Peterhead CCS Project

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Executive Summary

The purpose of this document is to outline the insurance strategy for the Peterhead carbon capture and storage (CCS) Project. It covers financial risk management and insurance aspects concerning hazard risks including liability.

The project risk engineering review considers hazard risks to which Shell will be exposed for the life cycle of the project. The principal focus is on the various loss exposures for property damage, liability and production interruption including well control liabilities. The objective of the Design Phase Risk and Insurance Review (DPRIR) is to identify and review the hazards, risks and risk controls associated with the design, construction (modification), commissioning, operation, closure and decommissioning and the post-decommissioning phases of Shell activities associated with the proposed Peterhead CCS project.

This document lists various known and identified risks through various stages of the project life and provides assessment and possible insurance solutions or explains lack of solutions via standard insurance risk transfer methods. It is important to note that whilst an important part of risk management, insurance will be able to address only part of the financial risk exposure. Limitations are outlined within this document.

It should be noted that many of the risks involved in CCS are not that different from a typical Upstream Oil & Gas project (although the process of extraction is reversed) and are closely aligned with those of Enhanced Oil Recovery (EOR) projects in which Shell and various partners have been involved over the past 20 years. CCS is however perceived by insurers to be a combination of new technology due to the project being the world's first commercial scale demonstration of CO_2 capture, transport and offshore storage from a gas-fired power station. However, many components of the project are using existing technologies of which there is experience worldwide. Nevertheless, the lack of available underwriting information, including the absence of claims history, limited number of existing CCS projects over which to spread their risk, and undefined liabilities make it difficult for insurers to price the risk, and may thus cause reluctance to underwrite the risk or result in large risk premiums. Other aspects that require consideration are future insurability during storage phase or escalating cost of insurance over the multiple decades of the project's lifecycle. This strategy may be updated to reflect changes in legislation, insurance market conditions, changes in risk appetite etc.

1. Introduction

1.1. Project Overview

The project consists of the installation of carbon dioxide capture technology at the existing Peterhead gas-fired power station, conditioning and compression of the captured carbon dioxide, transfer by subsea pipeline to the existing Goldeneye gas platform in the central North Sea, and injection into the depleted Goldeneye gas reservoir for permanent storage. The CO_2 will be injected into the storage site at a depth of greater than 2,516m (8,255ft) below sea level. Once the required volume of CO_2 has been injected it is currently planned to monitor the reservoir pressure build-up for three years, and to leave the Goldeneye Platform in place. After this the platform will be decommissioned. Handover to the UK Competent Authority will take place post-closure with the timescales to be defined depending on the dynamic performance of the reservoir.

The project is being developed by Shell in conjunction with its Key-Subcontractor, SSE, the owners and operators of the Peterhead power station and supported by the UK government through the Department of Energy and Climate Change Office of Carbon Capture and Storage (DECC OCCS) to demonstrate the practicability of delivering an affordable CCS operation.

1.2. Approach to insurance and placing of risks

Shell will put in place a robust and cost effective insurance programme to provide appropriate cover for both the Construction and Operational Phases of the CCS project. We envisage only placing insurance with insurers that meet minimum financial security requirements (being Standard and Poor's (A-) or equivalent by other rating agencies) including Shell's Group Insurance Companies (GICs).

1.2.1. *Procurement process*

Current insurance procurement strategy is based on the project being 100% Shell UK Ltd. The Project is also considering the use of a Special Purpose Vehicle as an alternative venture structure for the project; however, the scope of this plan does not address insurances in connection with such structure.

Shell will apply its standard Risk Insurance Strategy to CCS activities. Shell will utilise the GIC (the Group Insurance Company) to insure the more standard property damage, business interruption and third party liability risks associated with the project particularly during operational phase.

All Shell companies and affiliates procure insurances as required by law. Shell arranges Property and Casualty insurance (including General Third Party Liability) via the Group Insurance Company (Solen Versicherungen AG (SVAG)). These insurances are transacted directly without use of broker services. For insurances placed in the open market such as CAR (Construction All Risk) the intention is to use the services of an insurance broker.

1.2.2. *Risk engineering plans*

The cost of risk, often materialising as insurance spend, during the Construction, Commissioning, Operational and Decommissioning Phases of a CCS project will present a significant cost to the venture. Implementation of a specific Project Risk Engineering Strategy is planned to reduce the overall "cost of risk" to the CCS project venture through effective Risk Engineering techniques including a Design Phase Risk and Insurance Review (DPRIR), and Risk/Insurance Underwriting and Loss Control Surveys. Survey reports will assist any risk transfer process to the insurance markets by providing a document summarizing the hazards, controls and risk exposure quantifications necessary for this process

This Projects Risk Engineering Strategy would be aligned with the actual planned phases of the project, employing the activities detailed below to ensure risk management is optimised during the design, execution and closure of the project.

- **Design Phase Risk and Insurance Review & Construction All Risks (CAR) Underwriting Information Survey:** This will consist of an initial review of the project to identify risks and proposed risk controls and mitigations associated with the design, construction (modification), commissioning, operation, closure, decommissioning and the post-decommissioning phases of the project. The review would be conducted by an independent consultant professional risk engineer and include a report providing project risk information relevant to the purpose of transferring risk to the external insurance market. The stage 1 DPRIR review has already been conducted in May 2014 by Marsh & McLennan Global Energy Risk Engineering and the report is attached for reference.
- **CAR Underwriting and Loss Control Survey(s):** This will consist of risk review visits to the project during the execution (construction) phase of the project. The number and schedule of surveys would be based upon risks identified during the project design review and aimed to ensure project construction risks are being managed appropriately with cost effective recommendations made to reduce risk as necessary. The survey(s) would be conducted by an independent consultant professional risk engineer and include a report detailing their findings for provision to the insurance markets.
- **Operational and Decommissioning/Post decommissioning Underwriting and Loss Control Survey(s):** Survey(s) may be conducted during the injection, decommissioning and post decommissioning project phases on the basis of the risks identified during the design and construction execution phases of the project and be conducted by an independent consultant professional risk engineer include a report detailing the findings for provision to the insurance markets.

2. Exposures and Insurance solutions by phase

Solutions are required in order to facilitate the management of risk for the full CCS chain, defined over 4 key phases: 1) Design and Construction, 2) Operation, 3) Closure and Decommissioning, and 4) Post-Closure monitoring and maintenance. For each risk aspect, the feasibility of insurance solutions is examined.

2.1. Design and Construction

This covers the initial phases of the project, and includes commissioning, start up and initial operations up until the point that "stable" operations are achieved.

During the Front End Engineering Design (FEED) stage of the project, Shell UK Limited is relying on existing General Third Party Liability (TPL) policy with GIC (Solen), with defined limits of liability insured as required by relevant contractual agreements in place. This cover is renewed annually. This cover will continue apply until such time when more specific Construction All Risk policy and TPL cover is set up.

2.1.1. Damage to the Works - Construction All Risk (CAR)

The "Works" are the new assets onshore and offshore that are constructed as part of the project, including any existing assets being modified. The main causes for damage to the Works are anticipated to be fire, explosion, lightning, windstorm, mechanical failure / collapse, impact by vehicles/vessels. Apart from the Works, in the Brownfield setting there may also be a risk of damage to existing assets that do not form part of the CCS project.

Construction All Risk (CAR) insurance addresses the risk of physical loss/damage to construction works, damage to existing property and third party liability as a result of such construction works (as the latter are excluded from normal Third Party Liability (TPL) cover which is applicable during the operational phase). Coverage will be provided for principal insured, any counterparties/partners and (sub) contractors. The basis for declaration will be capital expenditure (i.e. the total estimated value attributable to the project).

Insurance Solutions: Physical damage to the Works under construction, including early works such as civil works or site preparatory works can be insured via a Construction All Risk (CAR) Insurance policy. Such cover is well established, and exposures are not substantially different between CCS and other construction projects, thus it is recommended to procure this cover.

It is expected that CAR insurance policies for the Onshore and Offshore scopes will be procured with deductibles and limits to be determined at time of placement, once further details are known regarding the scope of work and the breakdown of estimated capital expenditure for the project.

The risk retention level (deductible) under each policy will be evaluated based on the venture's contractual obligations, the insurance market conditions and the anticipated cost of risk associated with different deductible levels.

It is usually the case that offshore property damage is placed separately to the onshore risk during both the construction and operational phases. Separate policies for the Onshore and Offshore scopes of work are recommended as this is the most effective way to arrange cover from a pricing and insurance capacity point of view.

- It is anticipated that Shell will obtain "LEG 3" cover for the Onshore scope of works, i.e. damage resulting from defective parts will be included and standard terms of 12 months of maintenance cover is suggested, although LEG 3 cover availability and pricing will depend on insurers perception of the prototypical nature of the processes involved. In summary, with regards to the Onshore scope for proven "sections" Shell will be looking to secure "consequences defects cover" in line with LEG3/96; for new "sections" insurers may require an "outright defects" exclusion such as LEG1/96.
- The Offshore CAR policy wording will be based on Welcar-2001 Form. For the Offshore scope, cover for defective parts is not usually purchased due to the limitations associated with this extension to cover, however cover for loss/damage resulting from a defective part is provided under the Welcar 2001 Offshore CAR policy. There are cases where replacements of assets are concerned that Defective Part Buyback and Damage to Existing Property can be purchased. High additional premium will be applicable depending on the number of scheduled properties and pipeline crossings. Existing property is typically covered under relevant operational property insurance policies.
- Maintenance Period – project would look to secure Extended Maintenance coverage for the Onshore scope of work, which provides cover for loss or damage arising during the Maintenance Period from a cause occurring on site during the Construction Period.

2.1.2. Third Party Liability - Construction

This includes legal liability for third party property damage, consequential loss and bodily injury from construction activities onshore and offshore. TPL Insurance will also include coverage for the shareholding companies, lenders (if required) and all Contractors involved in the project construction activities.

Insurance Solutions: A third party liability extension to the CAR policy is generally available, and the Project would take out this type of insurance. It extends to Contractors on an excess basis, which further protects the project as a whole from financial difficulties of Contractors in case of such claims. The exact limit of cover will be determined before actual placement of the insurance and in compliance with contractual indemnities and liabilities requirements. The Risk Engineering and the DPRIR will be involved in establishing the potential exposure and required liability limits.

2.1.3. Transits

Materials and equipment may be damaged en route to or from construction site. If Risk and Title for the equipment and/or materials rests with the Project during transport to the work site, then the Project will arrange adequate marine cargo insurance to cover that risk.

Insurance Solutions: Marine Cargo insurance provides protection for property damage caused while plant/parts are in transit. The title "Marine" is misleading as air and land transits are also covered. This type of cover insures large value packages / skids / modules while in transit. It is recommended that Marine Cargo insurance is procured for this Project for the Onshore scope. Cover for the transits associated with the construction of the offshore scope will be insured under the Offshore CAR policy.

2.1.4. Automobile Physical Damage and Liability

Insurance Solutions: Auto physical damage cover is widely available and can be procured by the project if required and is economical. Liability cover associated with automobiles is a legislative requirement in the UK and as per statutory law it will be purchased accordingly.

2.1.5. Loss of Well Control

Well Control is lost if the reservoir pressure is not contained and an uncontrolled flow of fluids occurs either between subsurface zones or into the environment. Costs are incurred to bring the well under control, re-drill the damaged well and if applicable cover the resulting third party damages. For Peterhead CCS, the risk profile is different from a standard drilling operation as the reservoir fluid is far less polluting and the reservoir pressure, and with it the well control risk, actually increases over time (but never rises to the pressure in the original hydrocarbon reservoir)

Loss of control of a well at any phase during the project is expected to result in the need to seal the lost well. There are a total of five wells associated with the Goldeneye field; 4 are planned to be used for CO_2 injection and one will be abandoned.

Insurance Solutions: Shell will seek to insure the well control risk. Coverage will be in respect of activities associated with appraisal, development or injection and workover activities to indemnify against costs to control wells.

As the 5 Goldeneye wells are already existing assets, the wells are currently insured by the Control of Well policy for Shell UK Limited, which covers Shell share of all the wells for UK exploration and operations. Should this project adopt a different venture structure, then COW insurance might need to be placed in the commercial insurance market to accommodate future partners.

The five existing wells were evaluated as suitable for use in CO_2 injection. However, due to integrity issues and CO_2 phase behaviour management, it is not possible to use the wells without any modification. The associated risks will need to be assessed during the FEED study.

Appropriate limits will be determined with risk engineering input.

2.1.6. Other Exposures

- Employers' Liability (EL) is procured at an Operating Company level and as per applicable law with required limits of liability.
- Professional Liability (PI) - damages due to the negligence in the professional conduct of a party; claims may be brought against this party for professional negligence. Professional Indemnity (PI) insurance is available for this type of risk, but tends to be very restrictive, with complicated claims processes. Some contractors (e.g. small design contractors) may be required by the project to take out this cover. The limits would need to be determined based on exposure and availability.

2.2. Operations

This covers the phase from end of Construction up to the end of injection activities. Operational Insurance cannot commence until full Handover has taken place and Handover certificates are issued (after final testing and commissioning). Operational Insurance will be arranged from the anticipated Handover date.

Transition from Construction Phase to Operational Phase insurances is a key risk and Shell RI will work to ensure that there is no gap in coverage between the insurance policies for the respective phases.

2.2.1. Physical Damage to existing assets

In terms of infrastructure, from the CO_2 capture equipment at the source, through pipelines and the associated separation, compression and injection facilities, the risks should be insurable to the extent of any other physical assets. Limited insurance is available for subsurface assets such as down-hole equipment while no coverage is currently available for the storage reservoir itself.

Insurance Solutions: Physical loss or physical damage cover will be in place for all insurable assets, which will provide cover for the repair, reinstatement, replacement of the insured property that suffers sudden and accidental damage, subject to all the terms, conditions and limitations of the policy wording. Contractors' and vendors' or lenders interest in the property is covered to the extent of the Insured's liability imposed by law or assumed by contract.

2.2.2. Business Interruption coverage

Such cover provides protection for fixed costs and loss of profit and is triggered by an insured event under the Property Damage cover accordingly.

Typically insurance companies (including the GICs) provide Business Interruption Insurance, as part of Onshore/Offshore Operational Property insurance coverage

Insurance Solutions: A Property and Business Interruption insurance policy will be considered subject to more available risk information with deductible to be determined at the time of insurance negotiations and the limits will depend on the estimated maximum loss (EML) of the property assets estimated turnover/profits respectively.

2.2.3. Third Party Liability

Third Party liability (TPL) claims may be brought against any of the legal entities involved in the Project. The parties involved must therefore insure against loss of or damage to third party property and personal injury, death or disease, helicopter and marine liability (i.e. charterer's) exposures and contractual obligations to third parties using facilities, as applicable. It should be noted that sub-surface risks will be difficult to insure from a liability perspective. This is largely due to a lack of actuarial data and the huge challenges in determining damage and collecting accurate information to determine a claim.

Insurance Solutions: Shell will insure the TPL risk in the operational phase.

Coverage for third party liabilities are insurable in terms of bodily injury/death and property damage resulting from an escape of CO_2. Coverage would be on a sudden and accidental basis and subject to the strict reporting provisions of discovery. Sudden and Accidental pollution coverage is available; however, the extent and nature of CO_2 escape and its effects are not very well known and will need to be identified.

2.2.4. Loss of Well Control

Control of Well cover for existing wells is currently in place for Shell UK Ltd in respect of relevant equity shares in each well for exploration and operations. The cover will need to be reviewed near the time of the operation phase of the project in relation to the required cover limits and exposures.

*See corresponding section for Design and Construction phase in relation to the actual coverage.

2.2.5. Seepage and Pollution from Reservoir

It is, at least theoretically possible that CO_2 leaks out of the reservoir, e.g. due to cracks in the cap rock, along the casings of (old) wells, etc. At the current time it is very difficult to quantify this risk; however it is seen as very low probability given the quality of the reservoir and the extensive mitigation measures in place.

Insurance Solutions: Insurers are currently contemplating writing specific liability insurance for CCS projects. The terms and rates for such cover are still undetermined at this stage.

A legal requirement for this type of cover is not anticipated.

Any obligatory insurance covers by law or contract will be taken out accordingly.

2.2.6. Loss of Carbon Credits

In case of a CO_2 leak from the reservoir, the carbon credits awarded for the injection may be lost/may have to be repurchased. The risk depends on legislation, and there is a further risk that these rules may change over time. At this point in time, they are not specified, but no such penalties are expected.

Insurance Solutions: As the risk can currently neither be defined nor quantified, no insurance solutions are available. This should be re-evaluated should such insurance become available in the future, at an economic cost.

2.3. Closure and Decommissioning

Closure and Decommissioning exposures/risks are similar to those associated with the construction and operational phases until the process plant, pipeline and platform are free from the presence of CO_2 and include Physical Damage, TPL, Damage to Existing property, Seepage and Pollution and Transportation.

2.4. Post Closure monitoring and maintenance

This phase begins when there are no more active operating / closing activities being performed and is in principle open-ended. For Shell it ends in practical terms with the handover of long term liabilities to the government.

In the post-decommissioning phase, there is the potential for damage to the remaining structures due to third-party activity or deterioration from fatigue and corrosion. There will be monitoring equipment in place during the post-decommissioning phase to determine the on-going integrity of the reservoir and sealed wells. There is the potential for physical damage to the monitoring equipment due to natural catastrophe, third-party impact, manufacturing fault or general deterioration. The magnitude of the physical damage in the case of individual events will be expected to be relatively small, but if the sub-sea monitoring equipment is to be reinstalled it will be necessary to mobilise a vessel to carry out the installation activity.

Exposures are similar to those encountered during the operational phase; please refer to the list of exposures below and the corresponding reviews for other phases:

- Physical Damage to existing assets
- Third Party Liability
- Seepage & Pollution
- Loss of Carbon Credits

3. Conclusion

Shell plans, in consultation with DECC to put in place a robust and cost effective insurance programme to provide appropriate cover for both the Construction and Operational Phases of the Peterhead CCS project.

The insurance strategy will depend on the following aspects that will require consideration:

- The ownership structure of the operating venture and the indemnities and liabilities regime that will be agreed. This will in turn require insurance plan review and the relevant required insurance that will need to be procured.
- Insurance cannot be procured upfront for the whole lifecycle of the project, thus availability, price and terms & conditions of coverage may vary over time, especially if claims occur. A key constraint of insurance for CCS projects is the term of available insurance. Generally insurance policy periods are short term. This means that policies are issued for up to a maximum number of 2/3 years, which is less than the lifetime of a CCS project. If new policies are available, their pricing, limits, terms and conditions may change, depending on various factors including loss/claims experiences for this and other CCS projects. Insurance may be able to contribute to CCS risk mitigation; it will not provide complete risk transfer for the whole CCS project as such.
- Coverage may be very expensive and/or restricted for the "novel" aspects of the project (CCS liability, financial risks of repurchase of carbon credits, subsurface migration/pollution, etc.).
- Until the regulatory regime is defined, it is uncertain what the extent of liability for CO_2 release is. At present, no requirement for re-purchase of credits or financial penalties is expected in case of accidental CO_2 release from the reservoir. Protection against repayment of carbon credits (European Union Allowances (EUAs)) is currently uninsurable.
- The venture will also have to retain those risks which cannot be insured or for which only limited insurance capacity is available. Further engagement with the insurance markets and relevant professional bodies, government and environmental agencies will continue in order to share or obtain knowledge in relation to the CO_2 risks and exposures and how they can be mitigated.

Below is the overview table (Table 3-1) of the identified risks for Peterhead CCS project and how they are proposed to be dealt with. The green colour indicates insurability of the risk.

Table 3-1: Risk Matrix Overview

Risk	Design & Construction	Operations	Closure & Decommissioning	Post Closure
Liability				
Third Party Liability				
Seepage & Pollution (reservoir)				
Automobile Liability				
Employer's Liability				
Professional Liability				
Sub-surface Liabilities				
Physical Damage (PD)				
Damage to the Works				
Damage to existing assets				
Loss of well control				
Automobile Physical Damage				
Transits/Cargo				
Other				
Loss of Carbon Credits				
Business Interruption (caused by a PD event)				

Key	
Not applicable	
Insurable/To be insured	
Not to be insured/not insurable	

4. References

Stage 1 Design Phase Risk and Insurance Review report. Marsh. May 2014

Glossary of Terms

Term	Definition
CAR	Construction All Risk
CCS	Carbon Capture and Storage
COW	Control of Well
DECC	Department of Energy & Climate Change
DPRIR	Design Phase Risk and Insurance Review
EL	Employers Liability
EML	Estimates Maximum Loss
EOR	Enhanced Oil Recovery
FEED	Front End Engineering Design
GIC	Group Insurance Company
OCCS	Office of Carbon Capture and Storage
PD	Physical Damage
PI	Professional Liability
SSE	Scottish & Southern Energy Plc
SVAG	Solen Versicherungen AG
TPL	Third Party Liability

5. Appendix A - Stage 1 Design Phase Risk and Insurance Report. Marsh. March 2014

STAGE 1 DESIGN PHASE RISK AND INSURANCE REVIEW

PETERHEAD CCS PROJECT, SCOTLAND

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On behalf of: Shell UK Limited (Peterhead CCS Project Team)

Following: A meeting with the project team on 7 and 8 May 2014 and subsequent review of project documentation

REV. 0.1

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Revision	Date	Comments
0.0	May 2014	Draft Stage 1 Design Phase Risk and Insurance Review report following the May 2014 meetings
0.1	July 2014	Stage 1 Design Phase Risk and Insurance Review report following the May 2014 meetings and incorporating comments received from client

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Executive Summary

Introduction

The Peterhead Carbon Capture and Storage (CCS) project consists of the post-combustion capture of CO_2 from a gas-fired power station, compression, transport and geological storage. The project is intended to be the world's first commercial-scale demonstration of a system of this nature. The carbon capture technology is proposed to be installed at an existing gas-fired power station at Peterhead in Northeast Scotland. The project work at this site will consist of the post-combustion capture plant and the compression and conditioning plant.

Project Outline

Carbon capture technology will be fitted to an existing gas-fired power station at Peterhead Power Station in North East Scotland. There is sufficient space for the construction of the post-combustion CO_2 capture plant and the associated conditioning and compression facilities. After capture, the CO_2 will be routed to compression facilities where it will be compressed, cooled and conditioned by having water and oxygen removed from the CO_2 stream so that it is suitable to meet the transportation and storage specification.

Following post-compression cooling the dense phase CO_2 stream is transported directly offshore via a new offshore pipeline that will tie-in to the existing Goldeneye subsea pipeline. The CO_2 will be permanently stored in an area centred on the depleted Goldeneye gas field.

Loss Exposures

Various loss exposures have been considered for property damage, liability and production interruption. The scenarios providing the more significant overall exposures are summarised below:

Physical Damage Estimated Maximum Loss (EML)

Scenario	Property[1] (GBP million)	Business Interruption
Compressor failure during construction	13	19 months
Damage due to gas explosion on power station	10	12 month
Pipeline failure during construction	56	12 month
Pipeline failure during operation	56	21 months
Platform damage during construction	15	12 month
Compressor failure during commissioning	13	29 month
Failure of subsurface equipment[2]	22	12 months

Scenario	Property[1] (GBP million)	Business Interruption
Well blowout[2]	40	12 months

NOTES:
1. To two significant figures.
2. There are expected to be additional costs for monitoring, corrective action and purchase of carbon credits.

It is stressed that these loss estimates should be considered as preliminary, and may be subject to significant revision once further project information is available and once key assumptions are reviewed.

Project Outline

Overview

The Peterhead Carbon Capture and Storage (CCS) project is a demonstration project being supported by the UK government through the Department of Energy and Climate Change (DECC) to demonstrate the practicability of delivering an affordable CCS operation. The project consists of the installation of carbon dioxide capture technology at the existing Peterhead gas-fired power station, conditioning and compression of the captured carbon dioxide, transfer by subsea pipeline to the Goldeneye gas platform in the central North Sea, and injection into the depleted Goldeneye gas reservoir.

The project is being developed by Shell in conjunction with SSE, the owners and operators of the Peterhead power station. At the time of the DPRIR meetings the project was in the early stages of the Front End Engineering Design (FEED). The design engineering for the on-shore parts of the project is being carried out by consulting engineers Technip, with Mott MacDonald acting as the Project Management Organisation and the Shell project team providing management oversight. The details of the engineering contractor for the off-shore aspects of the FEED had not been finalised at the time of the DPRIR meetings.

SSE will be carrying some modifications to the Peterhead power station to enable the carbon capture project to be implemented on the Peterhead site.

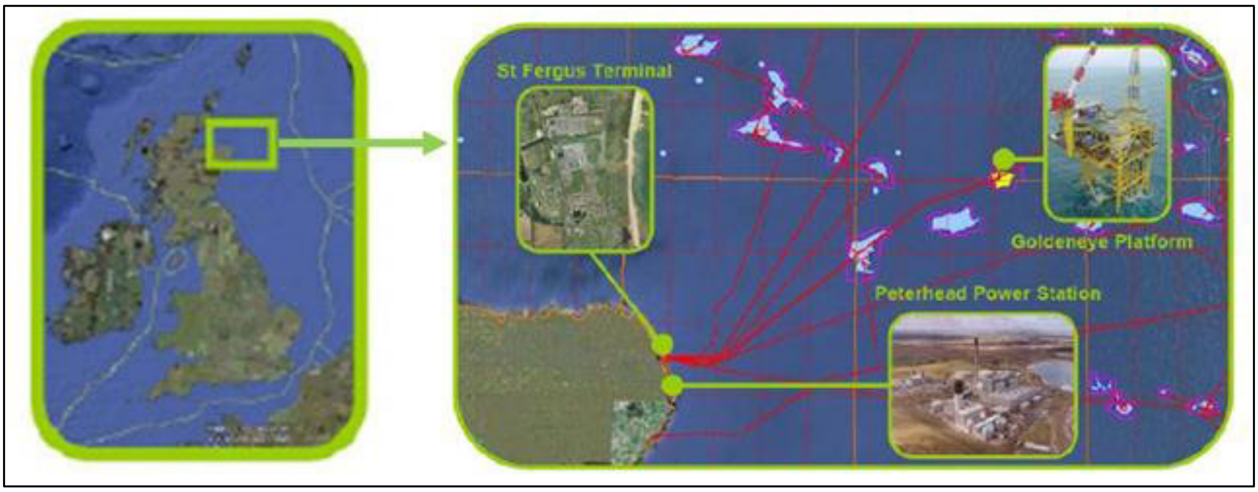
One of the objectives of this demonstration project is to enable the work being carried out to be reproduced by others carrying out CCS project developments, rather than it being unique work only applicable to the Peterhead project.

Location

The Peterhead power station is located approximately 2.5 km south of the port town of Peterhead on the east coast of Scotland. The coordinates of the site are 57° 29' N 1° 47' W. It is an operating Combined Cycle Gas Turbine (CCGT) power station which is currently planned to be in use until the late 2020s.

The Goldeneye platform is located in UKCS Block 14 / 29a, approximately 300 m south of the Miller pipeline. The platform location is 477550.4E and 6429204.6N in the UTM grid system (equivalent to 58° 00' N and 0° 23' W.) This is the outer Moray Firth area of the Central North Sea. This is an existing platform installed when the field was producing natural gas and is a Normally Unattended Installation (NUI.)

The CO_2 storage location will comprise an area centred on the depleted Goldeneye hydrocarbon field.



Location map of the Peterhead CCS Project

Project Scope

The project is intended to capture approximately 1 million tonnes of CO_2 per annum from the flue gas produced by the Peterhead power station and store the captured gas in the depleted Goldeneye reservoir.

After capture of the gas by an absorber the CO_2 will be routed to compression, also located on the Peterhead power station site, where it will be compressed, cooled and conditioned by removing water and oxygen to make it suitable for transport and to meet the specification for storage. The gas stream will then be cooled after compression resulting in a dense phase CO_2 stream that can then be transported directly offshore via a new pipeline that will tie-in with an existing pipeline to the existing Goldeneye platform. The CO_2 will be permanently stored in an area centred on the depleted Goldeneye gas field.

The project is also intended to demonstrate the practicability of installing a complete Carbon Capture and Storage (CCS) chain integrated into an existing CCGT power station at an affordable cost. The customers of this demonstration are the UK regulators and the energy and power industry as a whole.

Project Execution

At the time that this risk review was undertaken with Shell staff the project was in the Front End Engineering Design (FEED) stage for the onshore parts of the project. Technip are carrying out this FEED study. At the time of the risk review the Process Flow Diagrams (PFDs), plot plans and pipeline route were in the process of being finalized. The FEED is scheduled to last 10.5 months. The Engineering Procurement and Construction (EPC) tender will be prepared in parallel with carrying out the FEED. For the onshore EPC, the tender package is proposed to be issued before the end of the FEED to allow for a FEED verification period.

Contractors will be sought for the FEED for the pipeline and platform aspect of the project. This may involve two separate contractors; a decision will be made in June 2014. It is currently proposed that the FEED studies for the offshore aspects of the project will commence in July 2014.

For the onshore project execution, the FEED will be followed by a competitively tendered EPC contract for the Carbon Capture, Conditioning and Compression Plant scope.

For the offshore aspects, there will be a competitive tender for the landfall and offshore pipeline installation (with the possibility of a combined scope), and a competitive tender for the construction / modification of the Goldeneye Platform and the related facilities.

One main procured equipment package has been identified as a potentially critical long lead time item. The onshore compressor is assumed to have a tendering time of two months and a delivery time of 19 months.

The following estimates of equipment and system delivery times have been assumed in the project schedule development:

Third Party Equipment / Systems	**Execution Schedule Delivery Times (months)**	**Comment**
Steam Turbine	16	Including manufacture, construction and commissioning
Pipeline	12	Plus three months installation
Sub Sea Isolation Valves	14	Plus one week installation
Compressors	19	Plus two months tendering plus ten months hook-up and pre-commissioning
Pipeline Installation	One year	Needs to be timely to meet deadline for installation in 2017
Rig	One year	Contract award should preferably be two years prior to requirement date of Q2 2017

It is understood that apart from the capture plant that is on the critical path, there is substantial float in the execution schedule. Neither the subsea, pipeline nor the offshore scopes of work are critical, each having a three month float.

The current understanding of the key project milestones are summarized below:

Project Milestones[1]	
FEED contract (onshore) awarded to contractor	03 March 2014
Planning submission for onshore	End of Q1 - 2015
Storage permits / EIA DECC approval	25 February 2015
Final Investment Decision (FID)	31 December 2015
First injection	19 April 2019
Declare clean energy	18 July 2019

1 The post-FID milestones may be revised during the FEED phase.

Facilities

The project intends to capture the CO_2 from the output of one of the existing three gas turbines on the Peterhead power station from downstream of the Heat Recovery and Steam Generator (HRSG). This is expected to reduce the CCGT production by about 400 MWe compared to prior to the CCS retrofit.

The proposed design of the capture plant consists of a pre-scrubber, a single very large absorber, a smaller stripper column and the associated pumps and heat exchangers. The capture plant will use steam from the new steam turbine that will be installed at the Peterhead Power Station, for the amine regeneration. Power will be supplied from the national electricity grid.

The CO_2 product delivered from the capture plant to the compression and conditioning plant will be saturated with water and contain traces of oxygen. The oxygen will be removed by catalytic reaction with hydrogen and the water will be removed by a molecular sieve. The conditioned CO_2 will then be further compressed to about 120 bar(g), ready for export to the Goldeneye platform.

Following the post-compression cooling, the resulting dense phase CO_2 stream will be transported directly offshore through a new, short section of pipeline landfall and a new offshore pipeline which will be tie-in to the existing Goldeneye pipeline. It is proposed that the pipe landfall is installed using a Horizontal Directional Drilling (HDD) technique. At the time of the risk review, geotechnical surveys of the shore-line were being carried out to confirm the suitability for the application of HDD.

The tie-in between the new pipeline and the existing Goldeneye pipeline will be made via a flanged spool to enable expansion of the capacity of the connection in the future. From this connection, the CO_2 will be transported via the existing Goldeneye pipeline to the depleted Goldeneye hydrocarbon field.

The CO_2 will be permanently stored in an area centred on the depleted Goldeneye gas field. Geotechnical studies show that the depleted field has the capacity to store approximately 34 Million t of CO_2. The existing platform has been assessed and is considered to be in an excellent condition and will require minimal modification. The existing wells have been determined to be suitable for conversion to CO_2 injection wells and will have adequate capacity to meet the demand of the CCS project

Tie-Ins

Utility services for the Capture, Compression and Conditioning plant will be provided from the existing Power Station facilities. The new CCS plant requires piping tie-ins to the following systems:

- Demineralised water
- Firewater
- Medium pressure steam
- Low pressure steam
- Condensate return
- Cooling water (seawater) supply
- Cooling water (seawater) return
- Potable water
- Service water
- Vent
- Uncontaminated closed drains
- Uncontaminated open drains
- LP steam for start-up; and
- Waste water

Layout

The new CO_2 capture unit and associated equipment will have new equipment, structures, piperacks, ducting and foundations.

Two new substations will be provided and the existing Power Station pumphouse will be modified to incorporate a replacement pump for the cooling system. A new underground system will be installed to serve the new process equipment and paving drainage. New roads and paving will be provided where required.

The pre-scrubber and CO_2 Absorption Columns are the primary equipment items and are large concrete structures. They will be located to the west of the existing power station control room.

The main tie-ins for the flue gas system will be on the north side of the existing section of flue gas ducting between the HRSG and its associated stack. From the tie-in, the very large new duct (typically measuring 6.1 m x 6.1 m in cross-section) will be routed on a new pipe rack structure to two booster fans that will be located between the existing power station control room and the pre-scrubber. The main duct will then pass through the hot side of the rotary exchanger and tie back into one of the flue gas connections on the east side of the existing main stack on a new pipe rack structure running north / south between the auxiliary boiler house and the turbine hall. The rotary heat exchanger will be located at an elevation of approximately 25 m above grade.

There is a new pipe rack structure running east / west through the pre-scrubber and absorption column area. At the west end this connects to the main process area pipe rack, and at its east end it connects to the pipe rack supporting the treated gas outlet duct.

The main process area is located north of the pre-scrubber and absorption column area and to the west of the existing auxiliary boiler house main stack. There is the requirement to carry out major excavation work to remove much of this embankment to achieve a flat area for development.

The layout for the main process area is based on a central pipe rack that runs north / south, with equipment located either side of it. At the south end the pipe rack connects to the pre-scrubber and absorption column area and at the north connects to the compression and conditioning plant area.

The sea water supply and return headers, steam condensate and utility pipework will be routed through the pre-scrubber and absorption column area pipe rack to enter the main process area at the south end. A pipe bridge will be installed to carry the pipes from the amine and caustic storage areas to the main process area.

The CO_2 Stripper Column and associated equipment will be located in a structure to the east of the pipe rack adjacent to the west side of the existing auxiliary boiler house.

The selected site for the Compressor and Conditioning Plant is within the area of the Peterhead site that was previously the location of the oil storage tanks, to the north of the power station site. This is remote from the existing power station buildings and has been judged to be outside the explosion risk contours from the existing facilities.

All process pipework, utilities and cable racks will be routed to the Compressor and Conditioning Plant on an elevated pipe rack connecting the main capture plant and crossing the main site access road.

The compressor will be housed within an open-sided building. Vehicle access is available at both ends of the building.

To the north of the compressor building are the dehydration and oxygen removal packages and to the south of the compressor building is the LER building.

To the east of the area is the pig-launcher. The CO_2 export pipeline and the methanol pipeline will be routed above ground and to the north east of the compressor building location. The pipeline will then be routed underground.

The proposed layout at the Peterhead Power Station site is shown in *Appendix A*.

Pipeline

There will be a short length of pipeline as the pipeline exits the Peterhead Power Station comprising the 900 m landfall which will be installed using horizontal directional drilling. The landfall is located in a relatively small enclosed bay immediately to the north of Peterhead Power Station. The landfall is within the marine extension of a Special Protection Area (SPA) designated for nesting birds.

The landfall is routed directly offshore from the area formally occupied by the heavy oil fuel tanks in an easterly direction to a subsea exit point in approximately 12 m water depth which will enable subsea pipe-lay operations. The proposed length of the horizontal directional drilling landfall is 900 m.

The new pipeline crosses two existing pipelines, the 20 inch Fulmar A to St Fergus gas pipeline (PL 208) and the 28 inch Britannia to St Fergus gas pipeline (PL 1270). The new pipeline will be tied in to the existing Goldeneye pipeline. The location of the tie-in will be defined during the FEED. The tie-in will use flanged rigid spools to minimise the pre-investment while preserving some flexibility for future expansion and minimising the need for diving intervention. The flanges on the existing Goldeneye pipeline will be installed using hyperbaric subsea welding.

From the tie-in the CO_2 is exported through the existing pipeline, approximately 78 km in length to the existing Goldeneye platform which is located approximately 100 km north east of the Aberdeenshire coastline.

The existing Goldeneye pipeline was installed in 2004 and remained in operation until December 2010. No internal inspections were performed and the corrosion was managed using a risk based inspection approach. The pipeline was hydrocarbon freed in 2013. It has been cleaned to a low hydrocarbon in water and left mothballed with inhibited water.

An inspection pigging programme will be performed to confirm the condition of the pipeline. This will also serve as a base measurement for determining any metal loss as a result of the CO_2 service. An intelligent pig run will be executed after FEED and detailed design to confirm the remaining wall thickness of the pipeline, after the new pipeline section has been tied in to the existing line.

Platform

The Goldeneye platform was installed in 2003 with a design life of 20 years. It is expected that CO_2 injection will continue using the platform up to 2029, extending the platform operating life to 26 years. Engineering studies have been carried out to confirm the suitability of the Goldeneye platform for the proposed change in use and design life extension. These studies will be revalidated to assess the structural integrity of the platform for any changes in the design conditions.

In order to accommodate the change of use and additions to the platform the following may impact the structural integrity and require assessment:

- Removal or replacement of the 20” subsea check valve / isolation valve at the platform end of the pipeline
- Replacement of the existing pig launcher with an intelligent pig receiver
- Removal of the existing manifold and wellhead conductors
- Install new wellhead manifold including 10” piping between the riser tie-in manifold and pig receiver
- New valve access platform for two new CO_2 filter vessels

To assess these additions, there will be mechanical handling assessments and weight reports during the FEED.

Other than the existing pig launcher and associated piping, it is not necessary to remove any other items of equipment. All necessary decommissioning and mothballing of the existing plant has been completed. The plugging of wells has been completed in such a manner that the conductors and wellhead equipment can be disconnected, so the platform can be treated as isolated from the reservoir. The pipeline hydrocarbon inventory has been removed and the pipeline has been plugged and purged.

It has been determined that the height and geometry of the existing vent stack structure is sufficient for venting the CO_2 and no changes are required.

The Goldeneye platform is a normally unmanned installation. The current accommodation facilities have limited provisions and services to sustain habitation. Improvements to facilities and services would be required should on-board habitation become regularly planned. While the project work is undertaken on the platform it is proposed that there will be the utilisation of an accommodation vessel with a “walk to work” personnel transfer system to the platform.

The existing control facilities on the Goldeneye platform are contained in an Integrated Control and Safeguarding System (ICSS), containing the Process Control System, the Emergency Shutdown and the Fire and Gas safety instrumented functions. This is currently handled under the supervisory control of the St Fergus Terminal Human Machine Interface (HMI). For the CCS project a fully automated control strategy of the offshore facilities is to be adopted to minimise the need for offshore visits. The control of the platform ICSS will be transferred to the new control room at the Peterhead Power Station, but with the ICSS maintained with the ability to transfer control to the offshore facility when the platform is manned.

Wells

There are five wells in the Goldeneye platform that have been drilled and completed for hydrocarbon production. The current plan is to recomplete four of the existing wells by means of a workover and replacement of the upper completion. There is a requirement in the project for three injection wells for CO_2 and one monitoring well. A business decision has been made to retain the fifth well and convert it for CO_2 injection rather than abandoning or long-term suspension. The lower completion of the wells will remain in place. All wells will be recompleted prior to start-up.

There are still three slots available but there is no intention to drill any new wells for injection, appraisal or monitoring purposes.

The replacement of the upper completion is required because:

- There is the potential for a well integrity issue due to the potential cooling of the tubing in the current completion design
- The tubing must be designed to create a pressure drop to keep the injected CO_2 in the dense phase during injection
- Some of the current completion components present integrity issues at the SSSV level

The Goldeneye wells were suspended with mechanical plugs during 2012 / 2013, so they are considered safe prior to their adaption for CCS service.

The current Cameron Xmas Tree Class U and tubing hanger is rated to -18 °C and will be changed to equipment with a lower temperature rating. The details of the Xmas Tree will be defined during the FEED.

The casing wellhead will remain in place and has a limitation of -18 °C. This casing hangar is not in contact with the CO_2 but in metal to metal contact with the tubing hangar.

The Xmas Tree valves are controlled via hydraulic actuators. These valves also incorporate proximity sensors; there are two sensors per valve.

The permanent downhole gauges and distributed temperature sensing instrumentation will require surface cabling from the well-bay area to the control room, where they will be connected to equipment to monitor the sub-surface status, powered from a dedicated Uninterruptible Power Supply (UPS). Power will also be required for other sensors defined by well monitoring requirements, including pressure and temperature sensors on each well.

Hydraulic power will also be required to operate downhole safety valves and, if installed, downhole flow control valves.

It is proposed to use IR absorption and line-of-sight detectors to measure any accumulation and migration of released gas clouds.

Well intervention and integrity tests are planned during the lifetime of the CCS project. There is also the requirement to vent high pressure gas from the wells, though this will be of relatively small volumes but may contain hydrocarbons and CO_2.

Subsurface Safety Valves (SSSVs) will be installed in the wells. The frequency of testing of SSSVs in CO_2 service has not been defined but is normally every six months. The procedure will be developed during the FEED phase.

Reservoir

The Goldeneye field is located about 100 km northeast of St Fergus in water with a depth of about 120 m. the area is considered seismically inactive.

The CO_2 will be injected into the storage site at a depth of greater than 2,516 m (8,255 ft) below sea level into the previously gas bearing portion of the sandstone reservoir.

Since 2004 the field has produced 568 billion SCF of gas and 23 million barrels of condensate. During the production there was significant water ingress to the reservoir which served to end the gas production as the subsequent cut water increased.

The primary CO_2 storage mechanism will be accommodation in the pore space previously occupied by the produced gas and condensate. A secondary mechanism will be trapping in the water-leg below the original hydrocarbon accumulation.

When the CO_2 is injected it will displace water back into the aquifer. Analysis and modelling have shown that the field and water-leg have sufficient capacity to store over 30 million tonnes of $CO_{2.}$ This is more than sufficient for the 10 million tonnes proposed in this project.

The Goldeneye field is hydraulically connected through the aquifer water-leg to the neighbouring fields in the east and west. Other nearby fields include Ettrick, Buzzard and Buchan. Pressure and compositional data received from these fields shows that they are not in communication with the Goldeneye aquifer.

Vertical containment is provided by a 300 m thick storage seal. The sealing capacity of the formation is considered excellent as it acts as the primary seal for all the hydrocarbon fields in the location.

Further containment is provided by a complex seal made up of two mudstone units that can be reliably correlated across the area of the Goldeneye Field. These mudstone units are found at depths of greater than 800m across the entire area of the field, meaning that any CO_2 that is stored beneath them will remain in place.

Secondary storage is provided by the formation between the storage and complex seals. There is considered to be little or no chance of CO_2 escaping the storage site laterally under the spill point, owing to the significant spare capacity within the store. However, if the injection plume were to pass the structural spill point of the Goldeneye Field this CO_2 would be contained under the same cap rocks within the much larger formation.

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

Existing faults have been mapped and fractures have been analysed and none has been identified to be completely pervasive through the seal system. The caprock integrity has been tested and proven by the presence of a gas field containing the highly mobile gas that is under pressure compared to the surrounding formations.

The complex seal is penetrated by seven E&A wells. Only two of these wells have plugs at the secondary seal, meaning that the other wells have the potential to provide migration paths should CO_2 migrate out of the primary containment and travel through the secondary storage and create a plume that intersects one of the open wells.

A comprehensive monitoring programme has been designed for the reservoir, based on the results of the risk assessment work that has been carried out. This consists of two plans:

- Base case plan
  - Monitors the performance of the injection against plan and to identify unexpected CO_2 migration within the storage complex, enabling action to be taken before leakage occurs.
- Contingency plan
  - In the event of CO_2 leakage outside the storage complex this plan is mobilized to locate the source of the leakage and enable mitigation plans to be implemented.

The base case plan includes environmental baseline monitoring before and after injection, well monitoring and monitoring of the seawater under the platform for traces of CO_2.
The contingency plan ties closely to the corrective measures and includes focussed application of the techniques / technologies used in the base case plus additional options.

Once the required volume of CO_2 has been injected it is currently planned to monitor the reservoir pressure build-up for three years, and to leave the Goldeneye Platform in place. After this the platform will be decommissioned. Handover to the UK Competent Authority is proposed to take place between six and twenty years post-closure, depending on the dynamic performance of the reservoir.

Application of Technology

The project will be the world's first commercial scale demonstration of CO_2 capture, transport and offshore geological storage from a post-combustion gas-fired power station. However, the vast majority of the components the project are using rely on existing technologies for which there is substantial experience worldwide.

HAZOP studies have been carried out at all stages of the project to ensure that any novel hazards from the activities being proposed and the scale-up of the technology have been captured. Actions from the HAZOP studies are captured and incorporated into the project process.

Experience is being incorporated from other CCS projects from around the world (Quest in Canada, Boundary Dam in Canada, and Gorgon in Australia) and from the work carried out prior to the cancellation of the Longannet CCS Project.

Consideration is being given within the project to make sure that it is as far as possible repeatable as a concept by other operators. The proposal is to deliver the project with the lowest possible Capex expenditure to encourage future CCS projects that do not have access to very high capital reserves, as for future projects there will not be government capital grants available.

Commercial Framework

SSE are the operators of the Peterhead Power Station. Shell will lease land from SSE for the capture plant and compressors. SSE are the generator and will supply the flue gas plus steam and power for the operation of the capture plant and compressors. There will also be an access agreement for the Peterhead site.

The UK government is contributing to the project with a Capex grant.

Once the project is operational, power generated form the Peterhead Power Station will continue to be sold to the grid by the trading entity SSE. Revenues will go directly to SSE or to SSE acting as agents placing forward contracts on Shell's behalf.

SSE receives additional funding for the proportion of the electricity supplied that is clean energy. A Contract for Difference (CfD) is paid for the clean power to cover capital cost recovery, additional operating expenditure, monitoring costs and decommissioning costs. SSE then pay Shell their share of the CfD income for the CCS to generate the clean power.

The Goldeneye is a joint venture but the joint venture partners will be bought out to take the platform into 100 % Shell ownership.

Project Process Management

Process safety has been incorporated into the design and selection of the project, including a drive within the Select phase to promote inherent safety within the design. A number of Quantified Risk Assessments (QRA) were carried out, some specifically for the Peterhead Project and some which were performed for the earlier Longannet Project that are still relevant.

There is an existing QRA for the Peterhead Power Station that addresses the existing fire and explosion risks for the "as is" power generation operations at the power station. It is considered that the CCS plant is unlikely to present much additional risk to third-parties.

Full HAZOPs will be carried out by the various FEED contractors; the interfaces between the FEED phase HAZOP studies will need to be managed, potentially by employing a common HAZOP chairperson and key disciplines from each FEED contractor present at all of the HAZOPs.

It is proposed that SIL studies are conducted as appropriate during FEED.

The hazard identification during the Select phase resulted in the development of a Hazards and Effects Register. This will be maintained and updated during the FEED stage to incorporate the findings of the on-going hazard identification and risk assessment work.

HSE assurance will be performed during the project by Shell rather than PMO contractor. Changes will be identified in collaboration with the FEED contractors. Fundamental changes in the design from the project Basis for Design will be managed through a management of change process by Shell and the FEED contractor.

The power station is not currently a COMAH site, as defined under the requirements of the EU Seveso II Directive. It is considered unlikely that the changes with the implementation of the CCS project will change this status, however this will need to be clearly confirmed when there is detail of the inventories of relevant hazardous substances. Recognition is also necessary of the potential revision in qualification criteria following the adoption of the Seveso III Directive and its implementation into UK legislation and the change in chemicals classification (from CHIP to CLP.)

The Goldeneye Platform has a Safety Case for operation as a hydrocarbon facility as required by the Offshore (Safety Case) Regulations 2005. The national regulator currently do not expect to require a Safety Case since the platform will not fall under the requirements of the regulations as it will not be a hydrocarbon production facility. This position will be reviewed and confirmed over the duration of the FEED and beyond. A Safety Case will be produced as an internal document for the eventual platform operator.

It has also been confirmed that a pipeline conveying CO_2 is not considered to qualify under the requirements of the Pipeline Safety Regulations 1996 as a Hazardous Pipeline, though the FEED contractor will probably produce a short HSE case addressing the ALARP demonstration of the pipeline design.

A marine risk study was undertaken during the Select phase of the project to assess the relative hazards of interfaces between the pipeline and marine users. This reviewed the potential exposure of marine vessels to the proposed pipeline routes. This determined that the pipeline route directly offshore from Peterhead, while higher than the pipeline route from St Fergus was not sufficiently greater to be a major factor in the concept decision making. Further assessment will be carried out during the FEED stage to assess the requirement for pipeline protection from vessels.

2

Hazard Identification

To assist in the understanding of the risk and insurance management of the Peterhead CCS project, an assessment has been carried out of the potential hazards that the project may be exposed to during the phases of the project. The assessment is based on experience of on-shore and offshore construction projects, on-shore power and process plant operational loss experience, offshore operational loss experience, and decommissioning projects. In addition, consideration has been given to the particular risks associated with CO_2, its capture, transport and storage. Reference has been made to relevant guidance and references (see Appendix C.) Reference has also been made to the Concept Risk Assessment Report produced by Det Norske Veritas (DNV) for the project.

Construction

Onshore

- Natural Catastrophe
- Transport
- Heavy Lift
- Fabrication / Assembly
- Long Lead Time Items
- Hot Tapping / Tie-ins
- Pressure Testing
- Third Party

Pipeline

- Natural Catastrophe
- Transport
- Pipelay
- Pressure Test
- Third Party

Platform and Reservoir

- Natural Catastrophe
- Transport
- Heavy Lift / Dropped Object
- Fabrication / Assembly
- Subsea Installation
- Vessel Impact / Third Party
- Drilling / Blowout

Commissioning

Onshore

- Catastrophic Vessel Rupture
- Machinery Catastrophic Failure / Machinery Fire
- Release of CO_2

Pipeline

- Catastrophic Failure
- Release of CO_2
- Water Ingress

Platform and Reservoir

- Catastrophic Vessel Rupture
- Release of CO_2
- Subsea Release
- Water Ingress
- Reservoir Damage

Operation

Onshore

- Catastrophic Vessel Failure
- Machinery Failure / Machinery Fire
- Major CO_2 Release
- Natural Catastrophe
- Third Party Impact
- Fugitive Emissions
- Sabotage & Terrorism

Pipeline

- Catastrophic Failure
- Leakage
- Seawater Ingress
- Natural Catastrophe
- Third Party Impact
- Pipeline Crossings / Umbilicals

Platform and Reservoir

- Mechanical Failure
  - Platform Vessels / Pipework
  - Tubing
  - Xmas Tree
  - Conductors
- Blowout
- Natural Catastrophe
- Existing Wells and Drilling
- Aviation
- Fishing
- Field Development Drilling
- Sabotage & Terrorism
- Environmental

Closure and Decommissioning

- Mechanical Impact
- Heavy Lift / Dropped Objects
- Contamination (NORM)
- Third Parties
- Sabotage & Terrorism
- Environmental

Post-Decommissioning

- Natural Catastrophe
- Reservoir Failure
- Platform Collapse
- Third Parties
- Field Development Drilling

Non-Technical Risks

There are a number of non-technical risks that will need to be actively managed by the project over all the phases of work, including:

- Government Relations
- Regulatory Approvals
- Environmental Assessment
- Communications and Public Relations
- Industrial Relations

3

Project Values

Project Values

The following project values were supplied to Marsh. These include the SSE work scope and estimate a total project value of GBP 1.09 billion.

	Estimate (GBP '000)		Comment
	Subtotal	Total	
SSE Scope		99,629	
Steam Turbine	86,634		
SSE Project Management	12,995		
CCCC		334,118	Cost Estimate prepared by Shell Design Office
Engineering	26,612		
Equipment	86,578		
Steel	28,085		
E & I	19,489		
Civils & Construction	31,436		
Labour	136,917		
St Fergus MEG Facilities	5,000		
Pipeline & Subsea Scope		62,307	Estimate prepared using base scope from Pipelines group and Subsea Engineer.
Engineering	1,332		
Procurement	18,025		
Offshore Vessels	35,380		
Construction Management	2,883		
Commissioning	1,550		
IP Run	3,137		
Goldeneye Modifications		50,563	Scope from Design Office Discipline Engineers.
Engineering	3,485		
Procurement	8,555		
Construction Labour and Logistics	22,263		
Construction Management			
Offshore Vessels	16,261		
Wells		39,249	Updated estimate from Wells Engineer – includes four workovers
Engineering	400		
Procurement	6,998		
Rig	31,851		

	Estimate (GBP '000)		Comment
	Subtotal	**Total**	
Owners Costs		133,907	
Sunk Costs	25,963		
Pre-FID (Pre-FEED and FEED)	39,500		
Post FID Manning	38,352		
Other Post-FID Costs	12,093		
First Fill, Catalysts and Chemicals	10,000		
Licence Costs	8,000		
Escalation		48,371	
Contingency		139,168	
EPC Premium		60,460	
Inflation		122,910	
Total		**1,090,682**	

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Risk Assessment

From the identified hazards for the phases of the project, an initial assessment has been made of the risk to the project. The measures in place to mitigate the risk within the project scope of work are discussed.

Construction

Onshore

Natural Catastrophe

Type	Comment
Lightning:	Lightning exposures are typical for the area of Scotland and are considered low (an average of 0.2 to 1 strikes/km^2.y for this region). (Ref: Munich Re *Nathan Online*).
Earthquake:	Seismic activity in the area is very low, with the *Munich Re Nathan Online* categorising the area as Zone 0, i.e. Modified Mercalli scale V or less with an exceedence probability of 10 % in 50 years (equivalent to a return period of 475 years) for medium subsoil conditions.
Volcanic:	The *Munich Re Nathan Online* does not identify a volcanic eruption risk for this area of Scotland.
Tsunami:	*Munich Re Nathan Online* does not identify a tsunami potential for this area of Scotland.
Climate:	The area has a North European climate. The monthly maximum average temperature is 14.4 °C, with the corresponding minimum average temperature being 1 °C. The extreme maximum temperature recorded between 2000 and 2012 was 26.3 °C, with the extreme minimum being -5.8 °C. Annual rainfall is high, with an average monthly rainfall figure of approximately 745 mm (based on the information in the Design Basis and Design Requirements.) The maximum hourly rainfall is 36 mm. there are 147 days per year with more than 1 mm of rain.
Wind storm:	The *Munich Re Nathan Online* identifies this area as susceptible to : • Extratropical (winter) storms: This area is classified as Zone 4 (from a total of 4 Zones, with Zone 0 being the lowest). Wind speeds of over 200 km/h can be expected during these events • Tornado: Zone 1 (from a total of 4 Zones, with Zone 1 being the lowest)
Flooding:	The *Munich Re Nathan Online* identifies no potential for storm surge on this area of the coastline. The potential for flash flooding is classified as Zone 2, from a total of 6 Zones where Zone 1 is the lowest.
Bush fire:	No bush fire exposure is identified for this location.
Subsidence and Landslip:	The site is constructed on granite so there is limited potential for landslip or subsidence.

Transport
There is the potential for loss of high value and critical project items during transport to the Peterhead site. This will include transport of the gas compressor and of the scrubbing column. A transportation study has been conducted to identify the maximum size of module that can be transported to the Port of Peterhead and transferred by road to the power station site. This study has concluded that the modules should not exceed 10 m in width and 40 m in length, and a maximum axel loading of 20 tonne and a maximum loading on the road of 110 tonne per unit.

The estimate of the compressor weight is 320 tonne; the proposal is to modularise the transport by splitting it into three. The CO_2 stripper column will be split into two parts to meet the limitation of single transport module length. The column will be assembled on site.

The power station lies immediately to the east of the main road from Peterhead to Aberdeen, and access from the road to the site is via a single road. At the point of access the main road is a single carriageway construction.

There is the potential exposure to the project in the event of the catastrophic loss of a high value or critical component in transport from the manufacturers to the Peterhead Power station site. The compressors are the largest value single item. If the modules are transported together in a single shipping movement then all three modules could be lost resulting in loss of 100 % of the value of the compressors. The delivery time from successful tendering is scheduled to be 19 months (followed by 10 months hook-up and pre-commissioning) so loss of the loss of all of the modules could result in a project delay of up to 19 months.

The FOB cost estimate for the compressor package is GBP 12.8 million.

Heavy Lift
Heavy lifting equipment will be required for the positioning of the machinery and the lifting into position of the columns and process plant. Heavy lift plans will be developed during the construction planning to minimise the risk of damage to plant or equipment during heavy lift operations. The Peterhead Power station will be a live operating facility during the construction of the carbon capture plant.

There is limited space for laydown areas and cranes and it is proposed that two separate contractors will be carrying out the SSE power plant modifications and the Shell CC plant work scope. The equipment modularisation is seen as a positive step to minimise crane lifting activity.

Fabrication / Assembly
There is the potential for damage to process equipment during the fabrication and assemble stage of the CCS project due to the mechanical working taking place. There is also the potential for fires and explosions during the fabrication activities resulting in damage to the plant and equipment and delay in the finalisation and commissioning of the project plant.

It was observed during the risk review that the Peterhead site is relatively small and congested and there will need to be effective control of fabrication activities to minimise the risk exposure to existing and newly fabricated plant from the construction activity. However, there is experience on the site of carrying out major projects successfully and that experience is being utilised for the planning of the new project.

Long Lead Time Items
There are some long lead time items that form a critical part of the Peterhead CCS Project equipment. The one item with the longest lead time that is potentially critical to the project execution is the

compressors. These are estimated to have a delivery time of 19 months after a tendering time of 2 months and a period for hook-up and pre-commissioning of 10 months.

Hot Tapping / Tie-ins

Tie-ins will be made to the Peterhead Power Station plant for the supply of utilities for the capture plant. The flue gas ducting will also be tied in to the vent stack of one of the gas turbines. SSE will be responsible for the installation of the tie-ins, though and major accidents with the tie-ins could result in project delays.

Pressure Testing

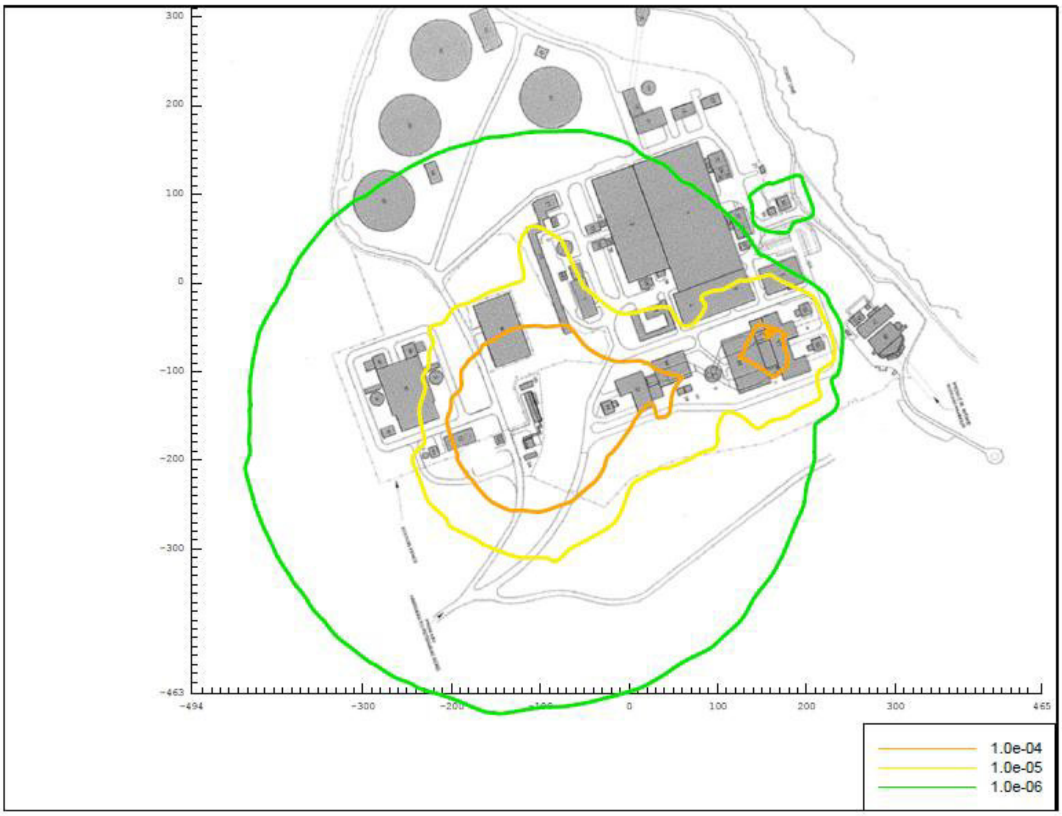
Pressure testing carried out during the construction phase will be carried out with water or nitrogen rather than compressed CO_2. However, pressure testing could result in the catastrophic failure of piping or vessels resulting in shock waves and the generation of missiles that could result in further damage to plant in the vicinity.

Third Party

The Peterhead Power Station is surrounded by coastal cliffs and farmland. Most of the immediate area is owned by SSE. The land immediately adjacent to the power station site is used for mixed farming and livestock grazing.

There is the potential for interaction with the existing power station facilities. These have been assessed in a quantified risk assessment study carried out by GL Noble Denton in 2011. This assesses the likelihood and consequences of accidents on the gas fired power station site to determine risk contours of harm to people on and outside the power station site. The report also estimates the exceedance contours of the overpressure and thermal radiation consequences (the cumulative frequency of exceeding various harm criteria), which could potentially have an impact on the CCS construction project.

Contours showing the frequency of exceeding 100 mbar



Contours showing frequency of exceeding 40 kW/m² regardless of duration

Contours showing the frequency of flame impingement regardless of duration

Therefore, it can be concluded that there is the potential for impact from the foreseeable risks on the operating SSE power station during the construction phase of the project that would result in damage to project plant and equipment being fabricated, assembled and tested on the Peterhead site.

The layout of the plant on the Peterhead Power Station site, including the CCS project plant is shown in *Appendix B.* Significant parts of the project plant and equipment are within the 1 x 10^{-4}/year exceedance contours for the consequences 100 mbar overpressure, 40 kW/m^2 thermal radiation and flame impingement.

The realisation of an accident resulting in these consequences will be expected to be as a result of an accident on the power station that would result in shutdown of the generating capacity while investigation, repair and remediation actions are carried out. If it were to occur during the construction phase of the CCS project then there would be additional impact on the plant and equipment being installed. The impact will be dependent upon the stage of the construction project, the magnitude of the accident on the power station and the protection and mitigation in place at the time of the accident.

It was observed during the risk review that it will be necessary to revise the emergency response plans for the Peterhead Power Station to take account of the significant change in the nature of the risks to which power station staff will be exposed and the different emergency response actions required to mitigate the consequences in the event of a major CO_2 release.

It is estimated that an explosion in the power station site could result in damage to CCS plant structures that could result in a six month delay in the project and property damage of GBP 10 million.

Pipeline

Natural Catastrophe
The significant water depths along the specified pipeline route are as follows:

Goldeneye Platform	-119.5 m
Subsea Tie-in	-80.0 m
Landfall	0.0 m
Horizontal Directional Drilling Exit Point (Landfall Tie-in)	-12.0 m

The absolute minimum sea water temperature recorded (between 2001 and 2012) is 5.2 °C and the absolute maximum sea water temperature recorded was 14.9 °C.

Offshore it is understood that the seabed comprises of one or two layers of glacial till (unsorted glacial sediment) overlaying weathered granite. The till is reported to contain gravel and boulders.

As part of the pipeline design study, a preliminary two-dimensional stability analysis has been performed using one-year omni-directional storm conditions to ensure that the pipeline is stable in the temporary condition prior to trenching and back-filling. It has been concluded that it is possible to achieve on-bottom stability during the installation phase using concrete weight coating. The thickness of the concrete weight coating is likely to vary between 30 and 60 mm along the length of the pipeline route.

Transport
There is the potential for the loss of lay-pipe in transport to the lay barge. However, it is considered that additional replacement pipe could be manufactured or supplied from alternative sources.

A dedicated pipe lay barge will be selected as part of the project FEED study and will be transported to the lay site. Any loss of the lay barge during transport to the site will result in project delay as an alternative will need to be identified, contracted to the project and transported to the site. This would therefore result in a one-year delay to the project as it would need to be pushed into the next pipelay season.

Pipelay
Details of the pipelay will be developed and finalised during the FEED study that, at the time of the survey had not commenced. The details of the contractual arrangements for the pipelay have not been finalised; whether the installation of the pipeline landfall and offshore pipeline section are installed by the same or different contractors.

As with any pipelay operation, there is the potential for damage to the pipeline during lay operations, testing or commissioning resulting in water ingress to the pipeline. Water ingress and prolonged exposure to seawater will result in damage to the pipeline. As a conservative estimate it has been assumed that damage would result in the need to replace the new pipe section including the HDD landfall section, and that the damage would result in a delay of the project for one year for the supply of replacement pipe and remobilisation of the pipelay barge and HDD equipment.

Pressure Test
Pressure testing of the pipeline could result in damage in the event of a pipeline manufacturing defect or defect initiated by the pipelay process being identified.

Major pipeline damage in a pressure test could result in seawater ingress into the pipeline, resulting in damage to the pipeline as detailed above for a loss during pipelay.

Third Party
It is normally judged that pipelines of 16 inch diameter and greater are able to withstand interactions from fishing gear and anchor dragging loads and do not require protection by trenching.

The new 20 inch CO_2 export pipeline will have a 4 inch methanol line piggybacking onto it. To assure protection of the small diameter line shall be trenched and buried to a minimum of 0.5 m cover over its entire length to the Goldeneye pipeline subsea tie-in. The 20 inch line will not be buried over most of its length. In the vicinity of the Peterhead harbour and the near-shore there will be a section of the pipeline that will be rock-dumped.

Damage by third parties could result in seawater ingress to the pipeline and damage to the internal integrity of the pipeline along large length of its structure. This is a more likely scenario in the stage after the pipelay and prior to burial and backfilling, and while the pipeline is empty.

Platform and Reservoir

Natural Catastrophe
The water depth at the Goldeneye platform is 119.0 m. The 100 year significant wave height is 13.3 m and the 100 year maximum wave height is 24.6 m.

The 100 year omni-directional extreme wind speeds at 10 m above mean sea-level are:

- Three second gust - 50.3 m/s
- One minute mean - 43.8 m/s
- One hour mean - 35.0 m/s

The 100 year minimum air temperature is -8 °C, and maximum air temperature is 25 °C.

The maximum thickness of wet snow that will build up on horizontal surfaces is 200 mm.

Seismic activity in the area is very low, with the *Munich Re Nathan Online* categorising the area as Zone 0, i.e. Modified Mercalli scale V or less with an exceedence probability of 10 % in 50 years (equivalent to a return period of 475 years) for medium subsoil conditions.

Munich Re Nathan Online does not identify a tsunami potential for this area of the North Sea.

The *Munich Re Nathan Online* identifies this area as susceptible to:

- Extratropical (winter) storms: This area is classified as Zone 4 (from a total of 4 Zones, with Zone 0 being the lowest). Wind speeds of over 200 km/h can be expected during these events

- Tornado: Zone 1 (from a total of 4 Zones, with Zone 1 being the lowest)

Transport
A jack-up drilling rig will be employed for well workover for the capture project. It is expected that a large jack-up will be required to carry out this activity that will need to be scheduled for the project one or two years in advance of the installation work. Any loss during the transport of the jack-up to the project site would require the mobilisation of another replacement rig. Due to the specialised nature of the rig required, due to the size of vessel and depth of the water, it is expected that this could result in delay of at least one year.

There is the potential for loss of mechanical equipment being transported to the offshore platform. There are no individually large, high value items of equipment that are to be installed onto the platform. However, loss of equipment that need to be installed would probably result in a one year delay as the work would be delayed until the next installation envelope, one year later. Three seasons are available in the project plan to complete this work, but if the loss were to occur in the transport of equipment in the final season then there is the potential for project delay.

Heavy Lift / Dropped Object
Any heavy lifting will be carried out by cranes on the platform or on the jack-up. Lifting plans will be developed and approved for heavy lifts. There will be no equipment that is operational or pressurised while these lifts are required to take place and the platform will be effectively hydrocarbon-free. Dropping of objects could result in damage and the need for replacement. As above, depending on the timing of the loss in the overall project and the criticality of the equipment lost, this could result in a one year delay to the project.

Fabrication / Assembly
The construction work to be carried out on the Goldeneye platform is to extend the operational life from 20 years to 30 years for the purpose of injecting CO_2 into the depleted reservoir.

The key workscope to be completed to allow CO_2 injection from the platform are:

- The topside process pipework to be replaced with piping suitable for CO_2 service conditions
- Two CO_2 filter vessels will be installed onto the platform
- The existing vent system will be replaced with a new vent system suitable for CO_2 service
- A CO_2 detection system will be installed to ensure the safety of personnel on the platform

In addition, there will be workover of the existing well completions to make them available for CO_2 injection.

There are no structural modifications to the platform planned. The scope of work for the structure is to verify the integrity of the platform to enable extension of the operational life in order to support the modifications required by the new mechanical and control equipment.

Mechanical work on the platform could result in damage to plant and equipment including fires associated with hot work activities. As the work being carried out offshore is limited and the limits on the new equipment being installed, it is not considered that there is the potential for a high-value loss associated with the fabrication activities.

Damage due to fabrication activities could result in the need to resupply or replace equipment. It is considered that this could result in a delay to the project of up to one year because of the limitation of carrying out offshore work in a good weather window.

Subsea Installation
The existing subsea isolation valve (SSIV) is located approximately 150 m from the Goldeneye platform riser tie-in. The SSIV structure is a piled, rectangular structure designed to resist dropped objects and trawl board impact. It has been recommended that the SSIV is retained for CO_2 service. The existing 20 inch check valve is considered functionally unsuitable for the new service and will require replacement with a remotely operable ball-valve. The other primary valves within the SSIV structure contain soft seals unsuitable for CO_2 service, so they will need to be recovered and refurbished or replaced. During the FEED study it should be established whether a SSIV is required for the pipeline to a normally unattended platform in CO_2 service.

Therefore the scope of the subsea work has not been finalised.

Vessel Impact / Third Party
The platform is potentially at risk of impact from third-parties such as vessels losing power and drifting into the structure. There will be increased vessel movements during the construction phase of the project from support and transportation vessels.

The platform is marked on nautical maps and there is an exclusion zone around the structure. Shipping is monitored in the area and ships are contacted by radio if seen to be entering exclusion zones. Fishing intensity in the development area is low. A shipping traffic study indicates moderate shipping with between one and ten vessels per day passing through the area.

There is a helicopter deck on the platform and this will be used during the construction phase. There is the potential for impact due to accidents in helicopter movements resulting in serious damage to the platform and fire. There is also the potential for aircraft impact, though this is considered to be a more remote risk.

There is one telecommunication cable and four hydrocarbon export pipelines in the vicinity of the development.

Drilling / Blowout

The injection of CO_2 into a depleted gas field has not been tested or performed before on an industrial scale on an offshore reservoir. The lack of prior experience introduces some additional risks relating to:

- Thermal effects and pressure cycling on the caprock
- The injection of cold dense-phase CO_2 into a low pressure reservoir
- The quantification of any leakage to surface (were it to take place)

The five existing wells were evaluated as suitable for use in CO_2 injection. However, due to integrity issues and CO_2 phase behaviour management, it is not possible to use the wells without any modification. A rig is required to carry out a workover of the upper completion by installing small tubing in order to manage the CO_2 expansion. There is no intention of drilling new wells, nor is there the intention of performing further workover at a later date.

Risk assessment studies have been carried out as a key aspect of the Storage Development Plan to identify the potential threats to integrity and assess the adequacy of measures to prevent and minimise the risk. A summary of the assessment work and the findings of these studies is included below:

CCS Theme	**Technique employed**	**Description**
Capacity	Subsurface modelling studies using scenarios to span the range of uncertainties.	Very low risk that the reservoir capacity is not available. The studies conducted have concluded that the available storage capacity is well above the 10 million t mandated by the CCS project, with a lower-end, worst-case scenario capacity of about 25 million t.
Containment	Bowtie risk assessments supported by geomechanical, geochemical, fluid dynamic and geological modelling; plus detailed assessments of current state and historical well engineering experience. There will also be monitoring and a corrective measures plan. Studies performed indicated that thermal fractures are not a high risk, but further modelling is required.	Some aspects have higher risks and therefore require additional active / reactive barriers to be put into place to reduce to ALARP – this is done through a combination of monitoring and corrective measures. The higher risk areas are considered to be: – Well injection tubing leaks. – Well penetrations in the secondary and tertiary seals. Risks that are being subject to further detailed study during the FEED are: – Fractures in the caprock caused by the stress of re-pressurisation and cold CO_2 injection.
Injectivity and Transport	Numerical modelling of the injection of CO_2 into the well tubing (temperature and pressure); the stresses and strains imposed on the wells; assessment of risks of plugging (including geochemical and thermal fluid dynamic modelling.)	A moderate risk of completion sand screen plugging was identified and mitigated by including in scope of the project the installation of surface filtration equipment. There is an increased risk of failure in the injection wells (resulting in down-time to ensure containment is preserved) if the whole chain delivery is not to specification. The technique for impedance matching of the surface and subsurface conditions has not been tested on an industrial scale before.

CCS Theme	Technique employed	Description
	Numerical modelling of the whole surface pipeline system. Numerical modelling of CO_2 releases. Analysis of the conditions of the surface materials and pipelines. Design: replacing materials and systems in offshore facilities – HAZID, HAZOP.	Risks do not differ significantly from conventional pipeline and plant activities, with the exception of the behaviour of CO_2 when released. The release modelling is being improved by physical release testing experimental work.
Monitorability	Feasibility study to identify and assess available techniques combined with bowtie risk assessment to identify the critical areas for monitoring. Surface facilities and pipeline monitoring follows standard practice as detection equipment exists.	Flows can be metered. Significant irregularities can be detected once they leave the reservoir however, monitoring of the movement of CO_2 within the store is limited to point measurement. Monitoring does not identify leak paths, only leaks. The store is under pressure (external pressure is greater than the internal pressure) and should not have the driving-force for leakage until the pressure recovers to near original levels, therefore leak-paths could exist and remain undetected for some time. Quantification of a leak to seabed is currently untested within the industry.
Corrective measures	Feasibility study identifying and assessing available techniques to address mitigation along the leak paths identified in the containment risk assessment.	Some geological leak paths are going to be almost impossible to seal however, these are likely to be of low flux and have negligible environmental impact. This assumption has not been subject to regulatory test.

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

The Xmas tree and the tubing hanger will be replaced in the workover with units having a lower minimum temperature rating than the currently installed. To validate the suitability of the wellhead system for CO_2 operations, detailed thermal simulations of wellhead and Xmas tree system operation under the scenario of uncontrolled CO_2 leaks will be carried out to evaluate the extent of the low temperature zone.

The fundamentals of the reservoir properties of the Goldeneye field, together with its hydrocarbon production history point to excellent properties for CO_2 injection and storage. However, the operating conditions and CO_2 composition present a risk of this injectivity declining over time as a result of plugging and hydrate / halite precipitation.

Screens are being installed on the platform to avoid plugging of the formation. It is considered that the most probable cause of low injectivity is thought to be the failure of the offshore filtration.

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

Commissioning

Onshore

Catastrophic Vessel Rupture
Commissioning of the onshore equipment with CO_2 has the potential to result in equipment failure and release of large quantities of gas.

There is understood to be a possibility of a phenomenon of a CO_2 Boiling Liquid Expanding Vapour Explosion (CO_2 BLEVE) as a result of the very rapid depressurisation of a dense phase CO_2 inventory. The project design has eliminated the requirement for storage of CO_2 after compression and cooling and so it is considered that there are no potential for cold BLEVE of the vessels on the Peterhead site.

Machinery Catastrophic Failure / Machinery Fire
The commissioning of the machinery for the CCS project on the Peterhead site has the potential to result in catastrophic failure resulting in serious damage to the machine and associated equipment. There is also the potential for a fire to result on the machinery during the commissioning activity.

The most important machine on the CCS project is the CO_2 compressor and associated driver. Catastrophic failure of the gas compressor during commissioning would result in major physical damage to the machine and its driver, potentially a major release of CO_2, depending on the effective operation of the associated isolation valves, and a major delay to the project.

Release of CO_2
There is the potential for seal leaks, pin-hole leaks, medium leaks from full-bore ruptures of small diameter pipes and large releases as a result of full-bore ruptures of large diameter pipes.

The very cold temperatures associated with liquid CO_2 releases will present a direct hazard to people in the vicinity. It will also have the effect of cooling systems, pipework equipment and structures in the area of the release, potentially causing low-temperature embrittlement failure and escalation of the event.

A quantified risk assessment (QRA) has been carried out by DNV for the project to assist in the option selection process. This includes an assessment of the dense phase export option that is being taken forward. The QRA is carried out to assess safety risks, but the modelling is informative when considering the broader risks associated with the project. The assessment models the dense phase / heavy gas dispersion and dilution of hazardous gas plumes. The study concludes that a leak from the compression facility or export pipeline on the Peterhead site would create a hazardous plume that will extend many 10s of metres from the leak point.

The geographical layout of the site, in particular the banking on three sides of the area of the site currently occupied by the oil storage tanks, where the gas compressor building is proposed to be sited, would contain any dense gas release and funnel it towards the seashore. However, an onshore wind could result in a gas plume being driven over the boundary banks and the CO_2 could migrate towards the station buildings and occupied areas of the site, and towards the main road that passes the site.

A leak from the inshore part of the export pipeline could also impact the occupied areas of the Peterhead site, as well as having an impact on the foreshore.

Pipeline

Catastrophic Failure
Catastrophic failure of the pipeline during commissioning would result in massive release of CO_2 and seawater ingress into the pipeline.

Major pipeline damage during commissioning could result in seawater ingress into the pipeline, resulting in damage to the pipeline as detailed above for a loss during pipelay.

Release of CO_2
Pipeline failure during the commissioning phase would also result in a major release of CO_2 subsea. This would have a physical impact similar to the failure a hydrocarbon gas pipe, producing plumes of bubbles with the potential to reduce buoyancy in the area above the leak. The chemical effect of the released CO_2 would also result in acidification of the seawater in the region of the leakage. This would have the potential to result in significant environmental impact to the flora and fauna in the area around the pipeline leakage and the operator may be held liable and be required to ensure that compensatory environmental remediation actions are carried out to maintain the overall biodiversity. The scale of the potential damage and the magnitude of the necessary remediation work is impossible to determine without detailed pipeline routing assessment. Only if the pipeline failure was very close to the landfall would it be expected to have any impact on people.

Water Ingress
Failure of a pipeline during commissioning could result in water ingress to the pipeline. Water ingress and prolonged exposure to seawater will result in damage to the pipeline. As a conservative estimate it has been assumed that damage would result in the need to replace the new pipe section including the HDD landfall section,

Platform and Reservoir

Catastrophic Vessel Rupture
As with the onshore equipment, commissioning of the offshore equipment with CO_2 has the potential to result in equipment failure and release of large quantities of CO_2. Commissioning of the platform process equipment for the first time with CO_2 has the potential to stress these components in the operating environment for the first time, and has the potential to result in catastrophic vessel failure.

Release of CO_2
It is considered that there is the possibility of structural failure from damage to the platform due to erosion by solid particles of CO_2. It is considered that this would occur gradually as a structure is eroded by the CO_2 stream and the stresses in the structure are concentrated. However, this is not considered to be a major hazard during commissioning as it should be possible to mitigate the effects. The low temperature effects of a CO_2 release could cause the complete rapid failure of a structural member on the platform.

The release of CO_2 would also affect the population on the platform and, if of sufficient size and depending on wind direction, the population on the adjacent jack-up rig, if it is still present (currently not planned to be used at this stage.)

Subsea Release
Initial injection of CO_2 in the commissioning phase will introduce additional risk to the reservoir operation. This is the point at which the well tubing will be first exposed to the potential corrosion due to CO_2. During normal operations water will be displaced by the CO_2 but during start-up and shutdown there is the

potential for water flow into the well. Methanol will be injected during the transient conditions such as commissioning to prevent hydrate formation. Well tubing is exposed to the potential for internal corrosion from CO_2 and impurities in the exported gas from Peterhead.

Low temperatures are not considered a risk as the lowest temperatures for the CO_2 injected into the reservoir is -10°C and the ductile / brittle transition temperature of the tubular steel grade is -15°C.

There is the potential for a subsea release of CO_2 during the commissioning if there are unrevealed issues with the materials of construction which are identified only by the low temperatures or incompatibilities of the CO_2 service. This may result in the release of a major plume of gas into the sea leading to boiling of the sea and acidification. In addition, this may occur below the Goldeneye platform and jack-up rig if it were still on station for the commissioning activities. There is therefore the potential for significant exposure to the working populations on the two structures, though the cloud would be expected to be low-lying and drift across the sea surface and unlikely to result in hazardous concentrations at the populated levels of the platform and jack-up.

Water Ingress
Failure of subsea piping during the commissioning phase could, following depressurisation, result in the water ingress into the piping, resulting in damage and the need to replace. The extent of the damage will depend upon the isolation valves around the piping.

Reservoir Damage
Initial injection of CO_2 into the reservoir has the potential to result in damage to the structure in the event of overpressurisation, high or low temperatures and contamination.

There is the potential for thermal induced fracturing of the primary caprock during injection. The risk has been assessed during the project development. For the case of fracturing due to thermal changes near the injection point assessment has concluded that the probability is very low but that strategies to mitigate the risk should be developed. For the case of the CO_2 plume encountering the caprock, it was concluded that hydraulic fracture of the caprock will not occur but that the plume will migrate along the reservoir-caprock interface.

Operation

Onshore

Catastrophic Vessel Failure
See above.

Machinery Failure / Machinery Fire
See above.

Major CO_2 Release
See above comments for the commissioning phase. The impact of cooling and effect of releases of solid CO_2 particles could increase the consequences of a release during the operational phase.

Natural Catastrophe
See above.

Third Party Impact
See above.

Fugitive Emissions
The operation of the onshore carbon capture and pressurisation plant at the Peterhead power station will potentially result in low-level emissions of CO_2 due to seal leaks and equipment venting. CO_2 will accumulate in pits, depressions and basement areas and has the potential to overcome people who are not aware of its presence. Safe practice on the Peterhead site will include the use of CO_2 monitors routinely by site personnel, and in particular when entering confined spaces especially below ground. The location and separation of the process plant from third parties and the environmental conditions in the Peterhead area mean that it is considered very unlikely that fugitive emissions will result in a hazardous atmosphere outside the site boundary.

Sabotage & Terrorism
The sabotage and terrorism risks associated with the Peterhead location are considered to be relatively low. The site is not considered to be a significant target for political activity and there is historically a very low level of political violence in Scotland.

Pipeline

Catastrophic Failure
The pipeline design life will be extended by the use of Cathodic Protection (CP). Monitoring of the CP system will be required during the operational life and replacement of anodes may be required.

In the operating mode of the pipeline no internal corrosion is expected as long as the CO_2 dew point is maintained. A corrosion allowance is in place to cater for limited duration operation below the dew point. Pipeline integrity monitoring will include corrosion monitoring of the pipeline.

Major CO_2 Leakage
See above.

Seawater Ingress
See above.

Natural Catastrophe
See above.

Third Party Impact
See above.

Pipeline Crossings / Umbilicals
The 4 inch methanol pipeline will be buried but the main 20 inch pipeline will only be buried in the vicinity of Peterhead Harbour and the near-shore area. Sections where the methanol pipeline crosses existing pipeline routes may not be able to be trenched and buried. At these locations rock dumping protection will be required.

Platform and Reservoir

Mechanical Failure

- Platform Vessels / Pipework

  Mechanical failure of the platform vessels or pipework would result in catastrophic release of CO_2 and potentially additional damage on the platform structure due to erosion or cooling effects (see above)

  During normal operations the platform will be unattended and to the identification of vessel or pipework failure will be dependent upon remote detection by gas detection, pressure changes or cameras. The protection of the structure and equipment will depend upon the remote isolation and shutdown of the facility in a timely manner. Failure to do this could result in additional damage to the platform and other equipment, increasing the magnitude of the loss and extending the project downtime

- Risers

  Mechanical failure of the risers will also result in the catastrophic release of CO_2 and mechanical damage to the platform. It is intended to re-commission the subsea isolation valve on the platform riser, so the operation of this should limit the duration of a release of CO_2 in the riser following detection or identification of a release

- Tubing

  Pressure and temperature sensors on the tubing and well annuli need to be installed and transmitted live to the project control room. There are also sub-surface shut-in valves (SSSVs) that are continuously monitored. The integrity monitoring of the well structures is part of the planned inspection regime

  Tubing failure during operation could lead to the release of CO_2 at the seabed below the platform. Injection activity could be ceased and SSSVs closed to limit the magnitude of the release. If the platform is unattended then there will be limited exposure to people and rapid operation of emergency shutdown systems should limit the overall impact of the loss

- Xmas Tree

  Xmas trees provide protection against reservoir upsets. There will be regular testing programmes to confirm their reliability and availability. Failure of a Xmas tree in testing will result in shutdown of the well and repair or replacement of the Xmas tree. Unrevealed failures will result in an inability to mitigate blowout events and the potential for event escalation

- Conductors

  Conductor failure will result in release of CO_2 on the platform and the associated effects, but detection by monitoring of operational pressure profiles should result in operation of the sub-surface isolation valves to limit the release and consequences

Blowout
For normal well operating conditions the wellhead system is compatible with the expected low temperature.

The current wells were designed for producing hydrocarbons, and as such were not designed to withstand the potential low temperatures that would be experienced during a CO_2 blowout. The temperatures around the SSSV need to be assessed during the FEED study to verify the sealing capability during a major release scenario.

Blowouts will potentially result in release of the stored content of the reservoir in the event of failure of multiple barriers. There could therefore be an extended release of CO_2.

Natural Catastrophe
See above.

Existing Wells and Drilling
During production and injection of CO_2 the stress state within and outside the reservoir will change. A geomechanical appraisal of the Goldeneye structure has been carried out to simulate the injection scenarios and assess the geomechanical threats to the integrity of the storage site. This concluded that there is no risk of shear or tensile failure in the reservoir or tensile failure of the caprock.

Faults and fractures can potentially provide natural leak paths through the overburden to reduce the reservoir integrity. A detailed study was undertaken to review the extent of faulting in the over burden. No faults have been identified that cross both the storage seal and the complex seal. No gas chimneys (which may be an indication of a leaking trap) have been identified on seismic above the Goldeneye field. There is no seismic signature of shallow gas accumulation.

The Goldeneye field itself was penetrated by four exploration and appraisal wells and five production / injection wells. All the production wells are suspended with downhole retrievable plugs. Nine additional abandoned exploration and appraisal wells located near the Goldeneye field were also evaluated. A well integrity assessment has been conducted and only one well is identified as having a poor barrier at the storage seal, but this well is located 3.8 km to the west of the Goldeneye storage complex.

Aviation
There is a helicopter deck on the platform and this will be used during the operational phase for accessing the platform for monitoring, inspection and maintenance activities. There is the potential for impact due to accidents in helicopter movements resulting in serious damage to the platform and fire. There is also the potential for aircraft impact, though this is considered to be a more remote risk.

Fishing
There is the potential for third-party impact due to fishing activities in the vicinity of the platform. There is an exclusion zone around the platform for vessels and the area will be monitored by radar. The subsea structures are protected against trawl gear impact.

Field Development Drilling
There is the potential for damage to the reservoir due to exploration drilling of the formation for other oil and gas projects. However, in this jurisdiction there is very close control over all exploration drilling activity so it is not considered credible that field development drilling would be able to commence in the vicinity of the operating CO_2 capture and injection project at Goldeneye that might impact the storage reservoir.

Sabotage & Terrorism
The project is not considered a significant target for sabotage or terrorism. The climate in Scotland for political violence is very low and there is no history of political violence involving offshore platforms.

The platform will normally be unattended so there is no immediate response to any terrorist activity on the platform, but once activity had been detected the operations could be shutdown to minimise the risk of release of CO_2 in the event of sabotage.

Closure and Decommissioning

Mechanical Impact
It is anticipated that deconstruction activities will be carried out during the closure and decommissioning phase and these would be expected to require rig movements in the vicinity of the platform. There is the potential for impact to the platform during rig movements resulting in mechanical damage. However, the reservoir would be expected to be isolated at this stage by SSSVs and the Xmas trees, though not necessarily permanently sealed. An accident resulting in impact to the platform may result in delay to the project to finally seal the reservoir and decommission the platform but is not considered likely to result in release from the reservoir.

Heavy Lift / Dropped Objects
There will be heavy lifts carried out as part of the decommissioning operation, removing equipment from the platform. There is the potential for dropped objects during the operation impacting the subsea equipment resulting in damage. The reservoir will have a primary seal from the SSSVs but there is the potential that secondary seals at the seabed may be damaged as a result of the dropped objects. Heavy lift plans should be developed for the decommissioning phase to, as far as possible, eliminate the risk of damage to the equipment located on the seabed.

Damage to the subsea completion valves would require immediate attention to ensure the sealing of the reservoir in advance of the permanent sealing operation. It would also be expected to result in a delay to the reservoir sealing operation prior to handover. Prior to the remedial action there is an increased risk of releases from the reservoir as it will at that stage be reliant on a single seal at the reservoir.

Contamination (NORM)
There is not considered to be a significant potential for exposure to material from the well and reservoir due to the nature of the operation, injecting CO_2 into the structure rather than extracting gas. Therefore, material from the reservoir including naturally occurring radioactive material would not expected to be released on the platform.

Third Parties
The platform is potentially at risk of impact from third-parties such as vessels losing power and drifting into the structure. There will be increased vessel movements during the construction phase of the project from support and transportation vessels.

The platform is marked on nautical maps and there is an exclusion zone around the structure. Shipping is monitored in the area and ships are contacted by radio if seen to be entering exclusion zones.

There is a helicopter deck on the platform and this will be used during the decommissioning phase. There is the potential for impact due to accidents in helicopter movements resulting in serious damage to the platform and fire. There is also the potential for aircraft impact, though this is considered to be a more remote risk.

Sabotage & Terrorism

See above.

Post-Decommissioning

Natural Catastrophe

See page 20.

Reservoir Failure

Following the completion of the injection into the reservoir the pressure will be monitored to show the long-term effectiveness of the CO_2 storage. There will also be detection of any significant irregularities or leakage from the reservoir. The monitoring programme at this phase will be informed by the information collected during the injection and post-injection phases. It is possible that the platform will be removed, making the need for ocean-bottom monitoring nodes. No further detail of the monitoring is possible at this stage of the project.

There will be no additional dynamic loading of the reservoir unless there is significant seismic activity, so the reservoir pressure will not be expected to increase significantly.

Platform Collapse

The platform will be decommissioned and abandoned, and potentially removed from the site. There is the potential for collapse of the platform after the abandonment or during the removal process. This may damage the subsea completion, though by this stage the reservoir will have been permanently sealed. This could result in damage to the reservoir monitoring equipment that would require repair and replacement.

Third Parties

See above.

Field Development Drilling

There is the potential for damage to the reservoir due to exploration drilling of the formation for new oil and gas projects during the post-decommissioning phase. In this jurisdiction there is very close control over all exploration drilling.

5

Loss Exposures

It should be noted that loss estimates are intended as a guide only and are not intended to cover every possible eventuality. It should also be noted that, due to the information at this early stage of the project being basic, and a number of key assumptions being made by Marsh, the loss estimates presented in this section should be considered as preliminary.

Loss Definition

The Estimated Maximum Loss (EML) is defined as 'the loss that could be sustained under abnormal conditions with the failure of all protective systems'.

No credit is given to the effectiveness of barriers or the impact of emergency response activities. The EML scenario is considered a credible event, and will typically have industry precedent. While probability is not quantified, it is appreciated by its very nature that the EML scenario has a very low likelihood of occurring.

The EML is not intended to represent or serve as a risk assessment, which requires mitigation or specific follow up actions. It is however assumed that the project has considered the factors leading to the EML event within an independent risk assessment and management process and has implemented the appropriate corrective actions. Residual risk in this regard should ideally be defined as part of ALARP verification.

Property Damage EML

Construction

Loss of the compressor package during the construction phase, for example due to an accident during transport or lifting operations, would result in a loss of GBP 13 million.

Damage to the onshore construction project on the Peterhead site could occur as a result of a gas explosion on the gas fired power station. There is an estimated exposure of GBP 10 million to the project equipment.

A construction loss during the lay of the pipeline could result in seawater ingress into the damaged pipeline requiring replacement of the new section. This would require remobilisation of the pipelay vessel in a later season as well as supply of replacement linepipe. An exposure of GBP 56 million is estimated.

There is the potential for damage to the Goldeneye platform during construction activity. A construction loss during work on the offshore platform is considered to result in a maximum property damage loss of GBP 15 million.

Commissioning

Commissioning could result in catastrophic failure of the gas compressor and the release of a large plume of CO_2. The location of the compressor building is such that no significant additional damage is considered likely in the event of catastrophic failure. The estimated maximum loss is GBP 13 million.

Commissioning of the pipeline could result in failure due to an unrevealed manufacturing fault. This would result in release of CO_2 into the sea or foreshore and potentially seawater ingress to the pipeline requiring replacement of the new section of pipe. This is estimated to have an exposure of GBP 56 million. In the event of water ingress into the existing Goldeneye pipeline it is considered that the project would want to reuse the pipeline by repairing, emptying, cleaning and drying before pressure testing, re-commissioning and returning to CO_2 service.

An accident in the course of commissioning the offshore structures on the Goldeneye platform could result in physical damage with an estimated loss value of GBP 10 million.

Commissioning of the injection operation of the reservoir has the potential to result in failure of subsea components. The physical damage is estimated to be GBP 2 million, but there would be a significant additional cost to replace damaged subsurface equipment. This would require the mobilisation of a suitable rig for the well control activity (if the well is to be continued to be used).

Operation

There is limited major fire or explosion potential identified for the CO_2 capture plant, though an explosion on the gas fired power station could affect the capture plant.

There is the potential for catastrophic failure of the gas compressor resulting in complete failure requiring full replacement of the compressor and associated driver.

Failure of the pipeline during the operational phase would result in the release of CO_2 into the sea followed by seawater ingress into the pipeline. This will potentially extend along the whole length of the pipeline as there are no sectional valves available. It is assumed that it will be possible to repair a damaged pipeline and dewater, to allow the pipeline to be replaced. There would be pipeline replacement cost of GBP 5 million, but there would be a significant additional cost to mobilise a vessel to carry out the repair activity, plus a considerable interruption to the operation of the pipeline.

A loss during the operational phase on the Goldeneye platform could result in damage to the process equipment. There is limited potential for fire or explosion, but there is the potential for loss as a result of catastrophic vessel failure. There could also be some cooling effect from the release of dense phase CO_2, but this is not considered to result in any long-term damage to process equipment or the platform structure.

A failure of subsurface equipment during the operational phase of the CO_2 injection operation will require repair or replacement of the equipment. This will require shut-in of the associated well and the mobilisation of a jack-up rig to effect repair. There is also the potential for a release of CO_2 from the reservoir due to failure of the sub-surface isolation. Depending on the location of the well relative to the platform, this could make working on the platform impossible without breathing apparatus due to the high concentration of released gas. There would in addition be the effect of the extreme cold of a CO_2 release and lack of visibility that would make working on the platform impossible. The cost of the physical damage due to a failure of reservoir equipment during the operational phase is estimated to be GBP 2 million, but there would be considerable additional costs in mobilising a rig to undertake the repair activity. This is estimated to cost up to GBP 20 million.

The project is currently scheduled to have an operational duration of ten years. In the event of a decision to extend the injection phase from ten to fifteen years it would be expected that the project would be subject to a detailed assessment under the requirements of the management of change procedure. If no significant additional risks are identified as part of the management of change risk review then the estimated maximum losses associated with the project would expect to result from similar loss scenarios and remain of the same size (subject to inflation.)

Closure and Decommissioning

During the closure and decommissioning phase there are similar risks to those associated with the commissioning and operational phases until the process plant, pipeline and platform are free from the presence of CO_2.

There will expected to be a rig in use for the reservoir sealing operations and there is the potential for damage to the platform or subsea equipment. There will be no requirement to repair or replace the equipment during this phase if the closure and decommissioning are the end of the useful life of this equipment.

Post-Decommissioning

In the post-decommissioning phase, there is the potential for damage to the remaining structures due to third-party activity or deterioration from fatigue and corrosion. There will be monitoring equipment in place during the post-decommissioning phase to determine the on-going integrity of the reservoir and sealed wells. There is the potential for physical damage to the monitoring equipment due to natural catastrophe, third-party impact, manufacturing fault or general deterioration. The magnitude of the physical damage in the case of individual events will be expected to be relatively small, but if the sub-sea monitoring equipment is to be reinstalled it will be necessary to mobilise a vessel to carry out the installation activity.

Advanced Loss of Profit / Business Interruption

Construction

Losses during the construction phase will be expected to result in a delay in the start-up of the operational phase of the project.

Loss of the compressor at the construction phase would result in the need to order a replacement. The compressor has quoted as having a deliver time of 19 months (there is an additional two months of tendering in the project timeline, but it will be assumed that this will be eliminated in the event of a resupply). There is an additional ten months of hook-up of the compressor and pre-commissioning. Assuming the loss occurs at the delivery and installation stage, then it is assumed that the impact due to re-supply of the compressor will delay the whole project by a total of 19 months. All other aspects of the project could be completed prior to commissioning.

The project execution plan has the date of the milestone for project completion and declaration of clean energy in July 2019. Therefore, the loss of the compressor during the construction phase would delay this until February 2021.

Pipeline damage requiring re-laying of the new section is expected to require supply of replacement pipeline. There is a delivery time of 12 months quoted. Depending on the time in the operational window when the failure resulting in pipeline damage occurs, it may be possible to carry out the re-laying activity 12 months later. The schedule of work has offshore activity carrying on over three seasons. The impact of a failure during pipeline laying depends which season is being used for the installation, but if it is the last one on the proposed schedule then a loss resulting in pipeline damage could result in a 12 month delay in the completion of the project.

Accidents during the construction phase for the modification of the Goldeneye Platform could result in the requirement to replace the equipment. It is estimated that any individual loss will result in a delay to manufacture a replacement and that the installation would be delayed for one year, from one offshore installation season to the next. If the loss occurs in the last available installation window then it will result in an overall loss to the project of one year.

Damage to the subsea completion during installation and conversion to CO_2 service would potentially result in the requirement to recover damaged subsurface equipment and replacement with new. It is estimated that it will require one year to supply the replacement subsurface equipment and for the mobilisation of a rig to support the subsurface activity. Therefore, the loss during the construction of the subsurface equipment could result in a project delay of up to one year.

Commissioning

Losses during the commissioning phase will be expected to result in a delay in the start-up of the operational phase of the project.

Loss of the compressor at the commissioning phase would result in the need to order a replacement. The compressor has quoted as having a deliver time of 19 months. There is an additional ten months of hook-up of the compressor and pre-commissioning. Assuming the loss occurs at the end of the hook-up and pre-commissioning phase, then it is assumed that the impact due to re-supply of the compressor will delay the whole project by a total of 29 months.

Other project delays during the commissioning phase are considered to be the same as the delays in the construction phase.

Operations

Losses during the operational phase will be expected to result in interruption to the delivery of the project. Repair, replacement and re-commissioning will depend on the stage during the project when it occurs. Major losses that occur approaching the end of the proposed project duration may result in early conclusion of the project.

Compressor failures will be expected to result in an interruption to the project of 29 months (see previous.)

Pipeline failures are expected to result in at least 12 months delay and this may be extended for the pipeline repair or replacement to occur during the offshore work window. This could extend the duration of the project interruption up to 21 months as a result of delay requiring mobilisation I the next season for offshore activity.

Similarly damage to the offshore platform or damage to the subsea and subsurface equipment could result in an interruption to the operation of the project of up to 21 months.

Decommissioning

Losses during the decommissioning phase of the CCS project will result in extension of the duration of that phase, but this will be after the completion of the injection phase of the project and will not therefore impact the operation of the Peterhead power station. However, this will result in extension and additional costs for the decommissioning phase while plans are developed for the decommissioning and recovery of damaged equipment.

Post-Decommissioning

Losses in the post-decommissioning phase are not considered to have an impact on the business or profitability of the project.

Control of Well

Loss of control of a well at any phase during the project is expected to result in the need to seal the lost well and drill a new well. There are a total of five wells associated with the Goldeneye field for the CO_2 capture; four for gas injection and one for reservoir monitoring. A decision will have to be made whether the lost well needs to be re-commissioned. Again, this may depend upon the timing of the loss in the overall duration of the project. It may be decided to seal the well but not re-drill.

The sealing and re-drilling will each require the mobilisation of a drilling rig.

From Marsh's experience of insurance claims, an estimate has been made of the cost of control in the event of loss of control of a single well in the North Sea of GBP 40 million.

In addition, it is expected that there would be additional costs incurred in the event of loss of containment of the stored CO_2 from the reservoir during the commissioning, operational, decommissioning or post-decommissioning phases. The expectation is that there would be the requirement to install permanent monitoring equipment around the reservoir to determine the status of any loss of containment, the location, magnitude and nature of any release. There may also be the requirement to prepare and execute remediation measures to reduce or eliminate the release of CO_2 from the reservoir.

During the operational phase of the project, there will be credit earned through the Contract for Difference (CfD) for the CO_2 sequestered in the reservoir. In the event of a loss of containment from the reservoir there may be the requirement on the project to repay these credits. This will be dependent upon the market value of carbon credits at the time of the loss event.

Considering the multiple variables and unknowns within the impact of a potential loss of containment from the reservoir (size, duration, location, value of carbon credits etc.), and estimate of the financial impact of a reservoir loss would be based on speculation.

Third Party Liability Worst Case Scenario Assessment

Construction

Major losses during the construction phase have the potential to result in an impact on third-parties. Prior to the commissioning the impacts would be as a result of transport accidents, dropped loads, plant failure during construction or major machine failure during testing. These have the potential to impact third-parties along the transport route or contractors. The transport route for heavy equipment is principally by sea to the harbour area in Peterhead and then a short road transfer to the power station site. The transport management plan that is being developed will minimise the exposure to third parties. The maximum exposure during the construction phase of the onshore aspects of the project is estimated to result in up to three fatalities.

Similarly, for the offshore aspects during the construction phase there is the potential for a transport accident, mechanical failure, dropped load or machine failure resulting in impact to contractors, estimated to result in up to three fatalities.

There is the potential for fires during construction phase, as there is in any construction project. The quantity of flammable material on the construction site will be limited and the impact to third parties as a result of fires is considered to be no greater than the impact due mechanical failure.

Commissioning

During the commissioning phase CO_2 is introduced into the plant, equipment, pipeline, offshore plant and reservoir.

Failure of any aspect of the project during the commissioning phase has the potential to impact contractors in the vicinity due to mechanical effects. It also has the potential to release the CO_2 being pressurised into the system. CO_2 could also extend to impact other workers on the Peterhead site and, if the dispersion is far enough, to populations outside the boundary of the power station site.

Failures during the commissioning of the pipeline have the potential to impact third-parties if the failure is in the near-shore area where a cloud of released CO_2 could drift on-shore. (See below.)

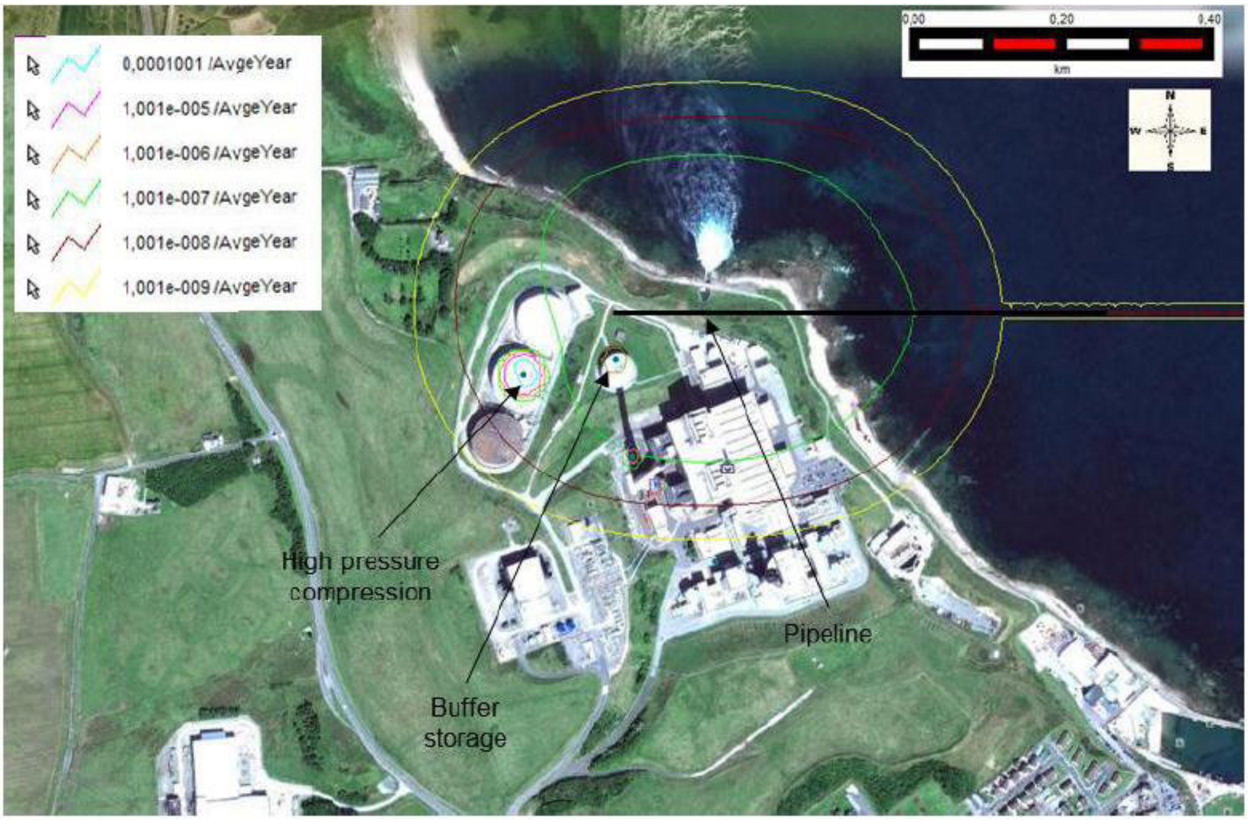
Losses from the pipeline during commissioning phase will only impact third parties significantly in the area close to the shore and close to the platform.

Losses of CO_2 during commissioning from the Goldeneye platform equipment could result in serious impact for the contractors working on the structure. Good practice would be to minimise the number of personnel on the platform who could potentially be exposed during the higher risk commissioning phase, and then have personal protective equipment to minimise the potential exposure. However, there remains a significant risk to contractors on the platform during the commissioning phase of impact due to release from equipment failure on the platform or reservoir leaks being routed back to the platform.

Operation

Modelling of releases of dense phase CO_2 from the compression plant and near-shore pipeline has been carried out as part of the quantified risk assessment carried out for the project. The modelling has used the software PHAST-RISK that has been updated to account for the particular physical properties of CO_2 including super-critical conditions.

The modelling identifies a 1×10^{-5} / year individual risk contour but this is localised around the CO_2 capture and compression plant and does not extend onto the power station site to any great extent.



Individual risk contours from quantified risk assessment – Alternative 2 – Compression of CO_2 to 130 bar – no subsea isolation valves

This suggests that in the event of an accident with a frequency equivalent to an EML type, it would have limited potential for harm to those working on the Peterhead site, and also limited offsite impact. In addition, in the event of a more remote event, the main working population will be located inside the control buildings which will be protected by gas detection and automatic isolation in the event of CO_2 releases, but there is the potential for the working population in unprotected locations to be impacted by major CO_2 releases, resulting in fatalities.

Losses from the pipeline during operational phase will only impact third parties significantly in the area close to the shore and close to the platform.

The platform will not normally be occupied, but in the event of a release of CO_2 as a result of equipment failure or reservoir failure there is the potential for workers on the platform being exposed to hazardous CO_2 atmospheres resulting in fatalities.

There is the potential while CO_2 is being injected into the reservoir for migration of the stored dense-phase gas into other reservoirs. However, the sub-surface study work that has been carried out has indicated that there is no route for migration of stored gas into other reservoirs.

Closure and Decommissioning

During the decommissioning phase there is the potential for accidents resulting in injuries or fatalities to the contractor population. The onshore and pipeline will become CO_2-free during this phase but for the closure and decommissioning work on the platform there will remain a risk of exposure to releases from the reservoir of CO_2, though these risks are considered low.

Post-Decommissioning

In the post-decommissioning phase there remains a potential risk of exposure to releases of CO_2 from the reservoir, though there will be no significant at-risk population.

Loss Exposures

Various loss exposures have been considered for property damage, liability and production interruption. The scenarios providing the more significant overall exposures are summarised below:

Physical Damage Estimated Maximum Loss (EML)

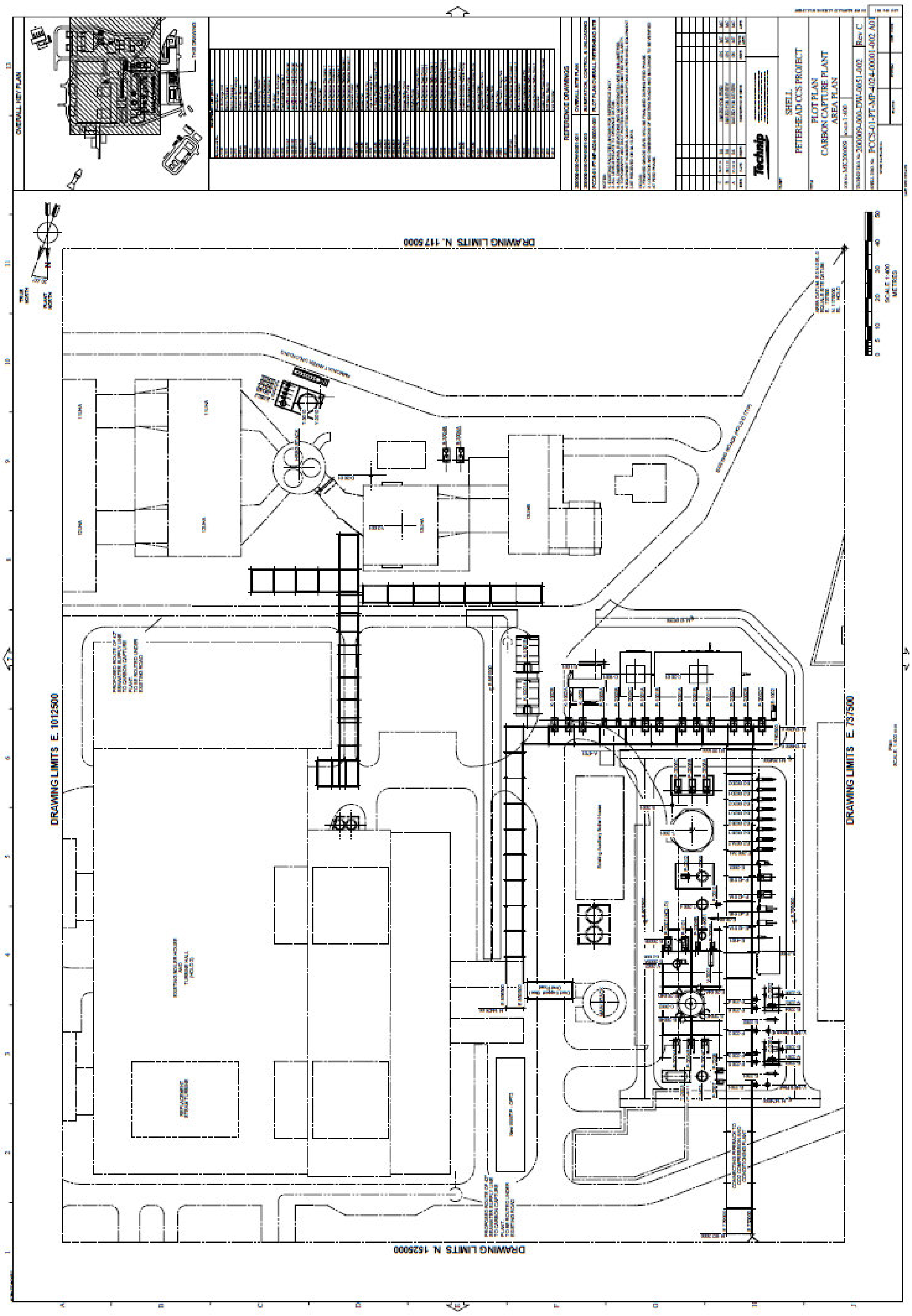
Scenario	Property[1] (GBP million)	Business Interruption
Compressor failure during construction	13	19 months
Damage due to gas explosion on power station	10	12 month
Pipeline failure during construction	56	12 month
Pipeline failure during operation	56	21 months
Platform damage during construction	15	12 month
Compressor failure during commissioning	13	29 month
Failure of subsurface equipment[2]	22	12 months
Well blowout[2]	40	12 months

NOTES:
1. To two significant figures.
2. There are expected to be additional costs for monitoring, corrective action and purchase of carbon credits.

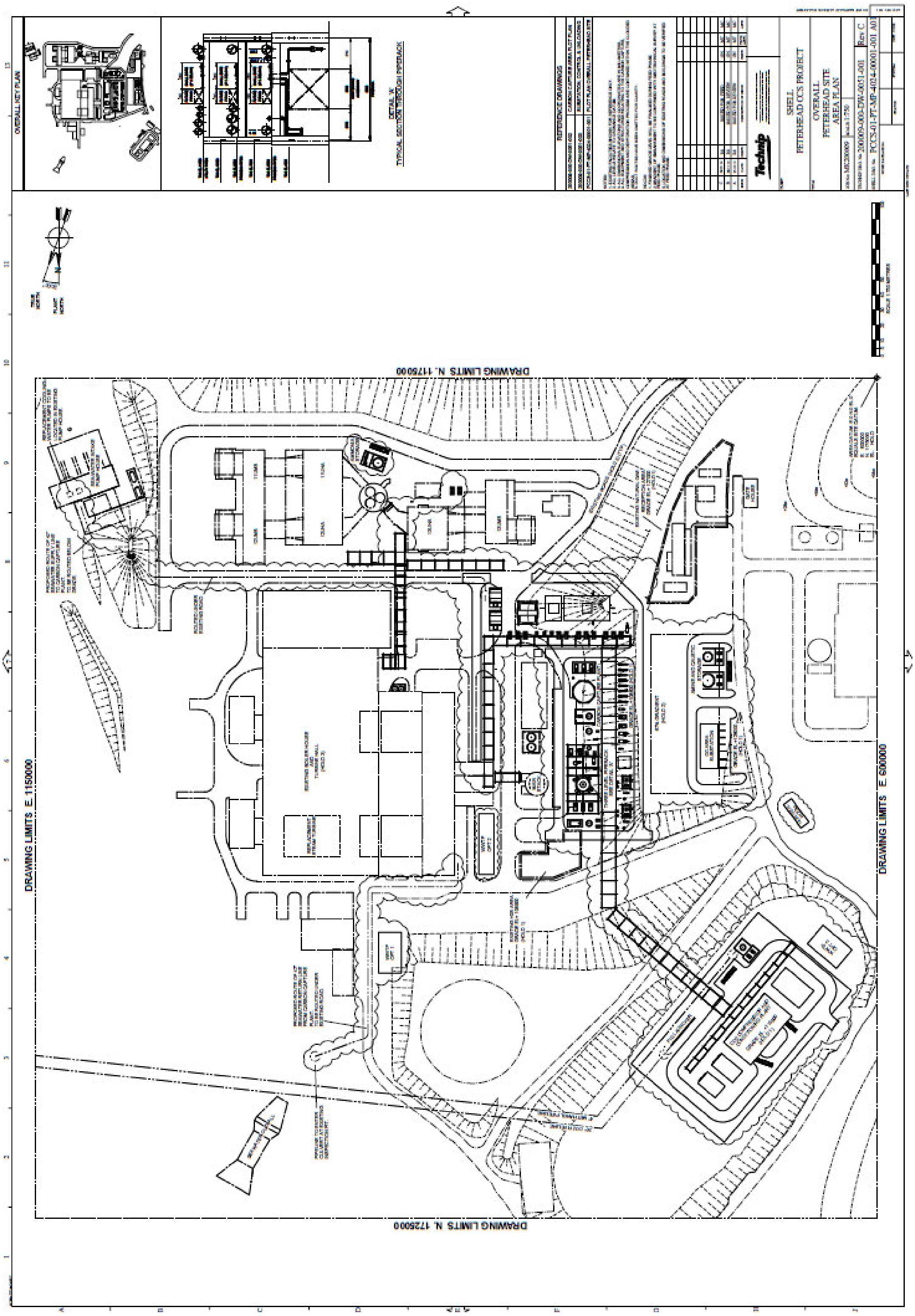
It is stressed that these loss estimates should be considered as preliminary, and may be subject to significant revision once further project information is available and once key assumptions are reviewed.

Appendices

Appendix A – Capture, Compression and Conditioning Plant Layout – Peterhead Power Station



Appendix B – Overall Peterhead Site Area Plan



Appendix C – References

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September 2010.

Good plant design and operation for onshore carbon capture installations and onshore pipelines.
First Edition.
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Qualification Procedures for CO_2 Capture Technology. Recommended Practice DNV-RP-J201.
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Design and Operation of CO_2 Pipelines. Recommended Practice DNV-RP-J202.
Det Norske Veritas.
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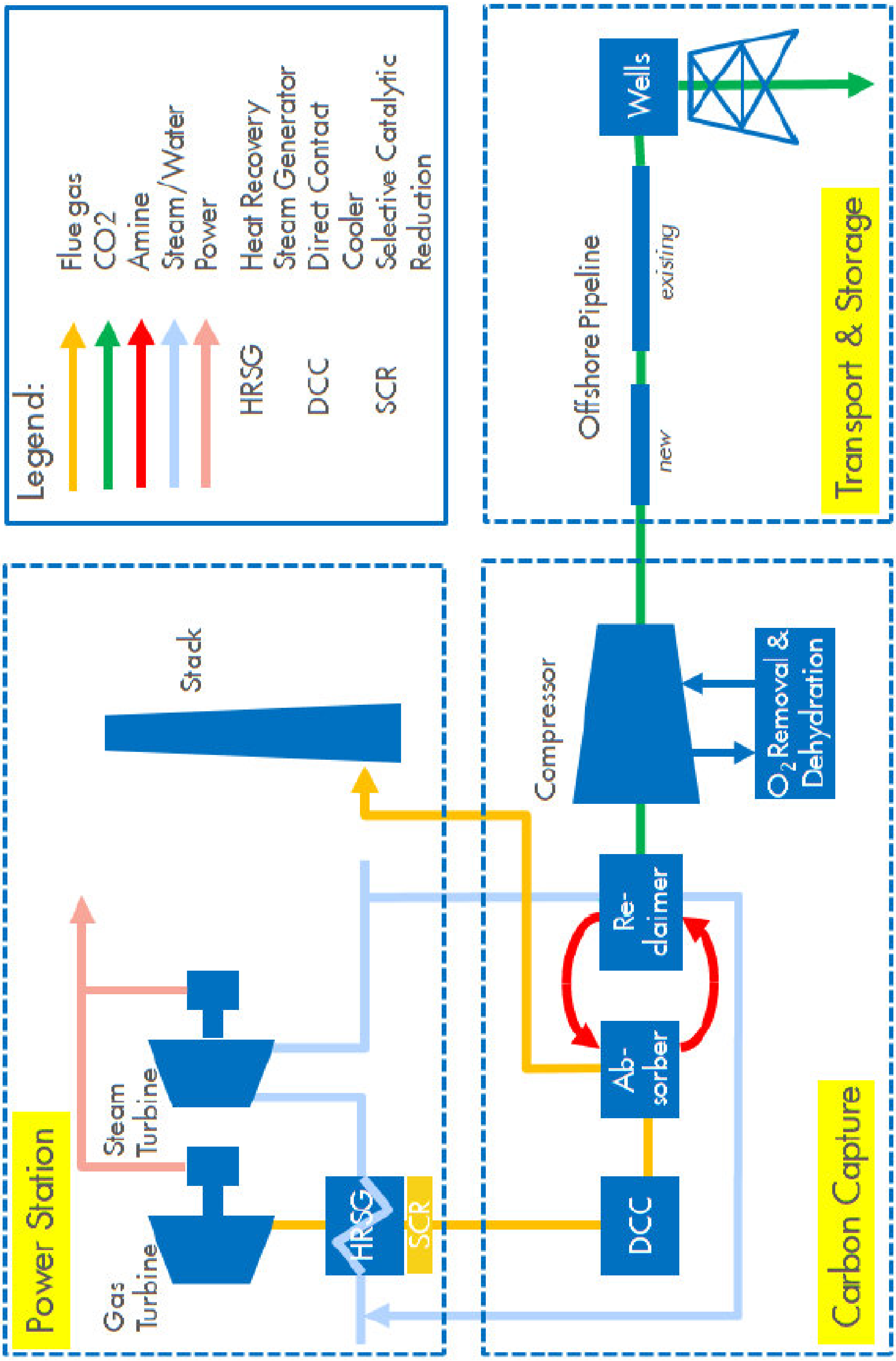
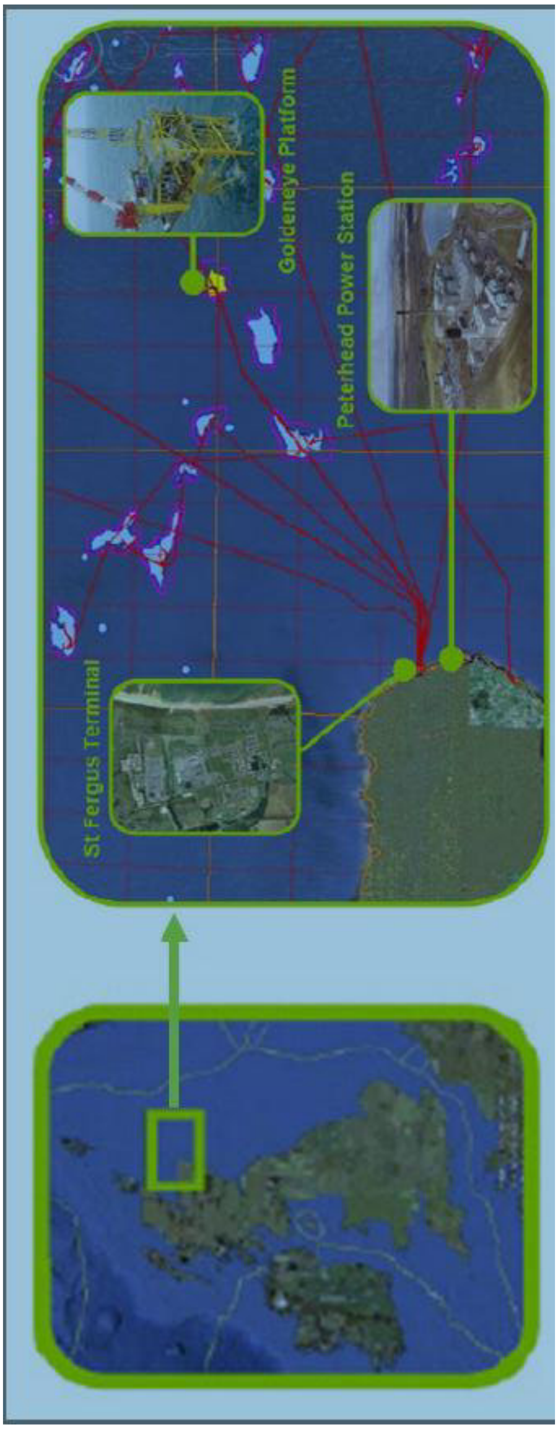
Appendix D – Overall CCS Block Flow Diagram



Appendix E – Location Map



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