefficient installation outweighs the benefits. Note that reactive shales are unlikely to be a risk in CO₂ injection wells.

The 9¾" shoe would be set around 12-24m into the Mey sandstone formation at an angle of 50 degrees, thereby providing some offset from the top injection point through the screens to the penetration point. This also provides a vertical stand-off of 12-24m TVD between the top injection depth and the caprock for thermal and frac initiation moderation.

**Upper Completion:**

A dual completion with two injection tubulars run into the same wellbore has been proposed. One tubular might be considered for low injection rates, the other for intermediate rates and both together for high injection rate. A dual completion consisting of a 2½" tubing string and a 4½" tubing string anchored at depth by a production packer in the 9¾" production casing (to be confirmed during FEED), achieves the target injection range.

Components include:

- 2½" 13Cr tubing (weight to be confirmed with tubing stress analysis work)
- 4½" 13Cr tubing (weight to be confirmed with tubing stress analysis work)
- 9¾" Production Packer
- ‘Y’ piece connector above packer depth
- Deep set surface-controlled tubing-retrievable isolation barrier valve (wireline retrievable, if available), on the 4½” ‘long string’
- Permanent downhole gauge (PDHG) for pressure and temperature above the production packer
- Optional DTS (Distributed Temperature Sensing) installation
- Tubing retrievable sub surface safety valve (TRSSSV) x 2
- Dual bore subsea production tree

The use of dual completion and (dual bore tree) with two different tubing sizes linked by a "Y piece" allows the pressure within the well during injection to be
regulated by limiting the change to amount of pressure loss due to friction as the rate changes. In this way the CO₂ can be maintained above its critical pressure giving more stable and predictable well behaviour.

The use of two TRSSSVs (one on each tubing string) provides a downhole barrier between the reservoir and surface. This could provide a critical means to prevent the release of CO₂ in the event of a failure in the subsea tree.

The DTS installation would give a detailed temperature profile along the injection tubulars and can enhance integrity monitoring (leak detection) and give some confidence in injected fluid phase behaviour. The value of this information should be further assessed, if confidence has been gained in other projects (tubing leaks can be monitored through annular pressure measurements at surface, leaks detected by wireline temperature logs and phase behaviour modelled with appropriate software). The remote subsea nature of the Mey injector well, however, adds some challenges to the installation and operation of a DTS system.

![Figure 6-5: Schematic of Proposed Completion](image-url)
6.3.2 Drilling Programme

The outline drilling, casing and mud programme for the well, is considered in the Axis Well Technology Preliminary Well Design and Modelling for the East Mey Subsea CO₂ Injector (Axis Well Technology, 2018).

The Mey G-1 CO₂ injector well will be drilled as a subsea well 150km North East of Peterhead as part of the Acorn CCS project.

The conceptual well design for a subsea CO₂ injector is as follows:

6.3.2.1 36" x 30" Conductor
For a subsea well a 30" conductor is normally used with a 36" top joint to provide sufficient fatigue resistance and bending strength against trawlboard impact. Normally 6 joints are being used and the conductor setting depth has been specified at 75m below the mudline.

6.3.2.2 17½" Surface hole and 13⅜" casing setting depth
The surface casing setting depth has been selected as 915m TVDSS (3,000ft TVDSS). This setting depth has been selected to provide sufficient formation strength to drill the intermediate hole section to the top of the Mey reservoir, while avoiding drilling into the top of the over-pressured shale section with seawater.

6.3.2.3 12¼" Intermediate hole and 9½" production casing setting depth
A 12¼" intermediate hole section will be drilled through the overburden formations and in to the top of the Mey aquifer, with the 9½" production casing being set approximately 30 m MD below the top of the Mey reservoir sands. This casing seat has been selected to isolate the Eocene, Balder and Sele formations and provide standoff between the caprock and injection interval, prior to drilling the injection interval with a lower mud weight.

6.3.2.4 8 ½" Production hole and 6" sand screens
An 8 ½" tangent hole section at 50° inclination will be drilled through the Mey sandstone for CO₂ injection purposes.

A 6" sand screen lower completion will be run to TD and hung of inside the 9¾" casing for sand control purposes.

6.3.3 Injection Forecast

For the Acorn CCS Project Phase 1, injection would commence in 2023 and continue for approximately 17 years. The final year of injection would be 2039. The injection forecast for the reference case starts at 200kT/yr and builds to 281kT/yr. This forecast results in a cumulative injection of 4.2MT of CO₂ which would be delivered by one injection well.

6.4 Offshore Infrastructure

This chapter reviews the recommended facility to transport and control CO₂ injection into the East Mey storage site from St Fergus.

6.4.1 Pipeline

The East Mey CO₂ storage site concept has been designed specifically to be serviced by the existing Miller Gas System (MGS) pipeline.
The MGS pipeline is 241 km long and extends from St Fergus out to the now decommissioned Miller oil platform near the Norwegian median line as shown in Figure 6-6 (extract from (BP, 2011)).

The first half of the 241 km, 0.762 mm (30") diameter pipeline from the St. Fergus terminal is trenched and buried and the second half is surface laid with the transition occurring at kilometre point (KP) 118 km (BP, 2011).

![Miller Gas System pipeline](image)

**Figure 6-6: Miller Gas System pipeline**

The decommissioning programme for the Miller platform was approved in December 2013 and the platform was removed in the summer of the 2018. The decommissioning programme did not include the MGS pipeline, instead the decommissioning programme sets out the facilities to be removed whilst leaving

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### Table 6-2: MGS pipeline design parameters, (Turin & Blacklaws, 2017)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>PL ID (DECC)</td>
<td>PL-720</td>
</tr>
<tr>
<td>Length</td>
<td>240 km (surface laid and buried)</td>
</tr>
<tr>
<td>Design Life</td>
<td>20 years</td>
</tr>
<tr>
<td>Outer Diameter</td>
<td>762 mm (30&quot;)</td>
</tr>
<tr>
<td>Material</td>
<td>X65 Carbon Steel HFW (high frequency welded)</td>
</tr>
<tr>
<td>Wall thickness</td>
<td>24 mm</td>
</tr>
<tr>
<td>Corrosion Allowance</td>
<td>3 mm</td>
</tr>
<tr>
<td>External</td>
<td>Coating concrete weight coating</td>
</tr>
<tr>
<td>Design Pressure</td>
<td>174 bar</td>
</tr>
<tr>
<td>Operating Temperature</td>
<td>+75 / -10°C</td>
</tr>
<tr>
<td>Capacity</td>
<td>10 MT/yr</td>
</tr>
</tbody>
</table>

---

6.4.1.1 Acquisition of the MGS Pipeline from BP

The Miller platform started production in 1992 and ceased operation in 2007. The pipeline was flushed clear of hydrocarbons in 2009. Since then, the pipeline has been serviced by BP, with the last known service/maintenance performed in 2013. The pipeline has been under the Interim Pipeline Regime (IPR) for the past 10 years, which has recently been extended for a period of further five years, until 2021. It is believed to have been filled with inhibited seawater at this time.
the pipeline in place, Figure 6-7 (BP, 2011). The onshore reception facilities have been removed.

![Diagram of pipeline suspension status]

**Figure 6-7: MGS 30" pipeline suspension status**

The pipeline was in use for 15 of its 20-year design life. Whilst in oil and gas it is not uncommon for pipeline life span to be used past the design life, a full inspection pigging programme and risk assessment would be required prior to the acquisition of the MGS pipeline from BP.

6.4.1.2 Pipeline Routing

The proposed injection site is approximately 200km from St Fergus and approximately 27km from the Miller Gas System (MGS) pipeline.

The maximum operating pressure (MOP) of the MGS pipeline is 170 barg.

A new pipeline will be required to connect the MGS pipeline to the injection manifold, as shown in Figure 6-8.

![Diagram of pipeline routes]

**Figure 6-8: MGS pipeline and East Mey wells, (Oil and Gas Authority, 2018)**

6.4.1.3 Preliminary infield pipeline sizing

The base case is to cut the MGS at 181km and install a new 16" tee with 30" and 16" pigging facilities. The 181km to 240km section of the MGS pipeline would be left flushed with inhibited seawater and isolated.

For the in-field 27km pipeline, the 16" size was chosen based on the previous the Acorn Storage Site flow assurance work (Pale Blue Dot Energy, 2018).

There are two pre-installed 12" tie-in points. One at KP145.25 and one at KP205.94. The use of either tee would require significantly longer additional “infield” pipeline runs (60km and 38km respectively). The additional cost of 12" lines would be in the order of £3.5m to £13.5m.

The use of these tees would be reviewed during feasibility and assuming that the flow profile for a longer 12" line is not adversely affected the cost of the additional longer 12" pipeline length will be reviewed against the cost of inserting a tie-in point at 181km.
Similarly, the technical feasibility of cleaning and drying of both of the pipelines during pre-commissioning and similar activities during the operational life of the pipeline will also be reviewed during feasibility.

6.4.2 Flow assurance along the MGS pipeline

Using the CO₂ supply scenarios, the expected operating conditions have been investigated along the MGS and proposed infield pipeline. The profiles were investigated under a no-NUI design scenario as CO₂ is able to arrive at the injection site, with envisaged arrival pressure of 130barg without compression requirement, under all investigated supply scenarios without violating the maximum design pressure of the MGS pipeline of 174barg. Table 6-2 shows the design parameters of the MGS pipeline.

With no-NUI design, the pipeline will be composed on two segments; a first segment MGS from St. Fergus (-1.824°E, 57.573°N) to the location of Tee at 0.799°E, 58.332°N and the second segment from the Tee location to the injection manifold at 1°11’39.3088”E, 58°14’9.3082”N. The entire length of the pipeline for this scenario is 207km composed of a 181km 30” MGS pipeline and another 26km 16” infield pipeline.

Without access to accurate MGS pipeline route depths from shore to the Tee location we have assumed that: the MGS pipeline deepens from shore (0m elevation) gradually to -90m at 45km of the pipeline and then from -90m to -145m (seabed depth) from 45km to the Tee location at 207km. The infield segment was assumed to be completely flat. Figure 6-9 schematically shows the pipeline profile from St. Fergus to injection manifold.

A few further assumptions have been made for estimating the pressure and temperature (P/T) profile. It has been assumed that the CO₂ stream is completely pure. Similar to the Acorn Storage Site work, a delivery pressure of 130barg at the East Mey injection manifold has been assumed. Water temperature was assumed to be constant at 7°C along the seabed at the periphery of the MGS pipeline. The discharge temperature of the compressor at St Fergus terminal is assumed to be 29°C. The discharge pressure was calculated accordingly. The pipeline has been assumed to be concrete coated with a heat transfer coefficient of 28tu/h.deg°F.ft². Profiles were also investigated under alternate conditions of heat transfer; a completely bare and a completely insulated pipeline scenarios with heat transfer coefficients of...
respectively 20Btu/h.deg°F.ft² and 0.2Btu/h.deg°F.ft². Schlumberger Pipesim has been used to generate the profiles, (Schlumberger, 2016).

Figure 6-10 shows profiles for actual pressure and temperature along the pipeline for the three different CO₂ supply scenarios mentioned above. First column of images illustrates pressure along the pipeline for different supply scenarios. Starting from the St. Fergus terminal (furthest left), pressure increases in the pipeline where the pipeline elevation decreases near the shore to the Tee location, after which pressure constantly decreases toward the East Mey injection manifold where the elevation flattens, and the pipeline diameter decreases from 30” to 16”. Under all scenarios, the difference between pipeline inlet and outlet pressures is negative (i.e. inlet pressure is less than the outlet pressure); however, the higher the injection rate, the lesser is this difference. Table 6-3 shows the inlet pressure and the maximum operating pressure observed for each CO₂ supply scenario. The inlet pressure is usually the pressure for which the CO₂ compression facilities should be designed.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>CO₂ inventory (MT)</th>
<th>Maximum Injection Quantity (kT/yr)</th>
<th>Inlet Pressure (barg)</th>
<th>Maximum Observed Pressure (barg)</th>
<th>Outlet Pressure (barg)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>4.2</td>
<td>281</td>
<td>116.7</td>
<td>130</td>
<td>130</td>
</tr>
<tr>
<td>2</td>
<td>63.8</td>
<td>2,682</td>
<td>119.7</td>
<td>132.1</td>
<td>130</td>
</tr>
<tr>
<td>3</td>
<td>152.4</td>
<td>5,000</td>
<td>126.4</td>
<td>137.1</td>
<td>130</td>
</tr>
</tbody>
</table>

Table 6-3: Maximum operating pressure under different CO₂ supply scenarios

The maximum operating pressure that was observed along the pipeline was for the 5MT/yr scenario estimated at 137barg which is well below the maximum operating pressure of the MGS pipeline of 174barg.

Inspection of temperature profiles in the second column of images in Figure 6-10 shows that unless the pipeline is completely insulated, the CO₂ stream temperature finally reaches the ambient water temperature for all the supply scenarios. Depending on the CO₂ flow rate, this may happen in between the first 5km of the pipeline length to more than its first 50km length from the shore. For the first supply scenario of 4.2MT, heat transfer and insulation does not affect the arrival temperature of CO₂ as because of very low CO₂ supply rates, sufficient time will be available for heat transfer to occur between CO₂ and water at the periphery of the pipeline.

Inspection of the velocity profiles shows that there is a sharp change of velocity at the location of Tee where the diameter decreases from 30” to 16”. As expected, the maximum velocity is for the 5MT/yr CO₂ supply scenario which is around 1.44m/s (5.2km/h). Along the 30” MGS pipeline, velocity constantly decrease as CO₂ temperature drops and its density increases.

Finally, the last column of images in Figure 6-10 show the P/T cross plot along the pipeline. As the supply rate increase, the profile shifts to the right in accordance with increased operating pressure.

Overall, these profiles together with the design parameters of the MGS pipeline depicted in Table 6-2 show that all the foreseen CO₂ supply scenarios can be effectively handled using the current MGS pipeline and the new 16” infield pipeline which will be constructed for the project.
Figure 6-10: Operating conditions along the MGS pipeline for the all four different CO$_2$ supply scenarios
6.4.2.1 Flow Assurance Considerations
6.4.2.1.1 Hydrate and Ice Formation

Formation of hydrate is described and controlled by the hydrate phase envelope. Hydrates could occur in presence of enough water concentration. Figure 6-11 shows the hydrate phase boundary generated for pure CO$_2$ using the Hydraflash software, (Hydrafact Hydraflash, 2016). The area below the envelope is where formation of hydrate could be expected and requires extra caution if the operating condition falls into this region.

![Hydrate phase envelope for a pure CO$_2$ stream](image)

Figure 6-11: Hydrate phase envelope for a pure CO$_2$ stream

![Pressure/Temperature profile observed in the MGS pipeline for different supply scenarios](image)

Figure 6-12: Pressure/Temperature profile observed in the MGS pipeline for different supply scenarios

*The inlet and outlet regions respectively correspond to the right and left ends of profiles. The red region is the region where formation of hydrate is expected.*

The phase envelope depicted in Figure 6-11 along with the profiles observed in Figure 6-12 may be combined to assess the probability of hydrate formation along the pipeline for different CO$_2$ supply scenarios. Figure 6-12 shows the operating window for each of the supply scenarios (coated pipeline) along the hydrate phase envelope transposed accordingly. It can be seen that certain regions of the profile fall in the hydrate phase envelope. This P/T region mostly occurs close to the outlet of the MGS pipeline and entirely within the infield pipeline as temperature drops to ambient water temperature.
Provisions for drying CO₂ before injecting it into pipeline (e.g. down to below 200ppm water content) should be undertaken. Use of inhibitors may also be considered as another option.

6.4.2  Corrosion
Pipeline corrosion due to presence of both water and CO₂ could be expected in the pipelines. Provisions should be in place for cooling and drying the CO₂ stream before injecting into the pipeline. Corrosion could be particularly significant at the inlet of the pipeline where CO₂ temperature is still high. In their Peterhead CCS project, Shell concluded that the pipeline inlet temperature should be maintained below 29°C to avoid the risk of ductile fracture.

6.4.2.3 CO₂ Shifting between Gaseous and Liquid Phases
CO₂ shifting between gaseous and liquid phases may cause significant sudden volume change which is not safe and must be avoided. CO₂ critical temperature and pressure are respectively 31°C and 74bar. Inspecting the P/T profiles in Figure 6-10 confirms that at all points along the pipeline, temperature is below CO₂ critical temperature. Therefore, CO₂ will be at liquid condition along both MGS and infield pipelines.

Should the temperature increase slightly from 29°C to above 31°C, CO₂ will appear at supercritical phase since pressure is well above CO₂ critical pressure and therefore CO₂ appearing at gaseous state is not expected. Overall, the risk of sudden CO₂ volume change along the transportation pipelines is very minimal.

6.4.3 Offshore CO₂ Injection Facilities

6.4.3.1 Subsea Manifold
The single tree will be completed with a subsea Xmas tree (X-tree) and fishing-friendly over-structure.

To allow the additional wells to tied-back through the same pipeline and control infrastructure, a simple subsea manifold will be installed local to the first well. This avoids having to shutdown injection operations at a later date when new wells are being tied into the existing infrastructure and eliminates costly duplication. The subsea manifold would also provide the facilities to allow pre-commissioning and operational cleaning and inspection pigs to be run.

The manifold would house the subsea umbilical termination unit (SUTU) which would also function as the subsea distribution assembly (SDA). Control and monitoring of the manifold would come via the subsea control module (SCM) mounted on the injection tree. This SCM would also control the actuated valves and monitoring for the well and X-tree. The subsea manifold will have a fishing friendly structure (shaped to minimise damage to and from fishing gear). A subsea well is considered as both the most economical and technically suited development concept for a single well development.

6.4.3.2 MGS Tee
To reduce the length of the infield pipeline it is assumed that the MGS will be cut and a piggable tee installed.

6.4.4 Control of the East Mey wells
One additional substantial cost carried by a subsea well is that of the umbilical.
An umbilical provides control and monitoring to subsea developments. Typically, they consist of a number of hoses containing high pressure, water-based hydraulic fluid used to actuate subsea valves, power and control cables and hoses used to provide chemicals, such as MEG, to the well. Long umbilicals are then protected by steel armour and a plastic coating.

The use of electro/hydraulic umbilicals is common within the oil and gas sector and although long umbilicals (e.g. >180km) are rare they have been installed. The 207km long electro/hydraulic umbilical for the East Mey development is an expensive option but is considered technically robust. Other options may provide a cost saving to the project and would be investigated fully during feasibility. The options that could be investigated during feasibility are:

- Use of a nearby oil and gas platform
- Use of a new normally unmanned (NUI) platform
- Fully electric development
- Power buoy

These are covered briefly in the following sections.

6.4.4.1 Control and monitoring using oil and gas infrastructure

The control and power requirements of small oil and gas developments would generally be provided by a nearby oil and gas facility which would provide a dual purpose, with the wells being tied back to the same development for conditioning of the oil and/or gas before being transported.

The oil and gas facilities that are local to the East Mey field are shown in the OGA map in Figure 6-13.

Figure 6-13: Oil and gas production facilities around East Mey, (Oil and Gas Authority, 2018)

Facilities within a 30km radius this side of the median are listed in Table 6-4 (OSPAR, 2015).
Oil and gas production facilities in the area of East Mey are still expected to be operational for a time after the start of injection but are not expected to be operational at the end of the injection period.

### 6.4.4.2 Control and monitoring using new NUI

Another control and power option that could be investigated is a small normally unmanned installation (NUI) for the development. The use of a NUI in the Central North Sea in a water depth of 140m requires significant capital outlay and an equally significant ongoing operational cost impact to the project.

If the design of the NUI can adequately reduce the capex and ongoing opex this may be an option.

### 6.4.4.3 Electrical umbilical

Most oil and gas wells use hydraulic fluid to power the opening of X-tree valves and subsurface safety valves. The technology for hydraulically actuated valves is a well understood, fail-safe, cost effective method of actuating valves in high pressure applications. In comparison, electric valves in similar duties have had less development. However, the use of fully electric X-trees and completions is being developed, with at least one fully electrical subsea well having been installed. The use of electric only umbilical’s is understood to have significant cost savings over a physically larger electric/hydraulic umbilical. However, the cost savings of an electric umbilical must be tied in with the cost of the technically less mature electric X-tree and subsurface completion.

### 6.4.4.4 Power buoy

The use of power buoy with satellite communications to St Fergus would also require the use of an electric X-tree and completion. As is the case for the electrical umbilical, the technology is less mature. Both options would be reviewed at feasibility stage to understand the cost and project risk trade-offs.

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**Table 6.4: Oil and Gas Production Facilities near East Mey**

<table>
<thead>
<tr>
<th>Name</th>
<th>Type/Age</th>
<th>Operated by</th>
<th>Distance from G1 (km)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Balmoral</td>
<td>Semi-sub floating production vessel; first production 1986 32 years</td>
<td>Premier Oil Talisman</td>
<td>5</td>
</tr>
<tr>
<td>Britannia</td>
<td>Large platform; first production 1998 20 years Bridge linked smaller platform; first production 2008 10 years</td>
<td>Conoco Philips</td>
<td>22</td>
</tr>
<tr>
<td>Alba</td>
<td>Large platform and floating storage unit (FSU); first production 1994</td>
<td>Chevron</td>
<td>23</td>
</tr>
<tr>
<td>Dumbarton/Donan</td>
<td>Global Producer 3 FPSO; first production from Dumbarton/Donan 2007 Global Producer 3 FPSO was used on the Leadon field from 2001 17 years</td>
<td>Total (was owned by Maersk)</td>
<td>23</td>
</tr>
<tr>
<td>Andrew</td>
<td>Platform; first production 1996 22 years</td>
<td>BP</td>
<td>24</td>
</tr>
<tr>
<td>Tiffany</td>
<td>Large platform; first production 1993 25 years</td>
<td>CNR</td>
<td>27</td>
</tr>
</tbody>
</table>
6.4.5 Fabrication and Construction

The onshore fabrication of the subsea X-tree, manifold, tee, umbilical and pipeline are likely to take in the order of 12 to 18 months, with a dive support vessel (DSV) for the installation of the subsea manifold, tee and local connections both at the tee and manifold.

A specialist umbilical reel lay vessel will be required for the umbilical installation, which is assumed to be along the approximate route of the MGS pipeline and infield pipeline and buried for protection. The infield pipeline from MGS is assumed to be surface laid out to the first well site.

A specialist s-lay vessel will be required for the infield pipeline installation.

6.5 Operations

The Acorn CCS Project development will inject CO\textsubscript{2} at an initial rate of 200kT/yr in phase 1, with potentially up to 5MT/yr in subsequent phases. The number of injection wells will vary depending on the phase of the project, ranging from one well to four wells in later phases.

The pipeline and any infield flowlines will require regular inspection, including surveys by remotely operated vehicles (ROV) to confirm integrity and ensure no spans have formed.

6.6 Decommissioning

The decommissioning philosophy for East Mey will be informed by the legal framework at the time of decommissioning but is likely to require comparative assessment of the decommissioning options. Decommissioning of the East Mey development is assumed to involve:

- Well(s) plugged and abandoned
- Subsea infrastructure recovered and taken ashore for recycling (manifold, X-tree)
- Pipeline cleaned and left in place, part end recovery and ends protected by burial
- Pipeline spools and flowlines recovered
- Umbilical and jumpers recovered

6.7 Post-closure Plan

The aim of post-injection/closure monitoring is to show that all available evidence indicates that the stored CO\textsubscript{2} will be completely and permanently contained. Once this has been shown the site can be transferred to the UK Competent Authority.

At the East Mey Storage site, this translates into the following performance criteria:

- The CO\textsubscript{2} has not migrated laterally or vertically from the storage complex
- The CO\textsubscript{2} within the structural containment storage site has reached a gravity stable equilibrium. Any CO\textsubscript{2} in an aquifer storage containment site is conforming to dynamic modelling assumptions – i.e. its size and rate of motion match the modelling results.
- The above is proven by a post-closure survey.

The post-closure period is assumed to last for a minimum of 20 years after the cessation of injection. During this time monitoring will be required.
6.8 Handover to Authority

Immediately following the completion of the post-closure period, the responsibility for the East Mey CO₂ storage site will be handed over to the UK Competent Authority. It is anticipated that a fee, estimated at ten times the annual cost of post-closure monitoring will accompany the handover.

6.9 Development Risk Assessment

This section will summarise new and open research questions that are of importance for the development of the East Mey CO₂ storage site. These questions have evolved during the technical work on East Mey and are therefore seen as recommendations for future work. Since the research questions are transferable to other projects, this also provides a summary of ideas for future storage development plans (SDP) for alternative storage sites.

6.9.1 Key uncertainties regarding CO₂ storage in the East Mey storage site

Permeability architecture: The main geological uncertainty that could have influence CO₂ injection and storage in East Mey is the overall permeability architecture and in particular the distribution and performance of the low permeability shale layers, which could act as baffles for injected CO₂ and could prevent the CO₂ from rising to the top of the reservoir. To fully exploit the capacity of the East Mey reservoir, the storage development plan explicitly recommends injection into multiple reservoir layers. However, the extent, permeability and thickness of the shale layers are uncertain and hence present an uncertainty for the performance of the development, but not a risk to the development itself. An improved understanding of the impact of baffles of CO₂ migration and plume development would lead to a more optimised storage operation. This is due to a more reliable prediction of the CO₂ migration paths and a more accurate estimation of storage capacity, including capillary and dissolution trapping; and hence would reduce uncertainty for CO₂ storage in the East Mey site.

In the state-of-the-art, large-scale East Mey reservoir model, the low permeability layers have only partially been populated as effective fluid flow baffles, mainly due to the upscaling procedure leading to large cells, which averages rather than captures the heterogeneity of the reservoir. Consequently, the assessment of the behaviour of the CO₂ in the multi-layered reservoir as well as the spreading of the plume after injection remains uncertain. This information is essential for a proposed CO₂ injection site and is recommended to refine the reservoir model going forward, based on the outcomes of the Acorn project. Geological studies and preliminary CO₂ flow simulations have shown that injected CO₂ will remain in a well-defined area and that the boundaries of the storage complex should be adjusted appropriately. This will reduce the number of cells in the dynamic model and hence the resolution of a smaller model area can be increased. The increased resolution should primarily be used to realise the horizontal low permeability shale layers as fluid baffles with true thicknesses. A range of realistic permeability functions and shale layer extents can then be applied to investigate the full impact of the geological uncertainty.

Abandoned wells: As in most CO₂ storage scenarios, the main risk for leakage is related to abandoned wells. There are more than 200 abandoned or soon-to-be-abandoned wells in the East Mey storage complex, excluding side-tracks and re-entries. In a preliminary study, Kapeerdoss selected 51 of these wells from the Common Data Access Limited database (Oil & Gas UK) and analysed them according to their risk for leakage (Kapeerdoss, 2018).
Although the study specifically states that it has a “large extent of uncertainty owing to limitations in data availability ...”, the results indicate that “overall abandonment practice in the region is suitable for geological storage of CO₂” (Kapeerdoss, 2018). However, the study only evaluated a subset of the existing wells in East Mey and a full survey including all wells would help to fully understand a) what data is missing for a complete abandoned well analysis; and b) if the wells for which data is available pose a risk for future CO₂ storage operations.

Uncertainty with regard to top structure map: A source of uncertainty is related to the seismic resolution of the top of the Mey Sandstone. The uncertainty is due to the quality of the seismic reflector pick and the velocity model used for the time-depth conversion, exacerbated by the underlying sedimentary geology of the Lista amalgamated channel structures, which varies laterally across the East Mey area.

A lack of acoustic impedance contrast between the reservoir sands and the surrounding shales makes it challenging to pick the reservoir-seal boundary. As the accuracy of the top structure map contributes to the determination of the fate of the CO₂ plume, the resulting uncertainty in the top reservoir pick will affect the CO₂ flow modelling. This uncertainty has to be analysed and quantified in order to be able to fully interpret the fluid flow modelling results.

Whilst the simulation results do not suggest that there is a significant dependence of the plume evolution upon detailed structural mapping (due in a large part to the low dips), nevertheless, it is therefore recommended to evaluate further the effect of uncertainties in the top reservoir structure using stochastic simulations.

6.9.2 Uncertainties Regarding CO₂ Injection and Migration within the Reservoir

6.9.2.1 Uncertainty with regards to the pressure response of the system

Pressure response is important during the CO₂ injection period, which is planned as a multi-well injection scenario in East Mey. The interpretation of pressure data in East Mey has shown strong evidence for good hydraulic communication within the reservoir. It is more complex than in the Acorn storage site. This is presumably due to the heterogeneity of the reservoir, where reservoir sections are separated by low-permeability shale layers. Additionally, rock strength can be compromised when fluid pressure exceeds the fracture pressure; experimental rock mechanics studies, being conducted by the University of Liverpool, could reduce the uncertainty of rock failure by measuring rock compressibility and fracture pressure.

6.9.2.2 Uncertainty with regards to geological data

Numerical fluid flow models have shown that storage performance post CO₂ injection is mostly controlled by buoyancy-driven CO₂ migration along and underneath low-permeability shale layers in the East Mey storage complex coupled with the effectiveness of trapping mechanisms i.e. residual and solubility trapping. The important parameters affecting any CO₂ migration are fluid properties (i.e. density contrast between CO₂ and brine), formation characteristics, formation tilt and, lastly, the effectiveness of trapping mechanisms over larger time scales. CO₂ trapping mechanisms may compete with CO₂ plume migration and make the plume migration slightly slower. A list of major uncertainties in this regard, which could affect the results, is presented;

Formation characteristics: The East Mey storage site in general and Mey Sandstone in particular are significantly large storage areas. Whilst there is
significant uncertainty with regards the precise architecture or reservoir heterogeneity away from wells, which may affect the extent of plume migration post CO₂ injection, thoughtful sensitivity analysis with dynamic modelling can quantify these effects and manage / contain these uncertainties. This is particularly relevant for shale layers, which control the extent of lateral and vertical plume migrations, during and post injection. The extent of the shale layers are difficult to resolve since well spacing is large in the East Mey complex. They are also not detectable by conventional seismic techniques. In addition to the extent of shale layers, their transmissibility is also not well known.

Relative permeability data: There are elements of uncertainty with regards to relative permeability data. As with Williams et al. (Williams, et al., 2013) in the absence of relative permeability data, the base set of relative permeability was taken from the Viking Field (Burnside & Nayer, 2014). Sensitivity analysis showed the plume migration is not significantly sensitive to the choice of relative permeability curves and is more sensitive to the properties/extent of shale layers. However, relative permeability is an important parameter controlling the injectivity of CO₂ during the injection phase, and thus accurate measurements of relative permeability data is required. Additionally, core flood experiments are usually conducted in viscous dominated conditions. The CO₂ flow pattern in the East Mey site away from injection wells is mostly gravity dominated. Therefore, there is added uncertainty related to the validity of these curves for East Mey displacement conditions.

Residual trapping: The derived residual trapping fraction of 0.3 is from a viscous core flood experiment taken from the literature, (Burnside & Nayer, 2014). The dependence of residual trapping on flow rates, especially for gravity dominated displacement, is still uncertain. Experimental measurement of relative permeability and residual trapping under different flow conditions on East Mey reservoir samples is required to improve the accuracy of the modelling results.

Rock Mechanical data: When modelling the CO₂ injection scenarios, no measurement of rock mechanical data over the East Mey area was available. As with Williams et al. (Williams, et al., 2013), a fracturing gradient of 0.181 bar/m (0.8psi/ft) was initially assumed for East Mey. This was confirmed by the detailed geomechanical analysis based upon core materials (Annex 9: East Mey Geomechanics). This was then corrected by applying a 10% safety margin to 0.158 bar/m (0.72psi/ft). This is an important input parameter in deciding the max injection rate per well and also for the process of well design.

6.9.2.3 Uncertainties with regards to modelling CO₂ flow

CO₂-brine interaction: There is no actual measurement of CO₂-brine interactions in the ambient conditions of East Mey. CO₂-brine interaction in East Mey has been estimated using correlations from the Eclipse300 CO₂SOL model. If the simulation is conducted using a different CO₂ solubility model, different results can be expected. Similar to the Acorn storage site development plan, simulations using alternative software packages (e.g. Tough, CMG) to benchmark the existing results is recommended.

Numerical dispersion: The impact of numerical dispersion, the effect of too large grid cells, on the accuracy of the CO₂ plume migration modelling and also CO₂ dissolution in the brine phase can be significant for East Mey. Identifying an appropriate gridding strategy, by reducing the size of the storage complex of local grid refinements, could decrease the effect of numerical dispersion and improve the quality and reliability of the modelling results.
6.9.3 Uncertainties Relating to Hydrocarbon Industry and Infrastructure

**Pipeline:** For East Mey, the base case for CO₂ transportation is from the St Fergus gas terminal to the East Mey Storage Site is re-use of the Miller Gas System (MGS) pipeline, which connects the Miller Field with the St Fergus Gas terminal. The MGS was constructed to handle CO₂ as hydrocarbons produced in the Miller field area contained significant proportions of dissolved CO₂. Production from the Miller Field ceased in 2007 and the pipeline was no longer in use. It is understood that the majority of the pipeline still exists and that it is flooded with inhibited seawater to preserve it.

Compared to the Atlantic and Goldeneye pipelines, which could connect the Acorn storage site with St Fergus, the re-use of the MGS for CO₂ transport is anticipated to be more complicated. A full survey and risk assessment are required to assess if it is worthwhile to re-use the pipeline and what is required to reconnect it between St Fergus and East Mey; or determine if it is more profitable to lay an entirely new pipeline system. It is also recommended to view a potentially re-installed MGS pipeline as a part of a future North Sea CO₂ transport network. The MGS pipeline reaches close to the Norwegian boundary and, if connected with Norwegian pipelines in the future, could be used for future trans-border CO₂ transport.

Uncertainty exists over particulates (rust, organics and produced sand) residing in the Miller pipeline, which could be a risk to injection. A pipeline pigging (cleaning) programme will reduce the initial particulate loading but there may still be a risk around long-term damage from continuous corrosive products. Investigation of solutions should be carried out during FEED, including options for subsea filtration systems.

**Pipeline Life:** The Miller pipeline had a design life of 20 years and was in service for 15 years before being taken out of use. Whilst it is common to run pipelines beyond the life span the inspection pigging run would be required to ensure that the pipeline is still fit for purpose.

**Hydrocarbon industry:** Uncertainty exists over possible future hydrocarbon exploration in a region with CO₂ storage, however on-going dialogue with OGA will ensure best practice is carried out to minimise risk.

6.9.4 The Assessment of Leakage Risk and Appropriate Remediation Strategies

**Quantifying leakage rates:** The risk analysis involved the quantification of actual CO₂ leakage rates for leakage scenarios based on expert elicitation. This process can be subjective and suffer bias. In order to improve the quality of the risk assessment, a better methodology has to be applied. When the CO₂ is injected into the primary storage reservoir, two types of mechanisms are at work, which affect the storage security at different scales: a) trapping mechanisms (reduce the mobility and ultimately permanently trap the CO₂ in the reservoir); and b) leakage mechanisms (lead to the release of the free-phase CO₂ back to the atmosphere). The impact of leakage versus trapping determines the volume of CO₂ that will remain trapped in the subsurface. The “Storage Security Calculator” (SSC), was recently developed to model the impact of these mechanisms on storage performance over geological timescales (Alcalde, et al., 2018). It is recommended to calibrate a numerical storage security calculator for an improved understanding of the leakage risk and a better and more specifically designed storage and monitoring plan.

**Mitigation and remediation strategies:**
Several mitigation and remediation strategies have been proposed to further reduce any residual leakage risk. However, a detailed analysis of the impact of these strategies using numerical simulations is required to evaluate their effectiveness. Additionally, mitigation and remediation strategies to reduce the risk and the severity of leakage have to be evaluated in terms of their costs and impact on the environment. It is recommended that during pre-FEED and FEED, a detailed MMV and corrective measures (remediation) plan should be developed that incorporates these recommendations.

6.9.5 Advanced Selection Criteria

Definition of the storage complex: The definition of the storage complex is an important decision. For East Mey, the horizontal boundaries are defined by the East Mey polygon covering an area of around 1,124 km². Recent research has shown that the injection of CO₂ will take place near the Balmoral Field in the south-east of the area and that injected CO₂ will not migrate into the south-west and the northern area of the storage complex. Hence, the initial storage complex could be unnecessarily large. By shrinking the storage complex and reducing the areal extent of models, the resolution of the reservoir model could be increased, and the quality of the modelling results could be improved.

As the secondary store, the Eocene Sandstones have been proposed because of their presence in most of the wells in the storage complex. However, little is known about how extensive and interconnected the sand formations are, so further research is required, including the possibility for a high resolution seismic survey (Annex 5: Shallow Seismic Feasibility) to better understand the Eocene reservoirs.

Predicting storage development costs: A proxy was used to calculate the development cost (i.e. drilling and connection to the pipeline network) of the storage site, based on the distance to the existent pipelines and the depth of the reservoir formation. This provided an early estimate of the costs and a method for the screening-out of potential sites that would be very expensive to develop. However, a CO₂ storage site has other costs that will be incurred during the lifetime of the project, which are not included in this calculation. In particular, storage efficiency can have a major indirect contribution to the cost of operations of a project: a site that appears very suitable in principle (e.g. located close to the existing infrastructures at an appropriate depth and with a great capacity), but with a very low storage efficiency may require extra injection wells and/or water withdrawal operations in order to reach its full potential, increasing overall costs dramatically. An accurate assessment of storage efficiency is required to calculate the levelised cost (i.e. the cost per stored tonne of CO₂) from which storage sites may be selected or dismissed. However, the way in which storage efficiency is calculated is currently not standardised. Future research efforts should focus on determining effective methods for the calculation of storage efficiency factors.

Stakeholder engagement: Operational factors may also have significant economic impact on development and should be taken into account from the early stages of the site selection process. The engagement of stakeholders was very useful for this as it provided feedback from specialists with a broad range of expertise (e.g. operators, industry experts, scientists etc.) and different points of view on the same problem. An even deeper collaboration as well as a more diverse selection of external experts is recommended for future projects.

Preliminary geomechanical and petrological assessment of shortlisted storage sites: The incorporation of a preliminary geomechanical and petrological characterisation study into the site selection process would further inform on the suitability and allow thorough comparison of the proposed storage
site lithologies. Particularly in regard to the accommodation of proposed injection rates, estimated fluid pressures and stress variations, as well as long-term geochemical interactions between the storage site lithologies and CO$_2$-rich fluids. Such procedures would be best implemented in the late stage short-listing of potential storage sites, with core from industrial hydrocarbon appraisal/exploration activities being acquired and tested to confirm suitability.

6.9.6 Risk Assessment

A workshop on the subsurface and wells containment risk assessment was completed for CO$_2$ storage in the East Mey storage site. The risk analysis on CO$_2$ leakage was conducted using a methodology, which allows a fast yet precise identification and assessment of relevant leakage scenarios. For the workshop, the term "loss of containment" was used for any undesired vertical or horizontal flow of CO$_2$ out of the primary reservoir.

The following risks and uncertainties are the outcome of the discussion of potential loss of containment. It should be mentioned that, at the time of this work, the development plan had not been finalised for the project and so this assessment represents a work in progress.

- Geological leakage across geological formations or structures is generally less likely than leakage along wells, and hence all scenarios with a likelihood of "medium" include potential leakage along abandoned wells. The main conclusion of this risk analysis is to carefully investigate the abandoned stage of all wells which might come into contact with the CO$_2$ plume.
- There is very little known about nature of the Eocene Sandstones. More research and a better understanding of the interaction of the CO$_2$ within the Eocene Sandstones would be helpful. In some areas, the Eocene Sandstones are overlain by shale with polygonal faults. The sealing capability of these faults remains unknown.
- Public acceptance is in some ways connected to storage integrity but is more sensitive. Clearly, leakage to the seafloor will have the greatest impact on public acceptance. However, leakage into shallower formations, below the storage complex, will be a concern for the public even though CO$_2$ remains subsurface.
- Environmental damage only occurs when CO$_2$ reaches the seafloor. No scenario predicts notable volumes of CO$_2$, relative to the amount of injected CO$_2$, reaching the seafloor and, generally, only local damage is expected.
- The remediation of any well that may have experienced a loss of containment of CO$_2$, whether they are abandoned or new wells, is a worst-case scenario and is technically extremely challenging. CO$_2$ leaving the storage horizontally will lead to the termination of the injection and storage project and, if necessary, remediation strategies.
- If the CO$_2$ reaches the surface, a wide range of remediation strategies are needed. However, leakage to the surface along geological formations can be avoided when monitoring techniques recognise a loss of containment out of the primary store early and remediation strategies can lower the severity of leakage in the subsurface.

The impact of a loss of containment of CO$_2$ on the hydrocarbon industry is generally low in most scenarios. Leakage of CO$_2$ will only have a "high" impact on the hydrocarbon industry when new hydrocarbon related wells are drilled through a CO$_2$ storage site.
6.10 Benchmarking to Previous SDPs

The East Mey is compared with four other CO₂ storage project SDPs – the Goldeneye (GY) (Shell, 2015; Chadwick, et al., 2014), the ETI SSAP Captain X SDP (Pale Blue Dot Energy & Axis Well Technology, 2016), the ACT Acorn SDP (Pale Blue Dot Energy, 2018) and the CO₂MultiStore project (SCCS, 2015). Information about ETI SSAP Captain X SDP and CO₂MultiStore were taken from the ETI SSAP Captain X SDP (Pale Blue Dot Energy & Axis Well Technology, 2016).
## Development Planning

<table>
<thead>
<tr>
<th>Aspect</th>
<th>CO₂Multistore</th>
<th>Peterhead CCS Project</th>
<th>ETI SSAP Captain X SDP study</th>
<th>ACT Acorn SDP</th>
<th>ACT East Mey SDP (this report)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Purpose</strong></td>
<td>Investigate the operation of multiple CO₂ injection sites within a single storage formation (Captain Sandstone).</td>
<td>Demonstrate that Goldeneye has sufficient capacity to contain 15MT of CO₂ for a period exceeding 1000 years.</td>
<td>To define a storage development plan for CO₂ storage in the Captain aquifer, including technical, commercial and outline regulatory considerations.</td>
<td>Built on existing ETI SSAP Captain X SDP to define an improved storage development plan for CO₂ storage in the Captain aquifer.</td>
<td>To define a storage development plan for CO₂ storage in the Mey Sandstone in the East Mey area.</td>
</tr>
<tr>
<td><strong>Seismic interpretation</strong></td>
<td>None performed.</td>
<td>Detailed seismic interpretation completed for the project across the full area of interest.</td>
<td>Specific seismic interpretation to identify secondary containment opportunities in shallow sediments.</td>
<td>Seismic interpretation to identify secondary containment opportunities in shallow sediments.</td>
<td>Seismic interpretation to identify secondary containment opportunities in shallow sediments. High-resolution feasibility study for shallow sediments.</td>
</tr>
<tr>
<td><strong>Road to consenting</strong></td>
<td>“The model does not support the level of accurate predictions needed for characterisation of a planned injection site and as underlying technical work for a CO₂ storage permit”.</td>
<td>The Project plan was to inject and store 10-15MT of CO₂ over a 10-15 year period commencing around 2020, but a potential extension of the site to 20MT has been demonstrated.</td>
<td>Project focused on deliver a specific outline storage development plan which can be progressed by a developer to a full permit application with an injected inventory of 60MT.</td>
<td>Project focused on CO₂ storage in the Captain aquifer based on the &quot;low-cost and easy to implement&quot; requirements defined for Acorn. Outline of future phases with multi-well injection scenarios.</td>
<td>Project focused on CO₂ storage in the Mey Sandstone aquifer based on the &quot;low-cost and easy to implement&quot; requirements defined for the Acorn project. Outline of future phases with multi-well injection scenarios.</td>
</tr>
<tr>
<td><strong>Reservoir correlation</strong></td>
<td>No detailed reservoir correlation across the full area of the study – constant 45m Upper Captain across the SCCS model.</td>
<td>No detailed reservoir correlation present in the report but detailed work was conducted by the operator and presented elsewhere.</td>
<td>Consistent correlation across the full area of the study.</td>
<td>As ETI SSAP Captain X SDP.</td>
<td>Consistent correlation across the full area of the study based on the petrophysical analysis prepared by GeoRes.</td>
</tr>
<tr>
<td><strong>Model gridding</strong></td>
<td>400m * 400m – potentially smoothing out key surface rugosity.</td>
<td>The static model of the regional aquifer stretches for approximately 100km from the west of Blake to the east of Hannay and is gridded at 200 x 200m.</td>
<td>200m * 200m for Primary model &amp; 400m * 400m for upscaled model.</td>
<td>400m *400m for flow model.</td>
<td>Horizontal extent: 400m *400m. Average vertical thickness 9.54m.</td>
</tr>
<tr>
<td><strong>Cap rock modelling</strong></td>
<td>Primary cap rock modelled as a single layer.</td>
<td>Geochemical and fault-slip/stress analysis.</td>
<td>Carry the Rodby, Carrack, Hidra and Plenus Marl unit as component layers (a suggestion from CO₂Multistore).</td>
<td>As per ETI SSAP Captain X study.</td>
<td>Lista, Sele and Balder Shales defined as cap rock. No further modelling performed at this stage.</td>
</tr>
</tbody>
</table>
**Modelling approach**
Splice of two models developed for two different reasons. Dynamic flow simulation including geomechanical modelling to analyse the effect of injection stresses on rock integrity and geochemical modelling to explore the rock chemistry interactions. Single coherent model built across the full area of interest with specific objective of site characterisation. Compositional simulator used, several injection scenarios modelled. Compositional simulator used, several injection scenarios modelled.

**Timeframe**
GY injecting 6MT from 2016 and Site B injecting 6MT from 2021 – operations active early whilst adjacent hydrocarbon fields in operation. Several injection scenarios with several wells, 1000 years recovery. GY injecting 1MT/yr from 2021 to 2031 in sensitivity. Site injecting 3MT/yr from 2022 in reference case. GY injection of a) 4.2MT, b) 32.2MT, c) 63.8MT, and d) 152MT; with 1000 years of recovery. CO₂ injection of a) 4.2MT, b) 32.2MT, c) 63.8MT, and d) 152MT; with 1000 years of recovery.

**Well schematic**
Uses all five existing Goldeneye Wells. Use of existing wells, which will be converted from production to injection service. Designed wells for the specific circumstances at Site X. As ETI SSAP Captain X SDP. As ETI SSAP Captain X SDP.

**Response**
Required the assignment of the underlying Valhall Formation (350m) with both porosity and permeability to keep the Captain operating at below fracture pressure. The minimum stress development is uncertain due to a re-pressurisation. Pressure rise in neighbouring fields expected. No evidence found for hydraulically active underburden. If the storage inventory is maximised (152MT) the bottom-hole pressure could be limited by the threshold fracture pressure. Even if the storage inventory is maximised (152MT), the bottomhole pressure (BHP) does not exceed the fracturing pressure in any of the wells, except in G2 and G3 at the time of well opening. This is expected to be manageable operationally. At all other times, the BHP for all injectors are below the fracture pressure.

**Hydrocarbon field fluid properties**
Used Goldeneye properties for all fields. Fluid samples and information available. Used published properties for each field as appropriate. As ETI SSAP Captain X SDP. Used published properties for oil in Balmoral and Blenheim fields.

**CO₂ plume movement**
Noted wide and rapid dispersal of plume but its full control was not required by the purpose of the study. A 3D three-phase Goldeneye numerical simulation model evaluated different injection scenarios to map out the range of capacity available for CO₂ storage. Injection inventory constrained to limit dispersal of plume within the defined storage complex. As ETI SSAP Captain X SDP, additionally the migration of hydrocarbons was simulated. Injection inventory constrained to limit dispersal of plume within the defined storage complex. Additionally, the potential migration of oil out of depleted oil fields was investigated.

**Table 6-5: Benchmarking East Mey to previous SDPs**
7.0 Budget & Schedule

7.1 Cost Estimating Basis

7.1.1 Introduction

An overview of the cost estimation process is presented in this section. This provides context for the project cost estimate information for both capital expenditure (Capex), operating expenditure (Opex) and abandonment expenditure (Abex).

7.1.2 Cost Estimate Accuracy

Cost estimates are prepared throughout the various phases of a large project development process. Estimate types are based on a standard international approach, (AACE International, 2016), and vary from Class 5 (least accurate) to Class 1 (most accurate) as the definition of each opportunity develops and matures through the process. Thus, progressing from a factored methodology (Class 5) to the use of detailed Material Take Off (MTO) information (Class 1). As the project moves through phases of maturation, the cost estimate should mature in line with the project. As time progresses, the base estimate becomes larger as the risk mitigations are incorporated in to the design, the contingency becomes less as the risks are understood and engineered out and the cost accuracy improves.

<table>
<thead>
<tr>
<th>Class</th>
<th>Project Definition (%)</th>
<th>Purpose</th>
<th>Estimating Accuracy</th>
<th>Basis</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>0 - 2</td>
<td>Concept Screening</td>
<td>L: -20% to -50%</td>
<td>Capacity factored, Judgement, parametric models</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>H: +30% to +100%</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>1 - 15</td>
<td>Feasibility</td>
<td>L: -15% to -30%</td>
<td>Equipment factored, parametric models</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>H: +20% to +50%</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>10 - 40</td>
<td>Budget</td>
<td>L: -10% to -20%</td>
<td>Semi-detailed unit costs; Major equipment list</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>H: +10% to +30%</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>30 - 75</td>
<td>Control</td>
<td>L: -5% to -15%</td>
<td>Detailed unit cost and material take-off</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>H: +5% to +20%</td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>65 - 100</td>
<td>Check</td>
<td>L: -3% to -10%</td>
<td>Detailed unit cost and material take-off</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>H: +3% to +15%</td>
<td></td>
</tr>
</tbody>
</table>

Table 7-1: Cost Estimate Class Definitions, (AACEI 18R-97)

7.1.3 Cost Estimate Components and Terminology

The components of a cost estimate generally include the following items:

- Base scope costs;
- Contingency;
- Market factors; and
- Inflation

**Reference Date Money:** Costs collected as an input to a cost model at a reference year.
RDM Escalated: Cost data referring to a base case estimate which has been escalated by market effects but without inclusion of the effects of inflation.

Nominal (or “Money of the Day”): Cost data to which the effects of inflation to the RDM Escalated value.

Real Terms (RT): Cost data consider the nominal value discounted to remove the effects of inflation considered at a specific date in time for the purpose of project comparison. The same principles are generally applied when defining Capex and Opex estimates.

Market factors include allowance for market escalation, i.e. experience of a Real Terms cost increase (or decrease) because of the market volatility, over and above the impact of inflation. Each activity within the estimate also needs to be uplifted to account for inflation and to estimate an equivalent cost at the time of Project Execution.

7.1.4 Cost Uncertainty

When preparing cost estimates, contingencies are assessed in order to arrive at a validity of the estimate with an accepted confidence level. Contingencies are assigned in order to raise the estimate to achieve a 50% confidence level, i.e. there is an equal chance that the 'as built' cost of the project will show an over or under expenditure. This figure is usually referred to as the P50 estimate and is, in statistical terms, the median of the range of possible final expenditure outcomes. The accuracy band for a cost estimate is defined by the range of costs from the P10 (10% probability that the project will come in on or under budget) to P90 (90% probability that the project will come in on or under budget).

7.1.5 Contingency

Contingency is added to a cost estimate to allow for further scope definition emerging in subsequent phases, and risks which have not been identified in the present project phase. It also covers minor design and field changes but does not include major scope changes, such as increased throughput/concept/layout.

Pale Blue Dot Energy uses commercially available simulation tools for cost risk analysis which apply a Monte Carlo simulation approach. This method generates a full range of possible outcomes and their associated probability of occurrence and is based on:

- Deterministic cost inputs and ranges;
- Probability distribution curves;
- Risks;
- Opportunities; and
- Levels of effort.

The output from the cost uncertainty modelling process provides an overall project contingency figure and also a cost uncertainty range, bounded by the P10 and P90 cost estimates.

7.2 Capital Expenditure Estimate

7.2.1 Methodology

Capital cost estimates have been taken from existing work wherever applicable or pro-rated from similar work to give a rough estimate at this stage of development.
7.2.2 Capex Estimate

The Class 4 estimate of capital required to develop Acorn Phase 1 is summarised in Table 7.2.

<table>
<thead>
<tr>
<th>Work area</th>
<th>Net Cost (£M)</th>
<th>Contingency (£M)</th>
<th>Gross Cost (£M)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-FID</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Concept &amp; FEED (including inspection pig)</td>
<td>19.3</td>
<td>1.2</td>
<td>20.5</td>
</tr>
<tr>
<td>Offshore</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MMV</td>
<td>9.0</td>
<td>0.1</td>
<td>9.1</td>
</tr>
<tr>
<td>Pipeline</td>
<td>38.9</td>
<td>15.1</td>
<td>54</td>
</tr>
<tr>
<td>Umbilical</td>
<td>149.2</td>
<td>59.7</td>
<td>208.9</td>
</tr>
<tr>
<td>Subsea</td>
<td>28.5</td>
<td>11.4</td>
<td>39.9</td>
</tr>
<tr>
<td>Well</td>
<td>32.6</td>
<td>6.5</td>
<td>39.1</td>
</tr>
<tr>
<td>Total offshore and pre-FID</td>
<td>277.5</td>
<td>94</td>
<td>371.5</td>
</tr>
<tr>
<td>Onshore</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total onshore</td>
<td>76.5</td>
<td>23.5</td>
<td>100</td>
</tr>
<tr>
<td>Full chain</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total full chain</td>
<td>354</td>
<td>117.5</td>
<td>471.5</td>
</tr>
</tbody>
</table>

Table 7-2: Capex estimate

Note: FEED, Front End Engineering and Design; FID, Final Investment Decision

7.3 Operating Expenditure Estimate

7.3.1 Methodology

Opex has been estimated by factoring the relevant Capex estimate. The post-closure and handover costs have been included in the Abex cost estimate.

7.3.2 Opex Estimate

The estimate of operating cost required to run the East Mey CO₂ CCS project per annum is summarised in Table 7-3 and over a 20-year period is summarised in Table 7-4.

The post-closure and handover costs have been included in the Abex cost estimate.

<table>
<thead>
<tr>
<th>Work area</th>
<th>Net Cost per year (£M)</th>
<th>Contingency per year (£M)</th>
<th>Gross Cost per year (£M)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Offshore</td>
<td>MMV (per annum)</td>
<td>1.1</td>
<td>0.5</td>
</tr>
<tr>
<td></td>
<td>Transport and subsea (per annum)</td>
<td>2.9</td>
<td>1.1</td>
</tr>
<tr>
<td>Onshore</td>
<td>Per annum</td>
<td>11.9</td>
<td>3.6</td>
</tr>
<tr>
<td>Full Chain</td>
<td>Total per annum</td>
<td>15.9</td>
<td>5.2</td>
</tr>
</tbody>
</table>

Table 7-3: Opex estimate (per annum)
7.4 Abandonment Expenditure Estimate

7.4.1 Methodology

Abandonment expenditure (Abex) costs are assumed to be 10% of the incurred capital cost of the project installed infrastructure and 25% of the capital cost of the well for the well abandonment.

7.4.2 Post-closure MMV

The post-closure and handover costs have been included in the Abex cost estimate.

Post-closure monitoring of the East Mey CO₂ storage site is expected to be required for a minimum of 20 years. The post-closure requirements are assumed to be 4D seismic initially after injection has ceased and seabed monitoring and sidescan sonar every 5 years for the post-closure monitoring period.

7.4.3 Handover to authority

Immediately following the completion of the post-closure period, the responsibility for the East Mey CO₂ storage site will be handed over to the UK Competent Authority. It is anticipated that a fee, estimated at ten times the annual cost of post-closure monitoring will accompany the handover.

7.4.4 Abex Estimate

The Abex estimate is shown in Table 7-5. These figures have not been adjusted for inflation.

<table>
<thead>
<tr>
<th>Work area</th>
<th>Net Cost (£M)</th>
<th>Contingency (£M)</th>
<th>Gross Cost (£M)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Offshore</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Well P&amp;A</td>
<td>17.9</td>
<td>3.6</td>
<td>21.5</td>
</tr>
<tr>
<td>Subsea, pipeline, umbilical</td>
<td>21.7</td>
<td>8.7</td>
<td>30.4</td>
</tr>
<tr>
<td>Post-closure MMV</td>
<td>10.2</td>
<td>0.3</td>
<td>10.5</td>
</tr>
<tr>
<td>Handover</td>
<td>5.2</td>
<td>1.0</td>
<td>6.2</td>
</tr>
<tr>
<td>Total offshore</td>
<td>55.0</td>
<td>13.6</td>
<td>68.6</td>
</tr>
<tr>
<td>Onshore</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total onshore</td>
<td>7.6</td>
<td>3.1</td>
<td>10.7</td>
</tr>
<tr>
<td>Full Chain</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total full chain</td>
<td>62.6</td>
<td>16.7</td>
<td>79.3</td>
</tr>
</tbody>
</table>

Table 7-5: Abex estimate

7.5 Uncertainty of Cost Estimates

The estimating accuracy associated with a Class 4 estimate is -30% / + 40%.

7.6 Schedule

The Acorn CCS Project schedule is shown in Figure 7-1.
Figure 7-1: Capex timeline
8.0 Conclusions & Recommendations

8.1 Conclusions

The work undertaken for the ACT Acorn study shows that the East Mey CO₂ storage site and corresponding development plan offers a significant storage resource in the Central North Sea that is accessible by existing infrastructure. Additionally, East Mey represents a strong candidate site for either backup to or buildout from the Acorn CO₂ Storage site.

Data

- The seismic 3D dataset used for the evaluation of the East Mey storage site was the PGS UK CNS Mega Survey (1900-2003), tiles G6, G7, F6 and F7. It covers all of the storage complex as data coverage was part of the site selection process.
- There is good regional well coverage across the East Mey site, including modern logs and both reservoir and caprock core data.
- The well data used included well logs, completion and abandonment reports from 51 wells. The data were downloaded from the UK Oil and Gas CDA database.
- The well log data analysed for the petrophysics was obtained from 45 wells and the core data from 17 wells.
- The geomechanical analysis (Annex 9: East Mey Geomechanics) was conducted on wells 16/21a-13 and 16/21a-20, near the proposed primary CO₂ injection site.
- Pressure data (from repeat formation testing (RFT) logs) were also used in the reservoir engineering work.

Containment

- The primary seal is provided by the Lista Shales, which is a proven seal for many hydrocarbon fields in the Central North Sea. Over the injection site it is about 75m thick and is continuous across the East Mey site.
- The storage complex has been defined as the subsurface volume between the Top Eocene Shale (the secondary caprock for the storage complex) and the Top Ekofisk. The base seal is provided by the Ekofisk Chalk Group.
- In addition to a high degree of confidence that the Phase 1 reference case of 4.2MT CO₂ can be safely and fully contained within the storage complex the same applies for the 152MT of CO₂ scenario for containment within the East Mey storage complex. One dynamic modelling case investigated injection of 500MT of CO₂, which was also fully contained within the storage complex boundaries.
- 1,000 years after the cessation of injection, the CO₂ plume would still be contained within the storage complex for all cases.
- Shale layers enhance the lateral migration of CO₂. However, they act as local traps in that they store a large volume of injected CO₂ preventing it from reaching the caprock. This, therefore, increases the security of storage.
- At no point during modelled CO₂ injection is the fracture pressure violated. A 10% safety margin has been applied to the fracture pressure.
The East Mey storage complex includes the Balmoral, MacCulloch, Donan, Brenda and Blenheim hydrocarbon fields, in addition to the saline aquifer beneath them. These fields may provide a degree of structural containment and are included in the dynamic model.

The Mey Sandstone reservoir quality is excellent, and the \( \text{CO}_2 \) plume is gravity dominated in between the interbedded shales.

A containment workshop was carried out. No high or very high likelihood events were identified. The loss of containment via an existing wellbore is not considered likely.

**Site Characterisation**

The East Mey \( \text{CO}_2 \) storage site complex covers an area of 1,124\( \text{km}^2 \) of the Mey Sandstone aquifer in UKCS quadrants 15 and 16 approximately 180km from St Fergus.

The Mey Sandstone of the East Mey storage site is 167m (550ft) to 259m (850ft) thick and comprises thickly bedded sandstones. Throughout the section there are thin pelagic mudstones present. These create localised baffles to vertical flow, but since the mudstones are thin, they are often not present everywhere.

The rock quality of the Mey Sandstone is excellent. The porosity ranges from 17-33\% with permeabilities from 16mD to 10D. The permeability shows a strong positive correlation with the porosity.

The rate of plume expansion is around 2m/year which is slow. This is because of low tilt angle of East Mey fairway coupled with the properties of shale layers.

The Top Mey Sandstone seismic pick is challenging to interpret across the storage site, due to the lack of impedance contrast between it and the overlying Lista Shale, but has been successfully achieved by all of the operators of nearby oilfields.

The depth conversion was carried out by using a velocity model extracted from the data available from the wells in the area. The velocity model was built using a velocity function calculated from the TWT seismic interpretation. The three TWT-interpreted surfaces were depth-converted using the velocity function.

There is no evidence of significant faulting in the reservoir or primary caprock and no faults have been included in the static model.

The Top Mey Sandstone dips gently at 1\(^\circ\) of tilt to the north west with 900m of elevation difference over a 50km distance, there will be areas with larger tilt due to local structures.

The well density is relatively high within the site and therefore the degree of confidence about the reservoir quality across the site is high. Core data is available for the primary caprock, which was studied in the rock laboratory (Annex 9: East Mey Geomechanics).

The geomechanics work indicates that The East Mey Storage Site lithologies are appropriate for the injection and storage of \( \text{CO}_2 \). The Mey Sandstone is highly porous and transmissible. Its bulk mineralogy is stable under \( \text{CO}_2 \)-rich conditions making it ideal for receiving and containing the proposed quantities of \( \text{CO}_2 \), 152MT (5MT/yr injection rate) for storage for a minimum of 1000 years after cessation of injection. The proposed injection pressures of 44.5-160bara can be accommodated by the lithologies without rock failure and disaggregation.
The Lista Shale caprock mineral composition has been assessed. The shale caprock has a suitable mineralogy and geomechanical character for long-term CO₂ storage.

The dynamic modelling results indicate the importance of using compositional simulation (versus black oil simulation) in correctly addressing the mixing effect between CO₂ and hydrocarbons.

**Storage Resource**
- The main storage unit is the Mey Sandstone of the Paleocene Moray Group.
- In addition to the Phase 1 reference minimum viable development case of 4MT CO₂ stored, significant volumes (up to 5MT/yr modelled) of CO₂ can be injected into the East Mey CO₂ storage site, with 152MT safely and fully contained within the Storage Complex. To store 152MT would require 4 injection wells. One case of 500MT at a rate of 5MT/yr using four wells has also been modelled, with the CO₂ fully contained within the storage complex.
- 1,000 years after Phase 1 injection stops, all the injected CO₂ remains effectively trapped by the trapping mechanisms and no CO₂ remains mobile 1000 years after injection.
- Strategies for increasing storage efficiency were modelled using a range of techniques regularly deployed in the petroleum industry. Dynamic storage efficiency could be increased from 7.4% to a little over 10%, but none of the techniques modelled has significant impact. This is due to the gravity dominated nature of injection.
- The fundamental challenge for improving CO₂ storage efficiency in the East Mey CO₂ storage site is the significantly gravity dominated displacement flow pattern that facilitates vertical migration of the CO₂ plume.
- Sensitivity analysis showed that storage in East Mey is not sensitive to relative permeability and that storage is largely controlled by the properties of shale layers. Transmissibility across the shale layers has an important impact on the final plume distribution and accumulation underneath the caprock.

**Appraisal**
- With many more than the 51 wells used here drilled into the Mey Sandstone aquifer, it is considered to be well appraised. In addition, decades of hydrocarbon production indicate that there is connectivity across the Mey Sandstone and good pressure support from a regional aquifer.
- Some performance uncertainties remain such as detailed reservoir architecture. These cannot be resolved by appraisal drilling.
- Additional production and pressure data from operators would help build a more thorough understanding of the regional connectivity.

**Development**
- Final Investment Decision needs to be in 2020 in order to achieve the first injection date of 2023.
- The planning work indicates that approximately 2 years are required to develop the store.
- A single subsea injection well is proposed for Phase 1 (200kT/yr), with a dual completion (common in oil and gas operations) capable of handling injection rates from 0.1MT/yr up to 2MT/yr as additional CO₂ sources come online. A dual 2½” and the 4½” tubing completion
can achieve a target rate range of 0.2 to 2MT/yr under initial reservoir conditions. One tubular might be considered for low injection rates, the other for intermediate rates and both together for high injection rate. A dual completion consisting of a 2⅞" tubing string and a 4½" tubing string achieves the target injection range.

- The existing 30" but decommissioned 174barg maximum operating pressure MGS pipeline that runs from St Fergus past the East Mey injection area can effectively handle all the envisaged CO₂ supply scenarios. Flow assurance is not a significant consideration for CO₂ transportation along the MGS pipeline if CO₂ is dried sufficiently. The MGS pipeline was first used in 1992 and was flushed clean of hydrocarbons in 2009. The Miller pipeline ceased use in 2007 so was in use for 15 years of its 20-year design life.
- A £372 million capital investment is required to design, build, install and commission the pipeline and subsea infrastructure and drill the well for phase 1, with a full development capex cost of £472 million. The pipeline, subsea and MMV operating cost is £112 million over the 20-year project life, with an average of £5.6 million per year. This cost is strongly dominated by the cost of the control umbilical at £209m. Alternative solutions to this should be found.
- The maximum allowable reservoir pressure within the simulation model has been constrained to 90% of the fracture pressure, which is 361 bara at the top of the perforations.
- The design assumption is a maximum 137barg arrival pressure of the CO₂ supply at the wellhead to enable injection through the life of the project. This would require a discharge pressure of between 117barg and 126barg from the pump station at St Fergus for Phase 1 and for the 152MT (5MT/yr) cases.

### 8.2 Recommendations

#### Appraisal Programme (including pre-FEED and FEED)

- Permeability prediction was a preliminary study and a thorough study is recommended for the next phase of the project, one that includes integration of all static and dynamic data, including electric logs, conventional and special core analyses, wireline formation tests and formation well tests. It should also extract as much useful information as possible from the seismic attributes which provide information on reservoir architecture.
- Explore pipeline particulate debris risk and pigging programme.
- Obtain well by well production and pressure data from the operators of Balmoral, Stirling, Blenheim, Brenda, and MacCulloch. Use this data to fully calibrate the reservoir simulation model.
- Obtain full abandonment records from operators and conduct a more comprehensive study and risk assessment of the abandoned wells in the planned storage complex.
- Detailed well design: explore the possibility of 10¾" casing for the dual completion. Although the well design was based on 95/8" casing for the purposes of this study, 10¾" casing may be required. Confirm the use of stand-alone screens to reduce chance of sand failure in the reservoir.
- Further investigation of transient pressure variations in the wellbore. If significant issues are identified, a combined deep-set shut-in valve
/ choke valve, could provide the solution to the variable rates (high injection range) required for this development.

- Explore suitable mechanism to perform downhole shut-in function which would mitigate transient effects. However, further work is required in the pre-FEED to substantiate this approach, or to provide alternate solutions.
- Investigation of thermal fracturing and the effect of increasing fracture pressure with increased pore pressure throughout the injection process to define fracture limits,
- Perform a full evaluation of a dual completion in GAP software.
- Refine the reservoir model near the injection site to incorporate shale layers more accurately during upscaling.
- Update the reservoir model with empirical data from the East Mey geomechanics workscope.
- Detailed mapping of secondary containment formations (Eocene sandstones and shales), including detailed review of possible leakage pathways.
- Undertake detailed seismic detectability modelling on the Mey Sandstone and secondary containment (Eocene sandstones).
- Develop detailed MMV and corrective measures plan, including thresholds for detectability, cost-benefit analysis and spatial requirements for monitoring technologies.
- Undertake stochastic modelling of the uncertainty in the top Mey structure map.

**Operational Planning**

- Identify and quantify opportunities for cost and risk reduction across the whole development, including operational efficiencies.

**Conclusions & Recommendations**

- Identify synergies with other offshore operations.

**Development Planning**

- Incorporate the regulatory licensing and permitting requirements into the development schedule and plan.
- Work with the petroleum operators of nearby hydrocarbon fields and the Regulator to ensure that the wells are abandoned using all best practice to secure the CO₂ integrity of the site.
- Work with the Regulator to ensure best practice in place for any future exploration drilling near the CO₂ storage site.
- Investigate options for decreasing the upfront and operational costs of controlling the development.
- Run intelligent pig through the Miller Gas System Pipeline.

**Future Study**

This section highlights areas which require further study which could be useful for broader industry research.

- A range of “worst case“ modelling studies to consider known uncertainties and knowledge gaps.
- Detailed modelling of CO₂ flow along shallower secondary containment (Paleocene) formations.
- Fault seal analysis to assess the likelihood of fault reactivation and faults as leakage pathways.
- Benchmark modelling results using other dynamic simulation software.
- Numerical modelling of sensitivities around CO₂ flow along an open well to the overburden or surface and impact of any mitigation and remediation strategies.
• Calibrate a numerical storage security calculator for an improved understanding of the leakage risk.
• Standardisation of calculating storage efficiency factors.
9.0 References


References


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Oil and Gas Authority. (2018). *UK Production Data*.


10.0 annexes

The following Annexes are provided in a separate document titled D08 East Mey CO\textsubscript{2} Storage Site - Annexes.

10.1 Annex 1: Data Inventory
10.2 Annex 2: Dynamic Modelling Report
10.3 Annex 3: Strategies for Increasing Storage Efficiency
10.4 Annex 4: Leakage Workshop Report
10.5 Annex 5: Shallow Seismic Feasibility
10.6 Annex 6: Petrophysics Report
10.7 Annex 7: Well Design
10.8 Annex 8: East Mey Modelling Philosophy and Research Test Report
10.9 Annex 9: East Mey Geomechanics
10.10 Annex 10: Risk Register