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REALISE CCUS

Demonstrating a Refinery-adapted cluster-integrated strategy
to enable full-chain CCUS implementation - REALISE

Deliverable D3.6 - Assessment of options to provide flexibility in the design and operation of the transport and storage network

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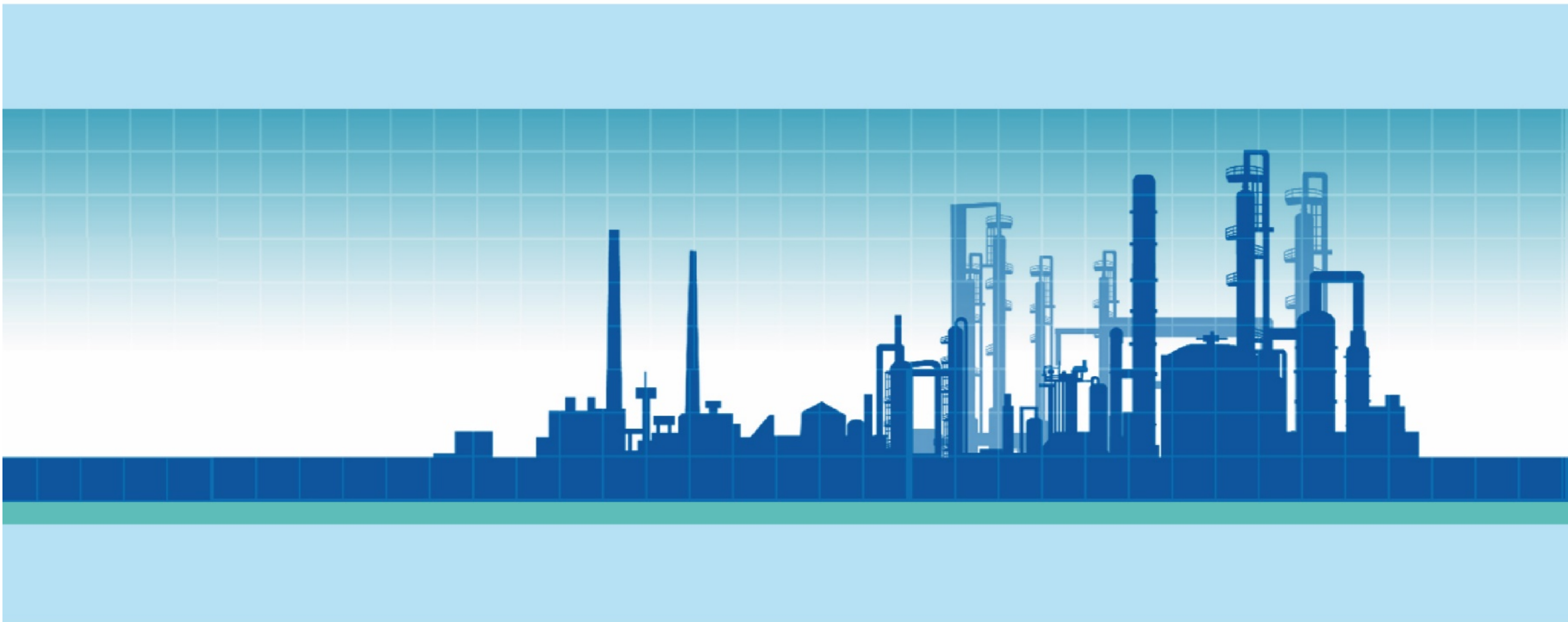

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Document History

Revision History

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Authorisation

This document requires the following approvals:

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Disclaimer

Glossary of Terms

Acronym, Term or Abbreviation	Explanation
°C	Degrees Celsius. SI Unit of temperature
bar	Bar is a metric unit of pressure. It is equal to 100 kPa.
bara	When pressure is measured relative to a perfect vacuum, it is called absolute pressure
barg	When pressure is measured relative to atmospheric pressure (1 bar), it is called gauge pressure
BoD	Basis of Design provides all the principles, business expectations, criteria, considerations, rationale, special requirements, and assumptions used for decisions and calculations required during the design stage
BGE	Bord Gáis Energy. Utility company that supplies gas and electricity and boiler services to customers in Ireland and operates the Whitegate CCGT. Realise partner.
BHP	Bottom Hole Pressure. The pressure measured at the bottom of the hole.
BHT	Bottom Hole Temperature. The temperature measured at the bottom of the hole.
CCGT	Combined Cycle Gas Turbine. A combined-cycle power plant uses both a gas and a steam turbine together to produce up to 50% more electricity from the same fuel than a traditional open-cycle gas turbine
CCUS	Carbon capture, utilization and storage, also referred to as carbon capture, utilization and sequestration, is a process that captures carbon dioxide emissions from sources like industry or power plants and either reuses or stores it so it will not enter the atmosphere.
CO_2	Carbon dioxide - a colourless gas having a faint sharp odour and a sour taste. It is a greenhouse gas, but it is a minor component of Earth's atmosphere, formed in combustion of carbon-containing materials, in fermentation, in respiration of animals, and employed by plants in the photosynthesis of carbohydrates.
Dense	Liquid or supercritical phase carbon dioxide
Depleted	Reservoir formations of natural gas fields that have produced all or part of their economically recoverable gas.
DNV	DNV (formerly DNV GL) is an international accredited registrar and classification society headquartered in Høvik, Norway.
Energy Institute	Global professional body for the energy sector; delivering good practice information and guidance, training courses and qualifications
EPA	Environmental Protection Agency
Equinor	Norwegian energy company formerly known as Statoil. Realise Partner
Ervia	State owned multi-utility company distributing natural gas, water and dark fibre services in Ireland. Realise partner
ESB	Electricity Supply Board. State owned vertically integrated utility in electricity generation, transmission and distribution to supply. Owner and operator of Aghada CCGT. Realise partner
GNI	Gas Networks Ireland. State owned utility who owns and operate the natural gas network in Ireland.
H_2O	Chemical symbol for water
HP	High Pressure
H_2	Hydrogen. This is a colourless, odourless gas. It is easily ignited. Once ignited it burns with a pale blue, almost invisible flame.
ID	Internal Diameter
Inch	Imperial unit of length. Equal to 25.4 mm. Widely used in oil and gas industry
Inch Terminal	The entry and exit point for gas between the KEL owned and operated KHGF and GNI owned natural gas network
Injectivity	Rate of injection over the pressure differential between the injector and the producer
Intermediate Storage	Temporary storage for gas prior to onward transport to shipping

Acronym, Term or Abbreviation	Explanation
Irving Oil	Irving Oil Ltd. is a Canadian gasoline, oil, and natural gas producing and exporting company. They own and operate the Whitegate oil refinery. Realise partner.
ISO	International Organisation for Standardisation
Joule-Thompson effect	A thermodynamic process that occurs when a fluid expands from high pressure to low pressure at constant enthalpy (an isenthalpic process). Such a process can be approximated in the real world by expanding a fluid from high pressure to low pressure across a valve. Under the right conditions, this can cause cooling of the fluid
KEL	Kinsale Energy Limited
Kg	SI unit of mass. Equal to 1000 grams
Kg/h	Measure of mass flow rate
KHGF	Kinsale Head Gas Field
kJ/(kg·K)	Kilojoules per kilogramme Kelvin. SI unit of specific heat capacity.
km	SI unit of length. Equal to 1000 metres
km^2	Unit of area
kVa	1000 Volt amps. Measures apparent power of an electrical installation
Lean	Carbon dioxide in gaseous phase
Load factor	Measure of power plant capacity utilisation for a period of time
Longship/Langskip	Norwegian full-scale CCS project that includes the capture, transport and storage of CO_2
LP	Low Pressure
LPG	Liquefied Petroleum Gas is a flammable mixture of hydrocarbon gases such as propane and butane
m	SI unit of length
m2	Unit of area
m3	Unit of volume
Mass flow rate	Mass of a liquid substance or gas passing per unit time
MEA	Monoethanolamine. Aqueous solution of MEA is a solvent commonly used in post combustion carbon capture.
Merit order	Merit order advises dispatch actions in the electricity grid. Sources of electricity are ranked according to price and pollution and generation is brought onto the grid in an order that takes account of this according to demand.
mol	Mole, the base unit of amount of substance in the International System of Units (SI). It is defined as exactly $6.02214076 \times 10^{23}$ elementary entities ("particles"), which may be atoms, molecules, ions, or electrons.
Mtpa	Million or Mega tonnes per annum - unit of measurement
MW	Megawatt - unit of energy. Equivalent to 1000 kilowatts
N_2	Nitrogen
Natural gas	Naturally occurring hydrocarbon gas consisting of mostly methane. Colourless, odourless and flammable
O_2	Oxygen. Tasteless and colourless gas
Opex	Operating Expenditure
Pa	Pascal. SI unit representing pressure
PE	Polyethylene. An inexpensive plastic material that is corrosion and chemical resistant and can be very durable.
Pentair	Pentair is an American water treatment and process engineering company. Its Danish subsidiary Pentair Union Engineering's main activities are worldwide sales, engineering, installation and commissioning of modular and individually designed CO2 plants. Pentair are a Realise partner
PI	Production Index
PPM	Parts Per Million
PSA	Pressure Swing Adsorption
psia	Pounds per square inch absolute. Imperial unit of pressure

Acronym, Term or Abbreviation	Explanation
REALISE	Demonstrating a Refinery-Adapted Cluster-Integrated Strategy to Enable Full-Chain CCUS Implementation. Project funded by the European Union's Horizon 2020 research and innovation programme under grant agreement No 884266
Reservoir	Naturally occurring storage area of oil or natural gas which is contained in fracture or porous rock formations
SEI	Sustainable Energy Ireland. The wholesale electricity market on the island of Ireland
SI	International System of Units
Sintef	SINTEF is a broad, multidisciplinary research organisation with international top-level expertise in the fields of technology, the natural sciences, medicine and the social sciences, based in Norway. Sintef are a Realise partner
SPA	Special Protection Area
Span-Wagner Equation Of State	Thermodynamic equation relating state variables which describe the state of matter under a given set of physical conditions. The Span and Wagner equation is based on an extensive range of fitted experimental thermal properties in the single-phase region, the liquid-vapour saturation curve, the speed of sound, the specific heat capacities, the specific internal energy and the Joule-Thomson coefficient
SS	Stainless Steels are a group of steels that are resistant to corrosion through the addition of alloying elements, generally chromium.
Supercritical	Fluid state of CO_2 where it is heated and held at or above its critical temperature and pressure. In this supercritical phase, CO_2 exhibits properties and behaviors between that of a liquid and a gas.
TNO	TNO is an independent Dutch research organisation. They focus on transitions or changes in nine social themes including energy and a sustainable future. TNO is a Realise partner
Tonnes	SI unit of mass equivalent to 1000kg
tpa	Tonnes per annum
Transmission	Gas pipeline system and associated facilities designed for gas supply to consumers
TEG	TriEthylene Glycol
TSA	Temperature Swing Adsorption
W	Watt. SI unit of power

Executive summary

The REALISE project team has examined a scenario of carbon capture from the largest industrial emitters in the Cork, Ireland area, consisting of two natural gas fired power plants and an oil refinery, where they are treated as a carbon capture cluster. It was found that the cluster which currently comprises approximately 80% of the emissions within a 60 km radius of Cork Harbour could capture CO_2 and permanently store it either in indigenous locations or export it to permanent storage overseas. The full study includes both technical and economic assessment for the cluster.

The estimated volume of CO_2 that could be captured from the cluster of three emitters in the case study ranges from 1.61 million tonnes to 2.77 Million tonnes per annum (Mtpa) under the low and high scenario respectively. The base case anticipates 2.23 Mtpa of CO_2 can be captured annually over a period of 25 years. The base case assumes the two power plants are operated at 55% load factor while Irving Oil Whitegate refinery is operated at 96% load factor and all plant are fitted with post combustion carbon capture rate of 90%. Further studies by REALISE are examining higher capture rate, possibly up to 99%.

This report presents an assessment of the flexibility of the systems in accommodating variations in CO_2 supply, or in growth of the captured volumes to be stored.

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1 Project Outline

1.1 Carbon Capture Utilisation and Storage

CCUS is being assessed for utilisation in Ireland as part of the overall goal to move Ireland towards a cleaner energy future by reducing CO_2 emissions from the electricity, heating, industry, agriculture and transport sectors.

This study is focused on the feasibility of developing a CCUS project located in the lower Cork harbour area; serving two large Combined Cycle Gas Turbine (CCGT) gas power generation plants and an oil refinery.

Cork is the second largest city of Ireland with a population in excess of 300,000. It is planned that this Cork cluster could be expanded over time to bring in other industries located in the greater Cork area. The city is contained within the county of Cork which has a population of just over 540,000, an area of 7,500 km^2 and contains Cork Harbour, the second largest natural harbour in the world after Sydney, Australia.

Other industrial clusters in Dublin (the capital city), Limerick (the third city) and Drogheda (port town with a large Liquefied Petroleum Gas (LPG) shipping facility and cement plant) are also either under consideration or could be considered in the future.

The focus of the Cork CCUS project is to utilise the depleted Kinsale Head Gas Field (KHGF) as a long-term storage facility, coupled with marine infrastructure that would facilitate the transportation of CO_2 to other long-term below ground storage facilities in Europe.

1.2 REALISE

REALISE – Demonstrating a Refinery-Adapted Cluster-Integrated Strategy to Enable Full-Chain CCUS Implementation

As part of the CCUS development process, REALISE will develop carbon capture, utilisation and storage strategies for oil refineries centred industrial clusters and demonstrate in a pilot scale an absorption technology based on novel solvent for cost-efficient and environmentally sustainable CO_2 capture from multiple flue gas sources.

REALISE further addresses the full CCUS chain including CO_2 transport, storage and utilisation options for the specific business cases to be developed in the project for Ireland, South Korea and China, as well as assessment of the financial, political and regulatory barriers and opportunities in these countries.

1.3 Basis Of Design (BoD)

The basis of design is determined the following design parameters:

1. The main **emitters** for the study table are listed below; along with respective CO_2 emissions to be included as the design basis.

The following are the selected cluster locations:-

- Whitegate Oil Refinery – Owned and operated by Irving Oil,
- Aghada CCGT Power Station - Owned and operated by Electricity Supply Board (ESB) and
- Whitegate CCGT Power Station Owned and operated by Bord Gáis Energy (BGE)

2. Current **options for storage** are export or indigenous storage i.e.;-

I. Export: by ship to another country for injection into their geological formations or

II. Indigenous storage: injection into Ireland's geological formations

While other options will become available in the future, for REALISE the Northern Lights Project will be considered in this study as the potential receiving faculty for the produced CO_2 for the export option (Option i).

The Kinsale Head depleted gas field will be considered for the indigenous storage option (Option ii).

3. The **Carbon Dioxide (CO_2) specification** for export to the Northern Lights Project is outlined in Table 1. Please note the specification for indigenous storage has not being developed but the Acorn Project is cited as a good example in Table 2.

Based on REALISE Task 2.0 the specification for export is given in Table 1**.**; Table **2** gives the CO_2 quality requirements for transport to indigenous storage. The captured CO_2 will contain impurities and non-condensable gases. The non-condensable gases are components that, when pure, will be in gaseous form at 15 barg and -26°C. The content of non-condensable gases will be limited by the actual solubility in the liquid CO_2 in the interim storage tanks at the capture plants.

The captured CO_2 will require further treatment since the CO_2 must be free of significant impurities such as hydrogen sulphide and water, otherwise, the gas can corrode the pipeline.

The major impurities influence the characteristics of the CO_2 stream; in general, the impurities lower the density of the CO_2 stream and increase the overall 'critical pressure' leading to uncertainties over what conditions are required within the transport system.

Table 1: Export Option - Northern Lights CO_2 Composition Requirements

Component	Concentration, ppm (mol)
Water, (H_2O)	≤ 30
Oxygen, (O_2)	≤ 10
Sulphur oxides, (SO_x)	≤ 10
Nitric oxide/Nitrogen dioxide, (NO_x)	≤ 10
Hydrogen Sulfide, (H_2S)	≤ 9
Carbon monoxide, (CO)	≤ 100
Amine	≤ 10
Ammonia, (NH_3)	≤ 10
Hydrogen, (H_2)	≤ 50
Formaldehyde	≤ 20
Acetaldehyde	≤ 20
Mercury, (Hg)	≤ 0.03
Cadmium, (Cd) and Thallium, (Tl)	≤ 0.03 (sum)

The captured CO_2 will contain impurities and non-condensable gases. The non-condensable gases are components that, when pure, will be in gaseous form at 15barg and -26°C. The content of non-condensable gases will be limited by the actual solubility in the liquid CO_2 in the interim storage tanks at the capture plants.

Table 2: Indigenous Storage Option - Amec Foster Wheeler report[1]: Requirements

Component	Recommended Specification,	Advisory Notes
CO_2	95 mol%	
Hydrogen Sulphide	<200 ppmv	Health & Safety
Carbon Monoxide	<2000 ppmv	Health & Safety
NO_x	<100 ppmv	Health & Safety
SO_x	<100 ppmv	Health & Safety
Oxygen	<10 ppmv	Technical: Pipeline and storage
Nitrogen	1 mol %	Technical: EOR led
Hydrogen	1 mol %	Technical: EOR led
Argon	1 mol %	Technical: EOR led
Methane	1 mol %	Technical: EOR led
Non-condensable	4 mol %	Technical: Pipeline led
Water	50 ppmv	Technical: Hydrate & corrosion
Hydrocarbons	2 mol %	
Particulates	1 mg/Nm³	Technical: Pipeline led
Particle size (micron)	≤10 µm	Technical: Pipeline led
Mercury	Regulation	
Ammonia	<50 ppmv	Technical
Other	Caution: must not negatively impact hazards of a release, pipeline/storage/well integrity	

1.3.1 Scope Premise

The main premise for the basis of design, is that CO_2 is received from the capture plant output battery limit (boundary fence), where the CO_2 can be conditioned and compressed for transport by pipeline to either:-

1. Intermediate storage for ship transport for export or
2. Onwards transportation to indigenous storage at a depleted gas field.

Note: The carbon capture plant and related technologies are not part of the scope for Task 3.3, the capture plant is dealt with in another Project Realise Task 2 This study (Task 3.3) is focused on the CO_2 cluster transportation of CO_2 and storage only.

[1] AMEC, 2015. TVU CCUS, Work pack 5-Onshore Infrastructure. Pipeline Network CO_2 Quality Specification.

The basis of this section of the study is:

- Conditioning of CO_2 to meet compression and transport requirements,
- Compression of CO_2 to meet transport requirements for export and indigenous storage ,
- Transportation of CO_2 via onshore pipelines,
- Export Storage of CO_2 to meet shipping requirements (ship size, liquefaction, temporary storage, jetty, and loading arms, and
- Indigenous Storage of CO_2 to meet depleted field requirements (pipelines, conditioning, compression, onshore and offshore infrastructure)

1.3.2 Emitters

The scope for the Task 3.3 report is a cluster transport study that centres on the transportation of captured CO_2 at the selected cluster locations to potential storage locations.

The main emitters for the study table are listed below along with respective CO_2 emissions; to be included as the design basis.

The following are the selected cluster locations:

- Whitegate Oil Refinery (Irving Oil) [Grid Ref 51°49'15.0"N 8°14'27.9"W]
- Aghada CCGT Power Station (ESB) [Grid Ref 51°50'02.5"N 8°14'14.7"W]
- Whitegate CCGT Power Station (BGE) [Grid Ref 51°48'58.8"N 8°14'49.1"W]

The locations were selected on the basis of being the optimal cluster of the largest CO_2 emitters in the Cork Harbour area and the cluster can be considered for potential expansions in the future, if deemed appropriate, based on the market evolution.

The cluster location also leverages selection based on:

- Existing assets/infrastructure for repurposing potential,
- Proximity to indigenous storage (Kinsale Head depleted gas field), and
- Proximity to a deep water harbour

Table 3: Emitter details and CO_2 emissions per year

Site / Location	Sector	Owner/Operator	Capacity (MWe)	CO_2 Emissions (Mt/y) As per CO2 Cork cluster proposed annual production base case scenario
Whitegate Refinery	Oil Refining	Irving Oil	N/A	.32
Aghada CCGT	Power Generation	ESB	430	1.08
Whitegate CCGT	Power Generation	BGE	450	1.08

Table 4: Emitter details and CO_2 flow rate in KG/hr

Site / Location	Min CO_2 KG/Hr	Max CO_2 KG/Hr	Average CO_2 KG/Hr
Whitegate Refinery	26,849	38,356	36,822
Aghada CCGT	65,687	199,053	109,479
Whitegate CCGT	65,687	199,053	109,479

Table 5: Composition table between amine unit and compression unit

Compound	Concentration	Units
CO_2	Balance	
N2	500	ppm-V/V
O2	50	ppm-V/V
Aldehydes	5	ppm-V/V
NOx	<10	ppm-V/V
NH3	<5	ppm-V/V
SO2	0	ppm-V/V
Water	Saturated at 30 C and 2 bara	

1.3.3 Design cases

The three design cases to be considered are shown in Table 6.

Table 6: Design Cases

Design Case	Description
1	**Export of CO_2** via a new jetty at Aghada site
2	**Export of CO_2** from the existing jetty at the Whitegate refinery
3	**Indigenous Storage of CO_2** via the Inch Terminal to the depleted Kinsale Head Reservoir

The REALISE project will incorporate the following components for the various export design cases:

1. Output from the respective Capture Plant battery limit
2. Conditioning / Compression Plant adjacent to the Capture Plant (gaseous phase output)
3. Pipeline transportation (gaseous phase)
4. Liquefaction Plant (liquid phase output)
5. Pipeline transportation (liquid phase)
6. Intermediate Storage (liquid phase)
7. Pipeline transportation to vessel (liquid phase)

The REALISE project will incorporate the following components for the indigenous storage design case:

1. Conditioning / Compression Plant adjacent to the Capture Plant (gaseous phase output);
2. Pipeline transportation (gaseous phase).

1.4 Description of the deliverable and purpose

The purpose of this Task group within REALISE is to undertake an assessment of the potential for CCUS at an oil refinery which is part of a large CCUS cluster. The cluster transport study centres on the transportation of the captured CO_2 at the identified cluster locations to selected storage locations.

This report outlines the findings for deliverable D3.6 assigned to this Task Group, which is as follows:

- Deliverable D3.6 Assessment of options to provide such flexibility in the design and operation of the transport and storage network

This report is closely linked with deliverables D3.5 and D3.7:

- Deliverable D3.5: Assessment of injection profile and infrastructure requirements to control & monitor of transportation pipelines and intermediate storage vessels;
- Deliverable D3.7 High-level schematics (process flow diagrams) from Emitter to Storage.

2 Assessment of options to provide flexibility in the design and operation of the transport and storage network

2.1 Introduction

The storage capacity and feasible injection rates of a transport and storage system are determined by the properties of the pipeline, the injection wells, and the properties of the reservoir. With reservoir properties fixed, injection rates and total storage capacity can be engineered to a certain degree through the choice of operational conditions, well design and number of wells. This can be seen in Figure 1 where the maximal flow rates are shown for different diameters of the well, reservoir pressure and reservoir injectivity (so-called PI).

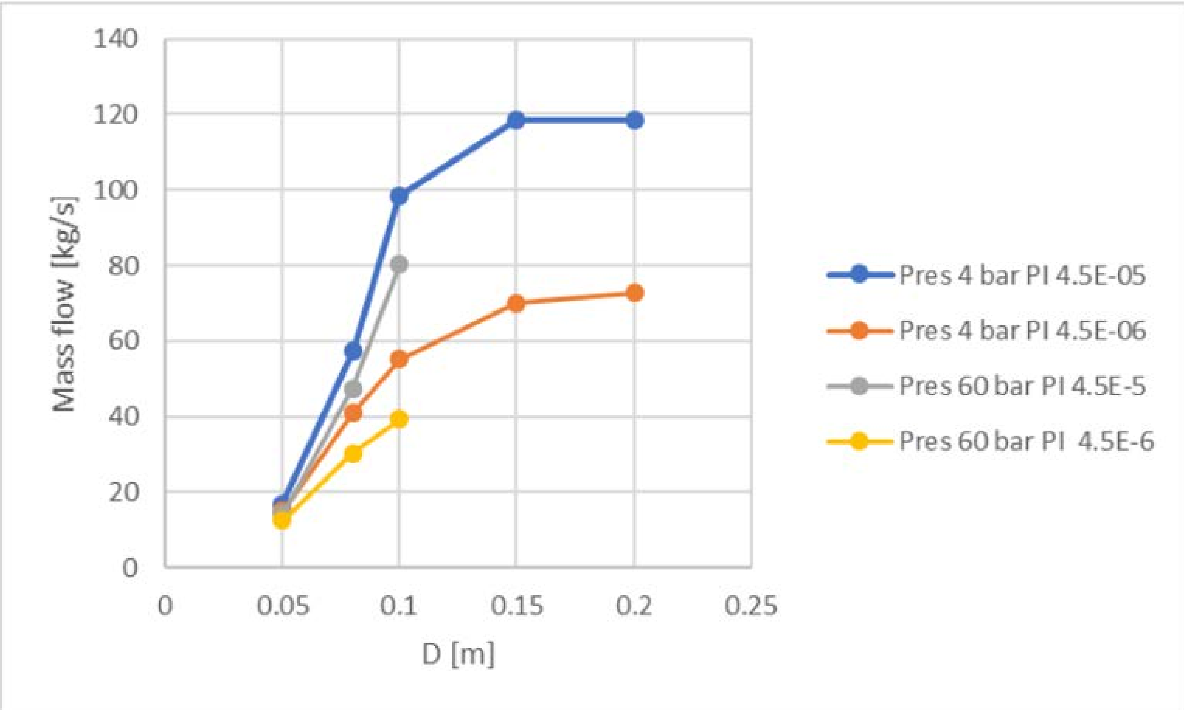

Figure 1. Maximum mass flows for different well diameters and injectivities

2.2 Transport and intermediate storage

Two sets of scenarios are considered separately and discussed in terms of their consequences for the layout and operability of the system.

However, in real world conditions, the reservoir pressure is not a choice, it has been decided by the historic gas production and extraction effects on the gas field. This means that the injection system downstream from the well head must be based on gas phase first before liquid can be injected.

It follows that the injection system must start with gas phase injection only for its first 50 or so years of production to raise the pressure sufficiently in the depleted field, and only after this switch to liquid (or two phase) injection when required past this point.

To evaluate injection scenarios, several simulations were performed using the OLGA simulator. OLGA is a one-dimensional transient multi-phase flow simulator. It has been developed for the Oil and Gas industry for flow assurance analyses. In recent years a single-component CO_2 module has been developed that can be used to simulate (multi-phase) CO_2 transport in pipelines and wells. Details of the simulations performed in this study are described at the end of this section. These simulations were performed to determine the allowable flow rates.

2.2.1 Gas phase

With a maximum flow rate of about 40 kg/s the required number of wells will be 3, to reach a total mass flow rate of at least 80 kg/s (about 2.5 Mtpa). With three wells, the spare capacity is about 40 kg/s. There is also a minimum flow rate for the wells considered, of about 30 kg/s for each well. In case the CO_2 supply approaches that rate, a single well is to be used; other injection wells are to be shut in. There is also the option to lower the pipeline pressure, which will result in lower minimum flow rates.

Table 7 lists the main advantages and disadvantages of operating the transport and storage system in gas phase. An advantage of this approach is that both onshore and offshore systems would operate at the same conditions and no additional compression is required to send the CO_2 to the offshore platforms and wells. The offshore pipeline is currently operating at a similar pressure and would be re-used with limited workover efforts.

With gas-phase CO_2 at a pipeline pressure of 35 bar, injection up to 50 bar reservoir pressure is possible. Above that reservoir pressure level, injection of CO_2 in liquid phase is required. This means that about half the available storage capacity is available for a system operating in gas phase. At a supply rate of about 2.5 Mtpa, this would be sufficient for more than 50 years of operation. If more storage capacity is required, the system will have to switch to liquid-phase CO_2, with all associated workovers.

The significant minimum flow rate of about 30 kg/s (roughly 1 Mtpa) for an injection well with the design used here means that if the CO_2 supply to a well decreases to below this value, the well must be shut in, to avoid too low temperatures in the well or in the near well area. As each shut-in and start-up procedure induces pressure and temperature fluctuations in the well that may affect its integrity, frequent shut-ins should probably be avoided.

There are options to do this:

- line pack,
- buffer storage,
- changing pressure in the transport pipeline, or
- using wells with different operational windows.

With CO_2 in gas phase the line pack capabilities are higher than they are for liquid phase CO_2, but still limited. It will take approximately 7.5 hours to achieve 50 bar starting at 30 bar. The data shown in Section 3.3 suggests that source downtime can be as long as 400 hrs, so the options with linepack are limited from an operational point of view.

An alternative way to even out supply intermittency would be to provide onshore storage (buffer). A buffer volume of about 40,000 m^3 (liquefied CO_2) would be needed to provide a flow rate of 30 kg/s for a duration of 400 hrs (this is a realistic period of zero delivery from the CCGTs; see also Section 3.3). This is much larger than the proposed CO_2 transport ship capacity in the Northern Lights project in Norway and, hence, the likely quayside buffer used in that project. The need for a buffer is to be investigated, once the information about the intermittency of CO_2 supply is clear and the impact of well shut-in on well integrity has been researched.

The minimum flow rate of injection wells is relatively high, as mentioned above, for the well design used here. The design of the wells – the size of the tubing through which the CO_2 is injected – defines the flow rate window and, hence, the number of wells. Also, the PI has effect on the minimal flow rate. If the PI is lower, a higher BHP is obtained and therefore less pressure drop over the valve is required. This means that also the temperature drop, which is the limiting factor, will be lower. A lower PI will reduce the maximum flowrate. The high minimum flow rate can be adjusted by changing well design (injection tubing size), pipeline operating pressure, or, perhaps, managing the perforation activity. It may be more efficient to have wells with different operational windows, to increase system flexibility. Such an investigation has not been performed here.

The total injection rate of about 2.5 Mtpa may require locating the injection wells at two (new) offshore platforms or subsea wells. As each well will generate its own near-well pressure field, a certain minimum separation between the wells at reservoir level is required, to avoid injection rate reduction due to pressure communication. It is assumed here that 2 wells from a single platform can be operated, but that two platforms at sufficient distance are to be constructed when more wells are needed. Detailed simulation of the CO_2 injection into the reservoir is required to establish the level of pressure communication, the required inter-well distance in the reservoir and the number of platforms.

With 3 wells to reach a mass flow rate of about 80 kg/s, each well would be operated at about 75% of its maximum rate to reach the target rate of 80 kg/s. With 3 wells, the system has about 50% spare capacity to accept CO_2 from sources in addition to the three listed above. For the well design that is used here, each well will add about 40 kg/s of injection rate increase. Depending on the results from the injection simulation, new injection locations and platforms may be needed.

Table 7: Pros and cons for a transport and storage system with CO_2 in gas phase

Pros (gas)	Cons (gas)
CO_2 in gas phase in onshore and offshore parts of the transport and storage system – no need for additional compression	Reservoir can be filled to ~50 bar; this means that only about half the storage capacity can be used (130-140 Mt)
Gas phase injection offers lower minimum flow rates than liquid phase injection; this offers greater flexibility to handle periods of lower supply rates	More wells (3) are needed in a system with gas phase CO_2 than in a system with liquid phase CO_2 (2 wells).
Existing offshore pipeline can be used (@ 35 bar)	

2.2.2 Liquid phase

The transport and storage system will be different when the CO_2 is in liquid (dense) phase. Injection is more efficient than in gas phase, so fewer wells and injection locations will be needed. With liquid injection the maximum flowrate is close to 90 kg/s (for the case considered here), meaning that only 2 wells will be necessary. A storage system with two wells would have a spare injection capacity of about 100%, allowing the connection of more sources of CO_2 without the immediate need to expand the system.

As the pipeline will be operated at 85 bar extra compression capacity will be required. The pipeline will need a workover to be operated at 85 bar or higher.

Advantages are that more CO_2 can be injected, and the system does not have to be changed during operations, as could be the case when operated with CO_2 in gas phase, although it is noted that that would occur only in case more storage capacity than about 130-140 Mt is required.

Very low temperatures are to be expected just downstream of the well head choke, requiring equipment which can operate in such conditions (for e.g., arctic wellheads could be required).

Table 8: Pros and cons for a transport and storage system with CO_2 in liquid phase

Pros (liquid)	Cons (liquid)
Higher mass flow per well, fewer wells needed (2-3 wells)	Additional compressor required to bring pipeline pressure to 80 – 100 bar
No change of the transport and storage system needed when more than 140 Mt storage is needed	Pipeline to be operated at 85 bar and above: needs workover or new pipeline
Fewer wells used in parallel (reduces complexity)	A significant minimum flow rate exists, which requires a relatively constant CO_2 supply, to avoid shutting in wells
Smaller diameter wells than for CO_2 in gas phase (reduces cost)	Arctic wellhead required (adds cost)
Wells have higher maximum rate, increasing flexibility to connect additional sources of CO_2	

As there would be no constant supply of CO_2 from the emission sources in their current deployment, flexibility could be a topic of investigation. In case of capture rates that are below individual well minimum rates, the well or wells are to be shut in and re-started once supply rates are high enough. Many start/stops will induce thermal stresses which could lower the integrity of the system. A detailed study of the impact of pressure and temperature cycling is required to establish well integrity effects.

If significant intermittency is likely and shutting in wells proves to be an issue, measures to even out CO_2 supply rates could be considered. Examples are an onshore buffer or using line pack in the onshore and offshore pipelines. In liquid phase the line pack capabilities are limited because of low compressibility of the CO_2. At 80 bar while injecting at 10 kg/s it takes only 40 minutes before the pressure becomes higher than 100 bar. Section 3.3 suggests that a period of 400 hrs of zero supply can occur for the CCGTs. This implies that an additional temporary storage location will be required to flatten the injection curves. The size of this storage should be large enough to compensate the 400 hrs of injection at a minimal flow rate of 56.5 kg/s. This would result in 90,000 m^3 of buffer capacity, which may be prohibitively large. These numbers will need further study; as there may be an incentive to prioritise the CCGTs in the power grid once they are outfitted with CO_2 capture systems and start delivering low-emission power. Import of CO_2 by ship is another option that can be explored; such an additional source of CO_2 can help create a stable flow of CO_2 in the pipeline and wells.

2.3 Platform and wells

This section details the consequences on the system design regarding the different scenarios. Both scenarios yield that we have very few contaminants in the CO_2.

2.3.1 Gas phase

The offshore injection system probably consists of two injection sites with a total of 3 wells.

The system in gas phase is relatively simple. The scaling up to higher flowrates is done by drilling more wells. The current pipeline can be used, and no additional compression is needed for the offshore part of the system.

The number of wells trades off with the flexibility of the system. A system can be designed with only two high-capacity wells that together achieve the target injection rate, but such wells have a significant minimum flow rate. Wells with lower minimum flow rates tend to also have lower maximum rates, so increasing the flexibility of the system to accept varying flow rates is likely to increase well count.

In this study the system is assumed to have 3 injection wells when operating in gas phase. A system design study that considers the various trade-offs, such as between system flexibility or ability to operate with highly variable CO_2 supply rates and system design could be performed at a later stage.

2.3.2 Liquid phase

The offshore system to transport and inject CO_2 in liquid phase consists of one injection location with 2 wells.

As these wells have a significant minimum flow rate, system operability in the presence of supply intermittency can be limited. Again, system design should be the result of a detailed analysis of overall system cost, which would include options to redefine the deployment (merit order) of the power plants.

2.3.3 Analysis of injection rates into KHGF

A first-order analysis is presented here of the CO_2 injection flow rates into the KHGF.

The low pressure in the reservoir after cessation of production results in a potential for low temperature of the CO_2 in the injection wells and in the regions near the wells in the reservoir. The injection process must be managed to ensure that the temperature in the injection and storage system remain within safe operational windows.

The results show that achievable flow rates strongly depend on the design of the injection wells, notably the diameter of the injection tubing, on the conditions in the transport pipeline and on the properties of the subsurface storage reservoir at the location of the wells.

Although the starting pressure in the reservoir is fixed, the for-pressure profile in the well this is not the case. With higher flow rates or smaller tubing sizes the pressure drop in the well be higher, leading to a higher bottom hole pressure (BHP). The pressure drop over the perforations with therefore also be higher to reach the same reservoir pressure.

For large-diameter injection wells (7” tubing), injection of CO_2 in gas phase, with a pressure of 30-35 bar, can take place at rates between about 30 and 40 kg/s. This suggests that 3 wells may suffice to reach the targeted capture (and storage) rates of about 80 kg/s. However, such high-capacity wells cannot be operated at rates below about 30 kg/s, due to temperature limits in the well. This limited operational flexibility can be significant for the CO_2 supply points considered, which show a high degree of intermittency.

Even higher injection flow rates can be achieved if the CO_2 is transported to the offshore injection locations in dense phase, with a pressure in the offshore transport pipeline in the range of 80-100 bar. Flow rate windows are in the range of 56 – 80 kg/s, requiring just 2 wells to reach the target rate. In this case, minimum flow rates for a single well are about 56 kg/s, in which case there is an even stronger requirement for a stable high-rate CO_2 supply. An intermittent supply of CO_2 may result in frequent well shut-ins, which may be detrimental to well integrity.

As mentioned above, engineering options exist to manage or design the window of operations of a CO_2 injection well. Narrower injection tubing and lower transport pipeline pressures both move the injection rate window to lower values. While this improves the flexibility to handle periods of lower CO_2 supply rates, the maximum flow rate per well also decreases, which may lead to requiring more wells to reach the target rate.

At this point, such trade-offs are highlighted, but cannot be resolved. For example, more detail about the cost of the system not being able to accept low flow rates is needed.

For both injection schemes, in liquid and gas phase, the CO_2 will be injected at a temperature lower than the existing reservoir temperature. Next to that, additional reduction of the temperature due to Joule-Thompson effect will occur when the CO_2 is flowing further in the reservoir. This will have an impact on the stress levels in the reservoir. Initial simulations and analysis, based on crude assumptions, show that thermal stresses could re-initiate existing faults in the reservoir leading to unwanted seismicity. A more detailed description of this analysis is presented in

Appendices D, E and F to this report. It is advised to perform a more comprehensive study on this phenomenon when more details of the selected injection strategy are available. In such a study the existing stress levels and realistic distances to faults should be incorporated, as well as the 3D structure of the relevant formations.

2.3.4 Indigenous Storage Summary

A first-order analysis of CO_2 injection into the KHGF suggests that injection of CO_2 in gas phase is feasible.

With CO_2 in gas phase in the system, the offshore transport pipeline will be operated at 30-35 bar. Injection wells with large-diameter (7”) tubing can reach a maximum injection rate of about 40 kg/s; 3 wells are needed to reach the target rate of about 80 kg/s. It is likely that two injection sites (platforms, or subsea templates) are to be constructed. Such wells will have a relatively high minimum flow rate per well, of the order of 30 kg/s. With the transport pipeline operating at 30-35 bar, the KHGF can be filled to about 130-150 Mt. Higher storage capacities, up to the total capacity of the field of 300 Mt, require higher pressure in the transport pipeline, i.e., a switch to CO_2 transported and injected in liquid phase.

The low depletion pressure in the gas field results in minimum flow rates of injection wells, to prevent excessively low temperatures in the injection wells. This limits operational flexibility of the indigenous storage system to accept low rates or strongly intermittent CO_2 supply. The flow rate window of individual wells and, by extension, of the overall storage system, can be engineered to best fit the expected CO_2 supply. Lower minimum rates can be reached through well design, at the cost of one or more additional wells to reach the target rates, as the maximum rate also decreases. Wells that can handle lower flow rates increase the operability of the system in case of variable supply rates, but such increased flexibility results in increased well count. Such optimisation has not been performed here but should be part of a more detailed injection system design study.

Injection of CO_2 in liquid (dense) phase can be considered. The higher density of the CO_2 leads to higher flow rates, up to about 80 kg/s per well; the target rate can be reached with only 2 wells, However, minimum flow rates per well are significant – of the order of 56 kg/s for the case considered here – and the system operates close to temperature limits in the well and in the near-well zones. Options to engineer the injection window of the wells are more limited, as the CO_2 in the pipeline needs to remain in liquid phase. These findings suggest that a system operating with CO_2 in liquid phase is not advisable during the period of low pressure in the depleted gas field.

3 Conclusion

This report presents an outline of the systems required to transport and store CO_2 captured at two natural gas fired power plants and an oil refinery near Cork either to indigenous storage – the depleted Kinsale Head gas field – or by ship transport to the Northern Lights storage system in Norway. Systems are designed to meet the captured rates mentioned above.

The flexibility is discussed of the systems in accommodating variations in CO_2 supply, or in growth of the captured volumes to be stored. A high-level description of the systems needed to monitor and control the transport and storage of CO_2 is provided.

The main conclusions of the study are as follows:

1. If the current variability in the rate of emitted CO_2 from the power plants is a measure of future capture flow rate variations, the transport and storage must be able to accommodate flow rates between zero and the maximum rate. The onshore and offshore transport pipelines can be shut in when the capture rate is zero. Injection wells have to be shut in when the rate falls below the minimum rate for the well; depending on the well completion and the condition of the CO_2 in the system (liquid or gaseous), minimum rates can be as high as 30 kg/s (or about 1 Mtpa; gaseous phase) or 60 kg/s (about 2 Mtpa; liquid phase). Wells must be shut in at rates below their minimum rate to avoid too low temperatures and, hence, unsafe conditions. The number of wells needed to reach the targeted capture (and injection) rate is 2 in case the CO_2 is injected in gaseous phase, or 1 in case of liquid CO_2 injection.
2. For a single well, flexibility in accepting variable flow rates will be limited to flow rates within its window of operation. The minimum and maximum flow rate can be engineered and made fit-for-purpose through the choice of tubing size or by setting the number of perforations. Furthermore, if CO_2 is in gaseous phase, the pressure in the transport pipeline will also influence the location of the operational window. If CO_2 is in liquid phase, this option offers little flexibility. However, in case the minimum flow rate of a well is reduced to avoid frequent shut-ins when supply rates are low, also reduce the maximum flow rate. This results in a higher well count and higher cost to meet target flow rates. An optimisation of the system was not performed, as too many currently unknown factors play a role in the definition of an optimum.
3. System flexibility to accommodate higher CO_2 supply rates, as a result of, for example, import by ship, is obtained by drilling additional wells. It is noted that these new wells will similarly have a window of operation with a minimum and maximum flow rate that determines system flexibility at the well level.
4. The indigenous storage section of the study established that the KHGF has a total storage capacity of up to 300 Mt. The Cork cluster based on this study would involve injecting circa 2.2 Mt/p.a. over 25 years equal to 55 Mt in the base case scenario. Therefore, there is significant flexibility to accommodate CO_2 from other emitters in Ireland or elsewhere. The study has also determined that initially CO_2 will be injected in gas phase. As pressure in the reservoir gradually increases over time with continuous injection, the switch to inject liquid (dense phase) CO_2 will come as the reservoir pressure rises to meet the injection pressure. It was also determined that up to three new injection wells (7-inch) would be required for injection along with the associated infrastructure.

5. The intermediate storage of CO_2 is required as a buffer to facilitate export of CO_2. Intermediate storage can also facilitate more variable production of CO_2 and importation of CO_2, although these have not been considered in detail in the study.

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