GLOBAL
CCS
INSTITUTE

THE GLOBAL STATUS OF CCS | 2016

VOLUME 3 CCS TECHNOLOGIES

© Global Carbon Capture and Storage Institute Ltd 2016.

Unless stated otherwise, copyright to this publication is owned by the Global Carbon Capture and Storage Institute Ltd (Global CCS Institute) or used under licence. Apart from any use permitted by law, no part of this publication may be reproduced without the written permission of the Global CCS Institute.

For enquiries please contact:

BY TELEPHONE: +61 (0)3 8620 7300

BY EMAIL: info@globalccsinstitute.com

BY MAIL: Global CCS Institute, PO Box 23335
Docklands VIC 8012 Australia

The Global CCS Institute has tried to make information in this publication as accurate as possible. However, it does not guarantee that the information in this publication is totally reliable, accurate or complete. Therefore, the information in this publication should not be relied upon solely when making investment or commercial decisions. The Global CCS Institute has no responsibility for the persistence or accuracy of URLs to any external or third-party internet websites referred to in this publication and does not guarantee that any content on such websites is, or will remain, accurate or appropriate.

To the maximum extent permitted, the Global CCS Institute, its employees and advisers accept no liability (including for negligence) for any use or reliance on the information in this publication, including any commercial or investment decisions made on the basis of information provided in this publication.

Please use the following to reference the report:

Global CCS Institute 2016,
The Global Status of CCS: 2016,
Volume 3: CCS Technologies,
Melbourne, Australia.

The information in this report is current as at October 2016.

Cover image: Aerial view of Tomakomai CCS Demonstration Project facilities, located at Tomakomai City, Hokkaido, Japan. Image provided by JCCS.

THE GLOBAL STATUS OF CCS | 2016

VOLUME 3 CCS TECHNOLOGIES

CONTENTS

1 CAPTURE

2 TRANSPORT

3 STORAGE

ACKNOWLEDGEMENTS

Capture

Principal contributors to the Capture section of this volume of the Global Status of CCS: 2016 report were **Ron Munson** (Global Lead - Capture, Global CCS Institute), **Guido Magneschi** (Senior Adviser - Carbon Capture, Europe, Middle East and Africa, Global CCS Institute) and **Dr Tony Zhang** (Senior Adviser - Carbon Capture, Asia Pacific, Global CCS Institute).

Parties from outside of the Global CCS Institute that reviewed and provided comment on the Capture section of this volume of the *Global Status of CCS: 2016 report* were **Dr John Marano** – JM Energy Consulting Inc., **Professor Paul Fennell** – Imperial College London, and **Dr Paul Feron** – CSIRO.

Transport

The Transport section of this volume of the *Global Status of CCS: 2016 report* was prepared by Energy Pipelines CRC with the principal authors being **Dr Klaas van Alphen** and **Professor Valerie Linton.**

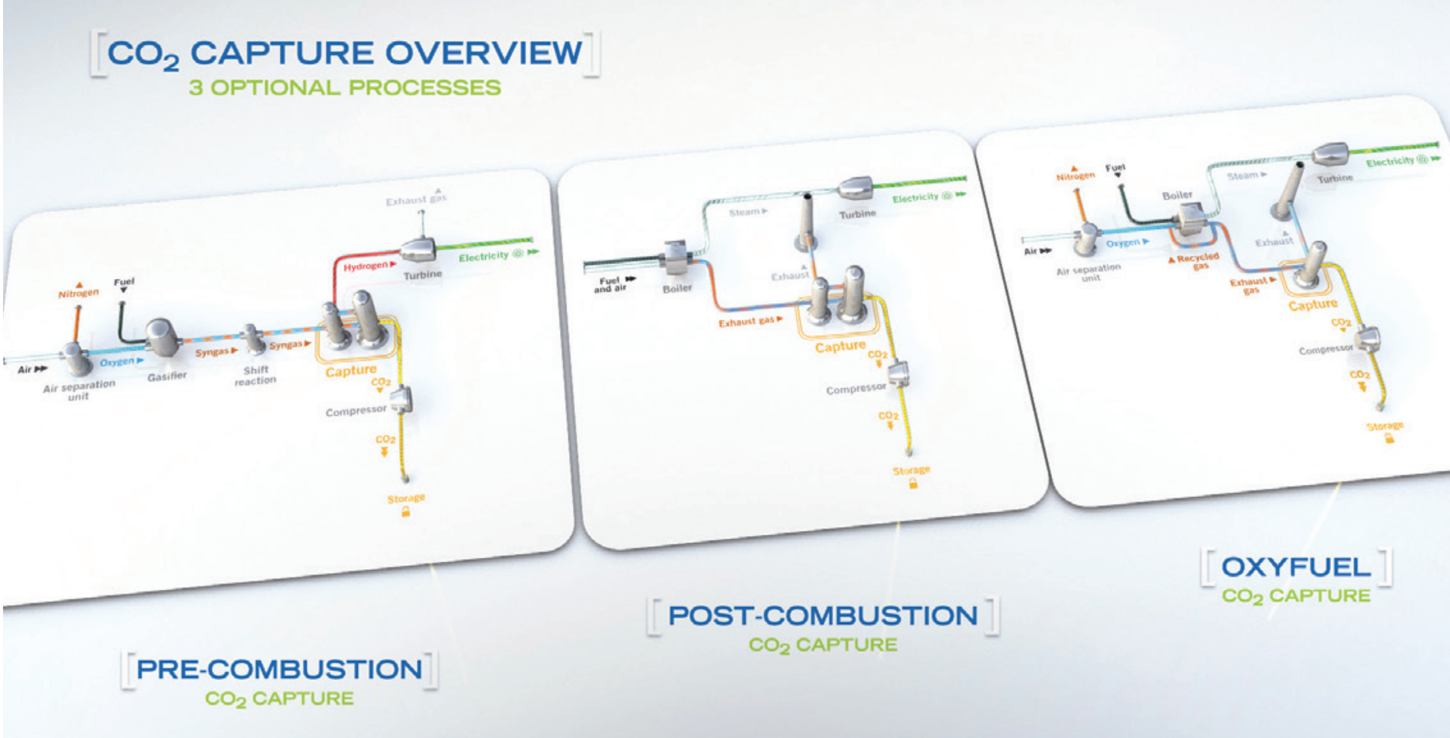
Storage

Principal contributors to the Storage section of this volume of the *Global Status of CCS: 2016 report* were **Neil Wildgust** (formerly Global Lead – Storage, Global CCS Institute) and **Dr Chris Consoli** (Senior Adviser – Storage, Asia Pacific, Global CCS Institute).

Parties from outside of the Global CCS Institute that reviewed and provided comment on the Storage section of this volume of the *Global Status of CCS: 2016 report* were **Simon O’Brien** – Shell and **Stefan Bachu** – Alberta Innovates Technology Futures.

[1]

CAPTURE



CO_2 CAPTURE OVERVIEW
3 OPTIONAL PROCESSES
Exhaust gas
Hydrogen
Turbine
Electricity
Nitrogen
Fuel
Air
Oxygen
Air separation unit
Gasifier
Syngas
Shift reaction
Syngas
Capture
CO_2
Compressor
CO_2
Storage
Steam
Turbine
Electricity
Fuel and air
Boiler
Exhaust
Exhaust gas
Capture
CO_2
Compressor
CO_2
Storage
Nitrogen
Fuel
Boiler
Steam
Turbine
Electricity
Air
Oxygen
Air separation unit
Recycled gas
Exhaust
Exhaust gas
Capture
CO_2
Compressor
CO_2
Storage
PRE-COMBUSTION
CO_2 CAPTURE
POST-COMBUSTION
CO_2 CAPTURE
OXYFUEL
CO_2 CAPTURE

SECTION HIGHLIGHTS

- There is growing acknowledgement that capture and storage of carbon dioxide (CO_2) emissions from industrial sources (commercial facilities, excluding the power sector) is a vital element in meeting climate goals.
- The industrial sector accounted for approximately 9 gigatonnes (Gt) of direct carbon emissions in 2013 (approximately one quarter of global energy-related CO_2 emissions). Under a 'business as usual' scenario, global CO_2 emissions from industrial sources could grow by around 50 per cent by 2050.
- The energy required for CO_2 separation increases rapidly as the CO_2 concentration in the gas stream decreases. The increase in energy requirement with decreasing concentration is of significance in industrial applications as the gas streams under consideration are so diverse.
- Industrial capture applications can be segregated into three basic categories:
  1. Sectors or processes in which production/separation of CO_2 is an inherent component of normal business operations (e.g. natural gas processing, bio-ethanol production, ammonia/fertiliser production).
  2. Sectors in which relevant volumes of CO_2 are present in process gas streams at concentrations high enough to allow for relatively inexpensive separation and subsequent sale (e.g. hydrogen production in oil refining applications).
  3. Sectors that generate substantial volumes of CO_2 that will need to be mitigated in order to achieve climate goals, but that currently do not have large-scale capture projects due to either (or a combination of) lack of regulatory requirements, high capture costs, global competitive pressures and inadequate incentives (e.g. iron and steel production, cement production, petroleum refining, and pulp and paper production).
- While for the first two categories CO_2 capture is relatively mature, and many commercial technologies have been proven at scale, for the third category CO_2 capture is more challenging. Lower concentrations of CO_2 in the gas streams of these sectors necessitate the use of capture approaches that are more capital and energy intensive. Ongoing research and development activity is targeting capture cost reductions, especially for low-concentration gas streams.
- There are a number of operating industrial plants with CO_2 capture capacity of one million tonnes per annum or greater, mainly in natural gas processing and fertiliser and hydrogen production. Across the full spectrum of industrial emission sources, there will be many individual facilities where the volume of CO_2 to be captured will be at smaller levels. As stand-alone developments, this can result in high costs for accessing transport and storage infrastructure. However, many emissions-intensive industries are located in tight geographical clusters. Development of strategically-sized, shared transport and storage infrastructure can facilitate the efficient aggregation of smaller volumes of CO_2 from industrial sources.

1.1

INTRODUCTION

At a basic level, carbon capture involves separating and removing CO_2 from a gas stream before it is emitted to the atmosphere. It is often viewed in the context of power production. This is not surprising given that the burning of coal, natural gas, and oil for electricity and heat is the largest single source of global energy-related CO_2 emissions (accounting for more than 40 per cent of CO_2 emissions in 2013).[1] Indeed, the terminology generally used to describe carbon capture technologies – pre-combustion, post-combustion, and oxy-combustion – is directly applicable to the power sector. Capture research and development trends, with an emphasis on reducing the cost impact of carbon capture systems on power plants, were highlighted in the *Global Status of CCS: 2015, Volume 3 CCS Technologies.*

There is growing acknowledgement that the capture and storage of CO_2 emissions from industrial sources is a vital element in meeting climate goals. Industrial CCS can be defined as the capture, transport and storage (or utilisation) of CO_2 that would otherwise have been emitted to the atmosphere from commercial facilities, excluding the power sector.[2]

---

[1] (IEA, 2016)

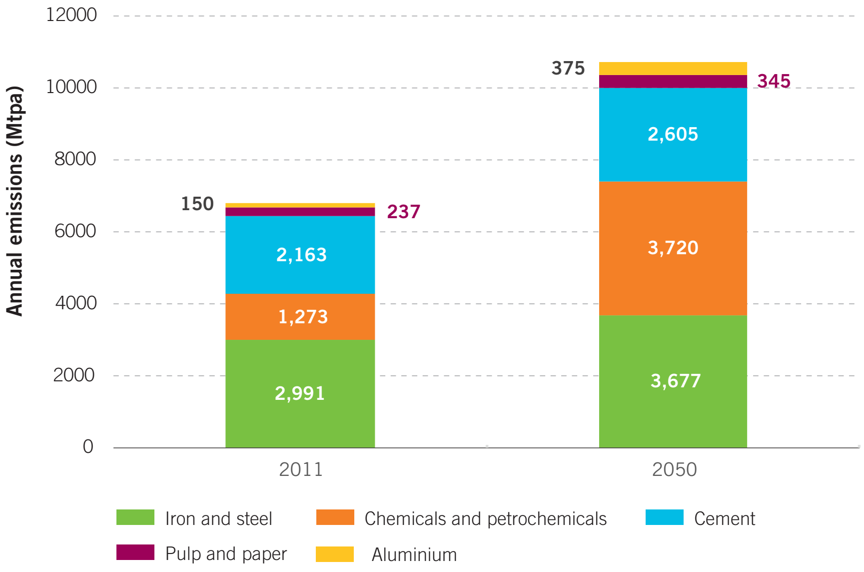
[2] (IEA, 2013a)

The industrial sector accounted for approximately 9 Gt of CO_2 emissions in 2013, equivalent to approximately one-quarter of global CO_2 emissions. Under a 'business as usual' scenario, global emissions from these industries are projected to grow by around 50 per cent by 2050.[3] In its 2013 CCS Roadmap, the International Energy Agency (IEA) projected that, in order to achieve its 2°C Scenario, almost half (45 per cent) of the CO_2 captured and stored between 2015 and 2050 would need to come from industrial applications.[4]

Much of the progress to date on CCS is associated with industrial applications. Of the 21 large-scale CCS projects currently in operation or under construction, 18 are in the industrial sector, mainly in natural gas processing and fertiliser production, where the CO_2 is already separated as part of the production process and is relatively inexpensive to 'capture' compared to other industrial processes. These 18 industrial projects have a CO_2 capture capacity of approximately 35 million tonnes per annum (Mtpa).[5]

However, natural gas processing and fertiliser production are relatively low emitters of CO_2 compared to iron and steel, cement and chemicals production where, with current knowledge and practice, the addition of CO_2 capture technologies would incur significant incremental costs. Significant decarbonisation of the latter three industries is important to help meet global CO_2 emissions reduction goals (Figure 1.1). At present, there is a paucity of large-scale CCS projects in these industries in either operation, construction or advanced planning.

Figure 1.1 **Industrial sector-specific direct CO_2 emissions to 2050 under a 'business as usual' scenario[6]**



Source: IEA, 2014a. Energy Technology Perspectives 2014: Harnessing Electricity's Potential.

Fossil fuels are an essential input to the production process - as it is currently practised - in a number of industries, including iron and steel, cement and chemical production. However, unlike power generation, it is currently not feasible to substitute renewable energy sources for fossil fuels in these production processes in order to reduce CO_2 emissions without extensive process redesign that has not been adequately tested. In addition, for a number of industrial processes, CO_2 emissions are not a product of the combustion of substitutable fossil fuels, but rather an unavoidable by-product of an inherent chemical process. In this case, aside from the application of energy efficiency measures, CCS is the only large-scale technology available that can help achieve deep reductions in CO_2 emissions in the longer run.

---

[3] (IEA, 2016)

[4] (IEA, 2013b)

[5] (Global CCS Institute, 2016a)

[6] (IEA, 2014a)

While industrial sources represent a significant percentage of global CO_2 emissions, there are challenges associated with widespread deployment of capture technologies. Industrial sector emissions are scattered over many industries with widely divergent characteristics - different gas compositions, process temperatures and pressures, and contaminants. In addition, much of the regulatory activity associated with reducing CO_2 emissions has focused on the power sector, reducing the urgency for development of approaches for capture in some industrial sectors.

An added consideration is that the products of the industrial sector can have a high exposure to global competition, making them highly sensitive to relative production costs. This aspect highlights a key area of interaction (and need for reconciliation) between climate policy and industrial policy.

> *Enabling trade-exposed sectors to take vital climate change mitigation actions, such as CCS, while retaining a competitive position, is a key challenge for CCS policy in a world with fragmented climate policies. Due to the potential importance of CCS to industrial emissions reductions, it is also a key challenge for achieving deep emissions reductions more broadly.*
>
> *IEA, Insights Series 2014, CCS 2014 What lies in store for CCS?, 2014.*[7]

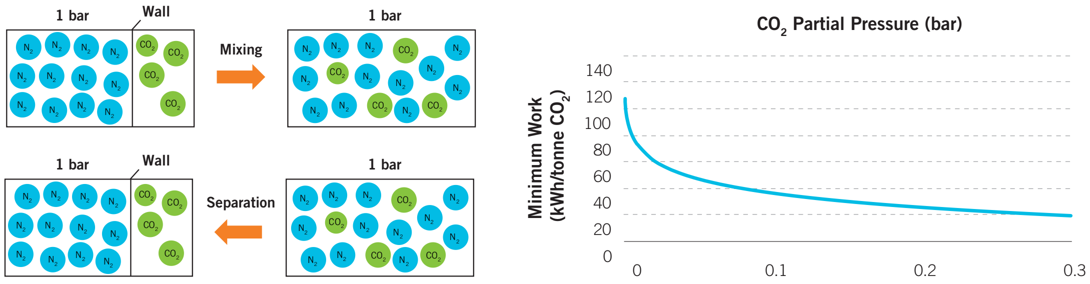
This section includes an overview of the capture process, emphasising those factors that are most important in evaluating separation approaches applicable to gas streams with differing characteristics. This is followed by a discussion of the state of capture technologies in specific industrial sectors. This information is then summarised and options for future implementation discussed.

1.2

OVERVIEW OF THE CAPTURE PROCESS

Separation of gases requires energy. The minimum energy required for gas separation can be calculated based on thermodynamic principles associated with mixing, as illustrated in Figure 1.2. The top left section in Figure 1.2 shows that if you start with pure nitrogen (N_2) and pure CO_2 in a box separated by a divider and then remove the divider, the N_2 and CO_2 will mix spontaneously, increasing entropy (disorder) and decreasing exergy (useful work or energy). The gas separation process is illustrated in the lower left section, and involves re-separating the CO_2 and N_2. The exergy lost by mixing represents the minimum work (energy) required for separation.

Figure 1.2 **Minimum work (energy) for gas separation (CO_2 product at 1 bar)**[8]



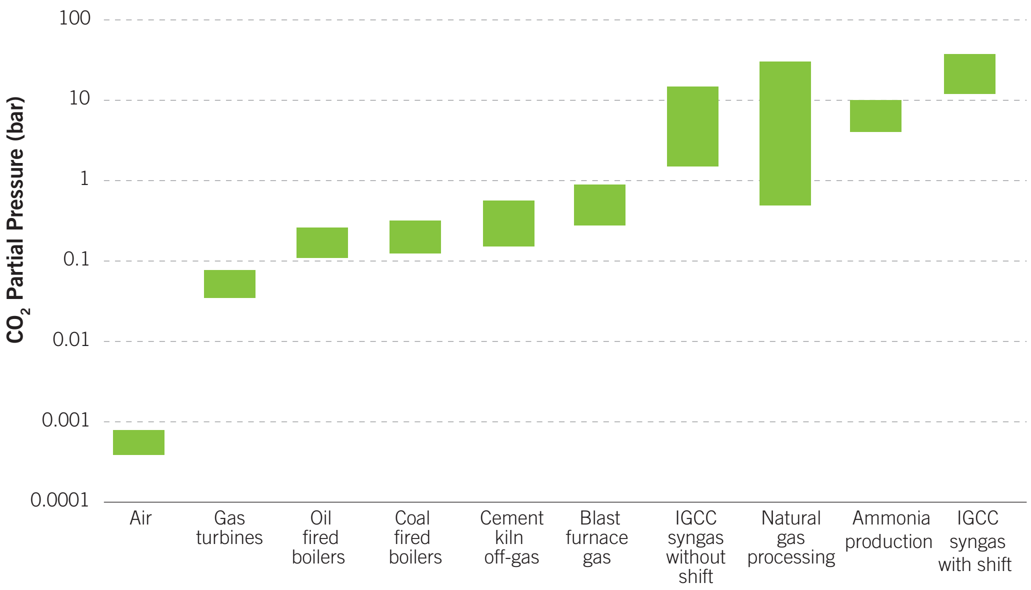
The minimum work required for CO_2 separation as a function of partial pressure is illustrated in the right section of Figure 1.2. As indicated, the work required for separation increases rapidly as the partial pressure decreases. This effect of increasing energy requirement with decreasing partial pressure – or CO_2 concentration - is of significant importance in industrial applications, as the gas streams under consideration exhibit diverse partial pressures, as illustrated in Figure 1.3.

---

[7] (IEA, 2014b)

[8] (Berger & Bhown, 2014)

Figure 1.3 CO_2 partial pressure ranges in air and a variety of flue/process gases[9]



The differing partial pressures influence energy requirements, applicable technologies and the cost of capturing CO_2. High partial pressure systems allow for the use of technologies that rely on physical (or bulk) properties of capture media to effect separation from the gas stream. These processes have the advantage that the energy requirements for regeneration of the capture media are relatively low. Low partial pressure systems rely on chemical processes (reactions) to separate CO_2 from the gas stream. These are more selective in removing the CO_2, but can require much more energy for regeneration. The significance of these factors is illustrated below.

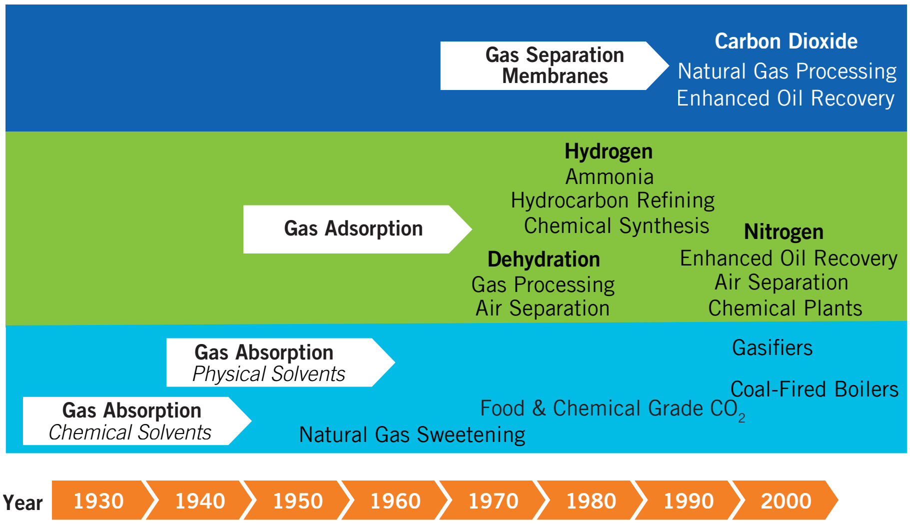
1.2.1 Brief history of CO_2 separation

Removal of CO_2 from industrial gas streams is not a new process. Gas absorption processes using chemical solvents, such as amines, to separate CO_2 from other gases have been in use since the 1930s in the natural gas industry, and to produce food and chemical grade CO_2 from gas streams containing 3 to 25 per cent CO_2 (Figure 1.4). Starting in the 1940s, physical solvents were developed to absorb CO_2 from gas streams with higher CO_2 concentration (25 to 70 per cent) and higher pressure (approximately 10 MPa). More recently, processes employing physical solvents have been developed to capture CO_2 in gasification applications (e.g. Selexol™ and Rectisol®). In the 1950s and 1960s, gas adsorption processes were developed to remove CO_2 from gas streams associated with hydrogen production (refineries), nitrogen separation, and dehydration. In the 1970s and 1980s, gas separation membranes were developed to capture CO_2 for use in enhanced oil recovery (EOR) and natural gas processing.

---

[9] (Bolland, 2010)

Figure 1.4 Previous experience with removal of CO_2 from gas streams



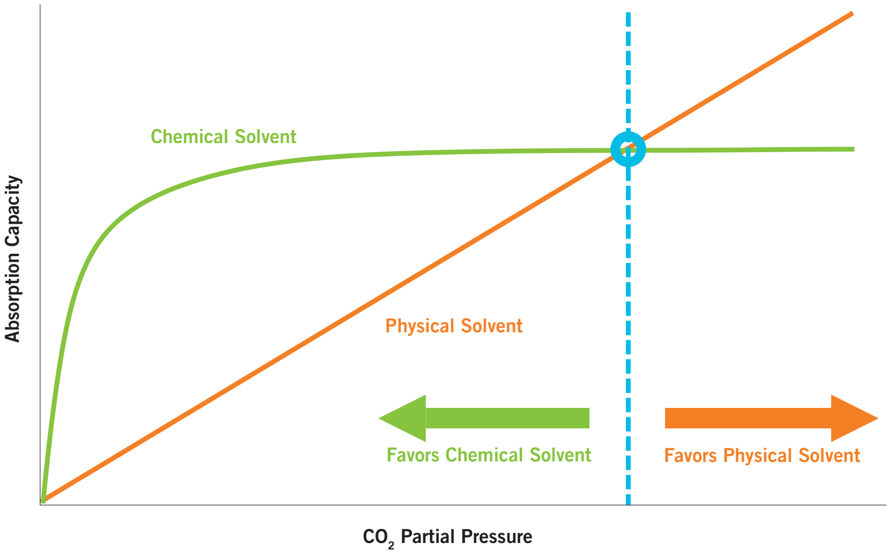
1.2.2 CO_2 separation technologies

Capture technologies that are currently available at large-scale rely on specific media – solvents, sorbents, and membranes - to separate CO_2 from a gas stream. This subsection provides basic information regarding each general class of separation media, as well as examples of technologies that are currently being applied.

Solvents

Absorption employing physical or chemical solvents is the most common technology used for gas separation. In an absorption process, a gaseous component dissolves into a liquid solvent forming a solution. Due to different solubility of gas components in a particular solvent, the solvent can be used for selective separation. Figure 1.5 illustrates the general behaviour of chemical and physical solvents. At lower CO_2 partial pressure, chemical solvents have a higher absorption capacity, which makes them more attractive for use for low partial pressure gas conditions. However, at higher partial pressures their absorption capacity levels off. The relationship between solvent capacity and partial pressure is nearly linear for physical solvents (Henry's Law behaviour).[10] Thus, at higher partial pressure, physical solvents are preferred.

Figure 1.5 Absorption using a chemical versus a physical solvent[11]



---

[10] (Separation Processes, 2016)

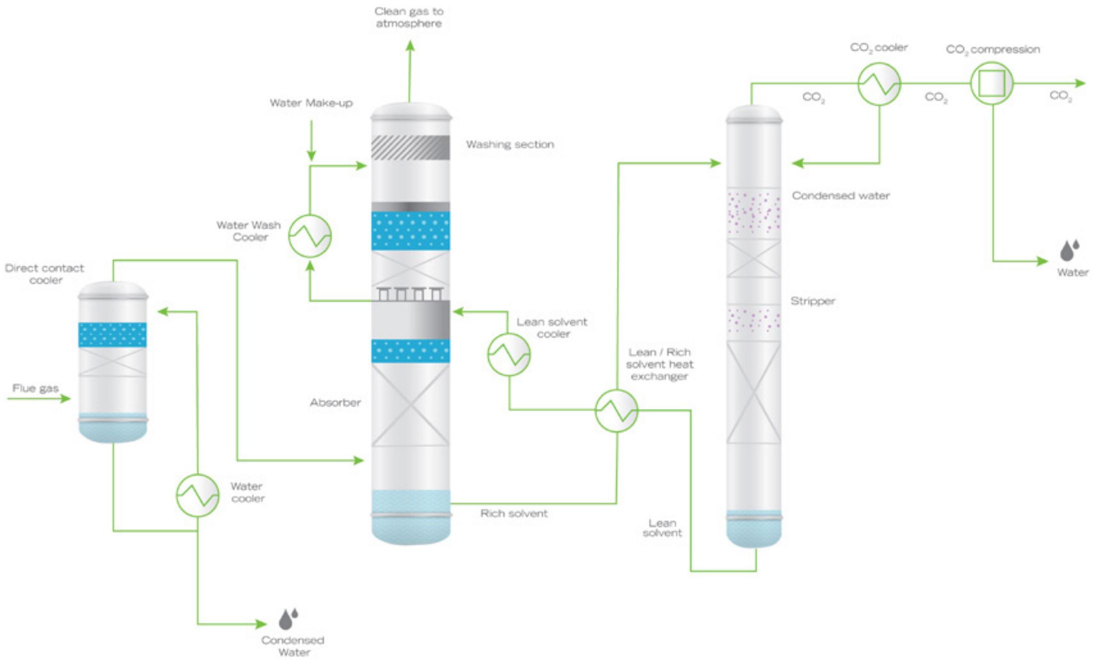
[11] (U.S. DOE, 2013a)

In a CO_2 absorption process, the gas is contacted with the solvent in an absorption column, also referred to as an absorber, and CO_2 in the gas is transferred to the solvent. The CO_2-rich solvent from the absorber is then regenerated so that it can be re-used. Chemical solvents are usually regenerated by raising the temperature to release CO_2, while with physical solvents pressure is reduced. Solvent regeneration is often accomplished in a desorption column, also referred to as a stripper.

The most widely used physical solvent-based technologies are the glycol-based Selexol™ and methanol-based Rectisol® systems.[12] The Selexol process operates at around ambient temperature whereas the Rectisol process operates as low as -60°C. These systems are presently in large-scale operation (4,000 tonnes per day CO_2 separation) in synthetic gas (syngas) purification and natural gas processing.

Chemical solvent-based systems available commercially or near commercialisation commonly use amine-based solvents. These systems are typically installed downstream from conventional pollution control equipment and use a chemical absorption/desorption cycle to separate CO_2 from the flue gas, as illustrated in Figure 1.6. The solvent binds with the CO_2 in an absorber. It is then routed to a stripping column where the temperature is increased, releasing the absorbed CO_2.[13]

Figure 1.6 **Simplified process scheme of chemical solvent-based CO_2 capture[14]**



Sorbents

Different molecules have varying affinity to the surface of a solid sorbent, which allows for the separation of a specific gas component from a mixture. Based on the interaction between gas molecules and the sorbent surface, adsorption can be characterised as chemical adsorption or physical adsorption.

Chemical adsorption - via chemical bonding - results in a strong interaction between the gas molecule and sorbent, and is appropriate for low-concentration gas streams. Regeneration is typically accomplished using a thermal swing adsorption (TSA) process - the adsorbent is regenerated by raising its temperature.

Physical adsorption — via van der Waals forces[15] — has a weaker interaction between the gas molecule and sorbent and is typically applied to high-concentration feed streams. Regeneration is typically based on a pressure swing adsorption (PSA) mechanism. In PSA, the gas mixture containing CO_2 flows through a packed bed of adsorbent at elevated pressure until the adsorption of the desired gas approaches equilibrium with the solid. The bed is then regenerated by stopping the feed mixture

---

[12] (Mohammed, et al., 2014)
[13] (U.S. DOE, 2013a)
[14] (Global CCS Institute, 2016b)
[15] (Chemguide, 2012)

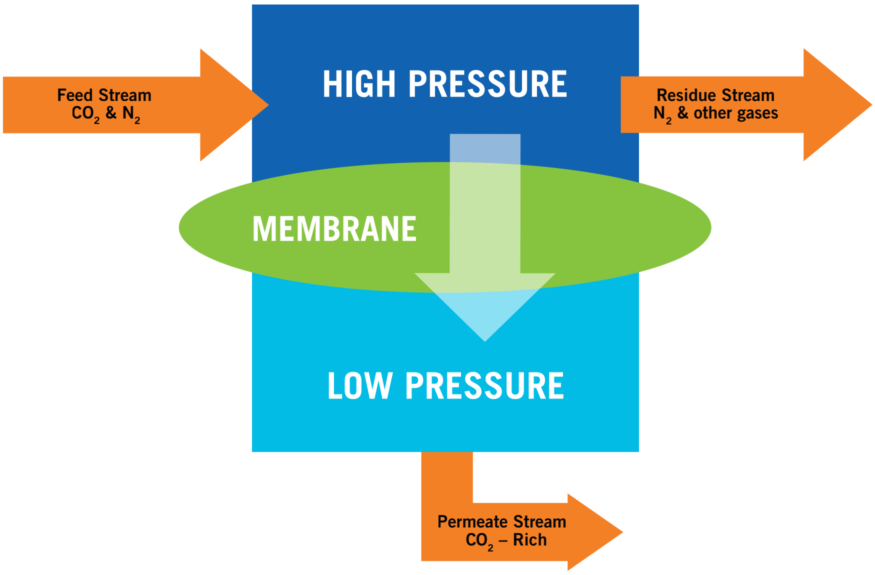
and reducing the pressure.[16] There are PSA sorbent based technologies in commercial use, an example being the Air Products Steam Methane Reformer EOR Project in Texas.[17] However, these types of systems are much less common than solvent-based technologies.

Membranes

A membrane is a barrier or medium that can separate the individual chemical constituents of a gas mixture based on the selective permeation of the constituents through the membrane at different rates (i.e. particular components of a mixture pass through the barrier faster than the other components). Generally, gas separation is accomplished by some physical or chemical interaction between the membrane and the gas being separated. Membrane separation uses partial pressure as the driving force and is usually more favourable when the feed gas stream is at a high pressure.

Figure 1.7 shows a simplified process schematic for a low-CO_2 concentration gas separation membrane. The feed stream contains CO_2, N_2, and other minor constituents. A pressure differential across the membrane surface area serves as a driving force for a portion of the CO_2 to selectively diffuse through the membrane, creating a CO_2-rich permeate stream. The N_2 and other gas constituents - including a small amount of CO_2 that did not pass through the membrane - make-up the residue stream that exits the membrane. Minimising the amount of CO_2 ultimately released as part of the residue stream is an essential component in applications requiring a high level of separation (e.g. 90 per cent) and high purity (e.g. 95 per cent). Process innovations such as installation of a second sweep membrane have enabled the use of membrane approaches in low-CO_2 concentration applications.[18] As with PSA sorbent-based technologies, membrane-based technologies are in commercial use – an example being the Petrobras Santos Basin Pre-Salt Oil Field CCS Project in Brazil.[19] However, these types of systems are much less common than solvent-based technologies.

Figure 1.7 Membrane process schematic



1.3

OVERVIEW OF CARBON CAPTURE IN SPECIFIC INDUSTRIAL SECTORS

Carbon capture is currently practised in selected industrial sectors at large scale. One of the significant factors in implementation is the concentration of CO_2 in the gas being separated.

---

[16] (U.S. DOE, 2013a)
[17] (Global CCS Institute, 2016a)
[18] (U.S. DOE, 2013a)
[19] (Global CCS Institute, 2016a)

In the following sections, the application of capture in specific sectors is discussed in terms of scale and approaches being pursued.

1.3.1 Natural gas processing

The natural gas used for power production, home heating, and various industrial processes is composed almost entirely of methane.[20] However, raw natural gas produced from geological formations, although high in methane content, often contains impurities that need to be removed before it is marketable as a fuel or feedstock. These impurities can include non-methane volatile organic compounds (ethane, propane and mixed butanes - sometimes referred to as natural gas liquids [NGLs]), nitrogen, CO_2, hydrogen sulphide (H_2S), and water[21] (as well as trace amounts of other impurities, such as helium).[22]

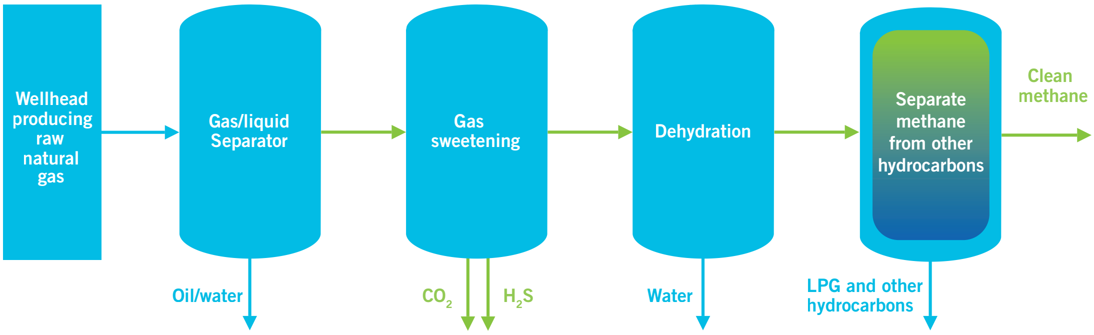
CO_2 content in extracted natural gas can range from 2 to 70 per cent by volume. Separation of CO_2 from methane in natural gas is an integral component of gas sales, but currently only a small fraction of the separated CO_2 is stored or utilised. Most is vented to the atmosphere. Global emissions have been estimated at 160 Mtpa.[23] US CO_2 emissions from natural gas processing - based on actual measurements and reported as part of the US greenhouse gas (GHG) inventory program - ranged from 21 to 24 Mtpa between 2010 and 2014.[24]

Overview of natural gas processing

Natural gas processing involves a series of steps/operations, as depicted in Figure 1.8. After leaving the gas well, the first step in processing is removal of oil, water and condensates. This is done in a separator using the force of gravity as well as temperature and pressure control. Once these constituents have been removed, any CO_2 and H_2S present is removed. This step is known as 'sweetening' the gas. Sweetening is followed by dehydration using solvent or sorbent technologies, and finally the methane is separated from other hydrocarbons present.[25]

One of the critical features of CO_2 separation from natural gas is the pressure of the gas stream. This pressure ranges from approximately 9 to 80+ bar, resulting in a CO_2 partial pressure ranges of 0.5 to 44 bar. As noted earlier, separation at high partial pressures is thermodynamically favoured compared to low partial pressures. This results in lower cost capture than is associated with gas streams in other applications. The processing that takes place prior to separation of CO_2 removes most of the contaminants that would otherwise complicate CO_2 capture, thus contaminants are not a significant concern.

Figure 1.8 **Natural gas processing schematic**



---

[20] (Naturalgas.org, 2013)
[21] (Bradbury, et al., 2015)
[22] (EIA, 2006)
[23] (UNIDO, 2010)
[24] (U.S. EPA, 2016)
[25] (Croft Production Systems, 2014)

Summary of CO_2 capture activity in natural gas processing

Demand for natural gas as a fuel or a feedstock was relatively low until after World War II. As gas demand increased, the need for processing rose as well. Many of the gas sources initially exploited were those with the highest methane contents and lowest CO_2 concentrations. Removal of low-concentration CO_2 lends itself to use of chemical solvents. With the development of higher-CO_2 content gas reservoirs, physical solvent-based processes were developed as well as membrane-based and cryogenic processes. While CO_2 separation is common in natural gas processing, as noted earlier, only a very small fraction of the separated CO_2 is actually used in CCS applications. These CCS applications are noted in Table 1.1. Full descriptions of each of these applications can be found on the Institute's projects webpage.

Table 1.1 **CCS applications in natural gas processing**[26]

PROJECT	LOCATION	START DATE	SCALE	CHARACTERISTICS/APPROACH
Val Verde	US	1972	1.3 Mtpa	Physical solvent-based capture; CO_2 content of NG = 25 – 50%
Shute Creek	US	1986	7 Mtpa	Physical solvent-based capture; CO_2 content of NG = ~65%; test site for CFZ™ cryogenic capture technology test (see Case Study)
Sleipner	Norway	1996	0.85 Mtpa	Chemical solvent-based capture; CO_2 content of NG = 4 – 9%; storage incentivised by Norwegian carbon tax ~US$50/tonne
Snøhvit	Norway	2008	0.7 Mtpa	Chemical solvent-based capture; CO_2 content of NG = 5 – 8%; storage incentivised by Norwegian carbon tax ~US$50/tonne
Century Plant	US	2010	8.4 Mtpa	Physical solvent-based capture; CO_2 content of NG = 60+%
Lost Cabin	US	2013	0.9 Mtpa	Physical solvent-based capture; CO_2 content of NG = ~20%
Petrobras Santos Basin Pre-Salt	Brazil	2013	~ 1 Mtpa	Membrane-based capture; CO_2 content of NG = 8 – 15%
Uthmaniyah	Saudi Arabia	2015	0.8 Mtpa	Solvent-based capture
Gorgon	Australia	2017*	3.4 - 4 Mtpa	Chemical solvent-based capture; CO_2 content of NG = Gorgon field ~14%

** Institute estimate*

Chemical solvent-based processes are used at Sleipner, Snøhvit and Gorgon. These locations typically have lower CO_2 contents (4 to 14 per cent) that lend themselves to amine-based capture technologies. However, the regeneration process for these technologies is more energy intensive than for physical solvent-based technologies, increasing capture costs.

Physical solvent-based processes are used for the high CO_2-content gases (approximately 25 to 65 per cent) at Lost Cabin, Shute Creek, Val Verde, and Century. Solvent regeneration for these applications can use pressure swing rather than temperature swing, reducing energy requirements.

Membrane separation processes typically have a smaller physical footprint and are simpler to operate than solvent-based processes. This is an important consideration in an off-shore environment like the Petrobras Santos Basin Pre-Salt development site.

Cryogenic processes have been tested but have not yet been applied at large-scale. A cryogenic-based process developed by ExxonMobil serves as the basis for the case study included below.[27]

---

[26] (Global CCS Institute, 2016a)

[27] (ExxonMobil, 2016)

CASE STUDY – ExxonMobil CFZ process

Project Proponent	ExxonMobil
Location	Shute Creek Treatment Facility at LaBarge, Wyoming, US
Status	Testing conducted March 2012 to November 2013
Capacity	Up to 14 million standard cubic feet per day (scfd) of gas
CO_2 Source	Shute Creek Treatment Facility
Technology	Cryogenic capture

Information

ExxonMobil has developed the Controlled Freeze Zone™ (CFZ™) Technology - a single-step cryogenic separation process that removes CO_2 and hydrogen sulphide (H_2S) from natural gas in a specially-designed section of a distillation tower, where CO_2 is allowed to freeze in a controlled manner. Next, the CO_2 is melted and further distilled to recover methane. The technology was first demonstrated at the Clear Lake Pilot Plant, near Houston, Texas, in 1986. The pilot plant processed natural gas with high levels of CO_2 (as high as 65 per cent), and at rates of up to 600,000 scfd. In 2008, construction started on a Commercial Demonstration Plant (CDP) at the Shute Creek Treatment Facility at LaBarge, Wyoming — a facility with the capacity to process up to 14 million scfd. After completing construction and commissioning, a formal test program was conducted from March 2012 through to November 2013. The CDP successfully processed a wide range of sour gas feeds (8 to 71 per cent CO_2 and as much as 36 per cent H_2S), producing natural gas that met pipeline specifications (<2 per cent CO_2 and <4 ppm H_2S). The separated CO_2 was produced at high pressure, reducing compression costs. The CDP demonstrated the effectiveness of the technology for CO_2 feed concentrations above 20 per cent.

1.3.2 Hydrogen and ammonia/fertiliser production

Hydrogen is a significant commodity used in petroleum refineries, in the production of ammonia for fertilisers and other chemicals, and in food processing. More than 50 million tonnes of hydrogen is produced annually worldwide, principally from steam methane reforming (SMR) of natural gas.[28] Depending on the quality of the feedstock (natural gas, rich gases, naphtha, etc.), one tonne of hydrogen produced will also produce 9 to 12 tonnes of CO_2.[29]

Overview of hydrogen production

A typical SMR process is depicted in Figure 1.9. This is a mature production process in which methane reacts with high-temperature steam (700°C–1,000°C) under 3–25 bar pressure in the presence of a catalyst to produce hydrogen, carbon monoxide, and a relatively small amount of CO_2.

Steam methane reforming reaction

$CH_4 + H_2O\ (+\ \text{heat}) \rightarrow CO + 3H_2$

This reaction is highly endothermic, requiring significant input of heat produced by combustion of fuel – usually methane – in a steam reformer heater.

Following the steam methane reforming step, in what is called the "water-gas shift reaction," the carbon monoxide and steam are reacted using a catalyst to produce CO_2 and more hydrogen. In a final process step called "pressure-swing adsorption" (PSA), the CO_2 and other impurities are removed from the gas stream, leaving essentially pure hydrogen.[30]

---

[28] (U.S. DOE, 2013b)

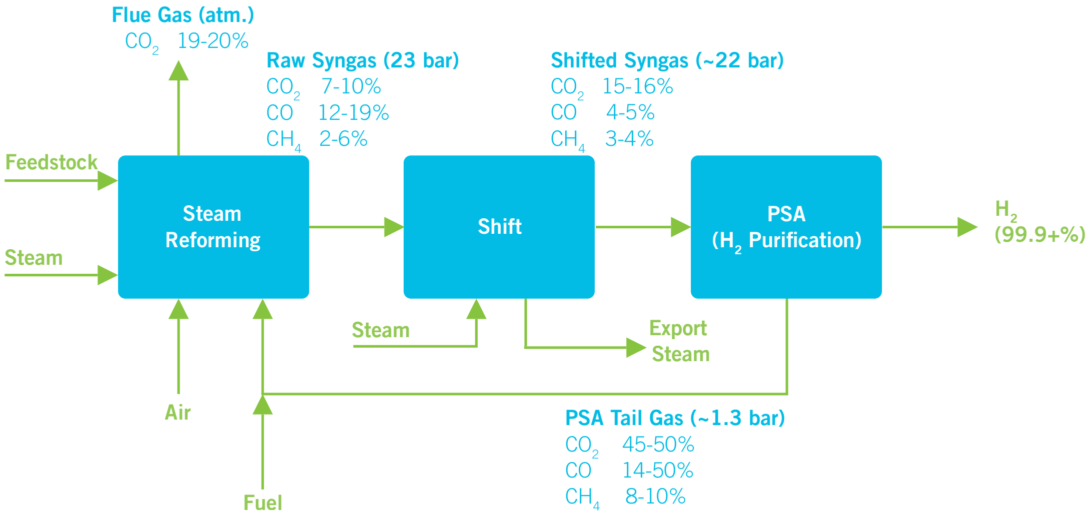
[29] (Collodi, 2011)

[30] (U.S. DOE, 2011)

Water-gas shift reaction

$CO + H_2O \rightarrow CO_2 + H_2$ (+ small amount of heat)

Figure 1.9 **Hydrogen production via steam methane reforming**[31]



Hydrogen can also be produced using other approaches and feedstocks - such as coal, petroleum coke (petcoke) and biomass. Solid feeds are gasified to produce syngas, after which the process is similar to that outlined for SMR. However, on a bulk basis, hydrogen production via SMR far outweighs production from any other source.

Summary of CO_2 capture activity in hydrogen production

Approximately 60 per cent of the total CO_2 produced in a steam reforming hydrogen plant is contained in the shifted gas (and then in the PSA tail gas), while the remaining 40 per cent is the product of the combustion of the additional fuel gas required by the steam reformer. As the process is typically configured (without carbon capture), all of the CO_2 eventually ends up in the flue gas of the steam reformer heater.

If a carbon capture system is implemented, the CO_2 could be captured from any of three process streams – the shifted syngas stream, the PSA tail gas, or the steam reformer flue gas. Capture from the steam reformer flue gas would allow for removal of nearly all of the CO_2 generated in the process. However, given the relatively low concentration of the flue gas (19 – 20 per cent CO_2) and the fact that the stream is at atmospheric pressure, it is likely that separation using chemical solvents/sorbents or advanced membrane configurations would be required, increasing capture costs. Capture from the shifted syngas or PSA tail gas streams offers the advantage of higher CO_2 partial pressures in both cases and higher total and CO_2 partial pressures in the shifted syngas case. These conditions open the door to use of physical solvents/sorbents and more conventional membrane configurations, reducing costs. This approach has been implemented at both of the SMR facilities that are currently capturing CO_2 at large scale (Quest and Air Products).[32] However, capture from the higher-concentration streams leaves the steam reformer flue gas stream unmitigated.

---

[31] (Santos, 2015)

[32] (Global CCS Institute, 2016a)

Hydrogen production for oil refining

CO_2 capture is being practised at large-scale and pilot scale in the hydrogen production process in support of both oil refining (Table 1.2) and fertiliser production. Large-scale applications supporting oil refining include the Air Products Steam Methane Reformer EOR Project and the Quest Project. Pilot scale applications in oil refining include the Tomakomai and Port Jerome projects.

Table 1.2 **CCS applications in hydrogen production supporting the oil refining industry**[33]

PROJECT	LOCATION	START DATE	SCALE	CHARACTERISTICS/APPROACH
Air Products Port Arthur	US	2012/13	1 Mtpa	Vacuum swing adsorption
Quest	Canada	2015	1 Mtpa	Chemical solvent-based absorption
Port Jérôme	France	2015	0.1 Mtpa	Cryogenic separation
Tomakomai	Japan	2016	0.1 Mtpa	Solvent-based absorption
Northwest Sturgeon	Canada	2017	1.2 Mtpa	Physical solvent-based absorption

Air Products started capturing CO_2 from two hydrogen production units at the Valero refinery in Port Arthur, Texas, in late 2012 and early 2013. When operating at full capacity both units capture a total of approximately 1 Mtpa of CO_2. The CO_2 is separated from shifted syngas using a solid sorbent vacuum swing adsorption (a subset of PSA) technology. As of June 2016, over 3 million tonnes of CO_2 had been captured at this facility.

The Quest project is located near Edmonton, Alberta, Canada. Quest was officially launched in November 2015. It is designed to capture and store more than one million tonnes of CO_2 each year. Quest captures the CO_2 produced from three hydrogen production units at the Scotford Upgrader facility, which uses the hydrogen to convert bitumen from the Athabasca Oil Sands Project into synthetic crude oil. The capture technology used is a chemical solvent system. In September 2016 it was announced that the Quest Project had captured and stored one million tonnes of CO_2. More information regarding the Quest project is included in the case study on the next page.

The Northwest Sturgeon project is also located near Edmonton, Alberta, Canada. It is under construction and expected to launch in 2017. It is designed to capture 1.2 million tonnes of CO_2 per year from the hydrogen production facility located at the Redwater bitumen refinery. The capture technology used is the Rectisol physical solvent system. The captured CO_2 is slated to be transported via the Alberta Carbon Trunk Line for EOR use in southern Alberta.

In addition to the large-scale applications, testing at lesser scale is being conducted as part of the Tomakomai CCS Demonstration Project. Tomakomai is a fully integrated project using carbon capture, compression, transport and geologic storage technologies and is located in Hokkaido, Japan. Since April 2016, CO_2 from the PSA tail gas of a hydrogen production unit in an oil refinery has been captured using a chemical solvent-based process. The project will capture at least 100,000 tonnes of CO_2 each year for three years.

Another pilot scale application is underway at ExxonMobil's refinery located in Port-Jérôme, Notre-Dame-de-Gravenchon, Normandy, France. This project is testing Air Liquide's cryogenic capture technology called Cryocap™. The system is treating PSA tail gas to produce up to 100,000 tonnes of CO_2 per year. One of the goals of the project is to demonstrate lower-cost separation.[34]

---

[33] (Global CCS Institute, 2016a)

[34] (Santos, 2015)

CASE STUDY – Quest

Project Proponent	Shell Canada, Chevron Canada and Marathon Oil Canada
Location	Alberta, Canada
Status	Operating since November 2015
Capacity	Approximately 1 Mtpa
CO_2 Source	Scotford Upgrader in Fort Saskatchewan
Technology	Solvent-based capture

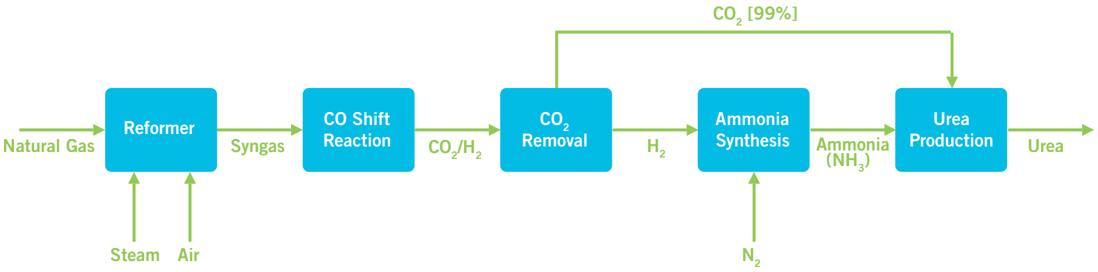
Information

Bitumen derived from oil sands at the Muskeg River and Jackpine mines in the Athabasca area of north-east Alberta (north of Fort McMurray) is transported by pipeline to the Scotford Upgrader near Edmonton, Alberta, where it is turned into synthetic crude oil. The Scotford Upgrader has the design capacity to process 255,000 barrels of oil equivalent per day of diluted bitumen. The CO_2 capture infrastructure involves process modification to the existing Scotford Upgrader. The CO_2 is captured from the three steam methane reformer (SMR) units that manufacture hydrogen for upgrading the bitumen into synthetic crude oil. The capture facilities consist of three amine absorption towers, an amine regeneration unit, a multistage CO_2 compressor with coolers and separators, and a triethylene glycol dehydration unit. The method of capture is based on a licensed Shell activated amine technology.

Hydrogen production for ammonia/fertiliser production

Ammonia is one of the most widely used chemicals in the world, primarily for the production of urea fertiliser.[35] Ammonia is commonly synthesised using hydrogen generated by steam methane reforming. When evaluated in the context of ammonia production, a typical ammonia plant would have a CO_2 intensity of 1.5 to 2 $tCO_2/t\ NH_3$.[36] However, much of the CO_2 generated to support ammonia production is captured and utilised for the production of urea, as illustrated in Figure 1.10.

Figure 1.10 Urea production process



Urea plants are generally located adjacent to or in proximity to an ammonia plant. In integrated ammonia/urea plants, about half of the CO_2 resulting from ammonia production is used to produce urea while the rest is vented.[37] The production of urea consumes CO_2 at the rate of 0.735–0.75 tonnes of CO_2 for every tonne of urea produced.[38] However, it must be noted that the CO_2 stored in urea will be released to the atmosphere as the urea decomposes in the soil upon contact with water. Urea has been produced on an industrial scale for over 40 years. Carbon dioxide capture plants for urea yield boosting have been installed since the late 1990s.

There are a few examples of large-scale CCS operations associated with ammonia/fertiliser production, as summarised in Table 1.3.

---

[35] (IEA/UNIDO, 2011)
[36] (ZEP, 2013b)
[37] (IEA/UNIDO, 2011)
[38] (Global CCS Institute, 2011)

Table 1.3 CCS applications in ammonia/fertiliser production[39]

PROJECT	LOCATION	START DATE	SCALE	CHARACTERISTICS/APPROACH
Enid Fertilizer	US	1982	0.68 Mtpa	Fraction of high-purity CO_2 stream not needed for urea production used for EOR
Coffeyville	US	2013	1 Mtpa	Petroleum coke feed

The Koch Nitrogen Company facility in Enid, Oklahoma, is one of the largest fertiliser production plants in North America, producing ammonia, liquid fertiliser and urea. Since 1982, Chaparral Energy and Merit Energy have sourced around 680,000 tonnes of CO_2 per year from the Enid Fertiliser plant for EOR purposes. Fertiliser plant upgrades were undertaken in 2011 and an expansion commenced in late 2014, with completion expected in 2017.

The Coffeyville fertiliser project is unique in that it uses solid feed rather than natural gas to produce hydrogen. It is described in the case study below.

CASE STUDY – Coffeyville Gasification Plant

Project Proponents	Chaparral Energy and Coffeyville Resources Nitrogen Fertilizers, LLC
Location	Coffeyville, Kansas, US
Status	Operational
Capacity	1 Mtpa
CO_2 Source	Petroleum coke gasification
Technology	Absorption physical solvent-based process - Selexol

Information

Coffeyville Resources Nitrogen Fertilizers, LLC, owns and operates a nitrogen fertiliser facility in Coffeyville, Kansas, US. The plant began operation in 2000 and is the only one in North America using a fertiliser production process based on petroleum coke instead of the more typical natural gas. The petroleum coke is generated at an oil refinery adjacent to the plant. In March 2011, Chaparral Energy announced a long-term agreement for the purchase of CO_2 from the plant for use in EOR operations at their North Burbank Oil Unit in north-eastern Oklahoma. Chaparral Energy undertook the installation of CO_2 compression and dehydration facilities at the fertiliser plant, the laying of a 112 km CO_2 pipeline to the injection site and the construction of facilities for the injection (and recycling) of CO_2 into the oil field. The compression facility is capable of delivering approximately one Mtpa of CO_2 into the pipeline. Injection of CO_2 into the North Burbank Unit began in June 2013.

1.3.3 Bio-ethanol production

Bio-ethanol is ethanol produced from biomass with high sugar and starch content (e.g. corn, sugar cane). In 2015, global bio-ethanol production was about 97 billion litres. The United States and Brazil are the biggest producers, accounting for about 60 per cent and 25 per cent of global production respectively, followed by Europe (Spain, Germany, Sweden and France), China and Canada.[40] Most of the bio-ethanol produced globally is used as transportation fuel.

Bio-ethanol production is of particular interest for CCS application because it generates a stream of nearly pure CO_2, which is ready for compression and transport after a relatively simple purification step (i.e. water removal). Bio-ethanol production facilities represent “low hanging fruit” for CCS because of the high purity of CO_2 produced by the process. Moreover, since the CO_2 produced is

---

[39] (Global CCS Institute, 2016a)

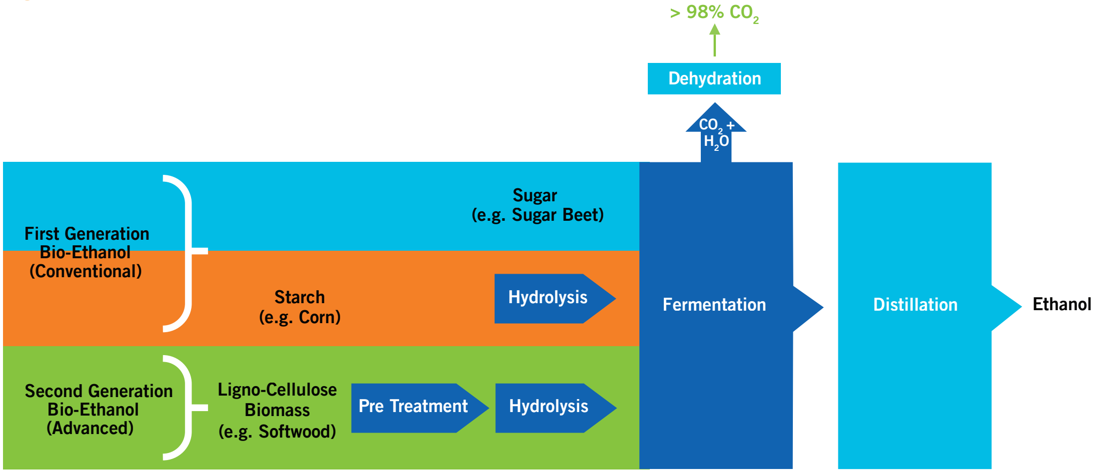
[40] (RFA, 2016)

biogenic in origin, bio-ethanol CCS can result in “negative emission” by permanently storing CO_2 previously removed from the atmosphere by the crops.[41] When CO_2 produced by fermentation is stored underground, a life cycle assessment of the bio-ethanol production process with CCS results in a neutral or slightly negative CO_2 footprint.[42]

Overview of the bio-ethanol production process

Bio-ethanol can be made from a wide range of biomass types, as noted in Figure 1.11. When sugar-based feedstocks are used, the process starts with crushing and then soaking the crop in water to dissolve sugars. The liquid part, called ‘mash’, is separated from the solid and, with the aid of enzymes, fermentation is initiated converting the sugars into alcohol and CO_2 by-product. The liquid fraction is then distilled to produce ethanol.

Figure 1.11 **Bio-ethanol production processes**



When starch-based feedstocks are used, after cleaning and milling of the crop, there is an extra step where enzyme amylases are used to convert the starches into fermentable sugars. From this point on, the process is similar to that for high-sugar crops.

Ligno-cellulosic biomass types like grass and woody crops can also be used as feedstock, although this requires a different technology - biomass pre-treatment to convert cellulose and hemicellulose into sugars - which are then fermented similarly to the conventional process. Fuel produced using this process is classified as 2nd generation bio-ethanol (also called “advanced biofuel”).

The fermentation step produces off-gases with high CO_2 concentration. For each tonne of bio-ethanol produced, about 0.7 tonne of almost pure CO_2 is emitted from the fermentation process. The CO_2 concentration in fermentation off-gases is about 98.8-99.6 per cent on a dry basis. When leaving the fermenter the gases have a temperature of about 25-50°C and atmospheric pressure. After water removal, the gas does not require further treatment and can be sent for compression and transport.[43]

Bio-ethanol production facilities sometimes include a combined heat and power (CHP) unit to help drive the process, resulting in additional CO_2 emissions. Natural gas is the most common fuel for these CHP units, but when sugar cane is used as the bio-ethanol production process feedstock, the woody fibers remaining after sugar extraction are usually used as fuel. The CO_2 concentration in CHP unit flue gas is considerably lower than that of the fermentation off-gases, but the total volume is similar. Capturing the CO_2 emitted by the CHP, together with that generated in the fermenter, would result in a negative carbon cycle,[44] although it would require an additional CO_2 separation process.

---

[41] Only a portion of the carbon contained in the feedstock ends up in the CO_2 stream, while the rest remains in the ethanol and in the by-products.

[42] (Bonijoly, et al., 2009)

[43] (IEAGHG, 2011)

[44] (Bonijoly, et al., 2009)

Summary of CO_2 capture activity in bio-ethanol production

Table 1.4 shows bio-ethanol production facilities worldwide where CO_2 is captured for further use or geological storage. In addition to the operational projects, the table also showcases projects in development planning at different scales ranging from 0.02 to 0.2 Mtpa CO_2 capture.[45]

Table 1.4 **CCS applications in bio-ethanol production**[46]

PROJECT	LOCATION	START DATE	SCALE	CHARACTERISTICS/APPROACH
Arkalon	US	2009	0.31 Mtpa	EOR, Texas
Bonanza	US	2011	0.16 Mtpa	EOR, Kansas
Rotterdam	Netherlands	2012	0.3 Mtpa	CO_2 supplied to greenhouses
Illinois Industrial Project	US	2017	1 Mtpa	Geological storage
Lantmännen Agroetanol	Sweden	Planned	0.17 Mtpa	Storage to be clarified
CPER Artenay	France	Planned	0.2 Mtpa	Storage to be clarified
Sao Paulo	Brazil	Planned	0.02 Mtpa	Storage to be clarified

CASE STUDY – Illinois Industrial CCS Project

Project Proponent	Archer Daniels Midland (ADM) Company
Location	Decatur, Illinois, US
Status	Construction completed, operations to begin in early 2017
Capacity	1 Mtpa
CO_2 Source	Bio-ethanol plant (fermenter)
Technology	Direct separation

Information

The ADM-owned corn-to-ethanol plant in Decatur, Illinois, was commissioned in 1978 and is one of the largest in the United States, with a production capacity of around 1,325 million litres per year. At capacity, the fermentation process produces over one Mtpa of CO_2. In the Illinois Industrial CCS Project, CO_2 collected at the Decatur plant is sent to a dehydration / compression facility near the northern border of the ADM plant, from where a short length pipeline will transfer the CO_2 for injection into the Mount Simon sandstone. The project is expected to be operational in early 2017.

1.3.4 Cement Production

Global CO_2 emissions associated with cement production are at around 2 Gt - about 6-7 per cent of global energy-related CO_2 emissions.[47] Cement sector roadmaps note that CCS is an essential technology to reach 2050 emission reduction targets.[48,49] While other decarbonisation measures are possible (e.g. bio-fuels, energy savings, new cement blends) they have a limited potential and have already been widely applied.[50] New cement production concepts with a lower CO_2 footprint are under development and have yet to be proven commercially.

---

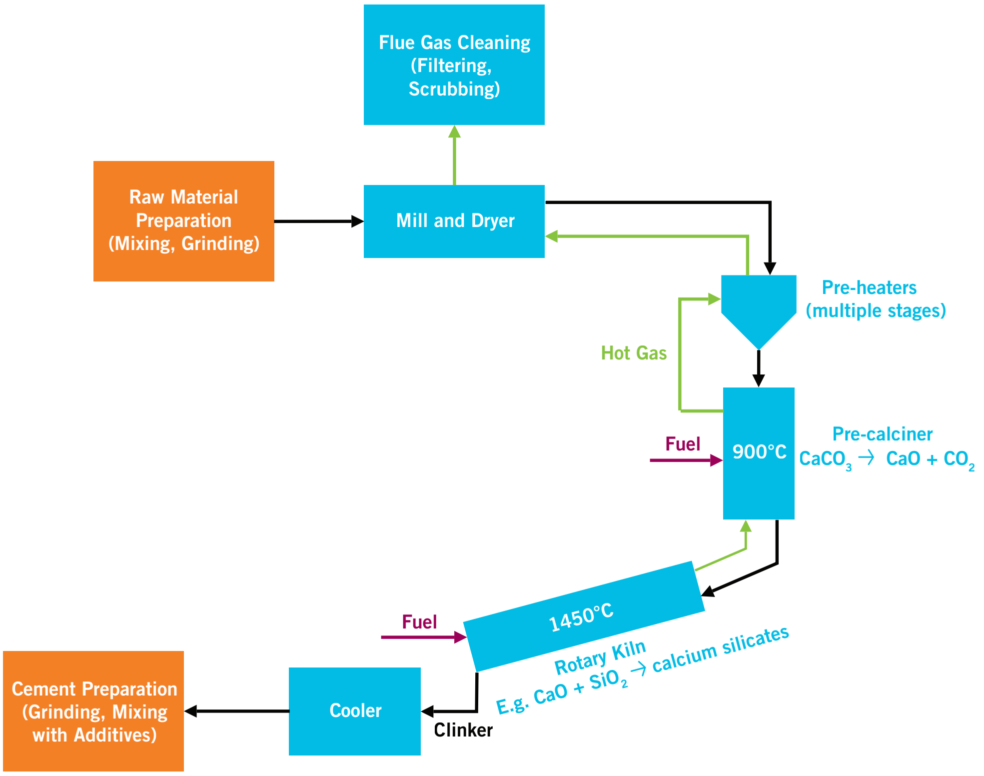
[45] (Kemper, 2015)
[46] (Global CCS Institute, 2016a)
[47] (IEA, 2014a)
[48] (IEA/WBCSD, 2010)
[49] (IEA/UNIDO, 2011)
[50] (ECRA, 2012)

Overview of the cement production process

Cement production consists of three major process steps: (1) raw material preparation, (2) clinker making, and (3) cement making. A process scheme is presented in Figure 1.12. Clinker making represents the most energy intensive part of the whole process. In the pre-calciner the raw material is heated above 900°C and limestone ($CaCO_3$) is converted into calcium oxide (CaO), releasing CO_2. Subsequently, the solids are further heated up to ~1,450°C in the rotary kiln to complete calcination and start clinkerisation - the agglomeration of the calcium oxides with silica, alumina and ferrous oxide. From the clinker, different cement types are created by adding specific components (e.g., gypsum for Portland cement).

Specific emissions associated with the production of 1 tonne of cement are in the range of 0.65 to 0.95 tonne of CO_2 depending on the fuel used and the process characteristics.[51] CO_2 is generated in two ways: about 62 per cent is released by the calcination reaction with the reminder produced by fuel combustion.[52] The CO_2 produced by calcination mixes with the hot flue gas flowing through the kiln and the pre-calciner, therefore all the CO_2 generated from both sources is emitted with the flue gas. Typical CO_2 concentrations in the flue gas range from 14 per cent to 33 per cent,[53] and the temperature is around 100°C.[54]

Figure 1.12 CO_2 sources in a cement production process



Summary of CO_2 capture activity in cement production

The discussion below provides information regarding work to date on CO_2 capture in the cement production sector, with a summary shown in Table 1.5.

---

[51] (Rootzen, 2015)
[52] (EC JRC, 2013)
[53] (Worrel, et al., 2001)
[54] (IEAGHG, 2008)

Chemical absorption

Chemical solvent based absorption is one option for separating CO_2 from gases associated with cement production. However, contaminants present in the gas stream can accelerate degradation of the solvents. Tests conducted at Norcem's Brevik cement factory in Norway as part of the SOLVit R&D program[55] have demonstrated that with flue gas pre-cleaning, a solvent scrubbing unit can operate without major solvent degradation issues.[56] In some cases, the heat required by the solvent-scrubbing unit for regeneration can be supplied completely or partially using waste heat available at the cement plant. Preliminary estimates carried out for the Brevik cement plant showed that by only using waste heat it is possible to capture around 400,000 tonnes of CO_2 per annum without additional heat sources (corresponding to about half the total plant CO_2 emissions).[57]

Oxy-combustion

In an oxy-fired cement production process, the fuel required to generate reaction heat is burned in a mixture of pure oxygen and recirculated flue gas instead of air. As a consequence, the flue gas produced by the process is composed primarily of water and CO_2. After purification and water removal, the CO_2 is ready for transport without further separation steps. Despite initial concerns regarding air in-leakage and process challenges that suggested oxy-combustion would be most applicable to new-build systems, the European Cement Research Academy (ECRA) has indicated that retrofit applications are feasible from a technical perspective.[58] In addition, the CEMCAP project will be testing oxy-combustion approaches for the burner, calciner and clinker cooler in the period 2016-2018.[59]

Calcium looping

Calcium looping (CaL) is a CO_2 capture process based on an adsorption/desorption cycle that uses calcium as a reactant. Flue gas is contacted with solid CaO in the fluidised-bed reactor where CO_2 forms calcium carbonate. The calcium carbonate is then passed to a desorber where it is regenerated at high temperature and releases CO_2. The availability of calcium carbonate at a cement plant makes this technology particularly suitable. However, given the high temperatures involved, a calcium looping retrofit would require a high level of process integration to optimise energy use.[60] Therefore this technology is more suitable for a new build operation where an integrated process design is easier to implement, and could lead to reduced cost and energy savings. A small calcium looping pilot plant developed by the Industrial Technology Research Institute (ITRI) has been tested and successfully operated in Taiwan, as described in the case study below.[61]

Direct separation

The working mechanism of direct separation technology is the indirect heating of limestone in a special steel vessel. This concept re-engineers the process flows of a traditional calciner to allow CO_2 capture without further separation. In fact, as a result of indirect heating, the CO_2 released in the pre-calciner during limestone conversion – about 60 per cent of total plant emissions – does not mix with the flue gases produced by the process and can be removed separately. The Low Emissions Intensity Lime and Cement (LEILAC) consortium will test Calix's flash calcination process between 2016 and 2020 at the Heidelberg Cement plant in Lixhe, Belgium, at a feed rate capacity of 200 tonnes ground limestone per day.[62]

---

[55] (SOLVit, 2016)
[56] (Graff, 2016)
[57] (Bjerge & Brevik, 2014)
[58] (ECRA, 2012)
[59] (Jordal, 2016)
[60] (Rodriguez, et al., 2012)
[61] (ITRI, 2014)
[62] (Global CCS Institute, 2016a)

Solid sorbents

This technology is based on an adsorption/desorption cycle using a solid sorbent. RTI International is currently testing their polyethylenimine (PEI) solid sorbent in a pilot plant at the Brevik Cement Factory. The testing is part of a two stage project, following a previous campaign where the sorbent stability and performance were demonstrated in a fixed-bed laboratory-scale reactor.[63]

Membranes

Fixed Site Carrier (FSC) membranes for CO_2 capture in cement production are being tested at the Brevik cement factory in a small pilot unit. The unit includes pre-conditioning equipment (purification, cooling) and a hollow fibre membrane module ($10m^2$). Pilot operation is expected to run until February 2017. This test campaign follows a previous campaign conducted in 2014 at the same site, where FSC membranes were tested using a similar rig, with a flat sheet ($2m^2$) membrane module.[64]

Table 1.5 CCS applications in the cement sector[65]

PROJECT	LOCATION	START DATE	SCALE	CHARACTERISTICS/APPROACH
ECRA studies	EU	2007	Desktop study	Screening CO_2 capture technologies for cement plants
ITRI pilot	Taiwan	2013	1 t/h	CaL pilot
Norcem (Brevik) tests	Norway	2014 (ongoing)	Multiple tests	Pilot tests (amine, membranes, solid sorbents)
CEMCAP	EU	2015 (ongoing)	Multiple tests	Oxy-fuel (burner, calciner, clinker cooler), chilled ammonia, membranes and CaL tests
LEILAC	Belgium	2017	~80 tpd	Direct separation pilot

CASE STUDY – ITRI Calcium Looping Project

Project Proponents	Industrial Technology Research Institute (ITRI), Taiwan Cement Company (TCC)
Location	TCC's cement factory in Hualien County
Status	Operational since June 2013
Capacity	One tonne of CO_2 per hour (1.9 MWth equivalent)
CO_2 Source	3.1 tonne per hour flue gas stream (20-25% CO_2)
Technology	Calcium Looping (Post-combustion capture)

Information

The Industrial Technology Research Institute (ITRI) in cooperation with the Taiwan Cement Company (TCC) have installed a calcium looping test facility at TCC's cement plant in Hualien, Taiwan. This is the largest test facility worldwide for this technology, with a capacity to capture around 1 tonne per hour of CO_2 from a slip stream of 3.1 tonnes per hour of flue gas produced by the cement plant, which has a content of 20-30 per cent in CO_2 and a temperature around 70°C. The process includes a fluidised bed carbonator where CO_2 is adsorbed by Calcium Oxide (CaO) to form Calcium Carbonate (600-700 °C). $CaCO_3$ is then routed to the rotary kiln calciner where the opposite reaction takes place to release CO_2 by heating up the solid (850-950°C). An oxy-fuel burner (with CO_2 recirculation) is used in the calciner in order to provide heat and produce a near pure stream of CO_2. The regenerated sorbent is then transported to the carbonator for a new adsorption cycle. The facility has a capture rate of around 85 per cent and requires a make-up of limestone of approximately 0.2 tonnes per hour. ITRI is now testing the third generation CaL technology at its new 500kW pilot including steam hydration and cascade cyclones at the same location.

---

[63] (RTI International, 2015)
[64] (Hägg & Nodeland, 2016)
[65] (Global CCS Institute, 2016a)

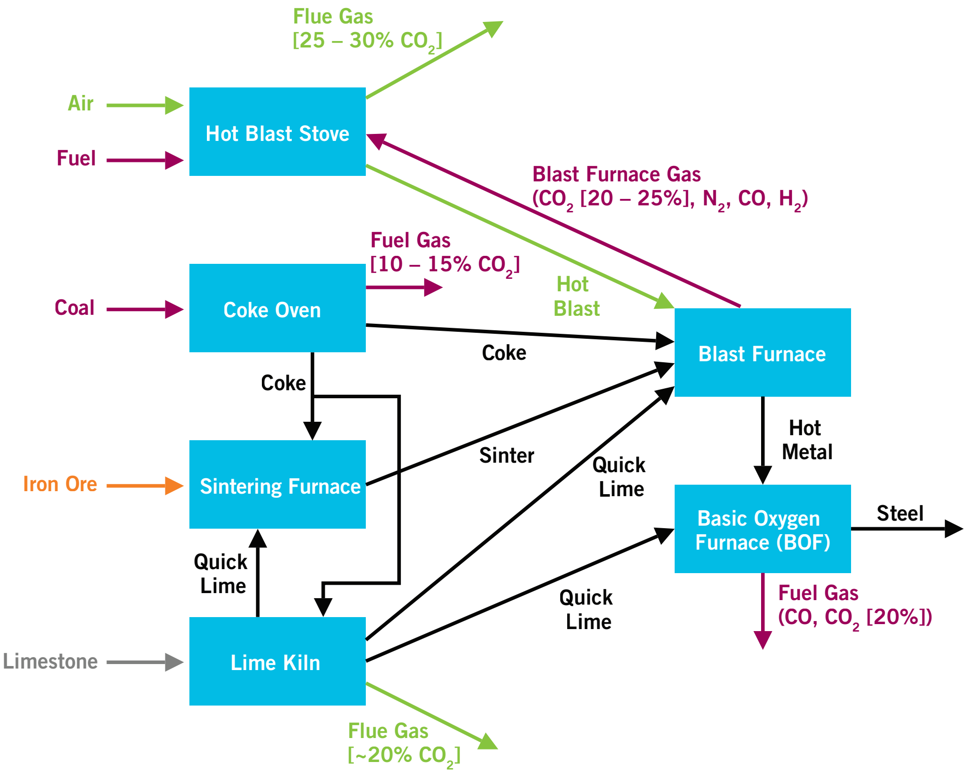
1.3.5 Iron and steel production

The iron and steel industry provides essential structural materials for economic development. Iron and steel making processes are energy and carbon intensive as a result of process/product heating, electricity requirements and the use of carbon as the main reductant for iron ore at high temperature. Carbon dioxide emissions from iron and steel production are estimated at near 3 Gt - approximately 9 per cent of global energy-related CO_2 emissions.[66] Steel production facilities typically have multiple CO_2 emission points due to the layout of the different processes. Some emissions are direct (e.g. combustion of coal or natural gas, CO_2 produced as a result of the reducing reactions converting iron oxides to iron), and others are indirect (electricity, steam, limestone supply). The steel industry has been working on energy efficiency, product recycling and other initiatives to reduce CO_2 emissions. However, the IEA has indicated that application of CCS is currently the only way for the industry to achieve emission reductions of more than 50 per cent.[67]

Overview of the steel production process

The most common method for producing steel from iron ore is called the Blast Furnace – Basic Oxygen Furnace (BF-BOF) process, which represents about 70 per cent of global steel production.[68] In a facility employing this process, iron ore, coal/coke, hot blast air and lime are fed into a Blast Furnace (BF) in layers where the carbon in the coke chemically reduces iron ore to elemental iron, producing hot metal called pig iron. The iron is then transferred into the Basic Oxygen Furnace (BOF) where pure oxygen is blown into the molten pig iron, to remove carbon and remaining impurities by oxidation, completing the conversion from iron into steel (Figure 1.13).

Figure 1.13 Iron and steel production process



---

[66] (IEA, 2014a)
[67] (IEA, 2013c)
[68] (World Steel Association, 2016)

Lime is usually purchased directly from a nearby lime kiln where limestone ($CaCO_3$) is split into CaO, releasing flue gas with a high concentration of CO_2. Coke production occurs on-site in the coke oven, generating an exhaust gas with a relatively high calorific value, which is reused as fuel in various parts of the plant (mainly in the coke oven itself). In the hot blast stove, cold air is indirectly heated - before entering the blast furnace - by combusting coke oven gas, blast furnace gas or natural gas. The blast furnace produces a large volume of exhaust gas with low calorific value, which typically is combusted in the coke oven or in the hot blast furnace.

The BF-BOF process produces about 2.3 tonnes of CO_2 per tonne of crude steel for all direct and indirect emissions. The principal CO_2 sources in the process include:

- Blast furnace (CO_2 contained in exhaust gas reused as fuel within the plant – the largest source of CO_2 in the process)
- Coke oven (CO_2 contained in exhaust gas reused as fuel within the plant)
- Lime kiln (CO_2 directly emitted with flue gas)
- Hot blast stoves (CO_2 directly emitted with flue gas)
- Basic oxygen furnace (CO_2 contained in exhaust gas reused as fuel within the plant)
- Electricity, steam and limestone use (indirect CO_2 emission)
- Co-generation plant fueled by the remaining combustible gas (principally CO) from all of the above processes

The exhaust gas emitted by the blast furnace contains up to 60 per cent of the total volume of CO_2 produced by the plant mixed with hydrogen and carbon monoxide; the direct capture of CO_2 from this stream would be similar to separation associated with hydrogen production processes. However, most steel plants combust the blast furnace gas (BFG), and the CO_2 is emitted with the flue gases. Under these circumstances, the most likely capture approach using currently available technologies would be chemical solvent based capture. The temperatures, pressures, and concentrations of major CO_2-containing gases are noted in Table 1.6. Given the higher CO_2 concentrations associated with some of these sources, separation using physical absorbents and adsorbents could be advantageous. The gases that are combustible are usually combined in a collection system and combusted in a co-generation plant, producing up to 70 per cent of the electricity needed for a facility.

Table 1.6 **Characteristics of high concentration CO_2 emissions in an iron and steel plant**[69]

LOCATION	TEMPERATURE, °C	PRESSURE	CO_2 CONCENTRATION, V/V
Lime kiln	~110	Ambient	~19.3%
Hot blast stove	~258	Ambient	~28.5%
Coke oven	~210	Ambient	~11.0%
Blast furnace gas[70]	~100-350	2-3 bar	~20%
BOF gas	~1,200[71]	Ambient	~10-15%

Iron ore can also be converted to steel through the Direct Reduced Iron (DRI) process by directly reducing iron ore with reducing gas (e.g. H_2 and CO - commonly produced by reforming natural gas). The metal generated in this process needs to be re-melted and further reduced in an Electric Arc Furnace (EAF). The DRI process uses 20 per cent more energy overall than the BF-BOF process, but has 20 per cent lower CO_2 emissions, resulting from the use of natural gas rather than coke. However, it is only applied in regions where there is abundant natural gas, such as the US and the Middle East.

---

[69] (Global CCS Institute, 2015)

[70] (JCoal, 2012)

[71] (Ernest Orlando Lawrence Berkeley National Laboratory, 2010)

Steel can also be produced by recycling scrap and melting it in an EAF; 29 per cent of global steel production is achieved using secondary materials via the EAF route. The carbon intensity of this process is about 1.1 tonne of CO_2 per tonne crude steel.[72] In developed countries, the proportion of EAF steel production is higher because more scrap feedstock material is available from mature markets and rebuilding of infrastructure.

Summary of CO_2 capture activity in iron and steel production

There has been substantial work (both pilot and large-scale) on carbon capture in the iron and steel sector around the world as listed in Table 1.7. Ultra-Low CO_2 Steel-making (ULCOS) was one of the first projects that looked into options for CCS at steel plants; the project originally included a planned large-scale demonstration CO_2 capture plant which was not pursued (though continued as a research project).

Nippon Steel (within the COURSE 50 consortium), China Steel Corporation, Baosteel and POSCO conducted pilot experiments to capture CO_2 from blast furnaces using chemical solvents. Toshiba conducted a feasibility study for a Chinese steel plant and identified the cost-effective emission sources for carbon capture: the hot blast stove and lime kiln.[73]

The Abu Dhabi CCS Project in the United Arab Emirates (UAE) is the world's first large-scale CCS project in the steel industry. It uses amine-based chemical solvent technology to capture CO_2 in a DRI process.

The STEPWISE project is building a small pilot capture unit at the Swerea/Mefos facility in Sweden to evaluate the use of Sorption Enhanced Water-Gas Shift (SEWGS) technology on blast furnace gases. SEWGS combines solid sorbent (hydrotalcite) based CO_2 capture with the water gas shift reaction in a single reactor. Although the technology was originally developed for gasification-based capture systems, application on blast furnace gases represents an alternative and interesting approach. Testing is expected to start in 2017.

Table 1.7 **CCS applications in the iron and steel sector**[74]

PROJECT	LOCATION	START DATE	CAPTURE CAPACITY	CHARACTERISTICS/APPROACH
ULCOS	EU	2009	Desk study	Screening of CO_2 capture technologies for steel plants
COURSE 50	Japan	2011	30 tpd	Chemical absorption based capture from blast furnace gas
POSCO	Korea	2012	10 tpd	Ammonia-base capture from blast furnace gas
Shougang Jingtang Iron and Steel	China	2014	Feasibility Study	300 tpd chemical absorption pilot, from hot blast stove and lime kiln flue gas
Abu Dhabi CCS Project	UAE	2016	0.8 Mtpa	Solvent-based capture in Direct Reduced Iron unit
STEPWISE	Sweden	2017	14 tpd	Sorption Enhanced Water-Gas Shift (SEWGS) pilot for blast furnace gas

---

[72] (Ganglian, 2016)
[73] (Toshiba, 2015)
[74] (Global CCS Institute, 2016a)

CASE STUDY – Abu Dhabi CCS Project

Project Proponents	Abu Dhabi National Oil Company (ADNOC), Masdar (Abu Dhabi Future Energy Company)
Location	Abu Dhabi, UAE
Status	Project launched in November 2016
Capacity	0.8 Mtpa
CO_2 Source	Emirates Steel plant
Technology	Amine solvent-based capture

Information

The Abu Dhabi CCS Project involves the capture of CO_2 from the Emirates Steel factory in Abu Dhabi and its transportation to the ADNOC reservoirs for EOR purposes. The DRI process employed at Emirates Steel produces a pure stream of CO_2 (greater than 98 per cent) which is currently vented to the atmosphere. The CO_2 will be captured using an amine based chemical absorption system. The CO_2 capture rate from the DRI process is greater than 90 per cent. The project scope includes design and construction of a green field CO_2 Compression Facility (CCF) including dehydration, to be located adjacent to the steel plant in Mussafah, Abu Dhabi. Carbon dioxide will be transferred at low pressure to the CCF where it is dehydrated, compressed to 235 bar(g) (via an Integrally Geared LP Compression followed by Reciprocating HP Compression), metered and transported to the EOR injection site via pipeline.

1.3.6 Petroleum refining

Petroleum refining is a broad term that includes many distinct processes. Carbon dioxide is emitted from various sources in an oil refinery. Carbon dioxide emissions per barrel of crude oil processed depends on the quality of the crude oil.[75] Lighter, hydrogen-rich crude oil requires less cracking and less hydrogenation, which result in lower emissions. Carbon dioxide emissions from refining are estimated at around 0.7 Gt.[76] Like other industrial emissions, there are direct emissions of CO_2 (such as flue gas generated by combustion of oil, fuel gas, natural gas) and indirect emissions of CO_2 due to secondary energy usage (such as electricity and steam). Carbon dioxide concentrations of various emission streams vary significantly, from the 99 per cent CO_2 emitted from the ethylene oxidation process to the low CO_2 concentration stream emitted from flare gas.

Overview of the petroleum refining process

An oil refinery generally includes crude oil distillation, vacuum distillation, catalytic cracking, catalytic reforming, hydrogenation, coking, and production units. The actual selection of units depends on the type of refinery (fuel type or petrochemical type). Carbon dioxide is generally emitted at several points:

- the fluid catalytic cracking (FCC) unit when catalyst is regenerated by combustion in air
- hydrogen production process
- oil/fuel combustion process for heaters and boilers (typically the largest CO_2 emission sources in refining)
- CHP emissions.

An ethylene plant is often built in the close proximity to an oil refinery due to availability of feedstock, and the oxidation of ethylene for the production of ethylene oxide emits high purity CO_2.

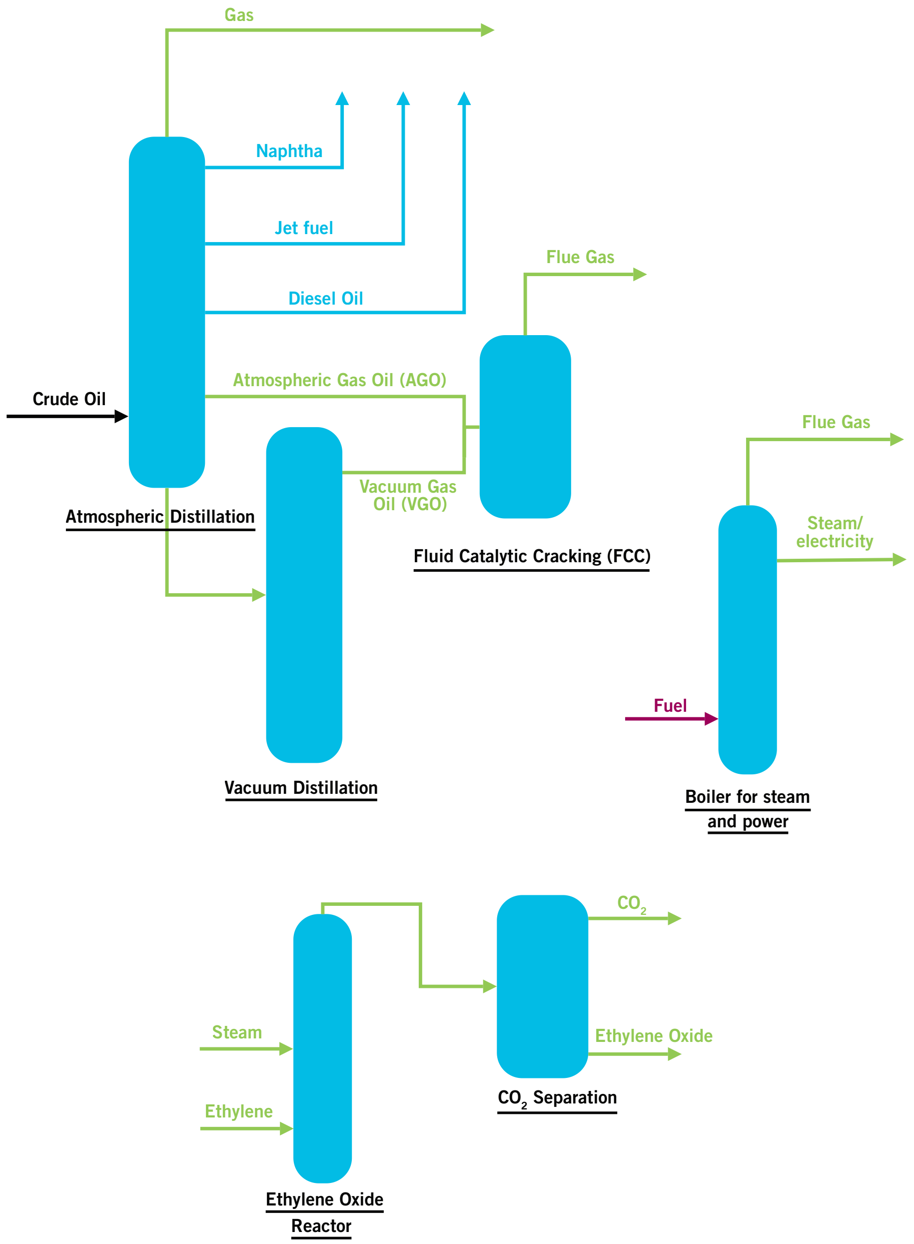
Simplified process flow diagrams for several different processes used in oil refining are shown in Figure 1.14.

---

[75] (Communities for a Better Environment, 2011)

[76] (IEA, 2013c)

Figure 1.14 Typical oil refinery units with major CO_2 emission points



Typical CO_2 emissions from an oil refinery are summarised in Table 1.8.

Table 1.8 Characteristics of CO_2 emissions in an oil refinery[77]

LOCATION	TEMPERATURE, °C	PRESSURE	CONCENTRATION, V/V
FCC catalyst regenerator	>700	Ambient to 2-3 bar	12%
Hydrogen production	20-40	Ambient	30-50%
Fuel gas combustion	>100	Ambient	8-12%
Ethylene oxidation process	~40	Ambient	99%

---

[77] (IEAGHG, 1999)

Summary of CO_2 capture as practised in petroleum refining

There have been many carbon capture efforts at refinery complexes around the world. Several of these have involved hydrogen production and are noted earlier in this section. Projects undertaken involving other processes at oil refineries are listed in Table 1.9. Technology Centre Mongstad (TCM) has two capture units testing amine-based solvents and chilled ammonia technologies. The facility is capable of testing carbon capture processes for flue gas from a catalytic cracker catalyst regenerator and for flue gas from a gas-fired CHP plant. The facility has become an important international carbon capture technology testing platform.[78] Another milestone project for FCC flue gas carbon capture is the Sinopec Zhongyuan Oilfield Project. This project is a 120,000 tonnes per annum full-chain CCS project. Flue gas from a catalyst regenerator goes through NOx, particulate, and SOx removal, and then enters the carbon capture unit. The capture unit uses amine-based solvent technology. This project is the largest of its kind to date.

Table 1.9 **CCS applications associated with oil refining (non-hydrogen production)**[79]

PROJECT	LOCATION	START DATE	SCALE	CHARACTERISTICS/APPROACH
Sinopec Zhongyuan Oil Field	China	2006	360 tpd	Solvent-based capture from FCC flue gas
CO_2 Capture Project (CCP)	Brazil	2011	<1 tpd	Oxy-firing trials on FCC
Technology Centre Mongstad	Norway	2012	240 tpd	Solvent-based capture from FCC flue gas

CASE STUDY – Sinopec Zhongyuan Carbon Capture Utilisation and Storage Pilot Project

Project Proponents	Sinopec Zhongyuan Oil Field Company
Location	Henan Province, China
Status	Operational
Capacity	0.12 Mtpa
CO_2 Source	Fluidised catalytic cracker catalyst regeneration flue gas
Technology	Amine solvent-based capture

Information

Sinopec Zhongyuan Oil Field Company started CO_2 capture from its oil refinery flue gas in 2006. The initial project was for 20,000 tonnes per year and it has been expanded since. The total capacity for this project is now around 120,000 tonnes per annum. The CO_2 is captured from the fluidised catalytic cracker catalyst regeneration flue gas. It uses an amine-based solvent process to capture CO_2. The flue gas flow rate is around 65,000 Nm^3/hr containing 12 per cent CO_2. The flue gas coming out of the catalyst regeneration unit goes through NOx removal, dust removal, SOx removal units in sequence before it is sent to the carbon capture unit. Captured CO_2 is compressed, cooled and liquefied using ammonia refrigerators. This project is the largest of its kind globally.

---

[78] Global CCS Institute, 2015b)

[79] (Global CCS Institute, 2016a)

1.3.7 Pulp and paper making

The pulp and paper making process is highly energy intensive - energy comprises 16-30 per cent of the total production cost.[80] Total global emissions of CO_2 from the pulp and paper industry are estimated at around 0.2 Gt.[81] This industry uses biomass - a material produced by removing CO_2 from the atmosphere - as its raw material. Certain intermediate products produced from biomass may be used as energy sources. The use of biomass makes it possible that a pulp and paper plant may be carbon neutral or of low emissions if energy is generated from biomass and if high-energy by-products (e.g. black liquor) are appropriately utilised.[82]

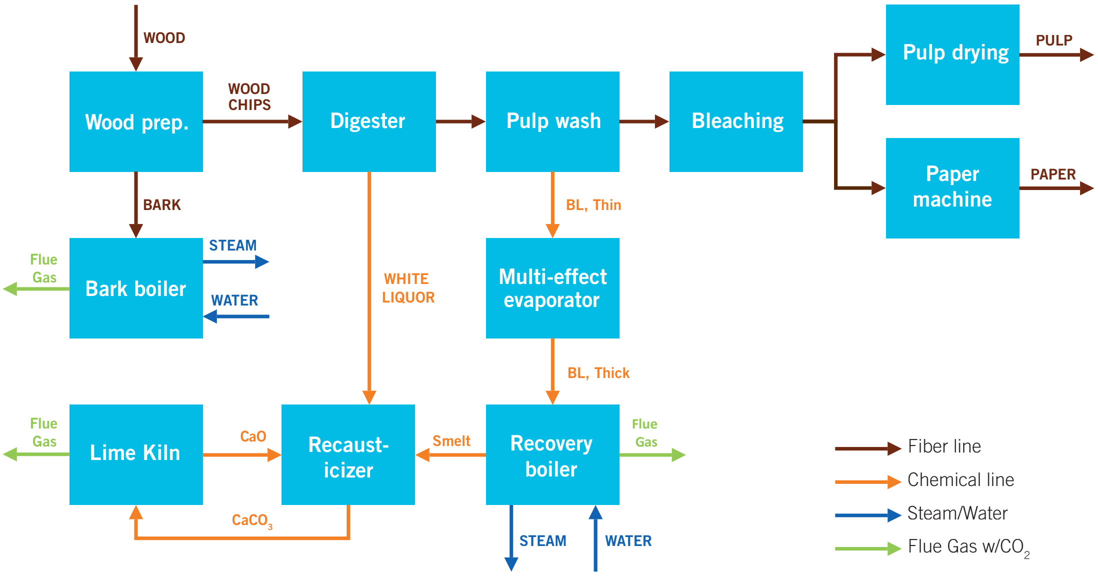
Overview of the pulp and paper making process

Processes with intensive energy use in a pulp and paper plant are:

- Pulping (mechanical, chemical and thermochemical)
- Paper recycling
- Paper production (drying)

Pulping and drying are the major energy users in a pulp and paper plant.[83] The major components of the process are shown in Figure 1.15.

Figure 1.15 Pulp and paper making process and emission points[84]



Production inputs (including wood chips and recycled paper) go through mechanical processing, chemical pulping and other operation units to produce pulp. Chemical pulping also produces black liquor which is generally combusted in a boiler for heat recovery. Such black liquor may be used in a gasification process to produce electricity for the plant and exporting to the grid. Carbon dioxide is also emitted from a lime kiln where calcium carbonate is split into calcium oxide and CO_2.

There are several direct emission sources in a pulp and paper plant as listed Table 1.10.

---

[80] (European Commission, 2012)
[81] (IEA, 2014a)
[82] (IEA, 2006)
[83] (IEA, 2006)
[84] (Grantham Institute, 2014)

Table 1.10 Characteristics of CO_2 emissions in a pulp and paper plant

LOCATION	TEMPERATURE, °C	PRESSURE	CONCENTRATION, V/V
Lime kiln	>120	Ambient	>15% (estimated)
Black liquor boiler	High	Ambient	8-12% (estimated)
Bark boiler	High	Ambient	8-12% (estimated)

Summary of CO_2 capture activity in pulp and paper making

There are a limited number of CCS studies/projects in the paper and pulp industry, as shown in Table 1.11. A feasibility study was conducted to study the business model and system design for the Boise White Paper Mill in Washington State.[85] The business model is based upon installation of a bio-mass boiler to generate power and steam while earning credits for storing CO_2. Flexible operation of the capture plant is another important aspect of the business model. The Quebec Pulp Mill CO_2 Utilisation Project under development would use enzyme-based solvent technology to capture CO_2 from a pulp and paper plant. It would have a capture capacity of 30 tonnes per day, and the captured CO_2 would be transported to a nearby greenhouse development for reuse.

Table 1.11 CCS applications in the pulp and paper industry[86]

PROJECT	LOCATION	START DATE	SCALE	CHARACTERISTICS/APPROACH
Piteå Black Liquor Gasification	Sweden	2005	Desktop	Analysis evaluating development of a 60 tpd, physical solvent-based capture system
Boise White Paper Mill Case Study	USA	2006	Desktop	Study for 1 Mtpa facility using solvent-based capture
Quebec Pulp Mill Utilisation Project	Canada	Planning	30 tpd	CO_2 reused in a nearby greenhouse development

CASE STUDY – Quebec Pulp Mill CO_2 Utilisation Project

Project Proponents	CO_2 Solutions, Resolute Forest Products, Serres Toundra
Location	Quebec, Canada
Status	Under development (awaiting financial close)
Capacity	30 tonnes per day
CO_2 Source	Pulp and paper
Technology	Enzyme-based solvent process

Information

This is a milestone project for applying carbon capture technology in a pulp and paper plant. There are few actual pilot CCS projects in the pulp and paper industry. This project brings together a capture technology provider, a pulp and paper plant, and a CO_2 user. The project captures CO_2 from a pulp mill using an innovative enzyme-based solvent technology. The captured CO_2 would be utilised in a nearby greenhouse development to increase vegetable yields. This project would confirm the technical feasibility of applying carbon capture technology to a pulp and paper mill.

---

[85] (McGrail, et al., 2012)

[86] (Global CCS Institute, 2016a)

1.4

IMPLICATIONS

The brief overviews provided regarding carbon capture activities in different industrial sectors point out both the promise and challenges of industrial capture. There are three basic categories that industrial capture applications can be segregated into:

1. Sectors or processes in which production/separation of CO_2 is an inherent component of normal business operations (e.g. natural gas processing, bio-ethanol production, ammonia production)
2. Sectors in which relevant volumes of CO_2 are present in process gas streams at concentrations high enough to allow for relatively inexpensive separation and subsequent sale (e.g. hydrogen production in oil refining applications)
3. Sectors that generate substantial volumes of CO_2 that will need to be mitigated in order to achieve global climate targets, but that currently do not have large-scale capture projects due to either (or a combination of) lack of regulatory requirements, high capture costs, global competitive pressures, and inadequate incentives (e.g. iron and steel production, cement production, petroleum refining, and pulp and paper production)

While for the first two categories CO_2 capture is relatively mature, and many commercial technologies have been proven at scale, for the third category CO_2 capture is more challenging. Lower concentrations of CO_2 in the gas streams of these sectors necessitate the use of capture approaches that are more energy intensive and thus more expensive. In addition, the existence of multiple emission points complicates the capture process and adds operational challenges and expense.

Implementation of CO_2 capture in these sectors would represent an innovative application of existing technologies or would require the development and scale-up of a new technology. In either case, the technical and financial risk would be significantly greater than applications in either of the first two industrial categories. Nonetheless, significant progress is being made on capture approaches applicable to lower-concentration gas streams, via continuing research and development and pilot scale testing of multiple technologies, such as the ITRI and LEILAC pilot-scale testing being done in the cement industry.

It is important to note that for the existing large-scale industrial CCS applications, all were implemented based on a business case that made economic sense. The specific drivers were varied and ranged from regulatory requirements (e.g. the price on carbon established in Norway that contributed to the development of the offshore Sleipner and Snøhvit CO_2 Storage Projects), to direct government incentives (e.g. Quest and Air Products at Port Arthur), to the ability to sell CO_2 as a commodity (e.g. for EOR) and achieve incidental storage. In some cases, several of these factors worked in concert to incentivise development of the project. This, of course, depends very much on local conditions. However, for all existing applications, lower-cost capture from high concentration (high partial pressure) gas streams was an important economic factor.

There are a number of operating industrial plants with CO_2 capture capacity of one million tonnes per annum or greater, mainly in natural gas processing and fertiliser and hydrogen production. Across the full spectrum of industrial emission sources, there will be many individual facilities where the volume of CO_2 to be captured will be at smaller levels. As stand-alone developments, this can result in high costs for accessing transport and storage infrastructure. However, many emissions-intensive industries are located in tight geographical clusters. Development of strategically-sized, shared transport and storage infrastructure can facilitate the efficient aggregation of smaller volumes of CO_2 from industrial sources.

LIST OF FIGURES AND TABLES

REFERENCES

Berger, A. & Bhown, A., 2014. *Selection of optimal solid sorbents for CO_2 capture based on gas phase CO_2 composition,* Palo Alto, California: Electric Power Research Institute.

Bjerge, L. & Brevik, P., 2014. CO_2 Capture in the Cement Industry, Norcem CO_2 Capture Project (Norway). *Energy Procedia,* 63(2014), pp. 6455-6463.

Bolland, O., 2010. CO_2 capture overview. Svalbard, Norway, IEAGHG CCS Summer School.

Bonijoly, D. et al., 2009. Technical and economic feasibility of the capture and geological storage of CO_2 from a bio-fuel distillery: CPER Artenay project. *Energy Procedia,* 1(2009), pp. 3927-3934.

Bradbury, J., Clement, Z. & Down, A., 2015. *Greenhouse Gas Emissions and Fuel Use within the Natural Gas Supply Chain – Sankey Diagram Methodology,* Washington, DC: U.S. Department of Energy, Office of Energy Policy and Systems Analysis.

Chemguide, 2012. *Intermolecular bonding - van der Waals forces.*
ONLINE ▶ Available at: http://www.chemguide.co.uk/atoms/bonding/vdw.html
[Accessed September 2016].

Collodi, G., 2011. *Hydrogen Production via Steam Reforming with CO_2 Capture,* Milan: Foster Wheeler.

Communities for a Better Environment, 2011. *Oil Refinery CO_2 Performance Measureme*nt.
ONLINE ▶ Available at: http://www.ucsusa.org/sites/default/files/legacy/assets/documents/global_warming/oil-refinery-CO2-performance.pdf

Croft Production Systems, 2014. *How do you process natural gas?.*
ONLINE ▶ Available at: https://www.croftsystems.net/oil-gas-blog/how-do-you-process-natural-gas
[Accessed August 2016].

EC JRC, 2013. *Best Available Techniques (BAT) reference document for the production of cement, lime and magnesium oxide.,* Brussels, BE: Joint Research Centre of the European Commission (Report EUR 26129 EN).

ECRA, 2012. *ECRA CCS Project - Report on Phase III (TR-ECRA-119/2012),* Dusseldorf, GE: European Cement Research Association.

EIA, 2006. *Natural gas processing: the crucial link between natural gas production and its transportation to market,* Washington, DC: Energy Information Administration, Office of Oil and Gas.

Ernest Orlando Lawrence Berkeley National Laboratory, 2010. *Energy Efficiency Improvement and Cost Saving Opportunities for the U.S. Iron and Steel Industry,* Berkeley, California: LBNL-Report .

European Commission, 2012. *Energy Efficiency and CO_2 Reduction in the Pulp and Paper Industry,* Brussels: European Commission.

ExxonMobil, 2016. *Controlled Freeze Zone™ (CFZ) technology.*
ONLINE ▶ Available at: http://corporate.exxonmobil.com/en/technology/carbon-capture-and-sequestration/controlled-freeze-zone/controlled-freeze-zone-technology
[Accessed August 2016].

Ganglian, 2016. *Shougang's Six CO_2 Reduction Approaches.*
ONLINE ▶ Available at: http://info.glinfo.com/13/0618/09/8FCBC8CA2171ADF9.html
[Accessed 16 August 2016].

Global CCS Institute, 2011. *Accelerating the uptake of CCS: industrial use of captured carbon dioxide,* Melbourne: Global CCS Institute.

Global CCS Institute, 2015. *Applying Carbon Capture and Storage to a Chinese Steel Plant,* Melbourne: Global CCS Institute.

Global CCS Institute, 2015. *Technology Centre Mongstad (TCM).*
ONLINE ▶ Available at: http://www.globalccsinstitute.com/sites/www.globalccsinstitute.com/files/content/page/122975/files/Technology%20Centre%20Mongstad%20%28TCM%29.pdf

Global CCS Institute, 2016a. *Global CCS Institute: Projects.*
ONLINE ▶ Available at: http://www.globalccsinstitute.com/projects/
[Accessed Oct 2016].

Global CCS Institute, 2016b. *Water use in thermal power plants equipped with CO_2 capture systems,* Melbourne: Global CCS Institute.

Graff, O., 2016. *Status CCS & EOR - business opportunities.* Bergen, Gassnova.

Grantham Institute, 2014. *A Systematic Review of Current Technology and Cost for Industrial Carbon Capture.*
ONLINE ▶ Available at: https://www.imperial.ac.uk/media/imperial-college/grantham-institute/public/publications/institute-reports-and-analytical-notes/A-Systematic-Review-of-Industrial-CCS----GR7.pdf
[Accessed 07 August 2016].

Hägg, M.-B. & Nodeland, S. G., 2016. *MemCCC-Membrane Based CO_2 Capture,* Oslo: CLIMIT.

IEA/UNIDO, 2011. *Technology Roadmap – Carbon Capture and Storage in Industrial Applications,* Paris: International Energy Agency .

IEA/WBCSD, 2010. *Cement Technology Roadmap 2009 – Carbon emissions reductions up to 2050,* Paris: International Energy Agency / World Business Council for Sustainable Development.

IEA, 2006. *Energy Use, Technologies and CO_2 Emissions in the Pulp and Paper Industry*, Paris: International Energy Agency.

IEA, 2013a. *CCS in industrial applications. A workshop of the CCUS Action Group in preparation for the 4th Clean Energy Ministerial,* Paris: OECD/IEA, http://www.iea.org/media/workshops/2013/ccs/industry/cem_workshopreport.pdf

IEA, 2013b. *Technology Roadmap Carbon Capture and Storage,* Paris: OECD/IEA.

IEA, 2013c. *Global Action to Advance Carbon Capture and Storage: A Focus on Industrial Applications,* Paris: International Energy Agency.

IEA, 2014a. E*nergy Technology Perspectives 2014: Harnessing Electricity's Potential,* Paris: OECD/IEA.

IEA, 2014b. *Insights Series 2014, CCS 2014 What lies in store for CCS?,* Paris: OECD/IEA.

IEA, 2016. *Energy Technology Perspectives 2016: Towards Sustainable Urban Energy Systems,* Paris: OECD/IEA.

IEAGHG, 1999. T*he reduction of greenhouse gas emission from the oil refining and petrochemical industry,* United Kingdom: IEAGHG.

IEAGHG, 2008. *CO_2 capture in the cement industry,* United Kingdom: IEA Greenhouse Gas R&D Program.

IEAGHG, 2011. *Potential for biomass and carbon dioxide capture and storage,* Cheltenham : IEA Environmental Projects ltd. (IEAGHG).

ITRI, 2014. *R&D Achievements on Carbon Capture and Storage in ITRI, Taiwan.*
ONLINE ▶ Available at: http://ccs.tw/sites/default/files/datashare/pdf/2014-10-06-0923-gong_yan_yuan_ccsyan_fa_cheng_guo_ying_wen_.pdf
[Accessed August 2016].

JCoal, 2012. *NSEC's Technologies dealing with CO_2 Emissions for Coal Utilization.*
ONLINE ▶ Available at: http://www.jcoal.or.jp/coaldb/shiryo/material/2012day2_session4_4.pdf
[Accessed 16 August 2016].

Jordal, K., 2016. *CEMCAP - Preparing the grounds for retrofit CO_2 capture from cement plants*. Brussels, Horizon 2020 CCS Projects Clustering Event - https://www.sintef.no/globalassets/sintef-energi/cemcap/cemcap-ccs-clustering-workshop-14-mar-2016.pdf .

Kemper, J., 2015. Biomass and carbon dioxide capture and storage: *A review. International Journal of Greenhouse Gas Control,* 40(2015), pp. 401-430.

McGrail, B. P. et al., 2012. Overcoming business model uncertainty in a carbon dioxide capture and sequestration project: Case study at the Boise White Paper Mill. *International Journal of Greenhouse Gas Control,* Volume 9, pp. 91-102.

Mohammed, I., Samah, M., Mohamed, A. & Sabina, G., 2014. Comparison of SelexolTM and Rectisol® Technologies in an Integrated Gasification Combined Cycle (IGCC) Plant for Clean E nergy Production. *International Journal of Engineering Research,* 3(12), pp. 742-744.

Naturalgas.org, 2013. *Processing Natural Gas.*
ONLINE ▶ Available at: http://naturalgas.org/naturalgas/processing-ng/
[Accessed July 2016].

RFA, 2016. *Renewable Fuels Association - World Fuel Ethanol Production.*
ONLINE ▶ Available at: http://www.ethanolrfa.org/resources/industry/statistics/#1454098996479-8715d404-e546
[Accessed August 2016].

Rodriguez, N., Murillo, R. & Abanades Garcia, J., 2012. CO_2 Capture from Cement Plants Using Oxyfired Precalcination and/or Calcium Looping. *Environmental Science Technology,* 46(2012), p. 2460–2466.

Rootzen, J., 2015. *Pathways to deep decarbonisation of carbon-intensive industry in the European Union. Techno-economic assessments of key technologies and measures.* Gothenburg: Chalmers University of Technology.

RTI International, 2015. *Results and Future Perspective of RTI's Advanced Solid Sorbent Project.* Langesund, International CCS Conference.

Santos, S., 2015. *Understanding the potential of CCS in hydrogen production,* Lisbon: IEAGHG Process Industry CCS Workshop, Joint IEAGHG & IETS Meeting, http://www.ieaghg.org/docs/General_Docs/IEAGHG_Presentations/18_-_S._Santos_IEAGHGSECURED.pdf.

Separation Processes, 2016. *Henry's law for gas absorption.*
ONLINE ▶ Available at: http://www.separationprocesses.com/Absorption/GA_Chp02e.htm
[Accessed September 2016].

SOLVit, 2016. *Solvents for the next generation of post combustion CO_2 capture systems (SOLVit – Phase 3).*
ONLINE ▶ Available at: http://www.climit.no/en/projects/development-project/227647
[Accessed August 2016].

Toshiba, 2015. *Applying Carbon Capture and Storage to a Chinese Steel Plant,* Melbourne: Prepared for Global Carbon Capture and Storage Institute Ltd By Toshiba International Corp Pty Ltd / Toshiba Corporation in collaboration with Tongfang Environment Co. Ltd .

U.S. DOE, 2011. H*ydrogen production: natural gas reforming,* U.S. DOE website: U.S. Department of Energy, http://energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming.

U.S. DOE, 2013a. *DOE/NETL Advanced Carbon Dioxide Capture R&D Program: Technology Update,* Pittsburgh, PA: DOE/NETL.

U.S. DOE, 2013b. *Report of the Hydrogen Production Expert Panel: A Subcommittee of the Hydrogen & Fuel Cell Technical Advisory Committee,* Washington DC: U.S. Department of Energy.

U.S. EPA, 2016. U.S. *Greenhouse Gas Emissions and Sinks: 1990-2014,* Washington DC: U.S. Environmental Protection Agency.

UNIDO, 2010. *Carbon Capture and Storage in Industrial Applications: Technology Synthesis Report,* Vienna: United Nations Industrial Development Organisation.

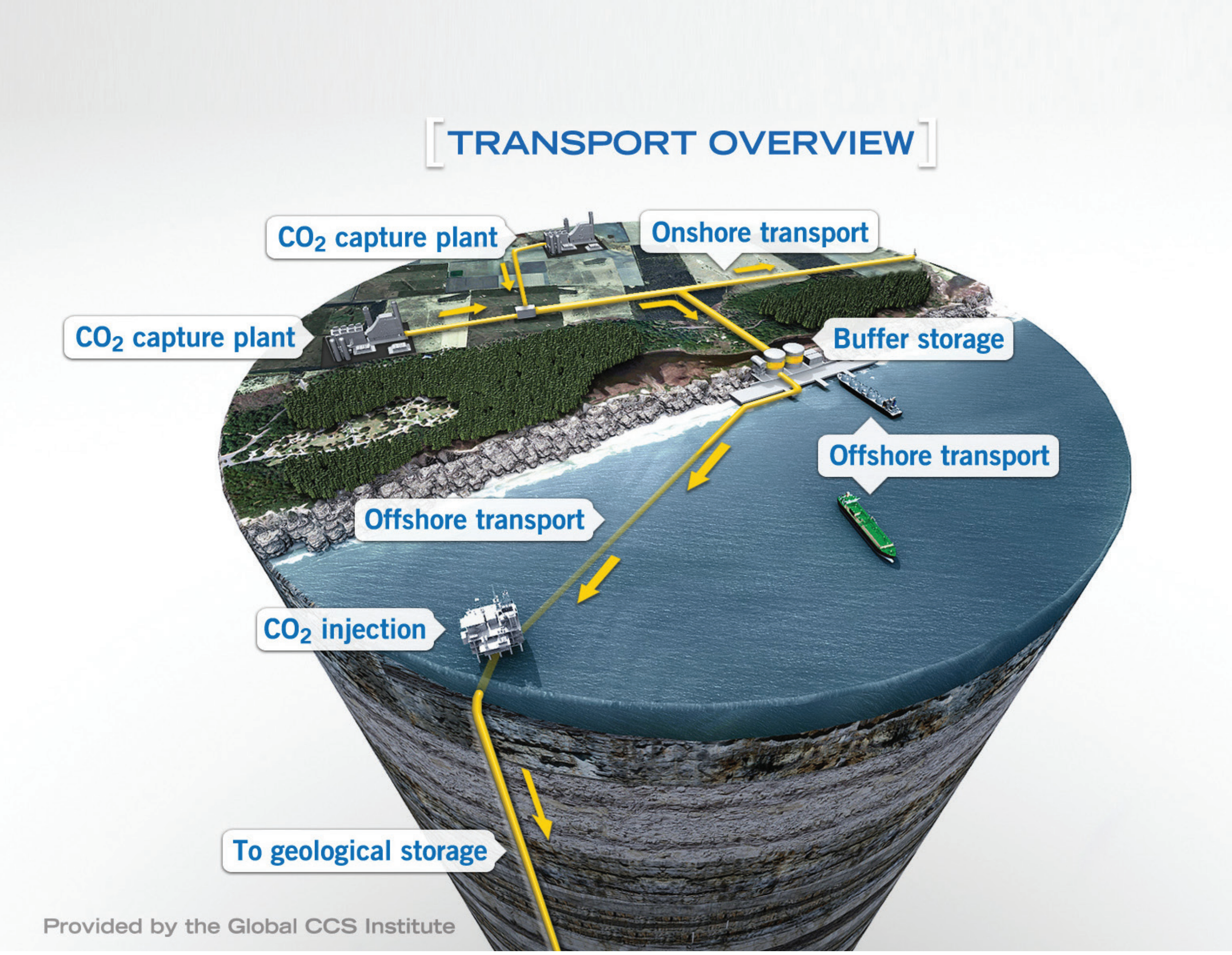
World Steel Association, 2016. *Energy use in the steel industry.*
ONLINE ▶ Available at: http://www.worldsteel.org/steel-by-topic/sustainable-steel/environmental/efficient-use.html
[Accessed 16 August 2016].

Worrel, E. et al., 2001. Carbon dioxide emission from the global cement industry. *Annual Review of Energy and the Environment,* 26(2001), pp. 303-329.

ZEP, 2013. *CO_2 capture and storage (CCS) in energy intensive industries,* ZEP website: European Zero Emission Platform.

[2]

TRANSPORT



TRANSPORT OVERVIEW
CO₂ capture plant
Onshore transport
CO₂ capture plant
Buffer storage
Offshore transport
Offshore transport
CO₂ injection
To geological storage
Provided by the Global CCS Institute

SECTION HIGHLIGHTS

- The technology for CO_2 pipelines is well established and CO_2 transportation infrastructure continues to be commissioned and built.
- Pipelines are – and are likely to continue to be – the most common method of transporting the large quantities of CO_2 involved in CCS projects.
- Several recent studies show that CO_2 transportation by ship can be a flexible and cost-effective alternative to CO_2 pipelines, especially where onshore and close-to-shore storage locations are not available.
- The development of large-scale 'trunk lines' for long distance CO_2 transport and distribution systems has proven to be successful in North America in terms of their ability to connect multiple industrial sources of CO_2 to a large number of mature oil fields, where CO_2 is used in enhanced oil recovery (EOR) operations.
- The North American experience may offer valuable lessons on the importance of incentivising infrastructure development in regions with a high density (or cluster) of CO_2 emissions and economically accessible storage locations.
- An International Standard for CO_2 transport has been finalised, covering specific issues related to transport of CO_2 in the context of large-scale CCS projects and as a supplement to existing national and international pipeline standards and codes.
- Ongoing research and development (R&D) activities are focussed on reducing cost and further improving the safety of CO_2 pipelines by developing and validating predictive models for CO_2 pipeline design.

2.1

INTRODUCTION

Safely and reliably transporting CO_2 from where it is captured to a storage site is an important stage in the CCS process. Transport of CO_2 by pipelines, trucks, trains, and ships is already a reality, occurring daily in many parts of the world. Pipelines are – and are likely to continue to be – the most common method of transporting the large quantities of CO_2 involved in CCS projects.

In the United States (US) alone there are around 7,600 kilometres (km) of onshore CO_2 pipelines transporting roughly 68 million tonnes per annum (Mtpa) of mainly naturally sourced CO_2 for EOR purposes.[1] These pipelines have been operated with an excellent safety record since the first pipelines were laid in the early 1970s.

In Europe, CO_2 pipelines are a more recent phenomenon, with the main pipeline infrastructure located in Norway (a 153 km offshore pipeline for the Snøhvit CO_2 Storage project) and in the Netherlands (an 85 km pipeline to transport CO_2 to greenhouses from Rotterdam to Amsterdam[2]).

CO_2 transportation by ships can be a flexible and cost-effective alternative to CO_2 pipelines, especially where onshore and near-shore storage locations are not available. Shipment of CO_2 already takes place on a small-scale in Europe for transport of food-quality CO_2.

Larger scale shipment of CO_2 is considered to be feasible given the experience with large-scale shipping of liquefied petroleum gas (LPG) and liquefied natural gas (LNG).[3]

Transport of smaller volumes of CO_2 has been undertaken by truck and rail for industrial and food grade CO_2 for over 40 years. However, the cost of transportation by truck or train is relatively high per tonne of CO_2 compared to pipelines, so it is unlikely that truck and rail transport will have a significant role in CCS deployment, except for small-scale CCS opportunities and pilot projects.

---

[1] (Wallace, 2015)
[2] (The Linde Group, 2016)
[3] (DNV GL, 2010)

Given the rich experience with CO_2 transport to date, the technology is considered well established. Nevertheless, it is an integral part of the CCS chain and presents opportunities for optimising technology and investment to enable successful CCS projects.

2.2

CO_2 PIPELINE STATUS

Spanning across more than a dozen US states and into Canada, a safe, reliable and extensive network of CO_2 pipelines has been constructed over the past four decades in North America. The current CO_2 pipeline system consists of over 50 individual CO_2 pipelines with a combined length of approximately 7,600 km.[4] These pipelines are operated by a number of different companies, including Kinder Morgan, Occidental, Trinity, Chevron, ExxonMobil, Anadarko and Denbury.

Approximately 80 per cent of the existing large-volume CO_2 pipelines connect natural sources of CO_2 (e.g. Bravo Dome, New Mexico) with CO_2-EOR projects in mature oil fields (e.g. Permian Basin, West Texas). The longest CO_2 pipeline built in the US is the Cortez Pipeline at a length of 800 km and with a capacity of over 20 Mtpa of CO_2.[5]

However, smaller volume pipelines also exist that connect point sources of industrial CO_2 (e.g. Coffeyville Chemical Plant, Kansas) with CO_2-EOR projects (e.g. North Burbank, Oklahoma). Similarly, in Canada, Cenovus Energy built the Rafferty pipeline (66 km) to transport CO_2 from SaskPower's Boundary Dam capture plant near Estevan to the Weyburn oil unit.[6]

With the recent completion of two long-distance CO_2 pipelines in the US – the Green Pipeline in the Gulf Coast (2011) and the Greencore Pipeline in the Rockies (2013) – a more geographically diverse CO_2 pipeline system is in place (Table 2.1). A variety of shorter and smaller volume laterals are planned to link these two large-scale CO_2 pipelines to surrounding oil fields for CO_2-EOR.[7] Appendix A provides a listing of all major CO_2 pipelines in the in North America.

Table 2.1 **Geographic areas in North America with major operating CO_2 transport pipelines**[8]

North American Regions with Large CO_2 Pipelines in Operation	Kilometres of Pipeline
Permian Basin (West Texas, New Mexico, Colorado)	4,180
Gulf Coast (Mississippi, Louisiana, East Texas)	1,190
Rocky Mountains (Colorado, Wyoming, Montana)	1,175
Mid-Continent (Oklahoma, Kansas)	770
Other (North Dakota, Michigan)	345

Two large-scale CCS projects in the power sector in the US that will become operational soon are within a moderate distance (less than 150 km) from existing CO_2 trunk lines or viable CO_2-EOR oil fields:

- The Petra Nova Carbon Capture Project will capture CO_2 emissions from the W.A. Parish power plant in Thompson, Texas and deliver CO_2 supplies to the CO_2-EOR project at the West Ranch oil field in Vanderbilt, Texas, via a 132 km CO_2 pipeline.
- Mississippi Power has built a 98 km 14-inch diameter CO_2 pipeline from the new build integrated gasification combine cycle (IGCC) power plant located in Kemper County, Mississippi, to connect with an existing CO_2 pipeline system near Heidelberg, Mississippi.

This relatively straightforward connection to the existing CO_2 pipeline system (and its market for CO_2) illustrates that it can improve the business case for CCS projects. It also illustrates that for

---

[4] (DiPietro, 2014)
[5] (Kinder Morgan, 2015)
[6] (Cenovus Energy, 2013)
[7] (Wallace, 2015)
[8] (Wallace, 2015)

smaller scale industrial facilities, which produce insufficient quantities of CO_2 to finance individual CO_2 transport solutions, the ability to utilise existing transportation infrastructure can improve the economic viability of such projects.

It should be noted that not all CO_2 pipeline projects in North America are linked to EOR operations. As part of the Quest CCS project in Alberta, Canada, a 64 km pipeline was commissioned in 2015.[9] This pipeline transports dense-phase CO_2 north from the Scotford upgrader to the storage site location, where the CO_2 is sequestered into a deep saline geological formation.

Outside North America, there is significantly less experience with the operation of CO_2 pipelines. The last CO_2 pipeline constructed in Europe was completed in 2008 as part of the Snøhvit CO_2 Storage Project (Norway).[10] This offshore pipeline covers some 153 km linking LNG facilities near Hammerfest in northern Norway to the Snøhvit field under the Barents Sea. Further offshore CO_2 pipelines are proposed in the United Kingdom and the Netherlands as part of planned large-scale CCS projects, all of which connect CO_2 capture facilities on the mainland with CO_2 storage reservoirs under the North Sea seabed.

In the Middle East, two CO_2 pipelines have recently been constructed. In Abu Dhabi, a 43 km 8-inch pipeline transports CO_2 from the Emirates Steel Plant to the Rumaitha oil field, where the CO_2 is used for EOR. In the Kingdom of Saudi Arabia, an 85 km pipeline transports CO_2 from the Hawiyah NGL (natural gas liquids) Recovery Plant to the injection site in the Uthmaniyah production unit of the giant Ghawar oil field. This pipeline was commissioned in 2015.

2.3

FUTURE TRANSPORT INFRASTRUCTURE REQUIREMENTS

Even though the cost of CO_2 transport per tonne of CO_2 is relatively low compared to the cost associated with capturing and storing the CO_2,[11] the scale of investment in CO_2 transportation infrastructure required to support large-scale deployment of CCS is considerable.[12]

One way to incentivise broader CCS deployment is to realise economies of scale by sharing a single CO_2 transportation and storage infrastructure system among several operators of separate CO_2 generating plants. The development of large-scale trunk-lines for long distance CO_2 transport and distribution systems has proven to be successful in the US in terms of their ability to connect multiple industrial sources of CO_2 to a large number of mature oil fields, where the CO_2 is used in EOR operations.

The US experience illustrates the importance of considering CO_2 transport infrastructure through a regional lens (as opposed to point-to-point systems). In regions that have high density of CO_2 emissions and economically accessible storage volumes, the development of large CO_2 trunk-lines and smaller distribution lines should be considered.[13] It is important to invest in CO_2 pipeline networks that could be expanded to allow for new industrial CO_2 generating facilities to connect into the network at a later stage.

A number of CO_2 transportation networks are at various stages of development outside the US, including: the Netherlands (Rotterdam), Australia (the CarbonNet and South West Hub projects), the United Kingdom (Yorkshire/Humber, Teesside, Scotland), Canada (Alberta Carbon Trunk Line) and Abu Dhabi (Masdar).

---

[9] (Shell Canada Ltd, 2015)

[10] (Statoil, 2015)

[11] A commonly used methodology for estimating costs for onshore pipelines that requires pipeline diameter and length as input can be found in the National Energy Technology Laboratory (NETL) study on Carbon Dioxide Transport and Storage costs (NETL, 2013).

[12] (Neele, et al., 2011) (ICF, 2009)

[13] (Global CCS Institute , 2012)

As an example, development of a CCS cluster in central Scotland could be facilitated by existing pipeline infrastructure, specifically by use of the existing 'Feeder 10' natural gas transmission pipeline. This pipeline connects the St Fergus gas treatment terminal (Aberdeenshire) via a 280 km onshore route through eastern Scotland to the Avonbridge compressor station (West Lothian), in Scotland's Central Belt. Approximately 80% of large point source CO_2 emissions in Scotland are within 40 km of the 'Feeder 10' pipeline. Scenario studies show that the 'Feeder 10' has capacity through known expansion potential for developments allowing capture volumes rising from 2 to 8 Mtpa of CO_2. This cluster development opportunity is described in detail in Brownsort et al. 2016.[14]

2.4

CO_2 TRANSPORTATION BY SHIP

Some regional CCS clusters, in particular port areas, also consider ship transport of CO_2 as an alternative for pipelines. Several modelling studies have shown that ship transport can be cost competitive with pipelines, especially where onshore and near-shore storage locations are not available.[15] In general, longer distances and smaller or varying CO_2 volumes favour shipping over pipelines.

A recent study commissioned by Norwegian gas transporter, Gassco, showed that shipping is a feasible option for a full chain CCS project under investigation as part of the Norwegian government's plans to realise a large-scale CCS project by 2022.[16]

Shipment of CO_2 already takes place on a small-scale in Europe for transport of food-quality CO_2 from large point sources to coastal distribution terminals. Currently, Yara has three CO_2 carriers in operation. The tanks on board Yara's ships are identical and the largest in Europe. Each can carry up to 1,800 tonnes of CO_2.[17]

Yara's CO_2 tanker fleet connects Yara production sites in Sluiskil (Netherlands), Porsgrunn (Norway), Fredericia (Denmark), Dormagen (Germany) and Wilton (UK) to terminals in Hamburg (Germany), Montoir (France), and Billingham (UK).

Figure 2.1 **Yara Gerda, a new dedicated liquid CO_2 marine tanker. Source: Yara 2015**

Larvik Shipping currently operates another three food grade CO_2 carriers from the Yara fertiliser plant in Larvik to terminals throughout Europe. Two of these carriers have a capacity of 900 tonnes and one has a capacity of 1,200 tonnes with CO_2 at -30°C and 20 bar.[18] Anthony Veder operates one 1,380 tonne CO_2 tanker at temperatures down to -40°C and pressures up to 18 bar, also in Europe.[19]

Larger-scale shipment of CO_2, with capacities in the range of 10,000 - 100,000 tonnes of CO_2, is considered to be feasible given experience with the shipping of natural gas as LPG and LNG, and design work is in progress by major carriers such as Mærsk, Anthony Veder, Chiyoda, and Yara.[20]

---

[14] (Brownsort, 2016)
[15] (Knoope, 2015) (Neele, 2014) (Brownsort, 2015)
[16] (Gassco, 2016))
[17] (Yara, 2015)
[18] (Brownsort, 2016)
[19] (Anthony Veder, 2016)
[20] (Brownsort, 2015)

Transportation of CO_2 by ship is governed by requirements put forward in the International Maritime Organization (IMO) International Code for Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code). Requirements for carriage of liquefied CO_2 were taken into the IGC Code in December 2006.[21]

2.5

STANDARDS AND CODES FOR CO_2 PIPELINES

The design of a pipeline should meet the requirements of regulations and industry-recognised standards in terms of: pressure (wall thickness, over-pressure protection systems), resistance to degradation (internal due to, for example, corrosion and external due to environmental conditions), protection from damage (e.g. in burying the line), appropriate monitoring facilities and safety systems, and location considerations.[22]

The existing network of CO_2 pipelines has been operated with an excellent safety record, applying internationally adopted standards and codes that are applicable to CO_2 pipelines, such as:[23]

- American Society of Mechanical Engineers – ASME B31.4 Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids
- Canadian Standards Association – CSA Z662 Oil and Gas Pipeline Systems
- Australian Standards – AS 2885: Pipelines – Gas and Liquid Petroleum
- British Standards/European Norms – BS EN 14161: Petroleum and natural gas industries – Pipeline transportation systems
- BS PD 8010:2004 Code of practice for pipelines
- International Standard – ISO 13623 – Petroleum and Gas Industries: Pipeline Transportation Systems
- Det Norske Veritas – DNV-OS-F101 – Submarine Pipeline Systems
- Det Norske Veritas – DNV-RP-J202 – Design and Operation of CO_2 Pipelines

In the US, the US Federal Code of Regulations (Title 149) – Transportation of Hazardous Liquids by Pipeline and the associated ASME standard B31.4 and B31.8 are the main codes which address the transportation of liquids and gases by pipeline respectively. However, these codes have been mainly applied for pipeline systems transporting naturally occurring CO_2 through sparsely populated areas for use in EOR operations.

A number of European standards are applicable to pipelines transporting CO_2 (Institute of Petroleum code IP6, BS EN 14161, and BS PD 8010). Unlike the recently updated Australian and Canadian pipeline Standards, none of these address anthropogenic CO_2 transported under high pressure as a dense-phase fluid or reference CO_2 transport in the context of CCS.

Widespread deployment of CCS would likely see pipeline systems developed that will transport CO_2 from multiple anthropogenic sources, and which may have different CO_2 streams in terms of their composition, temperature and pressure. These systems may possibly see greater use of offshore pipelines, and pipeline routes that are located closer to urban areas.

In anticipation of these developments, in 2010, DNV undertook a joint industry project (JIP), named CO_2PIPETRANS. The purpose of this project (now in Phase 2) is to adapt the existing pipeline standards to the specifications of the transmission of anthropogenic CO_2 and to provide guidance and set out criteria for the development, design, construction, testing, operation and maintenance of steel pipelines for the transmission of large volumes of CO_2.

---

[21] (IMO , 2016)

[22] (Serpa, 2011)

[23] A full listing of applicable Standards and Codes is provided in the References.

The guideline developed, the Recommended Practice for Design and Operation of CO_2 Pipelines DNV-RP-J202,[24] was released in 2010 and constitutes a supplement to current pipeline standards like ISO 13623, DNV-OS-F101, ASME B31.4 and others.

This Recommended Practice has formed the basis for a new ISO standard,[25] which is currently being published, aiming to harmonise the international standards for the petroleum and natural gas industries, including the international pipeline industry.

The new ISO Standard applies to onshore and offshore (metallic) pipelines, including existing pipelines converted for transportation of CO_2 streams. The Standard covers transport of CO_2 in both gaseous and dense phases, and sets out the properties of CO_2 (including CO_2 streams with impurities) and the implications for pipeline design and operation.

The Working Group tasked with the development of the International Standard (ISO/TC 265, WG2 'Transportation') is convened by Germany and includes CO_2 transport experts from Australia, the US, Italy, the UK, Spain, France, Norway and Japan.[26] The Working Group met for the first time in June 2013. It released its Final Draft International Standard (FDIS) in July 2016. This FDIS was approved for publication in September 2016. Once published, this new International Standard may be adopted by national Standard bodies and form part of national or state/provincial regulation.

The new ISO Standard 27913 for CO_2 transportation systems provides requirements and recommendations on certain aspects of safe and reliable design, construction and operation of CO_2 pipelines that are not already covered in existing pipeline standards.

Like the DNV-RP-J202, the new ISO Standard 27913 also makes reference to pipeline design areas that are still the subject of ongoing research or for which validated experimental data is not yet available. In some instances it describes the design approach to be taken by the operator, rather than providing validated data on which to base a design.

Consequently, in regards to the key areas of fracture control, internal corrosion and understanding the dispersion of the CO_2 plume following a rupture, the new ISO Standard 27913 directs the reader to consult the latest research or to conduct full-scale experiments to validate the design being considered. This is shown in the following extracts:

> “*Clause 7.3.5: Minimum wall thickness against ductile fracture: Where the combination of pipeline materials and CO_2 stream to be transported lies outside the range of available full scale test data, a full scale test should be conducted to provide confidence that the pipeline has adequate resistance to ductile fracture.*”

> “*Annex A: Composition of CO_2 streams: Impurities have impacts on the thermodynamic properties of a CO_2 stream which cannot be predicted out of the properties of pure CO_2. Furthermore, impurities can effect corrosion or generate chemical reactions. Also, properties of a CO_2 stream, like viscosity, can change. Research to identify those impurities that can have a critical impact on the thermodynamic, chemical and other properties of the CO_2 is still taking place.*”

> “*Annex C.2 Internal corrosion: Based on the present understanding of CO_2 corrosion mechanisms at high partial pressure, there exists significant uncertainty, particularly considering the effects of other components in the CO_2 stream. The most up to date research should be consulted during pipeline design.*”

> “*Annex B.3 Dispersion modelling: Empirical models for estimating dispersion of released gases in air and liquids are readily available; however, they may need further validation for CO_2 in CCS-scale applications.*”

Given these references, it is no surprise that corrosion, fracture control, and CO_2 dispersion following a rupture are the subject of a number of international collaborative R&D programs.

---

[24] (DNV GL, 2010)
[25] (ISO, 2016)
[26] (Global CCS Institute, 2015)

CO_2 Characteristics

CO_2 has properties that can be different from those of hydrocarbon fluids and can influence all stages of the pipeline life cycle, from design through construction to operation. The thermodynamic and chemical behaviour of pure CO_2 is readily available in literature.[27] It is commonly known that at pressures and temperatures above the critical point (73.8 bar, 31.1°C), CO_2 no longer exists in distinct gaseous and liquid phases, but as a dense-phase or supercritical phase with the density of a liquid but the viscosity of a gas. For most CCS projects, economics will drive the need to transport CO_2 in its dense-phase since gaseous phase transmission would require larger diameter pipelines for the same mass flow rate.

Transporting CO_2 in dense-phase can create some specific design considerations for pipelines, in particular when impurities are present in the CO_2 stream. The presence of impurities, like water vapor, methane, nitrogen, and oxygen, can have an impact on the physical properties of the transported CO_2 that consequently affects pipeline design, compressor power, recompression distance, pipeline capacity, and could also have adverse implications for the prevention of fracture propagation.

A sound understanding of the impact of impurities in the CO_2 stream is important to set safe and cost effective CO_2 purity specifications. Current best practice impurity levels and the factors driving these are available in literature.[28]

When designing a CO_2 transport system, it is important to consider that the flow properties of dense-phase CO_2 are different from those of natural gas. In dense-phase CO_2 streams (that may contain impurities) small changes in temperature or pressure can have a large impact on the density of the fluid, which could result in a change of fluid velocity and phase. In a two-phase flow, two physical phases are present in the pipeline simultaneously (e.g. liquid and gas), which can create problems for compressors and other pipeline equipment, increasing chances of pipeline failure.

It is therefore important for operators to maintain single-phase flow in CO_2 pipelines by avoiding rapid pressure drops using an appropriate pressure control system. Decades of CO_2 pipeline operating experience in the US, as well as new front-end engineering design studies carried out for a number of large-scale CCS projects in Europe[29] suggest, however, that the handling of CO_2 is feasible during normal operation, although customised solutions may be required to handle transient situations like emergency shut-down and pipeline re-pressurisation.

2.6

CO_2 TRANSPORT R&D ACTIVITIES

Current CO_2 pipeline infrastructure has an excellent safety and performance record that results from accumulated experience, proven design methodologies and established codes and regulation. Nevertheless, efforts to build on this knowledge base and increase know-how on pipeline integrity and management in support of widespread large-scale CCS deployment, and to provide input into relevant pipeline standards, are ongoing across the globe. Most of the R&D programs regarding CO_2 transport are concentrated in Europe and Australia. These programs are either ongoing or have only recently been completed:

- COOLTRANS – CO_2Liquid Pipeline TRANSportation
- COSHER – Carbon Dioxide, Safety, Health, Environment and Risks
- CO_2PIPETRANS Phase 2 – DNV GL Joint Industry Project (JIP)
- CO_2PipeHaz – Quantitative Failure Consequence Hazard Assessment for Next Generation CO_2 Pipelines

---

[27] (Mohitpour, et al., 2012)

[28] (de Visser, et al., 2008) (Mohitpour, et al., 2012) (Aursand, et al., 2013) (Brown, J. et al., 2014)

[29] (Hetland, 2014) (DECC, 2016) (Uilenreef, 2013) (DECC, 2016)

- CO2QUEST – Impact of the quality of CO_2 on transport and storage
- Energy Pipelines CRC/DNV GL – Improving safety and efficiency of CO_2 pipelines
- MATTRAN – Materials for Next Generation CO_2 Transport Systems
- SARCO$_2$ – Requirements for safe and reliable CO_2 transportation pipeline
- SubCO$_2$ JIP – CO_2 Subsea Releases Small Scale Experimental Programme

Most of these collaborative R&D efforts focus on the design and operational implications of different CO_2 stream compositions (and presence of impurities), especially on corrosion control, fracture propagation control and CO_2 dispersion modelling for safety analysis and risk assessment.

Corrosion Control

Decades of field experience and research show that dry pure CO_2 and pure CO_2 that contains dissolved water well below the saturation limit, are non-corrosive to carbon steel at standard pipeline operation conditions. However, given the susceptibility of most pipelines to internal corrosion due to the presence of carbonic acid, one of the most critical factors to control is the water content of the CO_2 stream entering the pipeline (CO_2 reacts with water to form carbonic acid). Carbonic acid can lead to corrosion rates ranging from one to more than 10 mm/y, depending on the CO_2 partial pressure, temperature, and the presence of other impurities.[30] Therefore, adequate dehydration to an acceptable level of water in the CO_2 stream is essential for corrosion control.

In addition, the presence of additional 'acid gases' such as hydrogen sulphide (H_2S), nitrogen oxides and sulphur oxides (NOx and SOx) needs to be considered in the design of pipelines as they arise from the capture process. The presence of free (non-saturated) water with H_2S can cause H_2S-induced corrosion phenomena. The presence of other chemical components such as NOx or SOx can lead to a free water phase containing additional acidic components, also increasing the corrosion rate.[31]

These problems are well understood and can also be resolved by using conventional dehydration technologies and active monitoring of the water content during pipeline operations. Furthermore, the CO$_2$PIPETRANS Phase 2 JIP has undertaken experimental work to improve knowledge and data availability related to corrosion rates with various CO_2 stream impurities.

CO$_2$PIPETRANS Phase 2 – DNV GL Joint Industry Project (JIP)[32]

CO$_2$PIPETRANS Phase 2 is a JIP led by DNV GL with a major corrosion work package to determine the mechanism and corrosion rate in dense-phase CO_2 for various impurities including O_2, SOx, NOx, and H_2S with and without free water. The CO_2 corrosion experiments were carried out using a specialised rotating autoclave.

The effect of the impurities on the solubility limits of water, which results in increased corrosion rates, was determined and a safe operating window for dense-phase CO_2 containing various impurities has been defined.[33]

The results are an important step in the refinement of the operational limits for different impurities found in pipelines carrying anthropogenic CO_2. Increased understanding of corrosion mechanisms leads to more cost effective pipeline design and design of CO_2 conditioning processes. The results serve as input for updating DNV-RP-J202.

Other work packages in the CO$_2$PIPETRANS JIP aim to generate experimental data to assist the development and validation of dense-phase CO_2 depressurisation, release and dispersion models. The data generated in this JIP have been made public.[34]

---

[30] (NETL, 2013) (de Visser, et al., 2008)
[31] (Dugstad, et al., 2014) (Cole, et al., 2011)
[32] (DNV GL, 2016)
[33] (Brown, J. et al., 2014)
[34] (DNV GL, 2012) (DNV GL, 2012) (DNV GL, 2015) (DNV GL, 2015)

Fracture Control

The decompression behaviour of CO_2 is different from that of methane because of the phase changes that occur as the fluid depressurises. The composition of the CO_2 stream may further impact the decompression behaviour of the CO_2 in the event of a pipeline leak (caused by, for example, mechanical damage or corrosion). This is important as the characteristics of dense-phase CO_2 during decompression can encourage the transition from leak to break and the onset of running fracture propagation.[35]

A running fracture involves the rapid tearing, or 'unzipping', of the pipeline and release of large volumes of CO_2 in a very short space of time. This can be a safety hazard for surrounding populations while the propagation of the fracture carries a significant repair cost for the operator. Therefore, one of the key requirements for the design and operation of pipelines is fracture control.

Dense-phase CO_2 is a challenging fluid when dealing with fracture control. Its thermodynamic characteristics during decompression mean that, due to a very high driving force, a running fracture can be sustained for a long time.[36] This phenomenon is not new and although it is a potential hazard, it has never been an issue in all the years of operation. CO_2 pipelines are provisioned against a long running fracture by ensuring that the pipe has sufficient fracture toughness, which can be managed in pipeline design by increasing wall thickness. Moreover, existing CO_2 pipelines are often equipped with regularly spaced 'crack arrestors', which are typically joints of pipe with greater wall thickness that will stop a longitudinal crack in a pipeline from propagating.

Fracture arrest calculations to determine wall thickness for pipelines carrying natural gas have been traditionally performed by use of the Battelle Two Curve Model (BTCM). The BTCM has been extensively validated for methane against full-scale fracture arrest tests since the 1970s. Over the years correction factors to the initial equations have been proposed for steel grades and pipe sizes beyond the validated range. These correction factors are established from full-scale fracture arrest tests with methane pipelines.

Around 2010 there was a need to perform full-scale fracture arrest tests to validate the numerical models used in estimation of fracture arrest criteria for CO_2 pipelines. These tests have revealed uncertainties as fractures have been observed where numerical predictions validated for natural gas pipelines predicted arrest. In the absence of accurate fracture models, CO_2 pipelines have either to be designed and constructed with excessive conservatism, or developers could initiate a full scale fracture propagation test program. This could make CO_2 pipelines more expensive than required. Ongoing research focuses on improving design and construction efficiencies to bring down the cost of CO_2 pipeline infrastructure projects.

Energy Pipelines CRC and DNV GL – Improving safety and efficiency of CO_2 pipelines

In order to address the existing gaps in knowledge associated with fracture control of high pressure dense-phase CO_2 pipelines, Energy Pipelines CRC in partnership with DNV GL, have started a large R&D project to develop and validate an accurate fracture model for CO_2 pipelines operated at high pressure.

The new fracture control model for CO_2 pipelines will be validated by two full scale fracture tests. The dispersion of the CO_2 into the atmosphere from the tests will be measured, allowing validation of CO_2 dispersion models. This is critical in mitigating hazards posed by releases of CO_2 from pipelines. The project will also quantify the possible financial benefits which could be gained by operating long distance pipelines at higher pressure.

The project has been awarded a total of AUD$6.4 million from the Australian Government under its CCS RD&D Fund and the Norwegian based CLIMIT programme.[37]

---

[35] (Spinelli & Demofonti, 2011)

[36] (Botros, et al., 2011) (Cosham, et al., 2012)

[37] (Energy Pipelines CRC, 2016)

Energy Pipelines CRC and DNV GL – Improving safety and efficiency of CO_2 pipelines

The proposed testing program will build on an extensive program of work undertaken by the Energy Pipelines CRC between 2011-2014 that allowed for CO_2 pipelines to be designed and operated under the Australian Standard AS 2885 Pipelines – Gas and Liquid Petroleum through the inclusion of Appendix BB (Guidelines for Pipelines for the Transport of CO_2).[38]

DNV GL will bring its experience in previous CO_2 pipeline test programs to the project, including the CO_2PIPETRANS JIP, the SubCO_2 JIP[39] and the COOLTRANS Project.

COOLTRANS – CO_2Liquid Pipeline TRANSportation

COOLTRANS was commissioned by National Grid to provide the technical foundations for the design and operation of dense-phase CO_2 pipelines in the UK. The program includes theoretical studies as well as experimental investigation, including shock tube tests, vent and puncture tests, and three large-scale fracture propagation tests.[40]

The results of this research program have been used to develop a comprehensive Quantitative Risk Assessment (QRA) methodology for dense-phase CO_2 pipelines, which has been used in routing and design studies for UK CCS projects to ensure that the principles of the UK standards and codes are correctly applied.

CO_2 Releases

The consequences and hazards of a CO_2 release are different from a natural gas pipeline. First, CO_2 is not toxic or flammable like natural gas, but can displace air and lead to oxygen deficiency. Furthermore, CO_2 is heavier than air, so leaks will not disperse as quickly as methane.[41]

Accidental release of CO_2 from an initial liquid state to ambient conditions involves decompression and expansion of the released CO_2 stream with a corresponding drop in temperature. Dense-phase CO_2 differs from the decompression of hydrocarbons in that the release can appear as a combination of gaseous and solid state CO_2 ('dry ice'). Any solid components in the CO_2 stream can potentially damage pipeline equipment. Furthermore, the solid CO_2 particles will be of much higher density than air and can sublime to vapour leading to a cloud of CO_2 which is very dense relative to the surrounding atmosphere, and will spread at ground level or flow downhill depending on topography.

Accurate modelling of CO_2 dispersion to identify hazards posed by intentional or accidental releases of CO_2 from pipelines is important to efficient and safe design of CO_2 pipelines. Central to these dispersion models is the accurate prediction of the decompression and the discharge rate of the escaping CO_2 in the event of a pipeline rupture, as well as the movement and composition of the so called 'CO_2 plume'. Such data forms the basis for determining the minimum safe distances to populated areas (as required for pipeline routing), emergency response planning and other risk management activities.

The release of CO_2 from a gaseous pipeline is relatively straightforward to model with available engineering software tools. However, releases from pipelines carrying dense-phase CO_2 are more complex, in particular when the CO_2 stream also contains impurities. A number of factors affect the dispersion patterns, namely the highly transient nature of the event, the behaviour of the fluid released,

---

[38] The Energy Pipelines CRC research into CO_2 pipelines resulted in a number of publications, including: (Elshahomi, et al., 2015) (Liu, et al., 2014) (Liu, et al., 2015) (Sim, et al., 2014) (Lu, 2015)

[39] (DNV GL, 2015)

[40] The COOLTRANS programme resulted in a number of publications, including (Barnett & Cooper, 2014) (Cooper, 2012) (Cosham, et al., 2012) (Wareing, et al., 2014)

[41] (McGillivray & Wilday, 2009)

the atmospheric conditions, and the characteristics of the surrounding terrain.

A recent review of available modelling tools, testing their applicability to individual CO_2 pipeline projects, found that only two models have the ability to simulate pipeline depressurisation: the DNV GL model PHAST and the TNO model EFFECTS.[42] These modelling tools are the only two that also have been field tested in major research projects including CO_2PIPETRANS, COOLTRANS, COSHER and CO_2PipeHaz.

COSHER: Carbon Dioxide, Safety, Health, Environment and Risks

The COSHER JIP involved a number of large-scale experiments to provide CO_2 release and dispersion data under well-defined conditions, studying the full bore rupture of a CO_2 dense-phase high pressure underground pipeline. The papers resulting from this project contain data from the largest experimental program on CO_2 releases to date.[43]

During the experiments, a ground crater was formed and the CO_2 was allowed to flow freely from both ends of the ruptured section of the pipeline. Measurements of the fluid pressure, temperature and pipeline wall temperature were made together with measurements of the dispersing gas cloud. The data generated are useful for (dispersion) model development and validation as well as for better understanding of the risks involved in underground CO_2 pipeline ruptures.

CO_2PipeHaz: Quantitative Failure Consequence Hazard Assessment for Next Generation CO_2 Pipelines[44]

The CO_2PipeHaz project has developed guidance specifically for use in integral consequence modelling for CO_2 releases and its use in Quantitative Risk Assessment (QRA).[45] The CO_2PipeHaz project was completed in 2014.

CO_2PipeHaz successfully developed and validated improved predictions of fluid phase, discharge rate and atmospheric dispersion - using Computational Fluid Dynamics (CFD) modelling - for accidental releases from pressurised CO_2 pipelines.[46]

Model validations were based on small-scale controlled laboratory conditions, medium-scale experimental investigations, and also large-scale field tests performed using a specially designed, constructed and fully instrumented 250 metre long section of 23 cm internal-diameter pipeline in China.[47] These experiments were modelled in order to obtain better understanding of the discharge phenomena and gas-cloud behaviour following a large-scale CO_2 release, thus providing the basis for calculating the safety distances required for pipeline routing.

---

[42] (Sherpa Consulting, 2015)
[43] (Ahmad, et al., 2015)
[44] (CO_2PipeHaz, 2014)
[45] (Woolley, et al., 2014)
[46] (Mahgerefteh, et al., 2012)
[47] (Woolley, et al., 2014)

APPENDIX A: EXISTING CO_2 TRANSPORT INFRASTRUCTURE

In the US there are approximately 7,600 km of pipelines that transport CO_2 today. These onshore pipelines cross six provincial/state boundaries and one international border (into Canada).

Much of the existing CO_2 pipeline infrastructure in the US was built in the 1980s and 1990s and delivers mainly naturally/sourced CO_2 for EOR purposes.

Table A-1 provides an overview of the main existing CO_2-EOR pipelines in the US.

Table A-1 **Existing major US CO_2 pipelines**[48]

PIPELINE	OWNER/ OPERATOR	LENGTH (KM)	DIAMETER (INCH)	ESTIMATED MAXIMUM FLOW CAPACITY (Mtpa)	LOCATION (STATE/ PROVINCE)
Permian Basin CO_2 transportation pipelines					
Large-Scale Trunk-lines					
Cortez	Kinder Morgan	808	30	23.6	Texas
Sheep Mountain	Oxy Permian	656	24	11.4	Texas
Bravo	Oxy Permian	351	20	7	New Mexico, Texas
Canyon Reef Carriers	Kinder Morgan	224	16	4.3	Texas
Central Basin	Kinder Morgan	230	16	4.3	Texas
Centerline	Kinder Morgan	182	16	4.3	Texas
Distribution Lines					
Este I to Welch	ExxonMobil	64	14	3.4	Texas
Este II to Salt Creek Field	Oxy Permian	72	12	2.6	Texas
Means	ExxonMobil	56	12	2.6	Texas
North Ward Estes	Whiting	42	12	2.6	Texas
Slaughter	Oxy Permian	56	12	2.6	Texas
Mabee Lateral	Chevron	29	10	2.1	Texas
Val Verde	Kinder Morgan	134	10	2.1	Texas
Rosebud	Hess	19	12	2.6	New Mexico
Anton Irish	Oxy Permian	64	8	1.6	Texas
Eastern Shelf	Kinder Morgan	146	10	2.1	Texas
Dollarhide	Chevron	37	8	1.6	Texas
Llano	Trinity CO_2	85	12	1.6	New Mexico
North Cowden	Oxy Permian	13	8	1.6	Texas
Pecos County	Kinder Morgan	42	8	1.6	Texas
Pikes Peak	SandRidge	64	8	1.6	Texas

---

[48] Adapted from: (Interstate Oil and Gas Compact Commission, 2010) and (Wallace, 2015)

PIPELINE	OWNER/ OPERATOR	LENGTH (KM)	DIAMETER (INCH)	ESTIMATED MAXIMUM FLOW CAPACITY (Mtpa)	LOCATION (STATE/ PROVINCE)
West Texas	Trinity CO_2	97	12	1.6	Texas, New Mexico
Comanche Creek	PetroSource	193	6	1.3	Texas
Cordona Lake	XTO	11	6	1.3	Texas
El Mar	Kinder Morgan	56	6	1.3	Texas
Wellman	PetroSource	42	6	1.3	Texas
Adair	Apache	24	4	1	Texas
Ford	Kinder Morgan	19	4	1	Texas
Gulf Coast CO_2 transportation pipelines					
Large-Scale Trunk-lines					
Green Line	Denbury Green Pipeline LLC	505	24	19	Louisiana
Delta	Denbury Onshore, LLC	174	24	11.4	Mississippi, Louisiana
Northeast Jackson Dome (NEJD)	Denbury Resources	295	20	7	Mississippi, Louisiana
Distribution Lines					
Free State	Denbury Onshore, LLC	138	20	7	Mississippi
Sonat	Denbury Onshore, LLC	80	18	3.2	Mississippi
Rocky Mountain CO_2 transportation pipelines					
Large-Scale Trunk-lines					
Greencore pipeline	Denbury Greencore Pipeline LLC	373	20	14	Montana, Wyoming
Wyoming CO_2	ExxonMobil	180	20	4.3	Wyoming
Distribution Lines					
Powder River Basin CO_2 PL	Anadarko	201	16	4.3	Wyoming
Shute Creek	ExxonMobil	48	30	23.6	Wyoming
Raven Ridge	Chevron	257	16	4.3	Wyoming, Colorado
McElmo Creek	Kinder Morgan	64	8	1.6	Colorado, Utah
Monell	Anadarko	53	8	1.6	Wyoming
Lost Soldier/Wertz	Merit	47	16	1.6	Wyoming
Beaver Creek	Devon	72	8	1.6	Wyoming

PIPELINE	OWNER/ OPERATOR	LENGTH (KM)	DIAMETER (INCH)	ESTIMATED MAXIMUM FLOW CAPACITY (Mtpa)	LOCATION (STATE/ PROVINCE)
Mid-Continent CO_2 transportation pipelines					
Distribution Lines					
Coffeyville–Burbank	Chaparral Energy	110	8	1.6	Kansas, Oklahoma
Enid–Purdy	Merit	225	8	1.6	Oklahoma
TransPetco	TransPetco	177	8	1.6	Texas, Oklahoma
TexOk	Chaparral Energy	153	8	1.6	Texas, Oklahoma
Borger to Camrick	Chaparral Energy	138	4	1	Texas, Oklahoma
Other CO_2 transportation pipelines in the US					
Dakota Gasification (Souris Valley)	Dakota Gasification	329	14	2.6	North Dakota (US), Saskatchewan (Canada)
White Frost	Core Energy, LLC	18	6	1.3	Michigan

LIST OF FIGURES AND TABLES

REFERENCES

Ahmad, M. et al., 2015. COSHER joint industry project: Large-scale pipeline rupture tests to study CO_2 release and dispersion. *International Journal for Greenhouse Gas Control,* Volume 37, p. 340–353.

Anthony Veder, 2016.
ONLINE ▶ Available at: http://www.anthonyveder.com/activities/segments/co2-shipping/
[Accessed August 2015].

Aursand, P., Hammer, M., Munkejord, S. & Wilhelmsen, Ø., 2013. Pipeline transport for CO_2 mixtures: Models for transient simulation. *International Journal of Greenhouse Gas Control,* Volume 15, pp. 174-185.

Barnett, J. & Cooper, R., 2014. T*he COOLTRANS Research Programme: Learning for the Design of CO_2 Pipelines.,* Calgary, Canada: 10th International Pipeline Conference.

Botros, K. et al., 2011. *Shock Tube Measurements of Decompression Wave Speed in CO_2 with Impurities - PRCI Project ALT-1-2,* Project No.: 250676, 2011: PRCI.

Brown, J. et al., 2014. Update of DNV Recommended Practice RP-J202 with focus on CO_2 corrosion with impurities. *Energy Prodedia,* 63(GHGT-12), pp. 2432-2441.

Brown, S. et al., 2014. CO2QUEST: Techno-economic Assessment of CO_2 Quality Effect on Its Storage and Transport. *Energy Procedia,* 63(GHGT-12), p. 2622–2629.

Brownsort, P., 2015. *Ship transport of CO_2 for Enhanced Oil Recovery - Literature Review,* Edinburgh: Scottish Carbon Capture & Storage.

Brownsort, P., Scott, V. & Haszeldine, S., 2016. Reducing costs of carbon capture and storage by shared reuse of existing pipeline—Case study of a CO_2 capture cluster for industry and power in Scotland. *International Journal of Greenhouse Gas Control,* Volume 52, pp. 130-138.

Cenovus Energy, 2013. *Cenovus Energy proposed Rafferty CO2 pipeline project: landowner information.*
ONLINE ▶ Available at: http://www.cenovus.com/operations/oil/docs/rafferty-landowner.pdf
[Accessed July 2015].

CO_2PipeHaz, 2014.
ONLINE ▶ Available at: http://www.co2pipehaz.eu/
[Accessed August 2016].

Cole, I., et al 2011. Corrosion of pipelines used for CO_2 transport in CCS: Is it a real problem?. *International Journal of Greenhouse Gas Control,* Volume 5, pp. 749-756.

Cooper, R., 2012. National Grid's COOLTRANS research programme. *J. Pipeline Eng.,* Volume 11, p. 155–172.

Cooper, R. & Barnett, J., 2014. Pipelines for transporting CO_2 in the UK. *Energy Procedia,* 63(GHGT-12), p. 2412–2431.

Cosham, A. et al., 2012. *Ruptures in gas pipelines, liquid pipelines and dense phase carbon dioxide pipelines,* Calgary, Canada: Proceedings of the 2012 9th International Pipeline Conference.

de Visser, E. et al., 2008. DYNAMIS CO_2 quality recommendations. *International Journal of Greenhouse Gas Control,* Volume 2, pp. 478-484.

DECC, 2016. *White Rose CCS Project - K33: Pipeline Infrastructure and Design Confirming the Engineering Design Rationale:* Department of Energy & Climate Change, UK Government.

DECC, 2016. *White Rose CCS Project - K34 - Flow Assurance Report:* Department of Energy & Climate Change, UK Government.

DiPietro, P., 2014. *Near-Term Projections of CO_2 Utilization for Enhanced Oil Recovery:* US DOE/NETL.

DNV GL, 2010. *DNV-RP-J202 Recommended Practice: Design and Operation of CO_2 pipelines,* Norway: Det Norske Veritas.

DNV GL, 2012. *Report Activity 5: CO_2 Transport. Report No./DNV Reg No.: 2012-0076/13REPT4-2.,* Hovik, Norway: Det Norske Veritas (DNV).

DNV GL, 2012. *1st Release of Model Validation Data (BP Data), Overview Report.,* CO_2PIPETRANS Phase 2, Joint Industry Program.

DNV GL, 2012. *2nd Release of Model Validation Data (Shell Data), Overview Report.,* CO_2PIPETRANS Phase 2, Joint Industry Program.

DNV GL, 2015.
ONLINE ▶ Available at: https://www.dnvgl.com/news/dnv-gl-conducts-largest-ever-controlled-release-of-co2-from-an-underwater-pipeline-47298
[Accessed August 2016].

DNV GL, 2015. *3rd Release of Model Validation Data (depressurisation tests on a CO_2 pipeline),* CO_2 PipeTrans Phase2 Joint Industry Program.

DNV GL, 2015. *4th Release of Model Validation Data (experimental discharge data for large diameter CO_2 releases).,* CO_2PipeTrans Phase 2 Joint Industry Program.

DNV GL, 2016. CO_2PIPETRANS.
ONLINE ▶ Available at: https://www.dnvgl.com/oilgas/joint-industry-projects/ongoing-jips/co2pipetrans.html
[Accessed August 2016].

Dugstad, A., Halseid, M. & Morland, B., 2014. Testing of CO_2 Specifications With Respect to Corrosion and Bulk Phase Reactions. *Energy Procedia,* 63(GHGT-12), p. 2547–2556.

Elshahomi, A. et al., 2015. Decompression wave speed in CO_2 mixtures: CFD modelling with the GERG-2008 equation of state. *Applied Energy,* Volume 140, pp. 20-32.

Energy Pipelines CRC, 2016. New international funding awarded to improve CO_2 pipelines.
ONLINE ▶ Available at: http://epcrc.com.au/about/news/new-international-funding-awarded-to-improve-co2-pipelines
[Accessed August 2016].

Gassco, 2016. Study contracts for carbon dioxide transport.
ONLINE ▶ Available at: https://www.gassco.no/en/media/news-archive/-Study-contracts-for-carbon-dioxide-transport/
[Accessed August 2016].

Global CCS Institute, 2012. *Carbon Dioxide (CO_2) Distribution Infrastructure,* Canberra, Australia: Global CCS Institute.

Global CCS Institute, 2015. *The Global CCS Institute and the International Organization for Standardization (ISO)..*
ONLINE ▶ Available at: http://hub.globalccsinstitute.com/sites/default/files/publications/192273/information-sheet-global-ccs-institute-international-organization-standardization-iso.pdf
[Accessed 2015].

Hetland, J., 2014. CO_2 transport systems development: Status of three large European CCS demonstration projects with EEPR funding. *Energy Procedia,* Volume 63, p. 2458 – 2466.

ICF, 2009. *Developing a Pipeline Infrastructure for CO_2 Capture and Storage: Issues and Challenges, Report to INGAA Foundation:* Cambridge University Press.

IMO, 2016. I*GC Code 2016 Edition,* London, UK: International Maritime Organization.

Interstate Oil and Gas Compact Commission, 2010. *Policy, legal, and regulatory evaluation of the feasibility of a national pipeline infrastructure for the transport and storage of carbon dioxide, Submitted to Southern States Energy Board,* US., Oklahoma City, USA

ISO, 2016. ISO/FDIS 27913 - *International Standard Carbon dioxide capture, transportation and geological storage — Pipeline transportation systems (FINAL DRAFT),* Geneva, Switzerland: International Organisation for Standarization.

Kinder Morgan, 2015. Cortez Pipeline and McElmo Creek Pipeline.
ONLINE ▶ Available at: http://www.kindermorgan.com/pages/business/co2/pipelines/transport_cortez.aspx
[Accessed August 2016].

Knoope, M., Ramírez, A. & Faaij, A., 2015. Investing in CO_2 transport infrastructure under uncertainty: A comparison between ships and pipelines. *International Journal of Greenhouse Gas Control,* Volume 41, p. 174–193.

Liu, X. et al., 2014. Source strength and dispersion of CO_2 releases from high-pressure pipelines: CFD model using real gas equation of state. *Applied Energy,* Volume 126, pp. 56-68.

Liu, X. et al., 2015. Study of the consequences of CO_2 released from high-pressure pipelines. *Atmospheric Environment,* Volume 116, p. 51–64.

Lu, C., G, M. & Venton, P., 2015. *A new fracture velocity model for high grade gas pipelines.* Paris, Joint Technical Meeting (JTM) on Pipeline Research.

Mahgerefteh, H., Brown, S. & Denton, G., 2012. Modelling the impact of stream impurities on ductile fractures in CO_2 pipelines. *Chem Eng Sci, V*olume 74, pp. 200-210.

McGillivray, A. & Wilday, J., 2009. *Comparison of risks from carbon dioxide and natural gas pipelines,* UK: Health and Safety Laboratory.

Mohitpour, M. et al., 2012. *Pipeline transportation of carbon dioxide containing impurities.* New York, USA: ASME Press.

Neele, F., Haugen, H. & Skagestad, R., 2014. Ship transport of CO_2 – breaking the CO_2-EOR deadlock. *Energy Procedia,* Volume 63, p. 2638 – 2644.

Neele, F. et al., 2011. Large-scale CCS transport and storage networks in North-west and Central Europe. *Energy Procedia,* 4 (10th International Conference on Greenhouse Gas Control Technologies), p. 2740–2747.

NETL, 2013. *Carbon Dioxide Transport and Storage Costs In NETL Studies Quality Guidelines for Energy Systems Studies:* US Department of Energy.

NETL, 2013. *Quality Guidelines for Energy System Studies, "CO_2 impurity design Parameters"*: DOE/NETL.

Serpa, J., Morbee, J. & Tzimas, E., 2011. *Technical and Economic Characteristics of a CO_2 Transmission Pipeline Infrastructure - EUR 24731 EN,* Luxembourg: European Commission Joint Research Centre.

Shell Canada Ltd, 2015. *Quest Carbon Capture and Storage Project - Annual Summary Report,* sl: Alberta Department of Energy.

Sherpa Consulting, 2015. *Dispersion modelling techniques for carbon dioxide pipelines in Australia (20873-RP-001),* Melbourne, Australia: Brown Coal Innovation Australia Limited.

Sim, S. et al., 2014. Investigating the Effect of Water Content in Supercritical CO_2 as Relevant to the Corrosion of Carbon Capture and Storage Pipelines. *Corrosion,* 70(2), pp. 185-195.

Spinelli, C. & Demofonti, G., 2011. Technical challenges facing the transport of anthropogenic CO_2 by pipeline for carbon capture and storage purposes. *6th Pipeline Technology Conference.*

Statoil, 2015. Snøhvit.
ONLINE ▶ Available at: http://www.statoil.com/en/OurOperations/ExplorationProd/ncs/snoehvit/Pages/default.aspx
[Accessed August 2016].

The Linde Group, 2016. CO_2 for Greenhouses.
ONLINE ▶ Available at: http://www.the-linde-group.com/en/clean_technology/clean_technology_portfolio/co2_applications/greenhouse_supply/index.html
[Accessed 29 August 2016].

Uilenreef, J. & Kombrink, M., 2013. *Flow assurance & control philosophy: Rotterdam Opslag en Afvang Demonstratieproject (ROAD),* Melbourne: Global CCS Institute.

Wallace, M., Goudarzi, L., Cllahan, K. & Wallace, R., 2015. *A Review of the CO_2 Pipeline Infrastructure in the US (DOE/NETL-2014/1681),* Pittsburgh, PA: US Department of Energy - National Energy Technology Laboratory.

Wareing, C., Fairweathera, M., Woolleya, R. & Falleb, S., 2014. Numerical Simulation of CO_2 Dispersion From Punctures and Ruptures of Buried High-pressure Dense Phase CO_2 Pipelines with Experimental Validation. *Energy Procedia,* 63(GHGT-12), p. 2500–2509.

Wareing, C., Fairweather, M., Falle, S. & Woolley, R., 2015. Validation of a model of gas and dense phase CO_2 jet releases for carbon capture and storage application. *International Journal of Greenhouse Gas Control,* Volume 20, pp. 254-271.

Woolley, R. et al., 2014. CO_2PipeHaz: Quantitative Hazard Assessment for Next Generation CO_2 Pipelines. *Energy Procedia,* Volume 63, pp. 2510-2529.

Woolley, R. et al., 2014. An integrated, multi-scale modelling approach for the simulation of multiphase dispersion from accidental CO_2 pipeline releases in realistic terrain. *International Journal of Greenhouse Gas Control,* Volume 27, pp. 221-238..

Yara, 2015. *New liquid CO_2 ship for Yara.*
ONLINE ▶ Available at: http://yara.com/media/news_archive/new_liquid_co2_ship_for_yara.aspx
[Geopend 31 August 2016].

INTERNATIONAL STANDARDS AND CODES APPLICABLE TO CO_2 TRANSPORT

ISO 27913 *(under publication),* International Standard Carbon dioxide capture, transportation and geological storage — Pipeline transportation systems

ISO 13623, Petroleum and natural gas industries — Pipeline transportation systems

ISO 15156-1, Petroleum and natural gas industries — Materials for use in H_2S-containing environments in oil and gas production — Part 1: General principles for selection of cracking-resistant materials

ISO 16708, Petroleum and natural gas industries — Pipeline transportation systems — Reliability-based limit state methods

ISO 17776, Petroleum and natural gas industries — Offshore production installations — Guidelines on tools and techniques for hazard identification and risk assessment

ISO/AWI TR 27912, Carbon dioxide capture – Carbon dioxide capture systems, technologies and processes

ISO 31000, Risk management — Principles and guidelines

EN 1594, Gas infrastructure — Pipelines for maximum operating pressure over 16 bar — Functional requirements

AS 2885, Pipelines for Gas and Liquid Petroleum

ASME B 31.4, Pipeline Transportation Systems for Liquids and Slurries, 2012-00-00

ASME B31G, Manual for Determining the Remaining Strength of Corroded Pipelines: Supplement to ASME B31 Code for Pressure Piping, 2012-24-10

CSA Z662-2015, Oil and Gas Pipeline Systems, Canadian Standard Association

DNV-RP-J202, Design and Operation of CO_2 Pipelines

DNV-OS-F101, 2013, Submarine Pipeline Systems

DNV-RP-C203, Fatigue Strength Analysis of Offshore Steel Structures

DNV-RP-F107, Risk Assessment of Pipeline Protection

DNV-RP-F116, Integrity Management of Submarine Pipeline Systems

NACE MR0175/ISO 15156-1, Petroleum and natural gas industries — Materials for use in H_2S-containing environments in oil and gas production — Part 1: General principles for selection of cracking-resistant materials

NACE TM0192-2003, Evaluating Electrometric Materials in Carbon Dioxide Decompression Environments

NACE TM 0297-2002, Effects of High-Temperature, High-Pressure Carbon Dioxide Decompression in Electrometric Materials

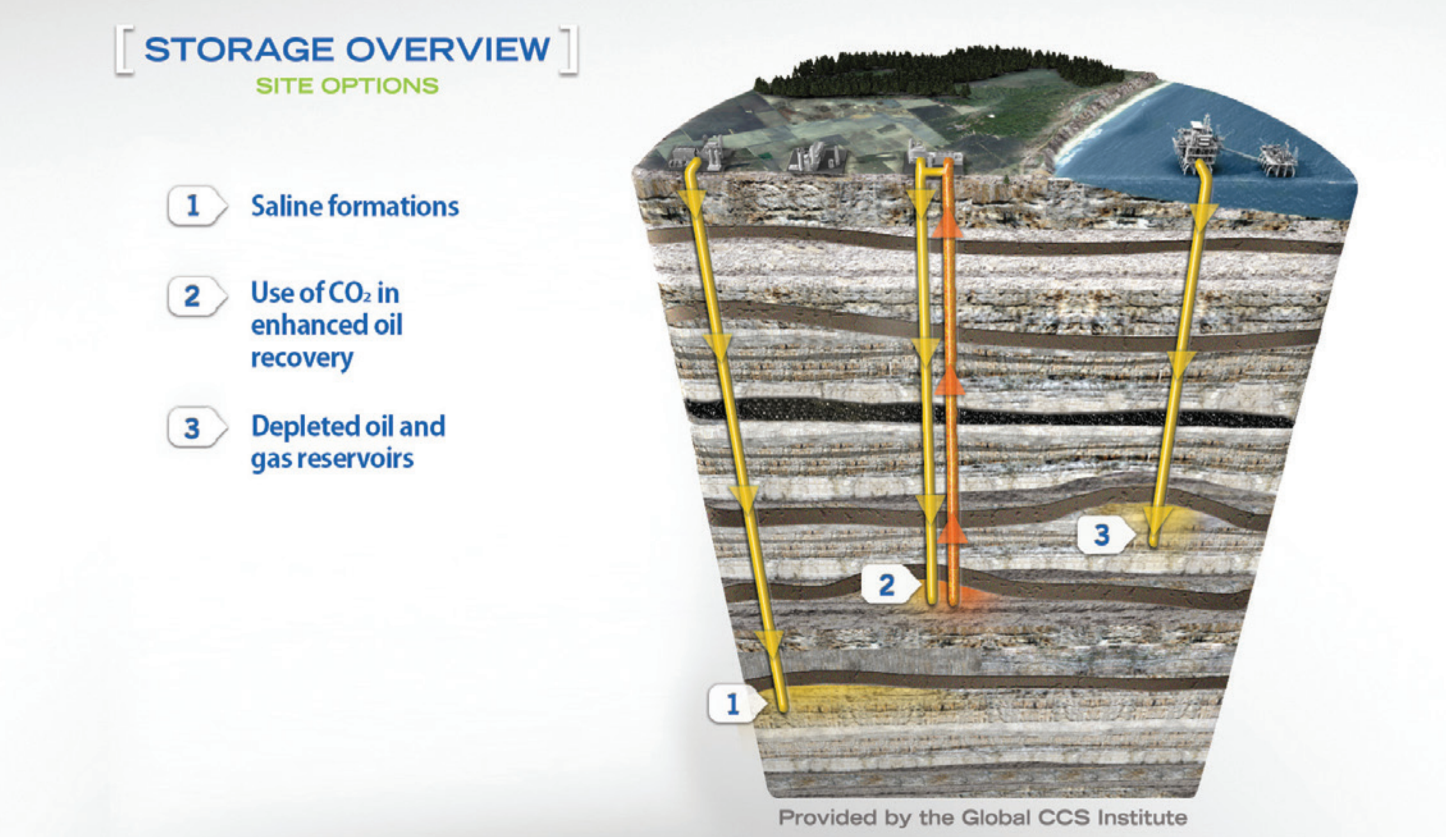
NORSOK Z-013, Risk and emergency preparedness analysis

PHMSA, Pipeline and Hazardous Materials Safety Administration, Pipeline Safety Regulations PART 195

NOTES

[3]

STORAGE



Provided by the Global CCS Institute

SECTION HIGHLIGHTS

- Fifteen dedicated geological storage projects, each having reached or soon projected to reach a total of at least 50,000 tonnes of injected CO_2, have been reviewed for learnings about injectivity.
- Adequate injectivity has been demonstrated by dedicated geological storage projects across a range of geological settings, depths and reservoir rock-types.
- Most dedicated geological storage projects to date have successfully targeted sandstone reservoirs in deep saline formations, including at commercial scale. Depleted gas fields also offer significant opportunities for dedicated storage, and have been demonstrated at small scale.
- Technical factors which control injectivity include reservoir permeability, thickness and pressure, in addition to engineering factors, including well construction and CO_2 stream composition.
- An understanding of the environment in which reservoir rocks were deposited can aid the interpretation of characterisation data.
- Reliable determination of injectivity for deep saline formations requires field testing of wells to account for heterogeneity (variability) in many reservoirs.
- Most of the reviewed projects conform to published site selection criteria; for example, minimum expectations of reservoir depth, thickness or permeability, that are used to undertake initial screening evaluations of dedicated geological storage sites at regional or national levels.
- Technology developed by the oil and gas industry provides remedial options for potential problems with injectivity at some sites, which can include unforeseen reservoir conditions or damage to the reservoir in the vicinity of a wellbore.
- Storage associated with CO_2-enhanced oil recovery can be undertaken in less favourable reservoirs than for deep saline formations, due to the typically large number of injection and production wells in comparison to dedicated storage sites.

3.1

INTRODUCTION

Geological storage of CO_2 (herein referred to as 'storage') has been successfully demonstrated over the last two decades as an essential element of integrated CCS projects. The secure storage of CO_2 has contributed significantly to the present understanding of subsurface CO_2 injection, which has also benefited from over four decades of CO_2-enhanced oil recovery (CO_2-EOR) operations, principally in the US.

There are three basic technical requirements for storage sites:

1. Containment – storage sites need to be able to securely store CO_2 in a subsurface reservoir(s) with low and manageable risks, including those associated with any potential leakage;
2. Capacity – storage sites need subsurface reservoirs that can permanently store the required amounts of CO_2;
3. Injectivity – storage sites require subsurface reservoirs that can accept CO_2 at an appropriate rate in relation to capture processes at the relevant industrial source(s).

The experience gained from both CO_2-EOR and dedicated storage projects, together with industrial analogues such as natural gas storage and acid gas waste disposal, has provided the foundation for an effective risk management process. This extensive experience ensures storage sites can be selected, characterised, operated and closed in a secure manner – addressing requirement *1 - Containment* above. The principles of this risk management process are described in Chapter 9 (Storage) of the *Global Status of CCS: 2014 report.*[1]

---

[1] (Global CCS Institute, 2014)

Regional storage resource assessments have been compiled by many key nations for the deployment of CCS, showing that very significant storage potential is present in relation to greenhouse gas mitigation targets. Volume 3 (CCS Technologies) of the *Global Status of CCS: 2015 report* provided a summary of regional resource assessments and concluded that sufficient storage resources are available to support CCS deployment in line with requirement *2 - Capacity* above.[2]

For this storage section of the *Global Status of CCS: 2016 report,* the focus is on requirement *3 – Injectivity.* The aim of the following section is to show that adequate injectivity has been achieved in a number of dedicated storage projects around the world and across a range of geological environments. The focus of the section is on projects where at least 50,000 tonnes (t) of CO_2 has been injected and stored in either deep saline formations or depleted gas fields; as at time of writing (end August 2016) twelve projects have been identified that meet this criteria. Three further projects are included in this review (bringing the total to 15 projects) (Figure 3.1 and Table 3.1):

- The Tomakomai CCS Demonstration Project began CO_2 injection in April 2016 and will soon reach the 50,000t milestone.
- The Gorgon CO_2 Injection Project is included as it will be largest geological storage project in the world, with CO_2 injection planned to begin in 2017.
- The Illinois Industrial Carbon Capture and Storage Project is included as it is expected to commence injection early in 2017. Note that this large-scale project is an extension of the Illinois Basin Decatur Project (IBDP) which injected almost one million tonnes of CO_2 into a deep saline formation in the three years to the end of November 2014.[3]

For the purposes of this report, injectivity can be regarded as the ability of a storage reservoir to accept an adequate flow rate of CO_2 from the relevant industrial source(s) within the safe limits of pressure management considerations. Injectivity can be defined in more precise mathematical terms for the purposes of reservoir engineering, but a detailed examination of such technical aspects of injectivity is considered beyond the scope of this section. Subsection 3.2 below does however provide an overview of some key factors that influence injectivity.

Figure 3.1 **Map of dedicated geological CO_2 storage projects that have injected, or will soon inject, greater than 50,000 tonnes**

---

[2] (Global CCS Institute, 2015)

[3] The IBDP was undertaken through the Midwest Geological Sequestration Consortium (MGSC) and its facilities will form part of the Illinois Industrial CCS Project.

This section outlines methods for determining injectivity and also provides some narrative on potential problems with injectivity, including case studies, and outlines some of the remedial options available to manage such issues.

The 15 projects which provide the data to inform this section are summarised in Table 3.1 below. The projects have been subdivided into commercial (greater than 1 million tonnes (MT) total CO_2 injection), demonstration (between 100,000 and 1MT total injection) and small scale (between 50,000t and 100,000t total injection). CO_2 storage in four of the projects is offshore and 11 are onshore. North America has the largest number of projects in this review (six) encompassing all storage sizes. Europe has five projects, three small scale and two at commercial scale (both in Norway). The Asia-Pacific region has three projects (one in Japan, two in Australia) and the remaining project is in Algeria.

All data related to the projects has been obtained from published sources, including the online Projects Database of the Global CCS Institute. However, the accuracy of data published may not be consistent across all projects.

The decision to limit this section to considering data from dedicated projects with over 50,000t of total CO_2 stored (or soon to have such an amount stored) is an arbitrary one, based on the need to consider significant scale projects for the analysis and work with a manageable dataset. Small-scale injection projects under 50,000t of total CO_2 injection have provided important technical and scientific learnings, and many are described on the Projects page of the Institute website. Similarly, CO_2-EOR projects have been omitted from the analysis because of the large number of operational projects of significant scale; key differences between dedicated storage and CO_2-EOR projects (from an injectivity perspective) are briefly discussed in subsection 3.6 below.

Table 3.1 **Dedicated geological CO_2 storage projects that have injected, or will soon inject, greater than 50,000 tonnes**

Project (injection period)	Country	Capture Facility	Storage Type	Total CO_2 Injection (MT)
In Salah (2004-2011)	Algeria	Natural gas processing	Deep saline formation	3.8
Sleipner (1996- current)	Norway	Natural gas processing	Deep saline formation	16 (to mid 2016)
Snøhvit (2008- current)	Norway	Natural gas processing	Deep saline formation	3.0 (to mid 2016)
Ketzin (2008-2013)	Germany	Hydrogen production	Deep saline formation	0.067
Lacq (2010-2013)	France	Lacq industrial complex	Depleted gas field	0.051
K12-B (2004-current)	Netherlands	Natural gas processing	Depleted gas field	0.095
Quest (2015-current)	Canada	Hydrogen production	Deep saline formation	1.0 (Sept. 2016)
Illinois Basin Decatur (2011-2014)	United States	Chemical production	Deep saline formation	0.99
Aquistore (2015-current)	Canada	Power generation	Deep saline formation	0.05 (to March 2016)
Plant Barry (2012-2014)	United States	Power generation	Deep saline formation	0.14
Michigan Basin Phase II (2009)	United States	Natural gas processing	Deep saline formation	0.06
Otway Stage 1 (2008-2009)	Australia	Natural CO_2 source	Depleted gas field	0.065

Project (injection period)	Country	Capture Facility	Storage	Target 2017 CO_2 Injection (MT)
Tomakomai (April 2016 start)	Japan	Hydrogen production	Deep saline formation	≥ 0.10 (Mtpa capacity)
Gorgon (2017 start*)	Australia	Natural gas processing	Deep saline formation	3.4-4.0 (Mtpa capacity)
Illinois Industrial Carbon Capture and Storage (2017 start)	United States	Chemical production	Deep saline formation	1.0 (Mtpa capacity)

Notes: **Institute estimated start date.*

3.2

TECHNICAL FACTORS AFFECTING INJECTIVITY

The technical factors controlling injectivity can be simply divided into two broad types:

- factors relating to natural characteristics of the storage reservoir and surrounding rock strata; and
- those factors relating to engineering design and operation of the CCS infrastructure; for example, wellbore construction or the composition and physical properties of the CO_2 injection stream resulting from the capture process.

3.2.1. Natural Characteristics

3.2.1.1. Geological Setting

The combination of natural characteristics required for storage reservoirs are typically found in basins – thick accumulations of sedimentary rocks which also host most of the world's fossil fuel resources. Each storage reservoir will have unique characteristics but there are two main rock-types that form suitable storage reservoirs, as well as most conventional oil and natural gas reservoirs:

- Sandstone, chiefly composed of grains of the minerals quartz and feldspar. Sandstones result from deposition and consolidation of sediments in a variety of environments including shallow marine, near shore (beach) or fluvial (rivers, meandering streams).
- Carbonates, either limestones or dolomites, deposited in marine environments through biological and/or chemical processes.

Both sandstone and carbonate reservoirs are naturally suitable for storage because they inherently allow the flow of fluids. But in reality, this flow can be variable due to significant heterogeneity – that is, variability of rock-types and mineralogy that can affect both injectivity and capacity. However, an understanding of the depositional environment can help engineers and geologists interpret characterisation data obtained from wells and geophysical surveys (Table 3.2). For both reservoir rock-types, how the rock has changed since deposition can significantly impact reservoir quality. This is often referred to as burial history or diagenesis and an example would be the precipitation of minerals in pore spaces during burial and consolidation of the sediments into rock, which would affect the fluid flow characteristics of the reservoir.

Table 3.2 **Depositional environments of reservoirs with significant storage potential**

Depositional Environment	Description	Typical Rock-Types	Heterogeneity	Storage Reservoir Potential
Delta	Mouth of a river	Highly variable mix dependent on environment; carbonates, sands, muds	Variable	High
Shelf	Shallow marine, between coast and deep marine	Highly variable mix dependent on environment; carbonates, sandstone, mudstone	Moderate to high; dependent on environment	
Strandplain/ Coastal	Coastal zone including beach	Primarily sandstone with minor carbonate sediment	Low to moderate	
Reef	Reef structure and carbonate debris surrounding reef	Carbonate with minimal terrestrial sediments	Low; subject to diagenesis	
Fluvial	River or streams	Terrestrial sediments; massive to mixed combination of sandstone ranging to mudstone	Variable; dependent on flow of system	Medium
Alluvial	Lake or river	Terrestrial sediments; typically mix of sands to mudstone. Often rapid deposition.	Variable; generally low	
Aeolian	Wind-blown deposition; typically deserts	Fine sandstones	High	
Turbidite	Mass flow onto sea floor	Massive sandstones, or carbonates often fining upwards to mudstone. Rapid deposition.	High	

Based on "Geological Storage Formation Classification" description contained in NETL (2013).[4]

3.2.1.2. Reservoir Properties

All storage reservoirs require certain basic and often inter-related properties to allow adequate injectivity and capacity. Porosity is the total proportion of the reservoir rock comprising pore spaces between individual grains; the pore spaces are occupied by fluids, most typically highly saline groundwater (brines). Porosity values greater than 10 per cent are typically considered favourable for storage reservoirs.[5]

Permeability is the ability of the rock to allow movement of fluids within the reservoir and thus has a fundamental influence on injectivity. The unit of permeability measurement is the Darcy, derived from Darcy's Law which governs fluid flow through porous media, including rocks; the permeability of storage reservoirs are typically expressed in units of millidarcy (mD). Published storage site selection criteria have variously suggested a minimum permeability value of 20mD,[6] and a 'positive indicator' minimum value of 300mD.[7] Note that because reservoir rocks typically display a degree of heterogeneity, permeability can be variable across the reservoir and can also be different in horizontal and vertical directions. The reservoir permeability values for storage projects used in this report have been obtained from published data sources and generally refer to mean or typical values for the reservoir in question. Relative permeability is another flow parameter that affects injectivity, basically describing the relative ease with which co-existing fluid phases (e.g. native brine and injected CO_2) can flow through a reservoir at the same time. Relative permeability is discussed further in subsection 3.3 below.

Reservoirs need adequate thickness (coupled with sufficient permeability) to allow the flow of injected CO_2 away from the wellbore at the required injection rate, and to provide the capacity to store sufficient quantities of CO_2. Published site selection criteria have suggested a minimum reservoir thickness of 20 metres,[8] which can range up to a 'positive indicator' minimum of 50 metres.[9]

---

[4] (NETL, 2013)
[5] (IEAGHG, 2009a)
[6] (IEAGHG, 2009a)
[7] (Chadwick, et al., 2008)
[8] (IEAGHG, 2009a)
[9] (Chadwick, et al., 2008)

The lateral extent of a reservoir away from wellbore(s), in combination with thickness, determines not only storage capacity but also injectivity over time. If the lateral extent of a reservoir is limited by faulting or thinning due to changes in rock-type, injectivity will decline more rapidly with time as pressure build up approaches acceptable limits. Reservoirs affected by faults which act as lateral flow barriers are often referred to as compartmentalised, and the resulting fluid flow systems are described as closed. Storage is preferable in reservoirs unaffected by faulting and with greater lateral continuity, resulting in fluid flow systems described as open.

3.2.1.3. Pressure and Temperature

Injectivity depends on the difference in pressure at well perforations between the injected fluid (CO_2) and the reservoir. As pressure in the reservoir increases as a result of injection, this difference decreases, leading to a decrease in injectivity. In cases where the storage reservoir has excellent natural charateristics and a very large capacity, this pressure increase may not be significant over a period of decades. In contrast, this temporal decrease in injectivity could affect operations in less favorable storage reservoirs and require mitigation techniques, as discussed in the following sections.

Injecting significant quantities of CO_2 into a reservoir means additional fluid is being added to a rock that is already saturated, typically with brine. This inevitably results in an increase in the reservoir pressure. At depths of greater than 800 metres the pressure is high enough for the CO_2 to remain in a supercritical or dense phase state, the most efficient method of storage. The rock sequence overlying the reservoir (overburden) largely determines reservoir pressure; so the deeper the reservoir, the higher the pressure. With the addition of CO_2 the reservoir pressure will increase. A pressure increase becomes exponential if the existing fluids cannot move away from the injection point easily, either because the reservoir is confined or compartmentalised by faults. Adequate monitoring of injection rates and pressures is required to maintain supercritical CO_2 and ensure the reservoir pressure does not exceed either the caprock capillary entry pressure or the reservoir/caprock fracturing pressure(s). Reservoir pressure can be measured and managed using basic oil and gas industry techniques and technologies. In some geological settings, reservoir rocks have relatively high in-situ pressures due to a combination of regional fluid flow patterns and geological structure. Such reservoirs are termed 'over pressured' and have less scope for accommodating the pressure increases from CO_2 injection.

One theoretical solution to aid pressure management and increase capacity would be to remove some of the highly saline groundwater (or brine) that occupies the pore spaces of deep saline formations, thereby reducing pressures and creating more 'space' for injected CO_2. This concept of brine extraction has been dubbed 'enhanced water recovery', to draw a parallel with the established EOR industry. Enhanced water recovery offers significant potential benefits to CCS projects through increased storage capacity in deep saline formations, improved reservoir pressure management strategies and potential economic and environmental benefits from the extracted brine. However, the costs associated with storage may increase with the application of enhanced water recovery because of increased drilling requirements and brine treatment. An alternative approach would be to re-inject untreated brine into other permeable rock strata in the vicinity of the storage site, thereby spreading increased pressure over a much larger volume of rock.

Injection into depleted gas fields typically face different challenges to deep saline formations. Many gas fields are encountered where compartmentalisation of the reservoir has acted as a trapping mechanism for the gas, and fluid flow connectivity with adjacent rock strata is also very low. Hence gas production results in depressurisation of the reservoir, and this creates 'space' for CO_2 injection. As a result, injectivity can be relatively high – even where permeability is relatively low. However, such low baseline pressures (post hydrocarbon production and pre CO_2 injection) may be unable to sustain dense phase storage during the early stages of injection, so management of phase behavior in the wells and reservoir requires careful design.

The density of CO_2 depends not only on the pressure of a reservoir, as discussed above, but also the temperature. Comparable to pressure, the subsurface has a natural temperature gradient and reservoirs will typically have suitable temperatures for dense phase storage at or below 800 metres depth. Reservoir temperature influences the migration of CO_2; higher temperatures lower the density of CO_2 and therefore reduce the efficiency of storage. Also, the viscosity of the injected fluid decreases with increasing temperature, in contrast to increasing pressures which increase viscosity. Lower viscosity leads to higher injectivity.

Temperature contrasts between injected CO_2 and the reservoir also need to be managed, as large contrasts can present risks of physical damage to the wellbore and reservoir through thermal stresses conducive to rock or well cement cracking.

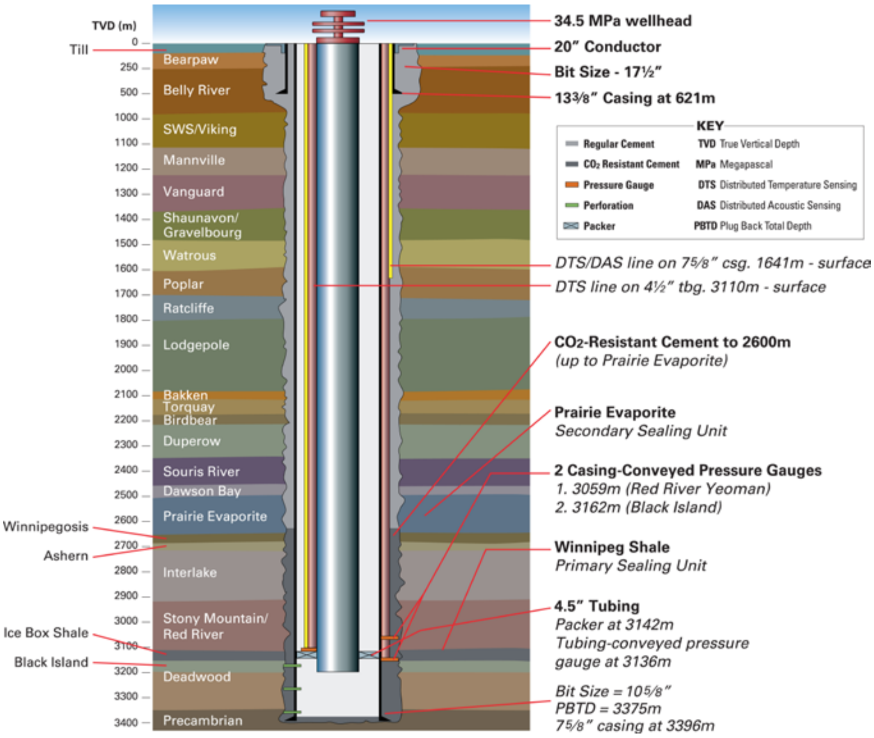
3.2.2. Engineering Aspects

3.2.2.1. Wells

The drilling of deep wells through sedimentary rock sequences as required for conventional storage scenarios is essentially the same technology that has been developed by the oil and gas industry over many decades of operation, including over 40 years of experience gained from CO_2-EOR operations. Storage is achieved by pumping CO_2 into the injection well(s) at higher pressures than the in-situ conditions of reservoirs, which are typically at sufficient depths and pressures such that CO_2 will be in a supercritical or dense phase, ensuring the most efficient use of pore space in the reservoir rocks. CO_2 flows through perforations in the well casing into the reservoir and spreads out through the pore spaces, mixing with, and displacing the in-situ reservoir fluids – brine in the case of deep saline formations. CO_2 injection pressures need to be carefully controlled to maintain dense phase injection at the required rates without damaging the storage reservoir, well infrastructure or sealing rock layers above the reservoir.

Technological advances that have driven higher productivity from oil and gas reservoirs can also benefit storage. In particular, the development of directional or deviated drilling (inclined or angled away from vertical) allows well casings to be perforated in contact with more extensive sections of reservoirs in comparison to vertical wells, therefore increasing the efficiency of wells in injecting or extracting fluids as appropriate. Of the 15 dedicated storage sites listed in Table 3.1, four (In Salah, Sleipner, Gorgon, Tomakomai) have made use of deviated wells. An example of a dedicated (non-deviated) storage well design is shown in Figure 3.2, taken from the Aquistore project in Canada. Features which differentiate storage injection wells from typical oil and gas industry production wells may include the use of corrosion-resistant cement and steel to complete the well and provide an additional safeguard against the potential loss of zonal isolation and consequent risks associated with leakage.

Figure 3.2 **Typical CO_2 injection well. Example shown is from the Aquistore Project. Modified image courtesy of the Petroleum Technology Research Centre (PTRC)**



3.2.2.2. CO_2 Stream Composition

Impurities in CO_2 streams can cause significant changes in physical and chemical characteristics in relation to pure CO_2, and these in turn can affect injectivity and capacity. Impurities could affect the phase behaviour of CO_2 streams and in some cases increase the reservoir depths and pressures required to store CO_2 in a dense phase.

A study commissioned by the IEAGHG found that changes in fluid properties such as viscosity and density in a CO_2 stream with 15% impurities could result in up to a 10% decrease in injectivity across most storage scenarios, with relatively shallow and high temperature storage sites prone to greater effects.[10] The same study concluded that impurities could enhance the precipitation of minerals in reservoir rocks, thus reducing pore space and injectivity, although the 'drying out' zones in the vicinity of CO_2 injection wells could minimise this effect.

3.3

DETERMINATION OF INJECTIVITY

3.3.1. Predictive Modelling

Predictive modelling of CO_2 injection is a core activity in the design and operation of storage sites, and a requirement of emerging CCS and storage regulations across most jurisdictions. Models are used to determine the injectivity and capacity of storage sites, predict the likely flow and distribution of CO_2 in the reservoir, design and calibrate infrastructure and monitoring programs, and inform risk assessments and risk management plans. During injection operations, models are routinely calibrated against monitoring data to allow refinement and improved accuracy, and used as a benchmark for ongoing risk assessment. Upon storage site closure, many jurisdictions will require an acceptable level of conformance between monitored CO_2 behavior and predictive models prior to licence or permit surrender.

The modelling process can be undertaken with a variety of commercial or research simulation software packages. Comparative studies (e.g. IEAGHG modelling network[11]) have shown that the choice of modelling software influences modelling results much less than the choice of input parameters for the model. These input parameters describe the key physical and chemical properties of the reservoir relevant to injection, including those which govern injectivity as described in subsection 3.2 above. Since deep saline formation storage sites often have very limited pre-existing characterisation data available (in comparison to depleted oil and gas fields or CO_2-EOR operations), initial predictive modelling and assessment of injectivity may be subject to significant uncertainty.

3.3.2. Laboratory Testing

Where drill core samples are available from the storage reservoir or the same geological formation in reasonable proximity to the reservoir, laboratory tests can be used to determine many key reservoir parameters including porosity, permeability, relative permeability of CO_2 and reservoir water, and geomechanical properties. Such data are obviously more reliable than assumed or generic data, but care needs to be taken to ensure that sample representativeness of the reservoir is understood – many reservoirs having significant heterogeneity; for example, spatial variations in rock type or mineralogy.

Relative permeability is a term used to describe the relative movements of different fluids in the pore spaces of a reservoir. Relative permeability is another key parameter needed to assess injectivity for storage sites, since in the case of deep saline formations, both native brine and injected CO_2 will be present as fluid phases. Unlike permeability, relative permeability is not an intrinsic property of reservoir rocks since the nature of the respective fluids present within the pore space will influence

---

[10] (IEAGHG, 2011)
[11] (IEAGHG, 2016)

the property. The Institute has recently published two reports by Stanford University which address some of the issues and research priorities related to relative permeability.[12,13]

3.3.3. Field Testing

Injectivity testing involves pumping fluid into the reservoir at a constant rate and measuring the pressure response. Injection is then stopped and the decline in pressure over time to original equilibrium is measured; these pressure responses allow the hydraulic characteristics and injectivity of the reservoir to be determined. Use of CO_2 as the test fluid is clearly preferable for determining the injectivity of a CCS storage site. However, the relatively small quantities of CO_2 required are often unavailable or expensive to acquire prior to commissioning of the capture facility of a CCS project. There has therefore been a tendency to use water as a substitute for CO_2 for injectivity tests, with the test results being subject to a mathematical conversion to allow for the differing properties of CO_2 and water.

However, the use of water for injectivity testing loses relative permeability effects and also has an accompanying risk of affecting the performance of the wellbore through chemical reactions causing the precipitation of minerals/dissolved solids in and around the wellbore (also referred to as 'skin'). This risk can be reduced by ensuring that injected water has a dissolved solids (salinity) content closely matching that of the native fluids of the deep saline formation. In contrast, the excellent solvent properties of CO_2 ensure that skin issues are not a significant risk for CO_2 injection. Another potential solution in the absence of an economic CO_2 source for testing is to conduct a pumping test, where brine is extracted at a constant rate from the reservoir and with pressure responses monitored during pumping and in the recovery of equilibrium conditions after pumping.

CASE STUDY – The ZeroGen Project

The ZeroGen Project was located in south-eastern Queensland, Australia, and designed to capture 60-90MT of CO_2 over 30 years from a proposed coal-fired IGCC power plant with storage in the Surat Basin.[14] One of the reasons the project did not proceed was that injectivity tests found the required minimum storage capacity and associated injection rates could not be achieved.

The project completed water and CO_2 injection well testing of the storage formations through one dedicated well, and additional water injection testing in another four wells. Upon injection of CO_2, the permeability of the reservoirs was found to be lower than measured from core samples and interpreted from geophysical data. The reason for the low permeability of field tests when compared to measured results was the high degree of vertical and lateral heterogeneity in the reservoir. Core measurements, for example, can only measure a very small part of an overall reservoir, whereas injection testing essentially tests the entire reservoir. Hence, if a rock unit varies significantly away from the well, the measured core will be misleading.

The ZeroGen experience highlighted that practical storage capacity should be determined through injection or production testing and that static capacity calculations can be misleading. The severe heterogeneity of the reservoirs was due to the fluvial-deltaic depositional environment where sandstones with excellent reservoir properties were deposited in channels that were not extensively developed or connected. Additional heterogeneity resulted from post-deposition diagenesis. Consequently, the field test results significantly downgraded the predicted injectivity and therefore the viability of this large-scale CCS project proposal.

---

[12] (Benson et al., 2015a)
[13] (Benson et al., 2015b)
[14] (Garnett et al., 2014)

3.4

SUMMARY OF INJECTIVITY CHARACTERISTICS AT STORAGE PROJECTS

3.4.1. Storage Scenarios

The injection of CO_2 has been demonstrated on every continent across a variety of storage scenarios, geological settings, depths and at different scales (Tables 3.1, 3.3; Figures 3.1, 3.3). Deep saline formations are arguably the primary target for CO_2 storage projects because they are the most abundant, widespread and have the highest storage potential.[15] All but three of the projects reviewed are injecting into deep saline formations. The majority of those have targeted large, thick, laterally extensive sandstones with an overlying regional caprock. Examples are the Illinois projects in the US targeting the Mt. Simon Sandstone, Quest (Canada) injecting into the Basal Cambrian Sandstone, and the Sleipner Project storing CO_2 in the Utsira Sand in the Norwegian North Sea. Drawing from knowledge of oil and gas fields, some projects have targeted folded layers of rock known as anticlines, as in the case of the Ketzin Project.

Depleted gas fields provide readily available and accessible dedicated storage targets.[16] This is partly because, unlike the majority of deep saline formations, depleted gas fields have been thoroughly characterised with a large amount of data, including production history. This data and knowledge of the reservoir can be easily adapted to storage and greatly reduce the duration of investigations into storage suitability. Also, depleted gas fields generally have existing infrastructure, including well(s) and surface facilities which enable immediate use of the reservoir. For this reason a number of small-scale projects have targeted these fields, including the Otway and Lacq projects.

There are also projects which could be regarded, to some extent, as hybrids of deep saline formation and depleted gas field, by injecting into the same formation as a nearby operating gas field; the In Salah and Snøhvit projects are commercial scale examples. At the Snøhvit project, the Stø Formation was a secondary option (see later case study) and at In Salah, the same formation as gas production was selected based on a risk and cost analysis.[17] The K12-B project, on the other hand, used the CO_2 for enhanced gas recovery; by injecting down dip, CO_2 increased the pressure in the gas-filled section of the reservoir thus increasing production.

The majority of projects target sandstones for injection because they are a more common reservoir rock than carbonates; only two of the projects in this assessment use carbonate reservoirs (Lacq and Michigan Basin Phase II). Specifically, the majority of the sandstones were deposited in environments where significant accumulations of sand are typically found, in fluvial settings (rivers, meandering streams) and in the delta/shallow marine settings (beach sands and river mouths) (Table 3.3). Two of the larger projects, Gorgon and Sleipner, target thick sequences of sandstones which were deposited in deep marine environments during mass flows onto the sea floor known as turbidite fans.

On the other hand, the Michigan Basin and Lacq projects inject into carbonate reservoirs sealed by lower permeability carbonates and clastics. In fact, the Michigan Basin project's immediate overlying caprock is a salt deposit. Carbonate reservoirs are commonly encountered in CO_2-EOR projects such as the Weyburn and Midale oil fields in Canada, where approximately 3MT of anthropogenic CO_2 is currently injected annually into relatively low permeability carbonates. These CO_2-EOR operations provided the opportunity for storage research in the form of the IEAGHG Weyburn-Midale CO_2 Monitoring and Storage Project.[18]

---

[15] (Global CCS Institute, 2015)
[16] (IEAGHG, 2009b)
[17] (Mathieson, et al., 2011)
[18] (Wildgust et al., 2013)

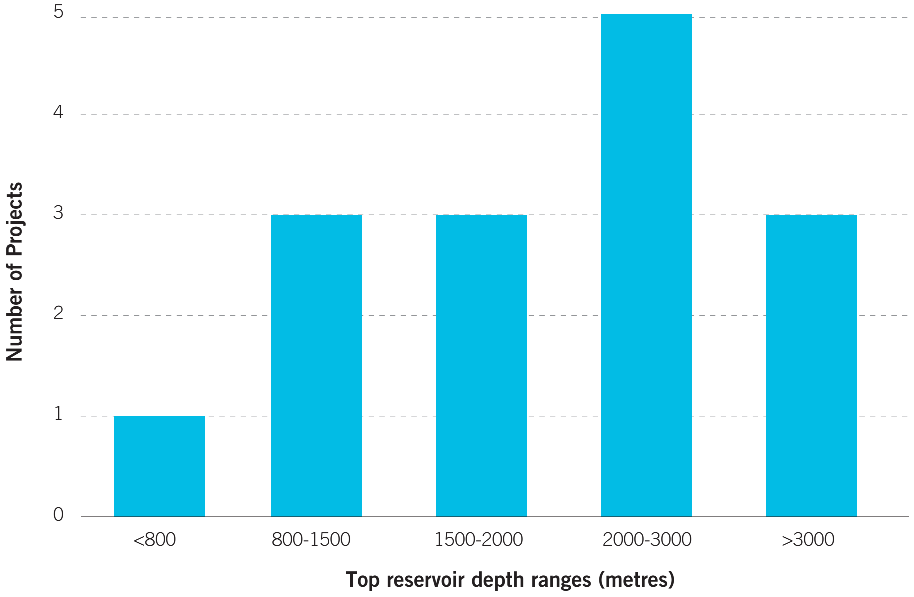
Table 3.3 Number of projects against reservoir depositional environment

Project Scale (Tonnes)	High Storage Potential Depositional Environments					Medium Storage Potential Depositional Environments			
	Delta	Shelf Clastic	Shelf Carbonate	Strand-plain/ Coastal	Reef	Aeolian	Fluvial-Alluvial	Fluvial-Delta	Turbidite
50,000 – 100,000	2	1	2	-	-	1	1	-	-
100,000 – 1 million	-	-	-	1	-	-	-	1	-
<1 million	2	-	-	1	-	-	-	1	2

3.4.2. Reservoir Properties

All but one of the reviewed projects injected and stored CO_2 at depths greater than 800 metres, with a majority injecting deeper than 1,500 metres (Figure 3.3). The Ketzin Project is the shallow anomaly, where injection at around 630 metres was unable to store CO_2 as a dense phase fluid but nevertheless supported a pilot-scale storage project and successful monitoring research project.[19] At the shallowest commercial scale project, Sleipner, dense phase CO_2 is injected at a depth of around 1,000 metres and CO_2 has migrated to the top of reservoir at about 800 metres depth, remaining in the dense phase.[20] At the extreme end of the depth range is the Lacq Project, which injected at about 4,500 metres. The wide range of project injection depths shows that depth is not a barrier to a storage project, provided dense phase storage can be achieved.

Figure 3.3 Depth to the top of CO_2 storage reservoir



The majority of small-scale projects reviewed, along with three commercial scale projects (Illinois, In Salah and Gorgon) have permeability of less than 100mD. The remaining projects, with the exception of the 1,000+ mD of Sleipner, have permeability between 200 and 500mD. The commercial scale Quest project has found permeability to be higher than the published characterisation data used in this assessment, with operational experience suggesting a value of close to 1,000mD (Simon O'Brien, Shell Canada, personal communication).

---

[19] (Martens et al., 2012)

[20] (Cavanagh & Hazeldine, 2014)

Figure 3.4 shows a plot of reservoir thickness versus permeability, with the 15 reviewed projects compared to published site selection criteria which may be used as guidelines for regional storage resource mapping and also aid in the identification of prospective storage sites. Whereas the majority of projects fall within the criteria defined as 'favourable' by the IEAGHG,[21] only two projects comfortably meet the criteria defined as 'positive' by Chadwick, et al.[22] The mathematical product of reservoir permeability and thickness can also be used as a measure of injectivity potential, with units in Darcy-metres.[23] Figure 3.5 shows that the majority of the reviewed projects have an injectivity potential of between 10-100 Darcy-metres across all three project scales. Only one project, Sleipner, has an injectivity of greater than 100 Darcy-metres.

Figure 3.4 **Reservoir thickness and permeability of storage projects. Trend lines are the minimum limits for site selection criteria according to a. Chadwick et al.[24] b. IEAGHG[25]. Note: The average permeability value has been used where reported, or the median value where a range is quoted**

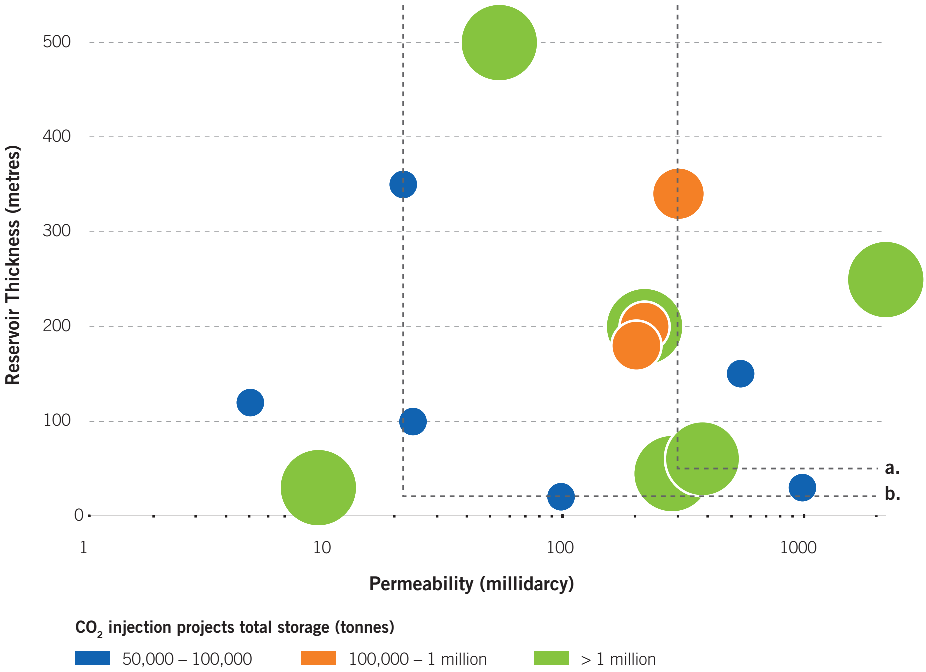
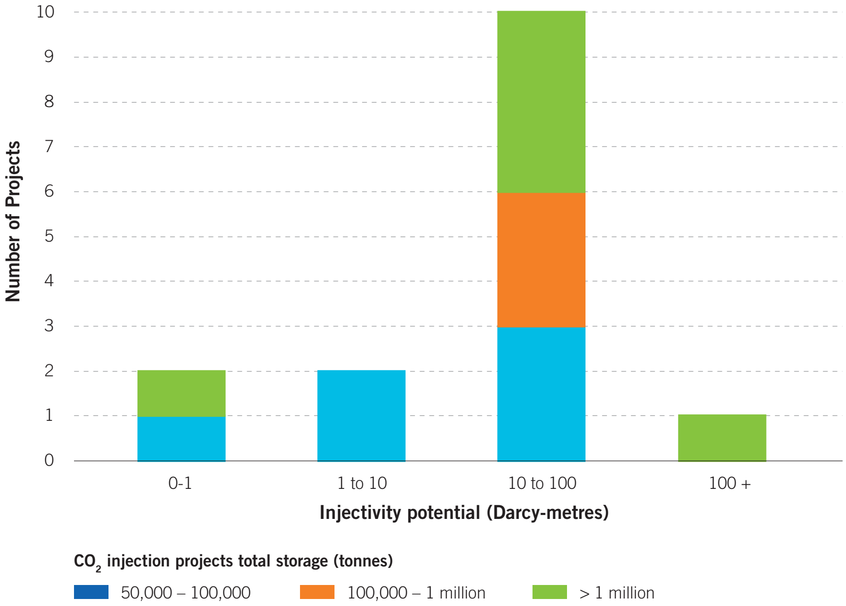


Figure 3.5 **Injectivity potential of project storage formations**



---

[21] (IEAGHG, 2009a)
[22] (Chadwick, et al., 2008)
[23] (Hosa et al., 2011)
[24] (Chadwick, et al., 2008)
[25] (IEAGHG, 2009a)

In all storage projects, the baseline reservoir pressure (prior to injection), injection pressure and fracture pressure are critical to the injection and containment of the CO_2. The baseline reservoir pressure for most projects is dependent on depth, and therefore the deeper projects have higher reservoir pressures. Figure 3.6 shows the increasing reservoir pressures with depth; note the trend is very clear but the plots do not form a simple straight line – this is because the pressure gradient will vary between different basins and site locations. Two depleted gas field sites show anomalous pressures with respect to gradients, because gas production has resulted in significant pressure depletion from compartmentalised reservoirs. For example, the very deep Lacq Project (~4,500 metres) had a post-production/pre-injection pressure of 4MPa (megapascal).

Figure 3.6 **Reservoir top depth and pressure of storage projects. Trend line is the minimum limit for site selection criteria according to a. IEAGHG.[26] Note: Chadwick et al.[27] did not include pressure criteria**

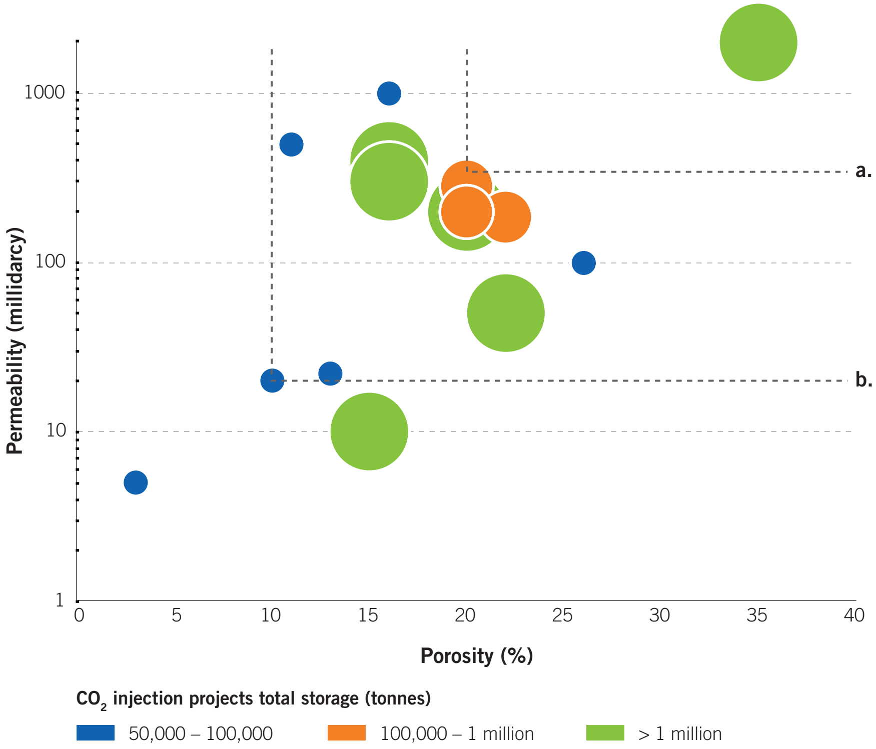
Figure 3.7 provides a plot of porosity against permeability for the reviewed projects. This plot shows a broad correlation between the two parameters, which would be expected given that the majority of reservoirs are sandstone (carbonate reservoirs are more likely to have a significant proportion of unconnected pores, giving rise to lower or more variable permeability at the same porosity value compared to sandstones). The plot again shows that the site selection criteria defined by the IEAGHG encompass most of the reviewed projects.

---

[26] (IEAGHG, 2009a)

[27] (Chadwick, et al., 2008)

Figure 3.7 **Reservoir porosity and permeability of storage projects. Trend lines are the minimum limits for site selection criteria according to a. Chadwick et al.[28] b. IEAGHG[29]. Note: The average porosity and permeability value has been used where reported, or the median value where a range is quoted**



3.4.3. Engineering

The range of geological environments and reservoir properties encountered by storage projects, as described above, has partly been made possible by advances in drilling technology. The number of wells an operator selects for injection is dependent on the rate of injection and the local reservoir conditions. The number of wells can typically increase the amount of CO_2 injected subject to reservoir specific issues, however fewer wells also cost less. The majority of storage operations reviewed use a single injection well per reservoir, but that is partly because of the relatively low injection rates in some of the projects. Multiple wells may be frequently needed as injection rates of over 1MT per annum are more commonly required for CCS deployment. Quest uses three wells to inject around 1MT per annum and Gorgon will likely utilise up to nine wells to reach an annual target injection rate of up to 4MT. Also, multiple wells may be needed where the permeability is low or where fracture pressure is lower than the injection rate pressure for a single well.

An alternative or complementary approach to multiple vertical wells is using deviated or horizontal wells, resulting in a greater access to the reservoir. The Sleipner project uses a horizontal well with a perforated injection interval of over 30 metres to achieve the required injectivity of around 1MT of CO_2 per year. The Tomakomai project is possibly the most advanced version to date using a highly deviated well to extend from onshore to the near shore. In the primary reservoir of the project, the storage site is around 3,000 metres offshore. CO_2 is then injected through a 1,000 metre long perforated well that enables a high rate of injection into the reservoir. This well design is cost effective as an onshore well site is cheaper and easier to maintain than an offshore platform well site.

In addition to deviated wells, the use of pressure-relief wells (alternatively called water management wells) can also enable higher injection rates and increase storage capacity. The production of water and then re-injection is standard practice in the oil and gas industry. The Gorgon CO_2 Injection Project provides a relevant case study.

---

[28] (Chadwick, et al., 2008)

[29] (IEAGHG, 2009a)

CASE STUDY – Gorgon CO_2 Injection Project

The injection facilities for the Gorgon CO_2 Injection Project are located on Barrow Island, approximately 70 kilometres off the northwest coast of Western Australia. The project plans to capture and store up to 4MT of CO_2 per annum as part of a large LNG development. The CO_2 injection project, which will be the world's largest in a deep saline formation when fully operational, plans to permanently store about 120MT of CO_2 over 30 years. Injection will be into the Dupuy Formation reservoir, approximately 2.3 kilometres below Barrow Island. Overall, the reservoir is thick (200-500 metres) with good porosity around 22 per cent and a permeability range of between 30-100mD. The Institute anticipates that CO_2 injection will begin 2017.

The injection strategy includes five drill centres. Three will contain the nine deviated injection wells which will deliver over 10,000 tonnes per day (tpd) of CO_2 into the Dupuy Formation. The remaining two drill sites will both have two pressure management wells (water production wells). Using a submersible electric pump in the wells, they will produce saline formation water from the Dupuy Formation. Two wells will then inject this brine into an overlying deep saline formation. The pressure management system was required to reduce the impact of rising pressure due to the large tonnage of CO_2. This will enable the project to maintain the required injection rates whilst ensuring that pressure increases are managed within permitted limits. An additional benefit of production wells is the ability to modify CO_2 plume migration towards a preferred and predicted direction.

3.5

CHALLENGES AND REMEDIAL OPTIONS

Managing uncertainty and risk is an inherent aspect of the exploitation of subsurface resources, including storage. The injectivity of a storage reservoir is subject to a number of natural and engineering factors as described in the sections above. The performance of injection wells may in some cases be less than predicted, or can deteriorate over time. The causes of injectivity problems can broadly be divided into those due to unforeseen reservoir characteristics, or those caused by engineering aspects of the CCS project and/or the injection well(s).

Reservoir performance issues can be experienced where any of the natural characteristics described in Subsection 3.2 turn out to be less favourable than anticipated or modelled prior to injection – for example, lower permeability, reduced reservoir thickness or reduced storage volume available due to compartmentalisation caused by faulting. In these instances, remedial options to improve injectivity could include additional injection wells and/or storage in alternative reservoirs. The Snøhvit project provides an example of where injectivity issues required adoption of a new strategy, as described in the case study below.

CASE STUDY – Snøhvit CO_2 Storage Project

The Snøhvit project is located in the Barents Sea off the north Norwegian coast. Approximately 700,000 tonnes of CO_2 per year is stripped from an onshore LNG facility and injected approximately 150 kilometres offshore via a single well for dedicated geological storage. The storage operation has been monitored with a combination of technologies including surface seismic surveys, time lapse gravimetric surveys and continuous pressure monitoring.

The original target storage reservoir was the Tubåen Formation, comprising mainly sandstones between 2,560 metres and 2,670 metres below sea level. Following the start of injection in 2008, monitoring identified pressures increasing in the reservoir more rapidly than expected – limiting injectivity in relation to maximum allowable injection pressures.

CASE STUDY – Snøhvit CO_2 Storage Project (Continued)

Mitigating actions were enacted over a two-year period, including injection of small volumes of solvents to dissolve suspected clogging deposits of salt and other materials in the formation near the injection wellbore. However, the most likely explanation of the rapid pressure build up was compartmentalisation of the reservoir in the vicinity of the injector caused by the presence of pre-existing, natural sealing faults.

Subsequently, the injection well was recompleted to facilitate storage in the overlying Stø Formation, at between 2,430 metres and 2,470 metres depth below sea level. This formation also contains producing natural gas fields and to minimise risks of stored CO_2 affecting these assets, a contingency is in place to drill a second injection well into the Stø Formation at a greater distance from gas production.

The performance of injection wells can also be affected by engineering issues. Most notable are issues relating to damage of the reservoir immediately around the wellbore caused by the drilling process, referred to by drilling engineers as skin damage, or reduced performance of the wellbore materials. Fine particles created by the drilling process can plug up wellbore perforations, filter materials or the reservoir rock pore spaces in the vicinity of the wellbore; chemical reactions between drilling fluids (including those used for injectivity tests) and in-situ reservoir fluids can precipitate minerals into pore spaces, also reducing permeability. Common remedial methods employed for improving injectivity include the use of acids to dissolve plugging materials, or controlled fracturing of the wellbore and adjacent reservoir to improve fluid flow characteristics in the perforated zone of the well. The risks of fluid reactions causing skin damage can also be mitigated by removal of drilling and formation fluids from the wellbore before injection, with initial pressurisation then undertaken using CO_2 prior to the commencement of injection.[30] Note that CO_2 has excellent solvent properties for the 'cleaning' of wellbores and improved injectivity. The Otway project in Australia provides an example where poor injectivity due to plugged perforations was successfully remediated.

CASE STUDY – The Otway Basin Pilot Project (Stage 1)

The Otway project is located onshore in the Otway Basin, Victoria. Stage 1 CO_2 injection ran during 2008-2009 and approximately 65,000 tonnes of naturally sourced CO_2-rich gas was injected into the Waarre C Formation within a small, fault-bound depleted gas field. The CO_2 was injected through a dedicated vertical injection well with two perforated intervals. The reservoir was depleted with low pressures and also had excellent permeability of up to 1000mD.

The initial use of brine in the Otway injection well caused a rapid pressure build-up that necessitated suspension of the activity to protect the well infrastructure. Subsequent investigations confirmed that the well perforations were plugged, and the well was re-perforated which restored injectivity and allowed CO_2 injection to proceed.[31]

In some cases, injectivity can be impacted by reduced injection pressures at the perforated zone of the well in the reservoir – also referred to as bottom-hole pressure. A number of factors can cause these pressure issues, including problems with CO_2 compression at the capture facility, surface pipeline leaks, variations in CO_2 stream composition, higher than expected wellhead temperatures, and leaks in the wellbore.[32]

---

[30] (CSLF, 2013)
[31] (IEAGHG, 2010)
[32] (IEAGHG, 2010)

3.6

ENHANCED OIL RECOVERY

A majority of the subsurface CO_2 injection undertaken to date has been in the US for CO_2-EOR, with significant quantities also injected in Canada and China. CO_2-EOR has also attracted growing interest in other nations, including Brazil, Mexico, Saudi Arabia and the UAE. Although increased oil production, as opposed to storage for greenhouse gas mitigation purposes, is the primary aim of CO_2-EOR operations, virtually all purchased CO_2 that is utilised for EOR is permanently stored in the subsurface by virtue of the recycling systems employed (subject to any minor system losses). Storage of anthropogenic CO_2 resulting from EOR is often referred to as associated or incidental storage. Hence the Institute includes CCS projects incorporating CO_2-EOR in its Projects Database, whilst recognising that operators and/or regulators in some cases may not want to seek recognition of this associated storage for greenhouse gas accounting purposes.

With over 100 CO_2-EOR sites currently operational in the US alone and with over 40 years of project experience, an assessment of injectivity in relation to CO_2-EOR operations is beyond the scope of this section. However, there are some interesting differences with respect to dedicated storage sites (particularly deep saline formations) that are worth noting:

- Characterisation data availability for CO_2-EOR operations is generally much higher than for deep saline formations, leading to greater understanding of injectivity issues and confidence in predictive models.
- CO_2-EOR operations are typified by a significant number (tens or hundreds) of injection and production wells in most fields.
- This very large number of wells in comparison to dedicated storage sites means that adequate injectivity can be achieved in less permeable or thinner reservoirs than is typically the case for deep saline formations. For example, sites such as Weyburn in Canada support large-scale injection of CO_2 in reservoirs with typical permeability values of under 50mD, which could be problematic or prohibitively expensive for deep saline formation storage in some cases.
- CO_2-EOR operations almost invariably involve the co-injection of large quantities of water in addition to CO_2 (a process known as water-alternating-gas injection, or WAG) to maintain high pressures in the reservoir and to enhance miscibility (mixing of oil and CO_2) to boost incremental oil production.

Advances in drilling and production technologies also offer alternative long term CO_2 utilisation possibilities to enhance oil production from residual oil zones beneath main oil pay zones and in unconventional hydrocarbon resources. Injectivity will be a key technical parameter that governs the potential for further storage associated with these opportunities.

LIST OF FIGURES AND TABLES

REFERENCES

Benson et al., 2015a. *Relative permeability analysis to describe multi-phase flow in CO_2 storage reservoirs,* Melbourne: Global CCS Institute.

Benson et al., 2015b. *Relative permeability for multi-phase flow in CO_2 storage reservoirs. Part II: resolving fundamental issues and filling data gaps,* Melbourne: Global CCS Institute and Stanford University.

Cavanagh, A. & Hazeldine, S., 2014. The Sleipner storage site: Capillary flow modeling of a layered CO_2 plume requires fractured shale barriers within the Utsira Formation. *International Journal of Greenhouse Gas Control,* Volume 21, pp. 101-112.

Chadwick et al., 2008. *Best Practice for the Storage of CO_2 in Saline Aquifers - Observations and Guidelines from the SACS and CO_2STORE Projects,* Nottingham: British Geological Survey.

CSLF, 2013. *Technical Challenges in the Conversion of CO_2-EOR Projects to CO_2 Storage Projects,* Washington DC: CSLF.

Garnett et al., 2014. *ZeroGen IGCC with CCS - A case history,* Brisbane: The University of Queensland.

Global CCS Institute, 2014. *The Global Status of CCS: 2014,* Melbourne: Global CCS Institute.

Global CCS Institute, 2015. *The Global Status of CCS: 2015,* Melbourne: Global CCS Institute.

Hosa et al., 2011. Injection of CO_2 into saline formations: Benchmarking worldwide projects. *Chemical Engineering Research and Design,* Volume 89, pp. 1855–1864.

IEAGHG, 2009a. *CCS site characterisation criteria, 2009/10,* Cheltenham: IEAGHG.

IEAGHG, 2009b. *CO_2 storage in depleted gas fields,* 2009/01, Cheltenham: IEAGHG.

IEAGHG, 2010. *Injection strategies for CO_2 storage sites,* 2010/14, Cheltenham: IEAGHG.

IEAGHG, 2011. *Effects of impurities on geological storage of CO_2, 2011/04,* Cheltenham: IEAGHG.

IEAGHG, 2016. *IEAGHG modelling network.*
ONLINE ▶ Available at: http://ieaghg.org/networks/modelling-network
[Accessed 30 August 2016].

Martens et al., 2012. Europe's longest-operating on-shore CO_2 storage site at Ketzin, Germany: a progress report after three years of injection. *Environmental Earth Sciences,* Volume: 67 pp. 323-334.

Mathieson et al., 2011. In Salah CO_2 Storage JIP: CO_2 sequestration monitoring and verification technologies applied at Krechba, Algeria. *Energy Procedia,* Volume 4, pp. 3596–3603.

NETL, 2013. *Site Screening, Selection, and Initial Characterization for Storage of CO_2 in Deep Geologic Formations,* Pittsburgh: National Energy Technology Laboratory.

Wildgust et al., 2013. The IEAGHG Weyburn-Midale CO_2 Monitoring and Storage Project. *International Journal of Greenhouse Gas Control,* Volume: 16 (Supplement 1), pp. S1-S308.

ABBREVIATIONS AND ACRONYMS

%	per cent
°C	degrees Celsius
ADM	Archer Daniels Midland
ADNOC	Abu Dhabi National Oil Company
AGO	atmospheric gas oil
AS	Australian Standard
ASME	American Society of Mechanical Engineers
bar	A bar is unit of pressure where 1 bar is equal to 100,000 pascal
BF	blast furnace
BFG	blast furnace gases
BOF	basic oxygen furnace
BS	British Standards
EN	European Norms
BTCM	Battelle Two Curve Model
CaL	calcium looping
CaO	calcium oxide
CaO_3	calcium carbonate/limestone
CCF	CO_2 compression facility
CCP	CO_2 capture project
CCS	carbon capture and storage
CDP	commercial demonstration plant
CFD	Computational Fluid Dynamics
CFZTM	Controlled Freeze ZoneTM
CHP	combined heat and power
CO	carbon monoxide
CO_2	carbon dioxide
COOLTRANS	Dense Phase Carbon Dioxide Pipeline Transportation
COSHER	Carbon Dioxide, Safety, Health & Environmental Risk
CRC	Cooperative Research Centre
CSA	Canadian Standard Association
DNV	Det Norske Veritas
DRI	direct-reduced iron
DOE	Department of Energy (US)
EAF	electric arc furnace
ECRA	European Cement Research Academy
EN	European Norms

EOR	enhanced oil recovery
FCC	fluidised catalytic cracking
FDIS	Final Draft International Standard
FSC	fixed site carrier
GHG	greenhouse gas
Gt	gigatonnes
H_2	hydrogen
H_2O	water
H_2S	hydrogen sulphide
IBDP	Illinois Basin Decatur Project
IEA	International Energy Agency
IEAGHG	IEA Greenhouse Gas R&D Programme
IGC	International Gas Carrier
IGCC	integrated gasification combine cycle
IMO	International Maritime Organization
ISO	International Organization for Standardization
ITRI	Industrial Technology Research Institute
JIP	joint industry project
km	kilometre (not explained in the text)
kW	kilowatt
LEILAC	Low Emissions Intensity Lime and Cement
LPG	liquefied petroleum gas
LNG	liquefied natural gas
mD	millidarcy, a unit of permeability
MGSC	Midwest Geological Sequestration Consortium
MPa	mega Pascal, a unit of pressure
Mt	million tonne/s (used also as “MT” in Storage section)
Mtpa	million tonnes per annum
MWe	megawatt electrical
MWth	megawatt thermal
N_2	nitrogen
NETL	National Energy Technology Laboratory
NG	natural gas
NGL	natural gas liquids
NH_3	ammonium
Nm^3/hr	normal cubic meter per hour
NOx	nitrous oxide
O_2	oxygen

PEI	polyethylenimine
Petcoke	petroleum coke
PHAST	process hazard analysis software tool
ppm	parts per million
PSA	pressure swing adsorption
PTRC	Petroleum Technology Research Centre
QRA	Quantitative Risk Assessment
R&D	research and development
RD&D	research, development and demonstration
scfd	standard cubic feet per day
SEWGS	sorption enhanced water gas shift
SMR	steam methane reforming
SOx	sulphur oxide
Syngas	synthetic gas
t	tonne
TC	Technical Committee (ISO)
TCC	Taiwan Cement Company
TCM	Technology Centre Mongstad (Norway)
TSA	temperature swing adsorption
tpd	tonnes per day
UAE	United Arab Emirates
ULCOS	ultra-low CO_2 steel-making
UK	United Kingdom
US	United States (of America)
WAG	water-alternating-gas
WG	working group (ISO)

GLOBAL
CCS
INSTITUTE

GLOBALCCSINSTITUTE.COM