

Future CCS Technologies

Executive Summary

In December 2015 at the Conference of the Parties (COP21), the world agreed to set an ambitious target: to limit the increase of the global average temperature to well below 2°C, and pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels.¹ Carbon capture and storage (CCS) is an essential element of the portfolio of measures needed to reduce greenhouse gas emissions. Without CCS, the cost of reaching the COP21 targets will increase by about 40%.² In the past decade, the European Commission and/or Member State governments funded large incentive programs set up in Europe. A number of financial instruments have been established to support projects throughout different stages of development. However, these have not produced a single, operational, large-scale CCS demonstration project to date. The two operational CCS projects in Norway remain the exception.

Until recently, CCS efforts were mainly targeted at reducing greenhouse gas emission from the power sector, where some of the largest emissions points are found. The past few years have seen significant changes in this sector in Europe: increased penetration of renewable energy, a rapid phase-out of coal-fired power plants in several Member States, a fuel switch from coal to gas and the emergence of nuclear power in Member State plans for medium-term reform of the energy system. This has led to a highly uncertain basis for the development of CCS-based emission reduction in the power sector in the short term, which is exacerbated by CO₂ emission prices that are not expected to increase significantly before 2025.

Making the environmental target set in COP 21 more stringent than the previous 2°C, strengthens the case for a need of deep-cut technologies such as carbon capture and storage, as deep reductions are needed not only in the power sector, but also for the industry, where decarbonisation options are limited. Greenhouse gas emission reduction from carbon-intensive industries is likely to depend on carbon capture as fuel switch is often not an option, or process related emissions cannot be avoided. Meeting the national emission reduction targets by 2030 will rely heavily on reducing emission from these carbon-intensive sectors, such as steel and refineries.

This report analyses emerging CCS technologies considering these timeframes and suggests processes and systems that, under specific criteria, appear promising compared to benchmarks. Our overview of technologies and analysis shows that CCS is ready for immediate implementation, thus, it is essential that current first-generation technologies are tested in actual CCS projects, to subsequently enable emerging techniques to progress.

¹ FCCC/CP/2015/L.9/Rev.1

²

<http://www.iea.org/publications/freepublications/publication/CarbonCaptureandStorageThesolutionfordeepemissionsreductions.pdf>

This report also identifies knowledge and experience gaps to be addressed in order to advance and bring currently emerging technologies to the market, helping to decrease the cost of CCS. While essential, this is not by itself expected to lead to commercially available capture and storage technology in the short term. With emission price levels not likely to exceed the cost of CCS in the short or medium term, there will be no commercial business case for CCS until probably at least a decade from today.

Therefore, EU Member State governments will have to work hand in hand with the EC to enable a market for CCS, to ensure that CCS becomes a commercially viable solution for CO₂ emission reduction, including negative CO₂ emissions by biomass combustion. The reform of the European Emissions Trading System (EU ETS) is ongoing, and a market stability reserve is to be established as of 2018.³ At the moment it is unclear how the reform will impact carbon price, so measures taken should include additional incentive programs and even government-coordinated CCS operations. The goal should be a stable and positive regulatory environment, in which CCS can deliver its promise of cost-effective, deep cuts in greenhouse gas emissions. Where possible, benefits from CCU - carbon capture and utilization - should also be exploited.⁴

In parallel, research and innovation (R&I) efforts are required to continue towards CCS cost reduction and applicability across power and industry sectors. This report provides an overview of the state-of-the-art of CCS technologies, covering capture, transport and storage.

The assessment of future CO₂ capture technologies carried out in this report has embraced not only the changing market conditions in power generation, but also the emerging importance of CCS for non-power industries. Furthermore, the assessment criteria of CCS technologies have been deliberately enlarged beyond typical cost and efficiency: assessment criteria incorporate key factors like operational flexibility, retrofitability, HSE issues, materials availability etc. in qualitative form.

The traffic light table below exhibits the improvement potential for emerging separation processes for CO₂ capture compared to benchmark, today's 1st-generation demo plants, with regards to assessment criteria. In this table, only processes with TRL>4 have been considered. Green colour indicates improvement potential. Yellow indicates indifferent, same or similar level and red means worse (or very uncertain) than benchmark. Yellow/green means that it could be better, but in the worst case is similar to the benchmark.

The table juxtaposes, in a qualitative way, the various emerging capture technologies according to the different assessment criteria introduced in this report. These will likely determine the economic viability and acceptability of the different CCS process options in a future CCS technology market.

³ https://ec.europa.eu/clima/policies/ets/reform/index_en.htm

⁴ Technologies for CCU, carbon capture and utilisation, are described in a separate report, 'Carbon capture and utilization', Zero Emission Platform, December 2015.

As far as transport and storage is concerned, requirements for improvement of currently available technologies and, where the need was identified, the development of new technologies, were derived from the projected growth of CCS. This growth will lead on from current demonstration and early commercial projects that can be classified as one-on-one projects, to increasingly interconnected transport and storage systems, in which economies of scale are obtained by sharing transport and storage structures.

Capture

Isolated improvements are expected to have an impact on the overall efficiency penalty and cost of CCS systems. However, technology improvements arising from R&D works need to also be assessed on system (plant) level.

Current solvent based capture processes are commercially available but there is a substantial scope to reduce their cost and efficiency penalty. They also display limited operational flexibility, which is increasingly required by power plants. The development of capture processes allowing for (higher) operational flexibility (load following operation) without additional cost is therefore a key R&D challenge. Flexibility is a key requirement for the transport and storage elements of the CCS chain (i.e., variable supply of CO₂) as well.

Transport

Transport of CO₂ by pipeline is a well-established technology and is commercially available. R&I should focus on modelling transient flow phenomena in pipelines, across platforms and into wells, taking into account recent advances in the knowledge on the effects of impurities in the CO₂. In transport networks, the management of CO₂ quality becomes an issue, where mixing of streams of differing quality could affect the performance of the system. The required knowledge about the relationship between CO₂ quality and the behaviour of the CO₂ in the system has advanced considerably in recent years, allowing CO₂ quality effects to be taken into account.

Ship transport of CO₂ is also an established technology, but for large-scale CCS ship transport it needs to be scaled up. CO₂ carriers exist, but larger ships will be required; the same can be said about loading and unloading facilities at ports. Offloading offshore, near the injection location requires some technology development and demonstration, such as flexible hoses and mooring systems. The effect of batch-wise injection, which may be the result of ship transport, on injection wells needs to be investigated.

Storage

The required operational flexibility holds for the whole CCS chain including CO₂ injection and storage, in particular in the early stages of CCS development from demonstration to early deployment where the dependence on single sources for a reliable continuous supply will dominate availability of CO₂. Systems analysis of the whole chain is necessary to evaluate where the capacity for flexibility is to be built most cost-effectively, e.g. flexible, cost-effective capture technology, in buffering and in networking to stabilize transport grid and storage load.

Research including full-scale demonstration is required on expanding the operational envelope of injection wells and subsea equipment under repetitive cycles of pressure and temperature changes, particularly for injection into low pressure stores like depleted pressure gas fields.

Approaches for effective storage portfolio management are necessary to efficiently exploit the available pore space, e.g. in large areal extent aquifers, to shorten the appraisal lead time and for timely expansion of the infrastructure for injection of CO₂, including mothballing of existing infrastructure. Pressure management could support optimising the use of pore space, e.g. by using water production wells; research could be directed to strategies for water production, the breakthrough of CO₂ and water treatment.

Developing lower-cost and storage specific monitoring and mitigation technologies remains an R&I target. Technology development should also be directed to less invasive leakage mitigation techniques and cost-effective methods for closing wells.

CCS systems

Incremental improvements in technologies of CCS chain elements can be obtained, but significant advances will only be made through operational testing and eventually commercialization. Emerging technologies depend on the operational use of existing technologies for their advancement, using market pull to develop lab, pilot and demonstration scale testing.

Detailed observations and recommendations for R&I are presented in Chapter 6 of this report.

Traffic light table of improvement potential for emerging separation processes for CO₂ capture (process with TRL>4 only) compared to benchmark, today's 1st-generation.

Process	Solvent based processes		Solid sorbent processes		High temperature solid looping systems		Membrane systems		
Separation Technology / Assessment criteria					Chemical looping	Calcium looping	Polymeric (post)	Ceramic (Oxy)	Metallic (pre)
Cost CAPEX									
Cost OPEX									
Efficiency penalty (thermodynamics, T- and P- level)									
Degradation solvent, sorbent, membrane									
Operational flexibility (on/off)									
HSE (waste, toxicity)									
Retrofitability ³⁾									
Materials availability (abundance, manufacturing chain)									
FOAK cost									
Applicability, most suitable to	Power, NG processing, Steel, Refineries, other		Power (pre combustion), Steel, Refineries		Power (solid fuels), Refineries	Power (post combustion, solid fuels), Cement	Power, NG processing, Cement, Steel	Power (oxy and pre combustion)	Power (pre combustion), Refineries

Contents

Executive Summary	2
1 Introduction & Motivation.....	12
2 CO ₂ capture technology	15
2.1 Benchmarking the Performance and Cost of Today's CO ₂ Capture Technologies	16
2.1.1 Maturity of the CO ₂ Capture Technologies (Technology Readiness Level)	16
2.1.1 Definition – Technology Generation	17
2.1.2 Existing Demonstration and Commercial Plants.....	18
2.1.3 Performance of the 1 st -Generation CO ₂ Capture Technologies and its Future Development and Improvement	22
2.2 1 st -Generation CO ₂ Capture Technologies costs overview	29
3 Emerging CO ₂ Capture Technologies for Power Generation and Carbon Intensive Industries	30
3.1 Introduction.....	30
3.2 Definition of a set boundary conditions for emerging capture technologies in different industrial settings.....	31
3.3 Emerging CO ₂ Capture Technologies for Fossil Based Power Plants	35
3.3.1 Solvent - based Processes	37
3.3.2 Solid Sorbent Processes.....	39
3.3.3 Chemical Looping and Calcium Looping High Temperature Systems	42
3.3.4 CO ₂ Liquefaction/Partial Condensation for Pre- and Post- Combustion CO ₂ Capture Applications.....	44
3.3.5 Membranes.....	46
3.4 Emerging CO ₂ capture technologies in the Iron & Steel industry.....	49
3.5 Emerging CO ₂ capture technologies in the Cement industry	50
3.6 Emerging CO ₂ capture technologies in the Refinery Industry	52
3.7 Comparative assessment of emerging CO ₂ capture technologies.....	53
4 Transport technology	61
4.1 Transport needs.....	61
4.2 CO ₂ pipeline transport experience.....	61
4.2.1 Operating pipeline projects	61
4.2.2 Planned projects	63

4.2.3	Potential development	64
4.3	Status of Pipeline technology	65
4.3.1	Phase Behaviour	66
4.3.2	Contamination and Material Selection.....	66
4.3.3	Compression.....	67
4.3.4	Economies of scale.....	68
4.3.5	Standards	68
4.4	Transport by ship	69
4.4.1	Ship transport in operation	69
4.4.2	Planned projects	70
4.4.3	Potential development	70
4.5	Status of shipping technology	71
4.5.1	Vessels.....	72
4.5.2	Loading and Unloading Facilities at Ports	73
4.5.3	Intermediate Storage Facility	73
4.5.4	Gasification, Heating and Compression	73
4.5.5	Offshore unloading	74
4.5.6	Benefits and Limitations of Ship Transportation	74
4.6	Transport network.....	75
4.7	Summary	76
5	CO ₂ injection and storage technologies.....	78
5.1	Storage technology needs	78
5.2	Performance of existing (and planned) storage projects in Europe	78
5.2.1	Dedicated CO ₂ storage pilots and demos.....	78
5.2.2	CO ₂ enhanced oil recovery (CO ₂ -EOR) projects	82
5.2.3	Summary	83
5.3	Development potential for injection and storage technology.....	83
5.3.1	Storage portfolio management.....	83
5.3.2	Uncertainty, risk and liability.....	84
5.3.3	Drilling, completing and operating wells	85
5.3.4	Pressure management for increasing capacity and injectivity	87
5.3.5	Low-cost monitoring and mitigation technology.....	87
5.3.6	Reducing costs and footprint of installations	90

5.3.7	Need for flexibility of CO ₂ throughput	91
5.3.8	Summary of development potential	92
5.4	Discussion and summary	93
6	Conclusions & Recommendations	96
6.1	CO ₂ capture	96
6.1.1	R&D Challenges & recommendations for CO ₂ capture.....	96
6.1.2	Benchmarking of emerging technologies for CO ₂ capture	98
6.2	Transport and Storage R&D challenges & recommendations	99
6.2.1	CO ₂ transport	99
6.2.2	CO ₂ storage	100
	Bibliography	101
	Annexe I.....	112
	Annexe II.....	115
	Annexe III.....	117
	Annexe IV	122
	Annexe V	124

List of abbreviations

AGR	Acid Gas Removal
ALARP	As Low As Reasonably Practicable
ASU	Air Separation Unit
AUV	Autonomous Underwater Vehicle
CaL	Calcium Looping
CAP	Chilled Ammonia Process
CASU	Cryogenic Air Separation Unit
CCS	Carbon Capture & Storage
CCU	Carbon Capture & Usage
CCUS	Carbon Capture Usage & Storage
CFB	Circulated Fluidized Bed
CFBC	Circulating Fluidized Bed Combustion
CHP	Combined Heat and Power
CLC	Chemical Looping
CSEM	Controlled Source Electromagnetics
ECCSEL	European CCS Laboratory Infrastructure
EERA	European Energy Research Alliance
EOR	Enhanced Oil Recovery
EU ETS	EU Emissions Trading System
EU FP7	EU Seventh Framework Program
FID	Financial Investment Decision
FOAK	First of a kind
GCCSI	Global CCS Institute
GHG	Greenhouse gas
GT	Gas Turbine
HC	Hydrocarbon
HHV	High Heating Value
HSE	Health Safety & Environment
IGCC	Integrated Gasification Combined Cycle
ISO	International Standards Organisation
IPCC	Intergovernmental Panel on Climate Change
LCA	Life Cycle Assessment
LCoE	Levelised Cost of Electricity
LHV	Low Heating Value
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MDEA	Methyldiethanolamine
MEA	Monoethanolamine
MMV	Measurement, Monitoring and Verification
MOF	Metal Organic Framework

Mtpa	Million Tonnes Per Annum
MS	EU Member State
NG	Natural Gas
NGCC	Natural Gas Combined Cycle
NOAK	Nth of its kind
NWT	ZEP Network Technology
O&G	Oil and Gas
OPCo	Operational Company
OTM	Oxygen Transfer Membrane
PC	Pulverized Coal
POX	Partial Oxidation
PSA	Pressure Swing Adsorption
QRA	Quantitative Risk Assessment
R&D	Research and Development
RWA	Rotary Wheel Adsorber
SEWGS	Sorption Enhanced Water Gas Shift
SLPM	Standard Litre per Minute
SMR	Steam Methane Reforming
tpd	Tonnes Per Day
TRL	Technology Readiness Level
TSA	Temperature Swing Adsorption
VLE	Vapour Liquid Equilibrium
VPsA	Vacuum Pressure Swing Adsorption
VSA	Vacuum Swing Adsorption
WGS	Water Gas Shift

1 Introduction & Motivation

The Intergovernmental Panel on Climate Change (IPCC) recently announced that without additional efforts, the global mean temperatures are likely to increase between 3.7 and 4.8°C compared to pre-industrial levels. On the way to the COP/MOP meeting in Paris, governments worldwide were asked to submit their Intended Nationally Determined Contributions (INDCs)⁵ and plans on how to achieve emissions reductions. Modelling suggests that if INDCs submitted were fully realised, the temperature increase would be limited to around 2.7°C [1].

Scenarios which limit the global mean temperature rise will involve deep cuts in Greenhouse Gas (GHG) emissions over the coming decades, requiring radical changes to industry, energy and transport systems, and a step-change in the uptake of low carbon technologies. As the COP21 meeting in Paris in December 2015 agreed to also pursue the long term target to limit global warming to 1.5°C, the worldwide efforts in cutting GHG emissions have to be even more ambitious.

Carbon Capture and Storage (CCS) represents techniques which have the ability to prevent hundreds of millions of tonnes of CO₂, generated by large point sources, to enter the atmosphere. The IEA and IPCC consider CCS a vital component of a portfolio of abatement options available to achieve the 2°C target, with CCS anticipated to mitigate about 8 Gt/a in the 2050's. The technology represents a key mitigation option in most of the emission reduction pathways described by IPCC. Studies show that both the total investment cost and the cost of emission reduction are higher for scenarios that exclude CCS. According to IEA calculations, CCS can reduce the cost of climate change mitigation by up to 40% [2].

Current forecasts assume fossil-based power generation and industrial output from major emitting sectors such as cement, iron and steel to rise globally, driven by economic growth in emerging economies [3]. CCS is the only technology which can achieve deep cuts in carbon dioxide (CO₂) emissions across fossil-fired power generation and carbon intensive industries – e.g. steel, cement, refineries, natural gas processing, chemical plants, etc.

While there are zero-emission and low-emission power generation technologies commercially available today - although many of these are intermittent - there are no such carbon free alternatives yet foreseeable for most carbon intensive industries.

However, as CO₂ emissions in some industries derive from intense power consumption as well as carbon intense input to the process, several CO₂ emission reduction options or combinations are possible, e.g. process modifications for efficiency improvement and fuel switching, e.g. to

⁵ http://unfccc.int/focus/indc_portal/items/8766.php

biomass. In this context, CCS can also be deployed in combination with the use of biomass to deliver negative emissions.

Therefore, the application potential of CCS has to be considered as broader than just for the power sector. It is not a 'one size fits all' technology but it can be applied to a wide range of carbon intensive sectors and sources, which also reflect national or regional circumstances. For some countries, the focus might be on coal-fired power generation due to their power generation mix. For others, the focus might be on the carbon intensive industries they host, or high-purity sectors, such as natural gas processing and hydrogen production.

Worldwide, first-generation capture technologies have already been tested at large pilot-scale facilities and demo plants. At the time of writing this report, there were 15 large-scale⁶ CCS projects in operation worldwide, capturing nearly 28 million tons of CO₂ per year across a range of sectors, and more large-scale applications will come into operation within the next 2-3 years [4].

Although capture technologies are commercially available and operating, there is still improvement potential with respect to cost, performance and operational flexibility.

CO₂ capture is in continuous development and historical experience with comparable processes, such as flue gas desulphurisation, suggests that significant improvements are achievable through further well-targeted Research and Development (R&D). This is the reason why ZEP started in 2010, with its reports on "Recommendations for research to support the deployment of CCS in Europe beyond 2020" identifying the main R&D areas for driving down costs through well-targeted R&D programmes.

The purpose of this report, "Future CCS technologies", is to provide an updated overview of the evolving 2nd and 3rd generation CCS technologies. The report covers capture technologies, their improvement potential with respect to cost, performance and operational flexibility as well as scale and current technical maturity (based on TRL – Technology Readiness Level). Operational flexibility and scale address differences in the boundary conditions and operation of plants in different branches, likely to have an impact on the choice of capture technology. While today's 1st-generation capture technologies are designed for flue gas streams in the range of hundreds to thousands kNm³/h and preferably continuous operation, future applications will face broader and diverse operational requirements, especially in the power sector.

This report also includes CCS application in carbon intensive industries and foresees the potential for mixed CCS clusters of power and industry sources. Emerging CO₂ capture technologies are not only assessed by their potential to reduce cost and improve performance but also by their potential to best match with the various boundary conditions of respective industries, even if qualitatively.

⁶ Definition available at <http://www.globalccsinstitute.com/projects/large-scale-ccs-projects-definitions>

CCS is an infrastructure type project, not just a single product. Therefore, challenges and barriers faced by one part of the CCS chain will delay or prevent the whole CCS technology from being applied. Hence, the report looks into emerging technologies along the whole value chain of CCS and also covers transportation and storage.

The performance improvement potential of the 1st-generation capture technologies deployed worldwide in large-scale applications (post-, pre- and oxy-CCS) may be modest, while their cost reduction potential due to standardisation/replication of scale and supply chain is substantial. The current costs of 1st-generation technologies will serve as a performance and cost benchmark for the assessment of the 2nd and 3rd capture generation technologies, provided in chapter 2.1 in this report. Section 2 provides further detail about emerging capture technologies and their current TRL status, including more precise definitions for 2nd and 3rd capture generation technology. Section 3 assesses the emerging CO₂ technologies; thereby using major scientific review papers, like a special issue of the International Journal of Greenhouse Gas Control, IEA GHG etc. reports etc., which are all listed in the references.

Section 4 evaluates the technical progress on transport technologies, both on pipeline and shipping technologies, including aspects of 'clusters' of multiple CO₂ sources, CO₂ purity and gas cleaning while Section 5 provides an overview on the status of CO₂ injection and storage.

Section 6 closes the report with 'conclusions & recommendations' as well as an outlook identifying working areas or gaps this report could not consider.

Section 6 therefore indicates which emerging CCS technologies might likely suit certain applications in industry or power better than others, and thereby allows the respective industries, as well as public R&D programmes, to promote or accelerate the development of these solutions.

2 CO₂ capture technology

CO₂ capture is a process that involves the separation of CO₂ from gas streams. These gas streams could include but are not limited to combustion flue gases, process off-gases (i.e. by-product gases from blast furnaces, basic oxygen furnace; tail gases from steam methane reforming (SMR) and various refinery processes, etc.), syngas (i.e. syngas produced from coal gasification, hydrocarbon reforming, coke oven, etc.) or natural gas (i.e. from NG processing). For many decades, CO₂ capture processes have been used in several industrial applications at a scale close to those required in any CCS applications.

In general CO₂ capture processes can be classified according to their gas separation principle, namely chemical absorption, physical absorption, adsorption, calcium and reversible chemical loops, membranes, and cryogenic separation. Brief descriptions of the major CO₂ capture processes are as follows.

Chemical absorption. Chemical absorption processes utilize the reversible chemical reaction of CO₂ with an aqueous solvent, usually an amine or ammonia. CO₂ is separated by passing the flue gas through a continuous scrubbing system. The absorbed CO₂ is stripped from the solution in a desorber, and a pure stream of CO₂ is sent for compression while the regenerated solvent is sent back to the absorber.

Physical absorption. In cases where there is a highly concentrated stream of almost pure CO₂ at high pressures, it is advantageous to use a physical solvent. The absorption capacity of these solvents increases with external gas pressure and decreases with temperature. Hence, CO₂ can be separated from such solvents mainly by reducing the pressure in the desorber, significantly reducing the energy requirements in the desorption process.

Adsorption. The gas is fed to a bed where CO₂ is selectively adsorbed. The CO₂ loaded bed is then regenerated by pressure swing adsorption (PSA) or temperature swing adsorption (TSA). In PSA, CO₂ is preferentially adsorbed on the surface of a solid adsorbent at high pressure, which will swing to low pressure (usually atmospheric) to desorb the adsorbent and release CO₂ for subsequent transport. In TSA, the adsorbed CO₂ is released by increasing the system temperature using hot air or steam injection.

Chemical looping. In Chemical Looping Combustion systems (CLC), the combustion of a fuel is achieved by transferring the oxygen to the combustor chamber using an oxygen carrier (usually a metal oxide that is reduced in such process). This enables an almost pure CO₂ gas to be produced, which can then be relatively easily stored without any further major processing. The reduced metal is then oxidised by air in a separate reactor, closing up the chemical loop.

Calcium looping. In calcium looping (CaL), a metal (M) is reversibly reacted between its carbonate form (MCO₃) and its oxide form (MO). The two species are calcium carbonate (CaCO₃) and calcium oxide (CaO). CO₂ is released from CaCO₃ in a subsequent thermal regeneration. Over multiple cycles, CO₂ is separated from other gases coming from either power generation or an industrial plant.

Membranes. Gas separation membranes allow one component in a gas stream to pass through faster than the others. There are many different types of gas separation membranes, including porous inorganic membranes, palladium membranes, polymeric membranes etc. To be effective for CO₂ capture, membrane materials should exhibit a number of features including high CO₂ or H₂ permeability, high CO₂/N₂ selectivity, thermal and chemical stabilities, resistant to plasticization and aging, and so on.

Cryogenic separation. CO₂ can be separated from other gases by cooling and condensation. For CO₂ separation, flue gas containing CO₂ is cooled to desublimation temperature (–100 to –135 °C) and then solidified CO₂ is separated from other light gases and compressed to a high pressure.

In power generation sector, CO₂ capture processes are traditionally classified as post-combustion CO₂ capture, pre-combustion CO₂ capture, and oxy combustion.

Further, CO₂ capture technologies can be labelled in accordance to their technology maturity, classifying them as 1st, 2nd and 3rd generation technologies.

2.1 Benchmarking the Performance and Cost of Today's CO₂ Capture Technologies

2.1.1 Maturity of the CO₂ Capture Technologies (Technology Readiness Level)

Different measures such as the Commercial Readiness Index⁷ have been used to track progress and development of a specific technology. However, being a globally accepted benchmarking tool, this report adopted the Technology Readiness Level or TRL to rank the maturity of the CO₂ capture technologies. Table 2.1 presents the range of TRLs adopted in this report. This is based on definitions as established from bodies such as the US Department of Energy National Energy Technology Laboratory⁸ and the European Horizon 2020 program,⁹ but adapted to expand on CO₂ capture as well as CO₂ storage technologies. It shall be noted that these TRL indicators are to be used in the analysis of emerging future technologies reported in this document.

2.1.2 Definition – Technology Generation

Generally, 1st-generation CCS technologies can be considered as mature technology with TRL between 7 and 9; fully ready for wide spread deployment in the immediate future, although there

⁷ <http://arena.gov.au/files/2014/02/Commercial-Readiness-Index.pdf>

⁸ <https://www.netl.doe.gov/File%20Library/Research/Coal/carbon%20capture/Program-Plan-Carbon-Capture-2013.pdf>

⁹ http://ec.europa.eu/research/participants/data/ref/h2020/other/wp/2016_2017/annexes/h2020-wp1617-annex-g-trl_en.pdf

is likely still scope for improvement in cost, performance and/or flexibility. Emerging technologies also offer potential for significant cost reduction and increased efficiency. Typically, 2nd generation CCS technologies can be considered as late-stage emerging technologies with TRL between 3 and 6; whilst 3rd generation CCS technologies are usually early-stage emerging technologies with TRL between 1 and 3.

1st-generation CCS technologies:

- CO₂ capture technologies that can be categorised as commercially available or near-commercial technology today. These technologies have been tested or operated as demo- or widely deployed in various commercial applications. In the near or medium term, it is expected that these technologies would likely involve further development to achieve incremental improvement.

2nd-generation CCS technologies:

- Emerging CCS technologies which can be demonstrated at pre-commercial scale and may become commercially available in the coming decade (i.e. between 2020 and 2030). 2nd generation CCS technologies are likely to be based on the scale-up of technologies which are assessed today with a TRL in the range of 3-6, likely achieving the TRL of 6 or 7 in the next five years (i.e. by 2020), including refinements of the 1st-generation CCS technologies.

3rd-generation CCS technologies:

- Emerging CCS technologies which may become commercially available during the next two decades (i.e. beyond 2030). 3rd generation CCS technologies are likely to be based on the progress of technologies which are today assessed with a low TRL in the range of 1-3, including likely refinements of the 2nd generation technologies.

Table 2.1. Technology Readiness Level (TRL).

	TRL	Description
Full Commercial Application	9	Actual system proven in operational environment (competitive manufacturing of full system, at scales of several 100s of MW _{th} or around 1MtCO ₂ /a stored)
Demonstration	8	System complete and demonstrated at industrial scales of 10s of MW _{th} or 0.1 to 1 MtCO ₂ /a stored
Pilot	7	System prototype demonstrated in operational environment (industrial pilots operating at 10s of MW _{th} and/or separating 10s of kt CO ₂ /a)
	6	Technology demonstrated in relevant environment (steady states at industrially relevant environments: pilots in the MW _{th} range and/or separating 1 to 10 kt CO ₂ /a)
Small Pilot	5	Technology validated in relevant environment (pilots operated at industrially relevant conditions at 0.05–1 MW _{th}) and/or less than 1 kt/a captured/stored

Lab/Bench	4	Technology validated in the lab (continuous operated pilots at lab scale <50 kW _{th})
	3	Experimental proof of concept (pilot testing of key components at small bench scale)
Concept	2	Technology concept formulated (basic process design)
	1	Basic principles observed

2.1.3 Existing Demonstration and Commercial Plants

There are several CO₂ capture facilities operating worldwide – with several of these involving the production of CO₂ for various commercial users (i.e. EOR, industrial, medical and food grade CO₂ for various uses). This section of the report only highlights and focuses on the Large-Scale Demonstration or Commercial Plants, which include the integration of the CO₂ capture facilities with CO₂ transport and storage (including EOR operation). A recent GCCSI report [4] identified numerous large-scale integrated CCS projects undertaken worldwide in various stages of development.

Generally, existing demonstration or commercial scale CCS plants that are in operation or under construction today could be broadly categorised as described in the following sections.

2.1.3.1 CCS in the Power Generation Industry

In the power generation sector, the capture of CO₂ based on post-combustion CO₂ capture has realised full commercial scale demonstration and pre-combustion is about to. Oxy combustion technology has achieved a mini-demonstration status.

For post-combustion CO₂ capture technology – the key demonstration projects include:

- Boundary Dam Unit #3 (Saskatchewan, Canada) is the world's first large-scale demonstration project capturing 1 Mtpa CO₂ from 115 MWe coal fired power plant using the amine based Cansolv Solvent. The plant commenced its operation in 2014. For further details – see Box 1. The captured CO₂ is mainly used for EOR operation, with a small part of the CO₂ also being injected in saline aquifer (the Aquistore Project).
- By 2018, the Petra Nova Unit #8 (Texas, USA) will be the largest post-combustion CO₂ capture demonstration project worldwide (using MHI's KS1 hindered amine solvent). The plant will capture 1.4 Mtpa CO₂ from a slip stream (equivalent to 240MWe) of a coal fired power plant. This will be used for EOR operation.
- In Europe, ROAD (Rotterdam, Netherlands) is the remaining large-scale CCS demonstration project in the power generation industry that could be realised by the end of this decade. This project involves the capture of 1.1 Mtpa CO₂ from a slip stream (equivalent to 250MWe) of a coal fired power plant using Fluor's Econamine solvent. The CO₂ will be stored off shore in a depleted gas field, however a gas field closer to shore is now also being considered.

For Pre-Combustion CO₂ Capture, the world first commercial scale demonstration project is the Kemper County Energy Facility (Mississippi, USA).

- The plant is currently in commissioning phase and expected to be in service toward the end of 2016 or early part of 2017. The plant captures about 60% of the CO₂ from a lignite fired IGCC plant (using a TRIG gasifier with Selexol based AGR). The captured CO₂ (3.0 Mtpa) is to be used for EOR operation.

For oxy combustion CO₂ capture, due to the cancellation of several projects, it is unlikely that any full demonstration for this technology will be realised in the short to medium term. Nonetheless, it is worthwhile to emphasise that this technology has achieved status approaching demonstration based on the accomplishment of the following projects:

- Callide Oxy fuel Project (75 tonnes CO₂ per day);
- Flexiburn (oxyfuel CFB – 11 tonnes CO₂ per day) tested at Ciuden¹⁰;
- Schwarze Pumpe (Vattenfall Oxy-fuel project – 75 Mtpa)¹¹;
- Huazhong University of Science and Technology (HUST) Oxyfuel Plant (100 Mtpa).¹²
- Lacq oxyfuel demonstration (75,000 tonnes/year between 2010 and 2013)¹³

¹⁰ http://cordis.europa.eu/project/rcn/94480_en.html

¹¹ https://sequestration.mit.edu/tools/projects/vattenfall_oxyfuel.html

¹² <http://www.globalccsinstitute.com/insights/authors//2016/05/05/milestone-oxyfuel-plant-going-operation-hubei-china?author=MTY4OTg%3D>

¹³ https://sequestration.mit.edu/tools/projects/total_lacq.html

BOX 1 – Boundary Dam

Boundary Dam Unit 3 (BD3) is the first-ever, commercial-scale, coal-fired power plant incorporating post-combustion CO₂ capture technologies using Cansolv solvent. This plant is situated near Estevan, Saskatchewan, Canada. The demonstration plant commenced its operation in October 2014. This is an important milestone proving that integrating CCS to a power plant works.

BD3 was approaching retirement. In 2010, Saskpower made a landmark decision to proceed with the refurbishment of the unit and fully integrating the CO₂ capture system. Such decision allows the extension of the life of the coal fired power plant by at least 30 years – meeting the stringent regulations on GHG emission set by the Province of Saskatchewan.

The CO₂ capture system is provided by Cansolv Technologies – a two stage removal of SO₂ and CO₂. In the first absorption column, SO₂ is removed; and in the second column CO₂ is removed.

The captured CO₂ is then geologically stored at two locations: in an oil reservoir approximately 1.4 kilometres deep at Cenovus' CO₂-EOR operation near Weyburn, Saskatchewan; and in a deep saline aquifer approximately 3.2 kilometres deep at the SaskPower Carbon Storage and Research Centre, located near the Boundary Dam Power Station. The latter geological storage site is the subject of the measurement, monitoring and verification (MMV) activities of the Aquistore Project that is managed by the Petroleum Technology Research Centre in Regina, Saskatchewan.

Details of the lessons learned in building the world's first full scale CCS plant is presented in the recent IEAGHG report [124].

To date, BD3 has achieved the following:

- Produces 115-120 MWe of power, which is enough to cover the electricity demand of 100,000 local homes;
- Surpassed the 1 MtCO₂ milestone in July 2016 reducing nearly 90% of the plant GHG emissions (see <http://www.globalccsinstitute.com/projects/large-scale-ccs-projects>);
- Reduces SO_x emissions from the coal-fired power plant;
- Demonstrate the economic, technical and environmental feasibility for coal-fired power generation with CCS;
- Support the development of industry-wide CCS regulations and policies.

2.1.3.2 CCS in the Industrial Sector

According to IEA [5], CCS is expected to have an important role in mitigating CO₂ emissions from the carbon intensive industries.

Carbon intensive Industries could include the steel, cement, fuel transformation (including oil refining, etc.), chemicals and petrochemical, pulp and paper industries.

In some of these industries (i.e. ammonia/urea production, some DRI¹⁴ plants, several of the SMR plants, etc.) could include the CO₂ removal as an integral part to their process or operation. For the purpose of this report, it is worthwhile to note the key experiences gained from operating these plants.

However, with full chain CCS applied to the carbon intensive industries, there are only a limited number of industrial CCS (with CO₂ capacity of greater than 0.8 – 1 Mtpa) in operation or under construction. The Global CCS Institute database provides a complete overview¹⁵ but some of the notable examples include:

- Great Plain's Synfuel Plant (Dakota, USA) could be considered the world's first fully integrated CCS in carbon intensive industry. The plant produces synthetic natural gas (SNG) from lignite using Lurgi gasifiers. About 3 Mtpa of CO₂ (~50% of the total emissions) is captured from the syngas using Rectisol physical solvent units. This is then transported to Weyburn / Midale field in Canada for EOR operation. This has been in operation since 2005.
- Port Arthur Project (Texas, USA) captures CO₂ from two trains of SMR based hydrogen plant attached to an oil refinery. The CO₂ is captured from the syngas of the SMR using VSA. This plant has been in operation since 2013 and has the capacity to capture around 1 Mtpa for EOR operation.
- Shell Quest Project (Alberta, Canada) captures CO₂ from three trains of SMR based hydrogen plant attached to Scotford Oil Sand Upgrader. The CO₂ is captured from the syngas of the SMR using the amine based Adipic-X solvent. This plant has been in operation since 2015 and has the capacity to capture around 1 Mtpa for deep saline aquifer storage.
- Before the end of this decade, there are three other notable industrial CCS demonstration projects to come on-stream, these include:
 - ADM's Illinois Industrial CCS Project (Decatur, Ill., USA) – which is expected to capture around 1 Mtpa of CO₂ from an existing ethanol plant and store it in a saline aquifer. This project is the continuation of the Illinois-Decatur project which has already successfully stored a total of 1 Mt of CO₂ over the course of approximately 3 years. The capture of CO₂ only involves compression and dehydration (i.e. with minimal processing or purification). This should start its operation by 2016.
 - ADNOC CCUS Project (Mussaffah, UAE), also known as ESI CCS (Abu Dhabi), will be the first steel mill to integrate CO₂ capture and EOR operation. Around 0.8 Mtpa of CO₂ will be captured from the DRI plant (based on Energiron III configuration). This should start its operation by 2017.

¹⁴ Direct Reduced Iron (DRI) plant mainly based on Energiron technology requires the removal of the CO₂ from its off-gas before being recycled as feedstock.

¹⁵ <http://www.globalccsinstitute.com/projects/large-scale-ccs-projects>

- Alberta Carbon Trunk Line (ACTL) project (Alberta, Canada) – will demonstrate the first industrial CCS cluster and once it becomes operational by 2018, it will initially capture around 1.7 Mtpa CO₂ for EOR operation. It should be noted that the pipeline is designed to accommodate the transport of up to 14 Mtpa of CO₂. This initial phase of the ACTL project covers the capture of CO₂ from Sturgeon Refinery (coming from H₂ production based on Lurgi Gasifer and Rectisol AGR) and NWR fertiliser plant (coming from SMR and its existing amine based CO₂ capture for Ammonia production).

2.1.3.3 CCS in the Natural Gas Processing Industry

Most of the early deployment of large-scale demonstration of CCS involves the capture of CO₂ using chemical absorption in the natural gas processing industry. The captured CO₂ is then used as the working fluid for EOR operation or permanently stored in saline aquifer.

Some of the key examples include the following.

- In Europe, projects involving the capture of CO₂ (using amine solvent) from NG Processing Industry include Statoil's Sleipner Project (Norway), operational since 1996, and the Snøhvit Project (Norway), operational since 2008. Sleipner was the world's first demonstration of CCS technology for a deep saline reservoir. The injection rate of almost 1 Mtpa also makes the project one of the largest demonstrations of CCS in the world to date. Around 16.2 million tonnes of CO₂ have been injected to June 2016. The purity of the CO₂ is at 98%; the remaining 2% is mostly methane.
At Snøhvit, the amine-based CO₂ removal process is designed to capture 0.7 million tonnes of carbon dioxide annually when the facility is at full capacity. Injection started in April 2008 and to date nearly 3 million tonnes of CO₂ has been stored. With a life span of around 30 years for the LNG plant, the total volume of CO₂ to be stored is estimated at between 15 to 20 million tonnes. The purity of the injected CO₂ is around 99%.¹⁶
- By 2018, the largest CCS project in the natural gas processing industry will be demonstrated once the Gorgon project (Australia) becomes online. This will involve the capture and storage of nearly 3 to 4 Mtpa of CO₂ off-shore.

2.1.4 Performance of the 1st-Generation CO₂ Capture Technologies and its Future Development and Improvement

CO₂ capture technologies have undergone notable development in the last decade. With the current large-scale CCS demonstrations under way, it is expected that further development and improvement will be realised as part of 'learning by doing'.

¹⁶

<https://member.globalccsinstitute.com/GSOCCS/Projects/Pages/Large-Scale-CCS-Projects---Project-Descriptions.aspx>

With the current generation of CO₂ capture technologies, the main focus of development in the short to medium term will be on cost reduction (i.e. in terms of CAPEX and OPEX) and on solvent/emission management.

In the power generation industry, further development in response to the requirement for plant flexibility (i.e. due to growing penetration of unpredictable renewable energy) will be expected. Development of “energy storage” should also have an impact in the future development of CCS technologies in the power generation industry.

In the carbon intensive industries, the development of the CO₂ capture technologies would come hand in hand with improvement of their impact on energy efficiency (not only in the CO₂ capture plant but also in their respective manufacturing processes). This is a necessity to maintain their competitiveness. CCU could play a role in the short to medium term deployment of large-scale CCS to allow early projects to benefit from additional revenues. However, it should be stressed that CCU is not a long-term GHG mitigation option to cope with climate change, as the products usually have short lifetimes (weeks to years) and will soon be emitted back to the atmosphere. Therefore, each CCU application requires (on a case by case basis) a detailed Life Cycle Assessment (LCA) to demonstrate the eventual climate change mitigation potential of the respective use of CO₂. Apart from the LCA of CCU products there is a huge discrepancy between the annually worldwide emitted amount of energy related CO₂, hence the annual mitigation potential of CO₂, and the anticipated worldwide market size of CCU products, i.e. more than 32 Gt of energy related CO₂ emission versus 100 – 250 Mt (CO₂ consumed) of CCU products per year [6].

2.1.4.1 Post Combustion CO₂ Capture – Chemical Absorption

The use of chemical solvent to capture CO₂ from combustion flue gases is well established. The review of literature [7, 8, 9, 10, 11] indicates that solvents used in CO₂ capture plants now include wide variety of amines, amino acid salts, aqueous ammonia, and many others. Table A.1.1 in Annexe I presents a list of amine solvents that are commercially offered in the market to capture CO₂ from flue gases. This indicates the current state of the art technology for 1st-generation post-combustion CO₂ capture technologies.

Throughout the past decades, lessons learned from operating various pilot plants have been projected into the design of large-scale demonstration and commercial plants worldwide. Studies have generally indicated that through the improvements of solvents, processes and equipment, the efficiency has increased significantly, as the steam demand for solvent regeneration has been reduced from 3.8 – 4.0 GJ/t CO₂ (reported in 2005) to 2.7 – 2.9 GJ/t CO₂ [11] or even to 2.3 – 2.4 GJ/t CO₂ [12], under certain conditions.

Figure 2.1 illustrates the theoretical minimum separation energy required to separate the CO₂ from the flue gas. The figure further re-emphasises that the current 1st-generation chemical absorption technologies (30% MEA) has improved its thermodynamic efficiency (W_{ideal}/W_{real}) from 26% to 37% in the past decade with advancements of the 1st-generation solvents (1G) as presented by industry and others [13, 14]. Phase change solvents can provide further improvement [15].

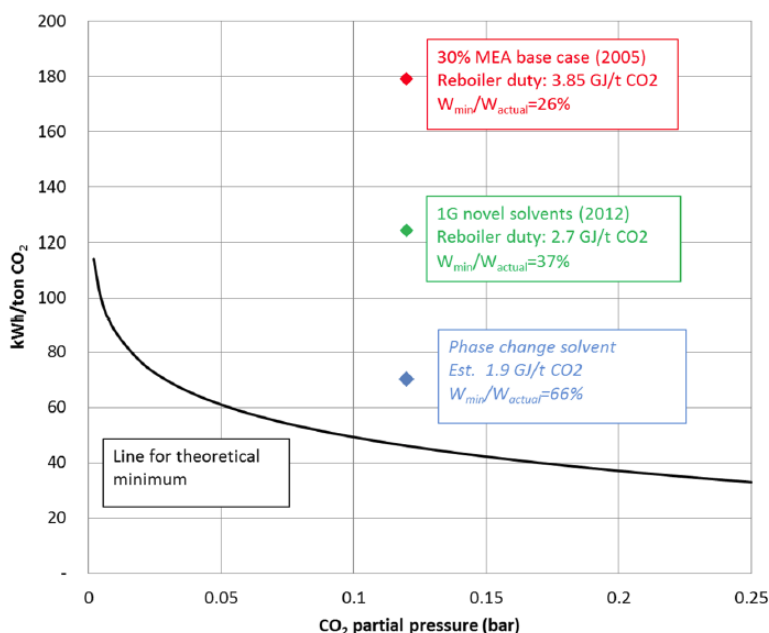


Figure 2.1 Theoretical minimum separation work of CO₂ capture [11].¹⁷

For the 1st-generation chemical absorption technology, it is expected that development work will continue to improve the efficiency and cost reduction including:

- Better formulation of the solvent to enhance kinetics and mass transfer;
- Improvements in the process designs– i.e. split-flow configuration, inter-cooling, vapour recompression, etc.;
- Better integration with the host power plant or industrial complex;
- Improvements to the equipment – i.e. absorber packing, heat exchangers, stripping column, etc.
- Scaling up of the equipment.

¹⁷ Figure presents the theoretical minimum separation work. The values are calculated based on the actual work done by the working fluid (i.e. steam) at around 20-25% thermodynamic efficiency. For comparison, 100 kWh ~ 0.36 GJ.

Further development will also occur in general areas such as materials (i.e. corrosion issues), environmental impact (i.e. emissions to air, water usage, etc.), solvent degradation (i.e. handling of degradation product, impact of inhibitors, etc.), and operation flexibility.

2.1.4.2 Pre-Combustion CO₂ Capture – IGCC based Power Plant

In power generation, pre-combustion CO₂ capture is generally synonymous to coal-fed IGCC plants. In recent years, several pilot plants¹⁸ have been implemented to validate the performance of capturing CO₂ from syngas.

Crucial to the development of pre-combustion CO₂ capture are the following elements:

- Improvements in the gasification process (i.e. syngas production and cleaning);
- Development of novel oxygen production;
- Integration of the water-gas shift reactor;
- Improvement in the acid gas removal unit (AGR);
- Development of gas turbine suitable for firing H₂ rich syngas (i.e. using lean premix burners).

This report focuses only on developments relative to CO₂ capture. Other areas are not discussed as they are beyond the scope of this report. An overview of the key developments necessary in these areas is given in a number of various papers and reports (e.g., [10], [16]). Enabling technologies for novel power cycles (i.e. involving solid oxide fuel cells or new turbomachinery) are also outside the scope of this report.

The integration of CO₂ capture in an IGCC plant could be achieved in two steps. This involves (a.) the conversion of CO to CO₂ in the water gas shift reactor; and (b.) the separation of the CO₂ from the syngas in the AGR unit.

For pre-combustion CO₂ capture, the “conventional” CO₂ removal processes could be considered as the 1st-generation technology. There are broadly classified under two general types of solvent that could be used to remove both H₂S and CO₂ – namely: 1) chemical solvent or 2) physical solvent. However, there are other solvents which could be considered as physico-chemical (hybrid) solvents. The most commonly referenced chemical solvent is Methyldiethanolamine (MDEA). The most commonly referenced physical solvents are Rectisol (cold methanol) and Selexol (dimethyl ether of poly-ethylene glycol).

The performance of pre-combustion CO₂ capture depends on the cumulative performance of all the integrated units of the whole IGCC plant (i.e., from gasification to gas turbine operation – it should be noted that this is not limited to the performance of AGR alone). Nonetheless, specific to the AGR unit, several incremental improvements should be expected.

¹⁸ Various pilot plants (using slip stream of syngas taken after the gasifier) at Buggenum (NL), Puertollano (Spain), and Polk (FL, USA) – evaluated the performance of various physical and chemical solvents including the performance of the shift reactor - See Ref [10].

MDEA has been commercially deployed; hence any improvements should be expected on a trajectory similar to that discussed for post-combustion CO₂ capture (section 2.1.4.1). With regards to the physical solvent, the list below highlights some of the key areas where potential improvement to either Rectisol or Selexol are desirable.

- For Rectisol Unit an operating temperature as low as -40°C is typical. The cost and energy penalty during refrigeration should be an area where further development is expected. Also, through modularisation and standardisation of the process will help to reduce cost.
- For Selexol Unit in standard configuration, ultra-high CO₂ purity would be a limitation. To achieve higher than 99% purity, a configuration with addition of chillers to reduce temperature down to around 5°C is necessary, which would add cost and inefficiency.
- For both Rectisol and Selexol a small amount of CO and H₂ slip are to be expected. Reducing such slip is an area of development that is necessary to address purity issues and energy penalty.
- Because methanol is such a volatile liquid, to avoid carryover into the product streams, refrigeration is usually applied to the Rectisol process. This has a positive effect on the absorbency of the process, but exacts an energy and capex penalty on the plant.
- Additionally, some H₂S (at ppm level) would also be co-captured with the CO₂. This becomes an issue if the CO₂ captured from physical solvents is to be delivered to a pipeline network. However, if free water is avoided in the pipeline system, sulphur-induced corrosion is not an issue.

In conclusion, it should be noted that there is a wealth of experience already available in existing commercial plants using chemical or physical solvents. These include the Great Plains Synfuel Plant (Rectisol), Coffeetown Gasification – Ammonia Complex (Selexol), and many other coal to liquid (CTL) or coal to chemical (CTC) plants deployed worldwide. Additionally, the use of chemical solvent in various ammonia/urea production units is considered as the current state of the art application for CO₂ capture in an industrial setting.

2.1.4.3 Oxy Combustion

Oxy Combustion technology is one of the important routes developed in the past decade to capture CO₂ from coal or gas fired power plants. Different key areas of development exist within oxy fuel combustion technology and these include:

- Boiler/gas turbine and burner development;
- Air separation unit (ASU);
- Flue gas processing unit;
- CO₂ processing unit (CPU).

This report focuses on CO₂ separation but details of developments on the areas above have been reviewed in the literature [10], [17, 18, 19, 20].

In principle, when applied to power plants this technology could provide near-zero CO₂ emissions (with only a small vent stream from the CPU and atmospheric CO₂ from the ASU). Similarly to post-combustion, water is a co-product also in oxy combustion. Unfortunately (unlike post- or pre- combustion CO₂ capture technologies), it is not possible to demonstrate this technology on a sub-scale or slip stream type of projects given that it requires a full conversion of the boiler or gas turbine.

In the past decade, significant advances have been made in all areas of development. Today, several boiler manufacturers could deliver oxy fuel fired boilers in demonstration or near-commercial scale. Likewise, all major industrial gas companies are also in position to offer a suite of technologies in ASU and CPU to suit the requirements of oxy fuel combustion technology.

It should be emphasised that there is no clear cut distinction between current and future generation oxy fuel combustion technology. It is important to note that the development of oxy combustion is evolutionary in nature. It should be expected that development pathway would be very similar to how conventional boilers (PC or CFB) are developed.

To enable the future development of new emerging oxy fuel technology it is required to deploy the 1st-generation oxy fuel combustion technology as several components in the 1st-generation technologies will also be used in any emerging oxy fuel technologies. Demonstration of 1st-generation technology is an important target to any successful deployment of future emerging technologies.

In the area of boiler and burner development, fundamental work will continue with the aim to accumulate a knowledge database in flame management, pollution formation and impact of process configuration. These developments show similarity to how conventional boilers are developed and improved.

In oxygen production, customised cryogenic ASUs that suit the requirement of oxy combustion are well established. It is expected that these ASUs will have an energy efficiency that is 25 – 30% better than that of conventional ASUs because they operate at lower pressure and produce a lower quality of oxygen. However, the cost reduction and optimisation will be the main focus of future work. Furthermore, large-scale ASUs (with a capacity greater than 5000 tpd) are now under construction in India and South Africa. Despite the fact that these are mainly used in gasification processes, key learning from building these large ASU units will be mutually beneficial to future demonstration of 1st-generation oxy combustion.

There are several developments in CPUs. Several of these components are extensively tested in various pilot plants and small demonstration plants. Despite the shelving of several oxy combustion projects, large-scale demonstration of the CPU has been achieved through applications in other industries. For example, principles of the CPU process have been deployed by Air Products in recovering helium from a natural CO₂ field; similarly, Air Liquide

used the same class of technology in demonstrating their CRYOCAP concept to capture CO₂ from an SMR based H₂ plant.

In summary, demonstrating oxy combustion is an important target in order to achieve wide deployment of this technology. It is essential to establish long term performance of the plant – which also includes management of air ingress (as this contributes to the main uncertainties in maintaining the long term performance target of the power plant). Furthermore, improvement to oxy combustion technologies is also aimed at optimising the process integration between boiler, flue gas processing units, ASU and CPU. Opportunities for co-production of water with oxy combustion plant are currently being explored [21].

Flexibility of the power plant has been addressed in various FEED studies. Options for energy storage have been noted as viable additions through the integration and management of the ASU and CPU.

In the medium to long term future development of novel technologies in oxygen production will be an important goal to reduce cost and improve performance. Novel oxy-GT technologies are now moving toward large-scale pilot demonstration. R&D interests are growing in the area of pressurised oxy combustion.

Table 2.2 Representative values of cost measures for power plants without and with CO₂ capture (adjusted from Rubin et al [22]).

Performance and Cost Measure	Post – Combustion	Pre- Combustion	Oxy Combustion	
Fuel	Bituminous coal	Natural gas ¹⁹	Bituminous coal	Bituminous/Sub-bituminous coal
Reference plant	SCPC	NGCC	IGCC	SCPC
Total capital requirement w/o capture (2013€/kW)	2,012	806	2,445	1,990
Total capital requirement w/ capture (2013€/kW)	3,520	1,584	3,356	3,796
LCOE w/o capture (2013€/MWh)	54	49	69	49
LCOE w/ capture (2013€/MWh)	87	71	92	85
Cost of CO ₂ captured (2013€/t CO ₂)	35	57	26	40
Cost of CO ₂ avoided ²⁰ (2013€/t CO ₂)	48	67	[33 – 48] ⁽¹⁰⁾	48

¹⁹ The gas CCS costs are very dependent on the fuel price and fuel price sensitivities should be included in evaluations

²⁰ Excluding Transport and Storage.

2.2 1st-Generation CO₂ Capture Technologies costs overview

In 2013, the UK CCS Cost Reduction Task Force²¹ estimated that generation and capture costs could drop approximately 17% for plants reaching FID in 2020, instead of in 2013. In the late 2020s generation and capture costs could drop a further 25% [23]. Key to the successful wide spread deployment of CCS is to achieve the cost reduction target by 2030.

In 2011, ZEP reported costs of 1st-generation CO₂ capture technologies, also comparing results against numerous studies in the literature [24]. More recently, Rubin et al. [22] presented current cost estimates for CO₂ capture, based on studies published until 2014.

Table 2.2 presents representative values as reported in various references used as cost benchmark for different CO₂ capture processes applicable to power plants (cost are adjusted to 2013€²²). These representative values constitute means among the minima and maxima, reported on the studies considered by Rubin et al. [22] for early commercial projects.

¹⁰ Reference plant is IGCC w.o. CCS although there are only 4-5 IGCC (1st of kind) IGCC plants worldwide operating. The ZEP Capture cost study [24] took a PC plant w.o. CCS as reference also for IGCC with CCS, in brackets are given the cost for a 1st of its kind plant (higher) and the cost for a nth of its kind (lower).)

²¹ <https://www.gov.uk/government/groups/ccs-cost-reduction-task-force>

²² 2013 EUR/USD exchange rate=1.301 (Rubin, et al., 2015)

3 Emerging CO₂ Capture Technologies for Power Generation and Carbon Intensive Industries

3.1 Introduction

There is a range of 1st-generation CO₂ capture technologies that can be deployed immediately. In Section 2, these 1st-generation technologies are described; they are taken here as benchmark to assess the performance and cost of any emerging CO₂ capture technology.

1st-generation technologies will naturally evolve and improve as experience is gained with an increasing number of plants built and operated successfully. Therefore, the main strategic objective of any emerging CO₂ capture technologies must be to grow in scale and compete against existing benchmarks, demonstrating during such scaling up process their benefits.

This chapter identifies several potential CO₂ capture technologies of the future and classifies these according to 2nd or 3rd generation technologies based on their TRLs. An assessment is made to indicate their potential application in a variety of industrial settings (power generation, natural gas processing, and several carbon intensive industries). The criteria for assessment should include performance parameters that are common in current debates: (a.) potential for cost reduction and efficiency improvement (b.) operational flexibility, (c.) retrofitability, (d.) health safety and environment (HSE) issues, and (e.) reliability and material availability.

Emerging technologies which can be retrofitted or adopted to existing 1st-generation large-scale CCS plants will provide additional value as these technologies are able to enter the market faster.

Combinations of 1st, 2nd and 3rd generation technologies, so called “hybrid systems” have been receiving growing research interest. These are expected to eventually offer case-specific solutions to many different applications in the future, e.g. absorption followed by cryogenic capture or the combination of chemical looping with H₂-membrane reactors for H₂ production with integrated CO₂ capture; such combinations are beyond the scope of this study. It is expected that different (combinations of) technologies will compete depending on the CO₂ concentration in the flue gas and production capacity (also in view of decentralized capture).

In order to achieve the assessment objective set by this task force, this chapter is organised as follows:

- Selection of a representative set of boundary conditions for future capture technologies in different settings (power, natural gas processing, iron& steel, cement, refineries, paper/biofuel sectors). See Section 3.2.
- Discussion of the characteristics of emerging technologies that could qualify best for different environments (3.3 Power sector; 3.4 Iron & Steel, 3.5 Cement, 3.6 Refineries, 3.7 Other), focusing on those that have experienced a recent progress towards high TRLs and defining key challenges and future priority areas for R&D.

- Assessment of emerging technologies along a defined set of performance parameters based on a qualitative expert judgement. The assessment highlights the relative strengths and weaknesses of emerging CO₂ capture technologies compared to today's benchmark 1st-generation technologies and point out the main knowledge gaps. The result of this assessment is reflected in Table 3.2 by a simple traffic light system.

3.2 Definition of a set boundary conditions for emerging capture technologies in different industrial settings

The development of many of the new CO₂ capture technologies (2nd and 3rd generation) referred in the previous sections has traditionally focused on the power sector [25], as this is the main source of anthropogenic CO₂ emissions. However, deploying CCS to carbon intensive industries has rapidly gained strategic importance in Europe. This changes the boundary conditions for the capture operation. Even for “add-on” post-combustion systems, the composition (CO₂ concentration, impurities) of flue gas or off-gas streams as well as flow rate (scale) varies among different industries, favouring different capture technologies depending on the application.

Table 3.1 provides an overview of boundary conditions relevant for CO₂ capture systems operating in typical power plant and industrial settings. These parameters will influence possible capture applications and, therefore, will be used to discuss the status and suitability of different emerging technologies under the different industrial boundaries in the following sections. Table 3.1 is only indicative as some of the assumptions in such table can already be challenged: coal power plants have been designed in the past for base load, thus operating at least 6,000 hours per year, while gas power plants in many countries in the world have been mostly used to provide part-load, thus operating between 4,000 – 5,500 hours per year (this is mainly due to natural gas being the more expensive fuel, which shifts gas power plants to the lower end of the merit order). More recently, in many parts of Europe, an increasing share of intermittent renewable power has been installed leading to a drastic reduction in the annual operational hours for gas power plants as well as coal power plants. Lower overall operational hours require more flexible CO₂ capture concepts, which may be at the expense of lower total capture rates or efficiency penalties. Different emission sources and non-steady operation (from power or industry) will also have a notable impact on the transport and storage infrastructure.

A brief review of the status of development of different emerging CO₂ capture technologies is given for the most relevant sectors in the following sections.

Table 3.1. Boundary conditions for CCS in the Power and carbon intensive industry sector.

	Hard Coal (Advance USC PC equipped with SCR & FGD)	Lignite (Advance USC PC equipped with SCR & FGD)	NGCC (F-Class GT with 2-2-1 arrangement)	Integrated Steel Mill (BF-BOF Route)	Cement (Dry Kiln w/ 5 Stage Preheater & Pre-calciner)	Hydro-skimming Refinery	Medium to High Complexity Refinery	High Complexity Refinery	Hydrogen (SMR with Pre-reformer, HT shift and PSA)
Nominal capacity	1,000 MW _e (Net)	800 MW _e (Net)	900MW _e (Net)	4 million tonne HRC/y	1.0 million tonne clinker/y (1.4 million tonne cement/y)	100,000 bbl/d (~5 million tonne crude/y)	220,000 bbl/d (~11 million tonne crude/y)	350,000 bbl/d (~17 million tonne crude/y)	100,000 Nm ³ /h
Emission factor	0.75-0.80 tCO ₂ /MWh	0.85-0.90 tCO ₂ /MWh	0.35-0.40 tCO ₂ /MWh	2.0-2.1 t CO ₂ /tHRC ^{1), 2)}	0.66-0.68 tCO ₂ /t cement ^{1), 2)}	0.14-0.16 tCO ₂ /tcrude ^{1), 3)}	0.20-0.22 tCO ₂ /tcrude ^{1), 3), 4)}	0.22-0.24 t CO ₂ /tcrude ^{1), 3), 5)}	0.80-0.81 kg/Nm ³ H ₂ ⁶⁾
Emission sources	Single Point Source	Single Point Source	Single Point Source	Multi-Points Sources	Single Point Source	Multi-Points Sources	Multi-Points Sources	Multi-Points Sources	Single point source (modern SMR)
Annual operating hours	7,500	7,500	7,500	8,784 ⁷⁾	8,400	8,400 ⁸⁾	8,400 ⁸⁾	8,400 ⁸⁾	8,400
Annual CO₂ emissions	5.80 - 6.20 Mtpa	5.00 - 5.40 Mtpa	2.30 - 2.70 Mtpa	8.00 - 8.40 Mtpa	0.90 - 0.95 Mtpa	0.70 - 0.80 Mtpa	2.20 - 2.40 Mtpa	3.50 - 4.00 Mtpa	0.65 - 0.70 Mtpa
Typical fuel	Hard Coal	Lignite (with 50% moisture)	Natural Gas	Off Gases supplemented by NG	Coal, Petcoke, Waste, Biomass	Off Gases	Off Gases	Off Gases	PSA Tail Gas supplemented by NG
Volume (Wet)	3,100 - 3,200 KNm ³ /h	3,250 - 3,350 KNm ³ /h	4,000 - 4,200 KNm ³ /h (Based on the cumulative volume of the 2 flue gas stacks)	For furnaces, utility boiler, hot stoves: 1.3-1.35 KNm ³ /h per t/h BFG; 2.1-2.2 KNm ³ /h per t/h BOFG; 11.8-12.5 KNm ³ /h per t/h of COG All burned @15% excess air	210-220 KNm ³ /h	14-17 KNm ³ /h per t ROG or fuel oil	14-17 KNm ³ /h per t ROG or fuel oil	14-17 KNm ³ /h per t ROG or fuel oil	200-220 KNm ³ /h

	Hard Coal (Advance USC PC equipped with SCR & FGD)	Lignite (Advance USC PC equipped with SCR & FGD)	NGCC (F-Class GT with 2-2-1 arrangement)	Integrated Steel Mill (BF-BOF Route)	Cement (Dry Kiln w/ 5 Stage Preheater & Pre-calcliner)	Hydro-skimming Refinery	Medium to High Complexity Refinery	High Complexity Refinery	Hydrogen (SMR with Pre-reformer, HT shift and PSA)
Pressure	1.0-1.1 Bara	1.0-1.1 Bara	1.0-1.1 Bara	1.0-1.1 Bara	1.0-1.1 Bara	1.0-1.1 Bara;	1.0-1.1 Bara; For FCC - 2-3 Bara	1.0-1.1 Bara; For FCC - 2-3 Bara	1.0-1.1 Bara
Temperature	80-90°C	80-90°C	80-90°C	Depending on process (between 120-250°C)	110-120°C	For fired heaters: process dependent, ambient to 400°C; utility boilers: up to 140-160°C	For fired heaters: process dependent, ambient to 400°C; Utility Boilers: up to 140-160°C FCC: up to 300°C	For fired heaters - process dependent ~ambient to 400°C; utility boilers: up to 140-160°C; FCC: up to 300°C	130-140°C
CO₂ Concentration (%v dry basis) in the stream to be separated	12-15%v	12-15%v	3-4%v	Any combustion appliance: COG - 4-5%v; BFG - 25-30%v; BOFG - 18-20%v	22-26%v ⁹⁾	For fired heaters and utility boilers 4-5%; ROG: 12-14%	For fired heaters and utility boilers 4-5%; ROG: 12-14%; FCC 12-16%	For fired heaters and utility boilers 4-5%; ROG: 12-14%; FCC - 12-16%	20-22%v
Non-CO₂ species in Flue Gas	SO _x , NO _x , N ₂ , O ₂ , Ar, H ₂ O, CO, dust, heavy metals	SO _x , NO _x , N ₂ , O ₂ , Ar, H ₂ O, CO, dust, heavy metals	NO _x , O ₂ , N ₂ , Ar, SO _x (if H ₂ S is present in NG)	Depending on process & fuel	SO _x , NO _x , N ₂ , O ₂ , Ar, H ₂ O, CO, dust, heavy metals	Depending on process and fuel	Depending on process and fuel	Depending on process and fuel	NO _x , O ₂ , N ₂ , Ar, CO

Abbreviations

ARU – acid gas removal unit; BFG – blast furnace gas; BOFG – basic oxygen furnace gas; COG – coke oven gas; DCK – delayed coker; FCC – fluid catalytic cracker; HC – hydrocarbons; HCK – hydrocracker; HRC – Hot Rolled Coil; LPG – liquefied petroleum gas; NG – natural gas; ROG – refinery off-gas; SDA - solvent de-asphalting unit; SMR – steam methane reformer; PSA – pressure swing adsorption; HTS – high temperature shift; TRT – top gas recovery turbine; PRT – power recovery turbine; FGD – flue gas desulphurisation; SCR – selective catalytic reactor (De-NO_x)

Notes

- 1 Include Scope 1 and Scope 2 Emissions (i.e. Direct Emissions and Emissions of the Imported Electricity from Grid)
- 2 This is calculated based on using 30% non-fossil fuel (i.e. biomass, waste, etc.)
- 3 Overall CO₂ emissions could also be dependent on the type of crude input as well - (i.e. feeding heavier and sourer crude will have higher specific CO₂ emissions)
- 4 Medium complexity refinery includes Fluid Catalytic Cracker (FCC), Steam Methane Reformer (SMR); whilst high complexity refineries include FCC, SMR, delayed coker (DCK) and hydrocracker (HCK).
- 5 High complexity refinery includes FCC, SMR, HCK, DCK and solvent deasphating unit (SDA); for refineries with petcoke gasifiers (i.e. deeper conversion) specific emissions could increase up to 0.6 - 0.8 t CO₂/t crude.
- 6 Calculation is based on natural gas as feedstock and fuel. Other fuel with lower HC ratio (i.e. LPG, naphtha, other light HC) will have higher specific emissions.
- 7 The blast furnace operates at 24/7 for at least 10-15 years before any shut down. Other processes within site operate at different load factors.
- 8 In an oil refinery, the Crude Distillation Unit generally operates at 100% load factors whilst other processes may not necessarily operate at the same load factor.
- 9 40% of the CO₂ are derived from fuel combustion and 60% are derived from the calcination reaction of limestone (process related CO₂).

3.3 Emerging CO₂ Capture Technologies for Fossil Based Power Plants

There are recent reviews and reports on emerging CO₂ capture technologies that could be applied to power plants [26, 27, 28]. This report will not attempt to re-write or update these reviews. The target here is to introduce the different families of emerging CO₂ capture technology applicable to the power sector, provide an overview of their current development status, point out the R&D challenges ahead to enable these technologies to live up to their expectations and anticipated key benefits, and identify their potential application in industrial sectors.

The emerging technologies are usually classified by their gas separation principles which are at the core of every CO₂ capture system [25]. For simplicity, we are not reviewing other important enabling future technologies for CCS in the power sector (e.g., new turbomachinery, fuel cells, new combustor or gasifiers designs, etc.), as these are considered outside the scope of this report. However, it should be emphasised that these can strongly affect the viability of 2nd and 3rd generation technologies. Therefore, some reference to the status and TRL of these enabling technologies will be made when needed.

Table 3.2 provides an overview of different classes of 2nd and 3rd generation (emerging or novel) capture technologies that are proposed for capturing CO₂ from power plants. These are characterised by their potential to achieve substantial improvement either with respect to the functional material, the reactor/contact design or in the gas separation concept. This table presents the progress of their development towards their scale up and commercialisation goals. Their TRL assessment in 2005 is presented to indicate their progress over the last decade of development.

These emerging technologies are compared against 1st-generation capture technologies which, as described in Chapter 2, are used as a benchmark - i.e. the commercial separation processes based on amine based chemical absorption technologies (that have reached TRL8 - 9 in the power sector); physical absorption technologies to separate CO₂ from syngas or fuel gases at high pressure (that have reached TRL8 - 9 in several industries) and cryogenic air separation technologies used to deliver O₂ to an oxygen blown gasifier or oxy combustion systems (TRL8-9 for the power sector and TRL9 for industries).

It should be noted that there are many more scientific and patent references presenting many more proposals for advanced separation technologies. Typically, these are assessed at TRL1-2 (i.e. encapsulated solvents, ionic liquids, electric regeneration, reactive gas electro-sorption, Metal Organic Frameworks). These technologies are considered to be too premature to be included in this assessment of emerging concepts as they need to demonstrate proof of concept under representative conditions (typical boundary conditions) relevant to power plants and industrial applications.

Some of the emerging technologies presented in Table 3.2 have not evolved in their TRL in the last 10 years, perhaps indicating some fundamental challenge to further development (e.g., functional material reactivity and/or stability, need of extreme operating conditions, limitations in

gas-liquid/solid contact area, etc.). These technologies may have fallen into the “valley of death” where further development may not be viable.

Numerous R&D projects worldwide have been completed in recent years to achieve the progress in TRLs as presented in Table 3.2. In the EU, 9 currently active R&D CO₂ capture projects have been identified within the 7th framework programme (FP7) and more projects have just started under the EU’s Horizon 2020 Programme. The Joint Programme on CCS of the EERA (40 participant R&D institutions from 14 countries),²³ attempts to provide coherence and strategic vision to the energy research capabilities and ongoing projects on CO₂ capture at MS and EU levels. In Europe, ECCSEL is a project dedicated to organize and share resources in a common pool amongst participating organisations, by making use of readily available laboratories, modifying existing ones, and planning and building entirely new advanced laboratories.²⁴ We briefly summarise the status of the technologies referred in Table 3.2 as applied to the power generation industry.

Table 3.2. Perceived status of a range of emerging 2nd and 3rd generation CO₂ capture technologies, by comparing their maximum TRL (cited by a reference) achieved in 2015 with respect to 2005 (advanced process variants tested at lower TRL exist for each of these category of technologies).

Separation Process	TRL 2005	TRL 2015	Reference
Precipitating solvents	3	5	[29, 30]
Biphasic solvents	3	4-5	[31, 32]
Enzyme catalysed enhanced solvents	4	5	[33, 34]
Vacuum Pressure Swing Adsorption (post combustion)	2	5	[35, 36, 37]
Temperature Swing Adsorption (post combustion)	2	3-4	[38]
CO ₂ liquefaction/partial condensation	2-3	6	[39]
Chemical looping combustion of solid fuels	3	6	[40]
Calcium looping, post combustion	2	6	[41]
Metallic membranes for H ₂	3	4-5	[42, 43]
Polymeric membranes for CO ₂	3	5-6	[44]
Ceramic membranes for O ₂	4	4	[45, 46]

²³ <http://www.eera-set.eu/eera-joint-programmes-jps/carbon-capture-and-storage>

²⁴ <http://www.eccsel.org/>

3.3.1 Solvent - based Processes

The 2nd or 3rd Generation solvent based processes comprise precipitating solvents, bi-phasic solvents and catalyzed enhanced solvents. This class of technologies can be considered as refined version of the 1st-generation amine-based post-combustion CO₂ capture technologies as reviewed in Chapter 2. The fundamental advantage of these 2nd generation solvent systems with respect to other emerging technologies is their potential adaptability/retrofitability. This means that such systems can rely on components and equipment demonstrated in large-scale power plants with CO₂ capture and in other industries (which have achieved a TRL of 9).

Solvent systems causing precipitation of bicarbonates, amino acids or other salts (solid phase formation) can speed-up absorption kinetics and lead to almost complete turn-over (shift of chemical equilibrium) in the absorber. Depending on the insolubility of the precipitated salt, its separation or the significant reduction of the CO₂ rich solution is possible, consequently reducing the regeneration energy in the stripper. The reduced amount of co-evaporated water in the stripper offers potential to reduce OPEX as well as the efficiency penalty. Moreover, the fast absorption kinetics due to the salt formation might make precipitating solvent processes better as compared to conventional amine processes when dealing with flue gases having low CO₂ concentration (i.e. for post-combustion capture in NGCC).

However, due to its nature, precipitation may encounter some operational issues, e.g., blocking of the packed bed or other equipment and subsequently fouling problems. On the other hand, precipitating solvent might not be superior against amine based chemical absorption technologies with respect to operational flexibility. This is due to the fact that all solvent based technologies will show some physical inertness towards fast shut down and turn on, especially when high volumes are circulated and a certain temperature level has to be maintained.

3.3.1.1 Enzyme catalysed enhanced solvents

A known performance limitation of enzyme catalysed enhance solvents is their inability to withstand temperatures of over 100°C, lower than the 120°C of a conventional regeneration (desorption) process. Options proposed to manage this include the immobilization of enzymes on packing in the absorber column, the filtration of enzymes out of the solution before it reaches the regenerator and the operation of the stripper at lower temperature and pressure. All of these options come with significant challenges and have yet to be demonstrated as viable options for large-scale CO₂ capture. If the enzymes are immobilized on the packing in the absorber, it is not clear if they will perform as efficiently as when they are freely floating in aqueous solution. The catalytic effect is most needed on the gas-liquid interface, and a catalyst sitting on the packing may therefore be less effective. Filtering the enzyme out before it reaches the regenerator requires new process equipment in the plant. Any filter is also likely to reject some solvent together with the enzyme and this may impact the overall efficiency of the capture cycle. A temperature of 120°C in regenerator and pressures around 2 bar, is often regarded as the optimal point in the trade-off between solvent stability and efficient process operation. Deviations from these conditions might entail deteriorations of the overall process performance.

Another concern regarding enzyme catalysis is which solvent systems benefit to which extent. Many conventional amine solvents already show fast kinetics, hence the potential benefits of an

enzyme catalysed process are likely to be quite limited. Carbonate solvents have been proposed as candidate solvents for enzyme catalysis. However, with respect to carbonate solvents kinetics does not appear to be the only issue, as under various conditions they also show a low cyclical capacity and difficult regeneration. It is therefore not clear if a carbonate system with enzyme catalysis will be competitive with conventional amine solvents. It is uncertain if there is any solvent system that will benefit enough from enzyme catalysis to justify the additional complexity of the system.

3.3.1.2 Encapsulated solvents

Encapsulated solvents are thin polymer beads that contain a liquid solvent. CO₂ will diffuse unimpeded through the particle to be absorbed in the liquid. Encapsulated solvents intend to combine the benefits of liquid solvents with the benefits of solid sorbent process configuration, e.g. non volatility of solvent, no co-evaporation etc. Another stated advantage of this concept is that it can utilize solvents with higher viscosity although this also slows down diffusion of the CO₂ through the gas-liquid interface. This problem is not addressed by encapsulation. If the encapsulated solvents are to be utilized in a thermal swing process there is a need to heat and cool the liquid; the encapsulation would appear to have a potential detrimental effect on the heat transfer in the medium.

While the encapsulated solvents represent a novel concept, it is not clear if they offer a path to more efficient CO₂ capture processes. Further work on encapsulated solvents should identify process configurations suitable to demonstrate that the technology can bring energy benefits on the overall system level.

3.3.1.3 Ionic liquids

Ionic liquids have been explored as novel solvents for CO₂ capture. Ionic liquids however tend to have high viscosity, which can impact the capture process in a number of ways. High viscosity affects the diffusion of free CO₂ through the liquid and thereby has an impact on the wetting of packings required for efficient gas-liquid contacting. Higher viscosity also influences the heat transfer properties of the liquid, potentially requiring larger equipment for heat transfer. The likely greatest merit of ionic liquids, their non-volatility, shows potential advantage in the stripper and in terms of emission control, but might be (over) compensated by higher energy consumption of pumps and higher vulnerability for corrosion of equipment. Moreover, the cost of the solvent will be significantly higher than that of a conventional system. The potential overall system benefits remain vague.

3.3.1.4 Challenges and R&D targets

Key challenges and R&D targets for solvent-based capture in the power sector include:

- Flexible operation of integrated capture and power plants. Develop processes that enable the integrated plant to respond quickly and efficiently to changes in power and carbon markets.
- Focus more on system level perspective. Process strategies are to be developed on how and to which extent to integrate capture facilities into different power plants indicating and guiding the trade-off between high degrees of integration and minimised efficiency penalties and lower degrees of integration at higher operation flexibility.

- The high energy requirement of the separation process. A penalty of ~8-12% points in efficiency loss on total plant level with present technology (MEA). A long-term R&D target (beyond 2030) should be to reduce this to below 5% points. Most of the recovery energy of CO₂ (efficiency penalty) is due to desorption of CO₂ from aqueous solution.
- The low CO₂ partial pressure (especially for NG power plants) and the large flue gas volumes imply very large equipment volumes and contacting surfaces. Reduce equipment volumes by developing more effective contacting surfaces and faster cycles.
- Flue gas impurities (depending on fuel/industrial process). Develop capture processes independent from, or at least very robust with respect to composition of impurities in the flue gas, e.g. SO_x. This seems almost impossible for amine based solvents or amine based functional groups, both currently available and in development, as the chemical bonding affinity between nitrogen and sulphur is higher than between nitrogen and carbon, affecting the CO₂ absorption capacity and leading to partly non-regenerable degradation products, hence a loss of solvent. If however future solvents could be created with a stronger binding affinity towards CO₂ than to the surrounding impurities in the flue gas solvent lifetime and robustness would be enhanced and eventually co-capture of gases would be possible with subsequent sequential regeneration.
- Degradation and environmental aspects. Ensure that capture processes have no significant effect on human health or the environment, e.g. emissions and/or degradation products. Deploy online technologies to constantly monitor plant emissions and allow for immediate actions in case thresholds are exceeded.
- Material of construction. Develop lower cost materials for construction of capture plants.

3.3.2 Solid Sorbent Processes

This section assesses emerging solid-sorbent based systems (using PSA, VPSA and TSA) for large-scale separation of CO₂ from flue gases of power plants or other industries. It further includes sorption enhanced processes conceived for pre-combustion applications that may be particularly relevant for industrial applications discussed in Section 3.3.

High temperature solid looping systems are discussed separately in section 3.3.3. Pressure swing adsorption (i.e. PSA or VPSA) processes are considered commercial in many gas separation applications. These are predominantly seen in the production of H₂ from syngas of IGCC, ATR, POX or SMR plants; in small-scale production of nitrogen or low-purity oxygen (i.e. up to 300 tpd of O₂ at 90-95% purity, with the balance being typically Argon) from air; or purification of air (i.e. removal of H₂O, CO₂ and others) in a cryogenic ASU. However, many of these separations processes are not directly applicable to CCS for the power sector because they tackle relatively small flows of gases adsorbed by the solid (i.e. impurity removal) and/or sorbent regeneration steps that do not/cannot release a concentrated stream of CO₂ for subsequent purification and disposal.

The use of VPSA is demonstrated in the Air Product's SMR plant at Port Arthur (Texas, USA) capturing around 1 Mtpa of CO₂ from the shifted syngas, transported and used for EOR operation. These mature capture systems have been discussed in Section 2.

The novelty of emerging solid sorbent systems (2nd or 3rd generation) is usually linked to the properties of a novel adsorbent material selectively capturing the CO₂ from the flue gas or to the design of more efficient cycle configurations. It is crucial to evaluate the viability of these novel concepts when handling a large volume of flue gas at near atmospheric pressure. The cost of compressing the flue gas will outweigh any advantages if the stream to be treated has a low partial pressure of CO₂. Furthermore, the scale of the gas flows requires that the adsorption processes are run at fast cyclic conditions in order to maximise the productivity [28]. However, temperature swing adsorption would be technically feasible.

There are several solid adsorbent materials being investigated for capturing CO₂ from flue gases. This includes activated carbons, zeolites, meso-porous silica, metal organic frameworks (MOFs), silicates, hydrotalcites etc. Depending on the type of interaction between CO₂ and the adsorbent material, different process configurations can be applied to separate the CO₂. Sorbents which show weak interaction with CO₂ (physisorption) usually show a high CO₂ loading or working capacity (2-4 mol/kg = 9–17 wt. %) with low heat of adsorption (0.34 – 1 GJ/tCO₂), depending on the pressure/temperature dependency of the adsorption equilibrium and on the operating pressures/temperatures. This type of adsorbent could be suitable for separating CO₂ from flue gas (with high concentration at >15%) using a VPSA configuration [28].

There are also different adsorbents being developed which are enhanced by the addition of a chemically active surface to provide stronger interaction with CO₂. These types of adsorbent usually shows lower working capacities (1-2.5 mol/kg = 4–11 wt. %) but high selectivity towards CO₂; therefore these could be suitable for flue gases with lower CO₂ concentrations. The heat requirements for regeneration are similar to the ones of solvents and range from 1.1 to 2.3 GJ/t CO₂, with the advantage that the heat capacities are lower since there is no need to dilute the amines in water. In applications to CO₂ concentrations below 10%, these materials can be used in temperature swing (TSA) processes.

The performance of a novel material in an adsorption process is difficult to predict from simple physical parameters, because for a given material the process itself can be optimized and adapted to achieve improved performance [47].

A PSA (pre-combustion capture) or a VPSA (post-combustion) carbon capture process will be designed in a configuration that is not like conventional processes (hydrogen production or air separation), because CO₂ will always be the more strongly adsorbed component. The actual configuration will depend on the specified purity and recovery. These are typically fixed at 95+% purity and 90+% recovery, but if these are allowed to vary, a broader range of process configurations and materials would be of interest. The greater flexibility would require a combined polishing step in hybrid systems to achieve pipeline quality conditions.

In a VPSA cycle the recovery will depend on the vacuum pressure that can be achieved and for large-scale systems (vacuum pressure ~ 0.2 bar) this constraint is likely to lead to two-stage multicolumn configurations.

In PSA cycles single stage multicolumn systems can achieve the required separation, possibly including a vacuum swing step to desorb fully the CO₂.

For low concentration streams, rapid TSA processes can be achieved using fluidized beds [48] or rotary wheel adsorbers (RWA) [49]. For higher concentration streams, PSA or VPSA processes will always be preferred since the cycle time will be at least an order of magnitude lower than that of TSA cycles (i.e. much higher productivity). To achieve very fast cycles in PSA, VPSA and RWA systems, structured packings that minimise pressure drop and maximise productivity need to be developed.

In power plant applications, it is likely that multiple trains will be needed. While in the short term this may seem to result in a higher cost, it does introduce flexibility in operation given that this will allow the carbon capture unit to operate at near optimal conditions even when the power plant varies its output, especially for PSA and VPSA systems which can be turned on and off with relatively short lead times. In industrial applications, where scales are smaller, it is likely that a single train will suffice.

Adsorbents are also used in the high temperature Sorption Enhanced Water Gas Shift SEWGS [50] process where an active component in the solid sorbent (hydrotalcite material) reacts with CO₂, shifting the WGS equilibrium towards H₂. CO₂ is released in concentrated form by a pressure swing and purge of the bed with low pressure steam. Proposals have been made to implement such process in pre combustion power plant systems, but the main developments are currently taking place in Europe focused on industrial applications (i.e. H2020 Stepwise project)²⁵ and will be discussed below.

Key challenges and R&D targets include:

- Development of structured packings or monoliths for novel families of adsorbent materials;
- Develop standardized testing procedures of new materials, including the effect of steam and flue gas impurities;
- Optimize materials and processes to decrease CAPEX (size of equipment) and OPEX, primarily by minimizing the cycle time and optimising the productivity of the unit. The use of more advanced structured materials, will further decrease relative contribution to the cost of the process;
- Develop reference process specifications to allow comparisons between different combinations of materials/processes, including the effect of water present in the flue gas;
- Stability of adsorbents and reduce adverse effects minor impurities present in gas.

²⁵ <http://www.stepwise.eu/>

3.3.3 Chemical Looping and Calcium Looping High Temperature Systems

These are a family of processes that can exploit the reversibility and high reaction rates of certain gas-solid reactions taking place at very high temperature (i.e. from 600°C to over 1,000°C depending on processes and reactors). This allows for the efficient energy recovery from the heat flows involved in the chemical loop, using conventional steam cycle equipment. In the most developed versions of these systems (TRL6 has been reached for chemical looping combustion of solid fuels at atmospheric pressure and for post-combustion calcium looping) the main reactors used are circulating fluidised beds, that closely resemble the thermal and mechanical characteristics of Circulating Fluidised Bed reactor systems that are mature in the power and refining sectors.

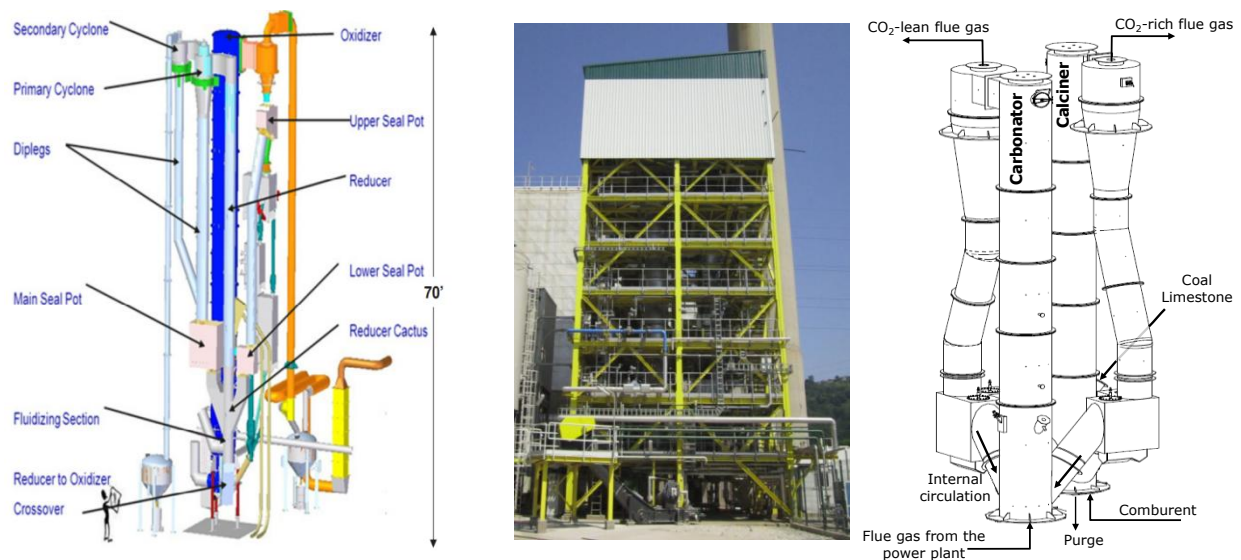


Figure 3.1. Left: ALSTOM 3 MWth chemical- chemical-looping combustor pilot [51], Center-right: “la Pereda” 1.7 MWth Calcium looping pilot [41].

In the Chemical Looping Combustion systems (CLC), the combustion of a fuel is achieved by transferring the oxygen to the combustor chamber using an oxygen carrier (usually a metal oxide that is reduced in such process). The reduced metal is then oxidised by air in a separate reactor, closing up the chemical loop.

In the post-combustion Calcium Looping systems (CaL), it is the CO₂ contained in a flue gas which reacts with a solid (CaO) forming CaCO₃. This is then regenerated back to CaO and pure CO₂ by oxy combustion of additional fuel in an additional oxy-fired CFBC power plant. The large surplus of high temperature heat from the Calcium loop makes this technology unsuitable for any application where power and/or high temperature heat is not a desired product. Both CLC and CaL have rapidly developed to TRL6 in recent years in process versions designed using interconnected fluidised bed reactors at atmospheric pressure (Table 3.1).

Key issues for CLC for solid fuels are linked to the reactivity, chemical and mechanical stability of the oxygen carrier (in relation to its specific cost and environmental impact), and the incomplete conversion (i.e. not full oxidation) of the fuel in the fluidised bed fuel reactor. This later problem can be managed by using an additional combustion step of fuel gas traces involving pure O₂ (i.e. “oxygen polishing”) or by recovery of the unconverted fuel gas in the CPU. The unconverted fuel in solid form can be minimized by a “carbon stripper”, where the fuel rich material has to be segregated from denser ash and oxygen carrier and recycle back to the fuel reactor. It is necessary to expand the experience in steady state operation when operating with solid fuels, in order to confirm the similarity with existing CFB boiler systems despite the differences in solid circulation rates and operation with interconnected reactors.

On the other hand, high-pressure CLC systems for NGCC are in theory highly energy efficient, but far less developed (TRL 2) as they require the operation of an interconnected fluidized bed system involving oxidizing and reducing atmospheres at high pressure and both upstream of a gas turbine that usually demands strict limits in loading of solid fines.

For post combustion CaL systems the key issues are related to minimizing O₂ consumption in the calciner, and the integration of solid purges in other applications (e.g., desulphurisation, cement, etc.). Material integrity (i.e. attrition) is an issue for some limestones and operating conditions.

Advanced concepts for fluidised chemical looping combustion and reforming systems (3rd generation) are also under development. In addition, some new developments exploiting theoretical advantages using packed bed reactors operated at high pressure are progressing towards TRL3-4²⁶ [52]. Also for NG, high-pressure Ca-looping pre-combustion concepts (sorption enhanced reforming) are being developed but remain at TRL<3.²⁷

Key challenges and R&D targets include:

- Scale up fluidised bed looping systems to confirm process and cost advantages by using mature CFB power plant technology. CLC and CaL technologies (currently at TRL5-6) should move to TRL7, which is the “dead valley” for emerging technologies, as it requires very large investments to build pilots of tens of MW_{th}. Also, demonstration of these technologies for biomass and other opportunity fuels need to be advanced to higher TRL.
- Improve stability of CLC materials.
- A priority for CLC reactor systems is to optimize the solid fuel reactor by maximising fuel conversion. Also, to test CLC systems using lower cost and high durability oxygen carriers while reducing the need of oxygen polishing. For natural gas systems, is still

²⁶ <https://www.sintef.no/projectweb/democlock/>

²⁷ see FP7 project <http://www.ascentproject.eu/>

necessary to achieve experimental proof of concept of the highest efficiency chemical looping systems, which require combustion or reforming at high pressures.

- Calcium looping post-combustion systems can further reduce energy penalties by demonstrating novel methods to minimise heat requirements in the calciner and reduce make up flows of limestone using sorbent reactivation strategies.
- Proof of concept of advanced CaL and CLC flexible concepts (at TRL1-2 today) to exploit the thermochemical energy storage potential of the reversible chemical reactions at high temperatures.

3.3.4 CO₂ Liquefaction/Partial Condensation for Pre- and Post-Combustion CO₂ Capture Applications

The basis for CO₂ liquefaction as an option for separating CO₂ from other gaseous species is by partial condensation of CO₂ in a gas stream that is compressed and cooled down (typically between -20 to -55°C depending on the cold box configuration). Capture rate and CO₂ purity will depend on the CO₂ concentration of the feed stream, as well as the process design (pressure and temperature at which the CO₂ condenses). The limitation to this capture principle is that it requires a feed stream that contains at least more than 50% of CO₂ for post-combustion flue gases and at least around 40% for syngases.

The technology behind CO₂ liquefaction on its own is considered a mature technology. Most of the components of these technologies have been developed as part of the CPU development for oxy combustion application. Several of these components have been demonstrated in industrial scale pilot plants.

Some of the key innovations using CO₂ liquefaction involves the use of an “auto-refrigeration” cycle using impure CO₂ as refrigerant, and the additional recovery of CO₂ from the vent using commercially available equipment, such as membrane or PSA/VPSA.

CO₂ liquefaction as stand-alone CO₂ capture technology was investigated theoretically for an IGCC power plant in the FP7 DECARBit project.²⁸ The stand-alone application is possible in this case since requirements on hydrogen purity are relaxed (a gas turbine actually operates better if the hydrogen is diluted), and the CO₂ capture rate is limited to 80%.

A wider range of applications for CO₂ liquefaction in IGCC with limited capture rate is possible if syngas (consisting of CO₂, CO, H₂, H₂S, H₂O and other components) is processed with the purpose of producing hydrogen of a certain purity *and* capture CO₂ with a purity that complies with CO₂ transport and storage specifications. CO₂ liquefaction is then typically envisaged as the second CO₂ separation stage of hybrid CO₂ capture processes (i.e. located downstream of PSA, VPSA or membrane).

²⁸ <http://www.sintef.no/projectweb/decarbit/>

The technology developed for this application is similar to the large-scale demonstration for CO₂ removal from the PSA tail gas of Air Liquide's SMR plant at Port Jerome (i.e. CRYOCAP Technology) – capturing 100,000 tpa of CO₂ for the food grade market.

The key research challenge in hybrid liquefaction process design lies in defining the techno-economic optimum between the two separation technologies. The TRL level for the hybrid capture system will be defined by the upstream capture technologies – which could be PSA, VPSA, membrane or others - that would sufficiently enrich the CO₂ composition of the gas stream, making it a suitable feed gas to the CO₂ liquefaction plant.

A critical element to the development for pre-combustion capture from coal based power/hydrogen production lies in the processing and removal of H₂S. Such removal may be required due to the constraints set by the upstream separation technology under considerations (i.e. PSA, VPSA, membrane or others).

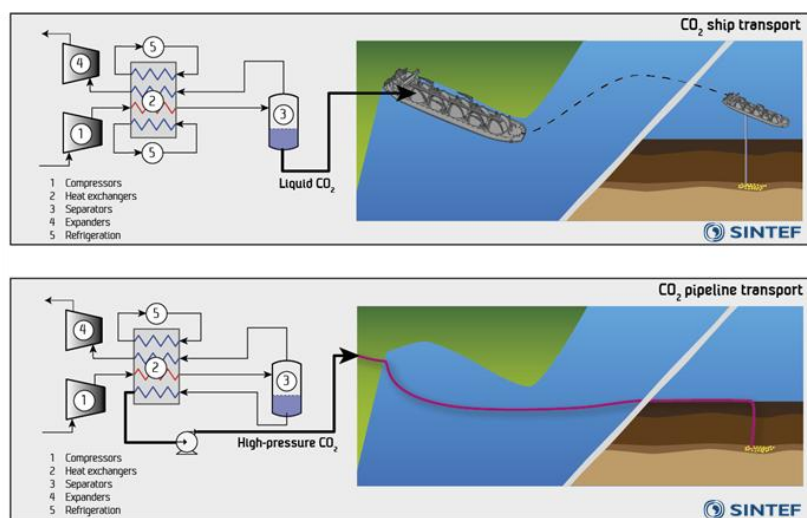


Figure 3.2 The CO₂ liquefaction process principle, and its flexibility with respect to ship/pipeline CO₂ transport. The process flow diagrams to the right are simplified, and can in practice include several process units of each kind.

Furthermore, it should be noted that an additional challenge lies in the relative lack of publicly available high-quality experimental VLE²⁹ data for CO₂/H₂ mixtures (although in-house data are believed to exist among key industry stakeholders). Such data are required in order to ensure confidence in CO₂ liquefaction process designs required for determining the optimum interface with the upstream separation technology.

To capture CO₂ from conventional flue gas (consisting of N₂, Ar, O₂, CO₂, H₂O, SO_x, NO_x and other components) using CO₂ liquefaction as a stand-alone capture technology is not viable due to low CO₂ concentration. However, the liquefaction technology becomes an option in hybrid

²⁹ The TREND software developed by Ruhr Universitat Bochum provides data to handle CO₂-CH₄ mixtures.

systems, after CO₂ enrichment through e.g. use of membranes producing a gas streams with CO₂ concentration of ~50-70%, or use of oxygen enriched combustion, or both. This concept of post-combustion capture technology is not yet validated, but is expected to advance from TRL 2 to TRL 6 by 2017 (when a CO₂ liquefaction test rig becomes operational as part of the ECCSEL lab infrastructure at SINTEF). It should be noted that the overall TRL of this technology is governed by the TRL of the upstream CO₂ enrichment technology to be used rather than the CO₂ liquefaction plant. Additionally, the treatment of the NO_x and SO_x will be an important element of the development of the whole capture system.

One of the advantages of capturing CO₂ in its liquid state is the flexibility it could offer in terms of choice of transport mode. The CO₂ can either be obtained at conditions ready for ship transport, or slightly heated and pumped to pipeline transport conditions. Redesign of the CO₂ capture process between the two options should be straightforward (Figure 3.2).

A number of projects such as Prometheus (Joule-Thompson), Clodic/Younes (heat exchangers), IFP (fluidized beds), Shell/Eindhoven Technical University (packed-beds) are developing different processes for cryogenic freeze-out of CO₂ as a solid, to avoid compression of the flue gas. This CO₂ freeze-out technology appears particularly interesting as part of hybrid technologies (downstream purification), specifically for biogas as cold duty at LNG regasification stations.

3.3.5 Membranes

Membrane technology can be relevant within capture lines such as post-, -pre-, and oxy-fuel. In principle, membranes allow the selective permeation of a target gas from one side of the membrane to the other. The driving force for the gas separation is a gradient in gas concentration, i.e. high partial pressure in the feed or vacuum in the permeate. Selectivity and permeability of the material, as well as stability and durability under realistic process conditions, are the key properties defining the suitability of a membrane for large-scale CO₂ capture systems.

Membrane separation technology is mature in some industries, but its application to the power sector for large-scale CCS is still the subject to R&D work. Polymeric membranes, which target the separation of CO₂ from flue gases, have experienced the greatest advance in the last 10 years. These have been commercially used in natural gas separation but some notable advances have also been achieved with inorganic membranes for oxygen transport and the pre-combustion separation of CO₂ from H₂.

3.3.5.1 Post-combustion application

Polymeric membrane systems for removing CO₂ from flue gas have received a lot of attention during the last decade. The technology has been tested at a 20 tpd scale demonstration (TRL~6) of the MTR membrane technology at the NCCC. Two projects in Norway, one at Norcem's Brevik cement plant and one for various types of flue gases at the Tiller demonstration plant (TRL~5), are also testing the technology planning to continue until the end of 2016. Membrane modularity and easy scale-up opens chances for retrofitting of existing plants as well as flexibility with respect to the CO₂ capture rate.

Due to the limited membrane selectivity of standard polymeric membranes and the need for a driving force for permeation, it is difficult to use one-stage membrane systems to achieve 90% removal efficiency and 95% purity [43], as usually targeted. Membrane systems using multiple stages could fulfil the targets of removal efficiency and product purity for CO₂. However, a cost minimization analysis shows that membranes are particularly well-suited for partial capture (40-60%) [53].

Standard membrane systems are always subject to a trade-off between permeance and selectivity. Progress in membrane development over the years led to an outperformance of the traditional Robeson plot, the plot of membrane selectivity versus membrane permeability. Recent developments on facilitated transport membranes, i.e. membranes with a “carrier component” incorporated in the structure itself, show that these membranes are able to achieve both high permeance and selectivity. Passing the Robeson trade-off line with respect to performance, they are able to reach the purity demand of 95% [54, 55].

Key issues are related to water vapour present in flue gases that is known to have a strong influence on permeability and performance of polymeric membranes (except for the facilitated transport membranes), e.g., causing competitive sorption plasticization and ageing. Below the dew point, water condensation on the surface and inside porous structures can cause severe reduction of permeance and selectivity. The presence of impurities such as SO_x and NO_x in conjunction with water vapour may form acids [28].

3.3.5.2 Pre-combustion application

A promising option for pre-combustion CO₂ capture in both coal and gas fired power stations [56] is the utilization of high temperature H₂-selective membranes. These are “Pd-based membranes” or “ceramic membranes (HTM)”) that can selectively transport hydrogen over other gases. Applied in a reactor integrated in a combined power cycle, this membrane technology combines the conversion of fuel into H₂ for large-scale power production with capture of CO₂. The process leaves concentrated CO₂ at high pressure reducing the compression energy for transport and storage. Key challenges are related to the further upscaling of the membrane manufacturing and the membrane stability at operating conditions and in the presence of contaminants. For successful commercialization of Pd-based membranes, the membrane must have sufficient permeability, selectivity, robustness, and durability in relevant environments. With current understanding, production of hydrogen from coal and other sulphur-containing sources is challenging for Pd-based membranes particularly due to their limited stability towards sulphur. Initiatives such as the Horizon 2020 project BIONICO, are undertaken on alloying Pd/Ag membranes with metals such as Au and Ru to improve membrane stability under mild H₂S conditions (1-5 ppm).

The membrane technology is also relevant for the production of hydrogen as a decarbonised fuel for many applications, such as boilers, furnaces, engines and fuel cells. Tokyo Gas has demonstrated the world’s largest scale Pd membrane reformer with a rated H₂ production capacity of 40 Nm³/h (150 kW_{th}) from natural gas, claiming to be achieving the world’s best hydrogen production efficiency (High Heating Value, HHV) of 81.4% [57]. The high temperature

H₂-selective membrane technology is currently in the TRL 4-5 level, and further upscaling projects have been established [58, 59, 60].

Alternatively, high temperature membranes can be applied to separate CO₂ from the other species present in a pre-combustion decarbonisation scheme. For this dual-phase process, membranes that are highly selective to CO₂ at an operating range of 400-700 °C are under development [61]. This technology is still at a low TRL of ~1-2.

3.3.5.3 Oxy Combustion Application (i.e. Air Separation)

Oxygen Transfer Membrane (OTM) technology is an oxygen production technology for use in oxy-fuel capture processes. Air Products and Praxair have developed and demonstrated this membrane technology in TRL 4-5, and tested several modules containing > 200 planar/tubes units for more than 4,000 h in the scale of 5 tons O₂/day. This technology shows an efficiency comparable to cryogenic air separation unit (CASU), but due to the low difference in efficiency and the lack of scale up demonstration, CASU technology is often preferred.

3.3.5.4 Challenges and R&D targets

Key challenges and long term R&D targets include:

- Enhance permanence to reduce the required membrane area (material cost) especially with respect to large flue gas streams.
- Enhance CO₂ selectivity compared to other flue gas constituents and impurities which will have great impact on CAPEX and CO₂ purity, hence the number of required membrane stages and the required membrane area.
- Address membrane sealing as it appears to be one of the most important challenges (ceramic – metal connection) with respect to CO₂ selectivity for ceramic and metallic membranes.
- Enhance O₂ selectivity and permeance for air separating membranes.
- Enhance stability of Pd-based membranes.
- Improve stability and resilience of membranes against mechanical stress, impurities and fouling, especially long term durability of membrane towards CO₂ atmospheres, SO_x, NO_x and particles in flue gas.
- Address the requirement for handling condensed water in the process.
- Introduce novel reactor designs to decrease concentration polarization effects.

New membranes which show promising results often remain on the same low TRL for years, because further up-scaling and development is blocked by the non-availability of the tested material in large amounts (no commercial supply chain in place). The up-scaling of non-commercially available materials showing promising results on lab-scale, could support the

technology moving up on TRL. European Horizon 2020 projects such as Fluidcell³⁰ and FERRET³¹ are expected to contribute on this.

3.4 Emerging CO₂ capture technologies in the Iron & Steel industry

The main source of CO₂ emissions from integrated steel mills (based on the BF-BOF steelmaking route) is the coal used to reduce iron ores in the blast furnace. Additional fuel is often imported as natural gas. Depending on specific site configuration, a variety of CO₂ emission points will exist on any site. The main CO₂ emission points are the blast furnace hot stoves, steam boilers, sinter plant, hot strip mill, BOS plant and coke plant. Assuming that works arising gases are utilized for electrical power, the largest CO₂ emission will be caused by the power plant, which can be located on- or off-site.

The ULCOS project has investigated the following strategies for CO₂ reduction in the steel industry:

- Decarbonising, replacing coal by natural gas, hydrogen or electricity for iron ore reduction;
- Usage of sustainable biomass as carbon source for iron ore reduction;
- Introduction of CCS technology.

After evaluation of nearly 200 different process route options, four technologies were selected for further development and scale-up. These technologies are the blast furnace with top-gas recycling (ULCOS-BF), HIsarna (coal based smelting reduction technology), natural gas based reduction and electrolytic iron making. Carbon and gas based technologies require carbon capture and storage to achieve the target of >50% reduction of CO₂ emissions. To improve process efficiency and to reduce capture costs both the retro-fitted ULCOS-BF and HIsarna are based on the use of pure oxygen instead of air, thus increasing CO₂ content of the flue gas.

3.4.1.1 Post combustion capture technology

A conventional amine system, like the MEA amine system, can be considered a 1st-generation capture technology. A weakness of the amine system is its need for large amounts of steam. The amine technology could be applied to flue gases with relatively lower CO₂ concentrations, such as from hot stove flue or steam boilers. It strongly depends on the steel plant configuration whether it makes sense economically to combine smaller flue gas streams into one large capture plant. BF gas can be made richer in CO₂ by oxygen enrichment of the hot blast air, which will influence the cost of CO₂ capture. PSA or VPSA technologies are more cost effective when CO₂ concentrations in the flue gas are higher, but will usually require additional particulate removal.

³⁰ <http://www.fluidcell.eu/>

³¹ <http://www.ferret-h2.eu/objectives>

PSA is already used at commercial scale in the Finex process (South Korea) and the Corex process (South Africa). As with the ULCOS-BF process, the purpose of the PSA is then primarily to separate the CO gas for re-use in the process. The produced CO₂ would fail to meet transport and storage specifications, requiring an additional separation step such as cryogenic purification.

3.4.1.2 Oxy-combustion capture technology

Drivers for oxy-combustion technology are greater process or cycle efficiency and higher CO₂ concentration in the flue gas, thus leading to lower cost CO₂ capture technology like cryogenic separation. The concept of oxy-combustion can be applied to power plants using works arising gases but also to all other combustion processes in integrated steel mills, such as hot stoves and reheat furnaces. In the ULCOS-BF project carbon capture technology was demonstrated at pilot scale using VPSA technology.

3.4.1.3 Pre-combustion capture technology

By sorption enhanced water-gas shift (SEWGS) or conventional WGS it is possible to enable the capture of a large proportion of steelmaking CO₂. H₂ can also be harvested from coke oven gas directly but this is not directly linked to CO₂ capture. Even though the CO-to-H₂ technology conversion is mature, its practical application is constrained by the impact on the gas and energy balance of an integrated steelmaking site, including the required burner modifications for high H₂ concentrations.

Passing compressed BF gas through a saturator, preheater and WGS, then cooling it (recovering the heat back into the process where possible) will produce a stream that is suitable for physical solvent CO₂ removal. Unlike the IGCC application described in Section 2.1.4.2 there is no H₂S to be removed, so the CO₂ removal plant can be greatly simplified. This promising concept has been validated theoretically, and there is no reason why the technology developed for different industrial contexts should not be transferred to the steel industry. However, it has yet to be demonstrated on real BF gas, so its TRL has not yet reached 5. Steelworks are known to be interested, but await increased profitability before committing to additional plant investment, even at pilot scale.

3.5 Emerging CO₂ capture technologies in the Cement industry

Cement production globally contributes to approximately 5% of anthropogenic CO₂ emissions. A major share (~60%) of the emissions occurs from the conversion of CaCO₃ to CaO, meaning that fuel switching is not sufficient to achieve significant CO₂ emissions reductions from this sector. Very few new cement plants are being built or are foreseen to be built in Europe, meaning that CO₂ capture technologies for the European cement sector have to be retrofitable to existing plants.

Cement plants typically operate at steady state, i.e. deliver a steady-state production of clinker that is ground and mixed with additives to produce cement. Downtime is typically scheduled during the winter, when construction activity is lower. Although operation mainly is stationary, CO₂ emissions may vary over time from a plant, due to factors such as type of clinker being burnt, type of fuel, type of raw meal (limestone) being employed, the amount of air leakage and

process design (heat recovery or not). What is important from the perspective of the adaption of post-combustion CO₂ capture technologies to cement plants, even with constant clinker production and fuel feed, is that the flue gas flow is likely to vary on a daily basis.

A cement plant is run in *interconnected mode* when the raw mill is operating, and in *direct mode* when the mill is out of operation. In interconnected mode, the air leakage into the flue gas stream is significantly higher, i.e. gas volume flow increases and CO₂ concentration decreases. It is normal to switch between the operating modes every day (typically 10% direct mode operation every day, although this varies over a year). In short, requirements on flexibility with regards to flue gas volumes and CO₂ concentrations are higher for post-combustion capture technology for cement plants, compared to power plants. The CO₂ concentration at the stack can vary from 14-35% [62], and as indicated above, the concentration will depend on several factors: operating mode (direct or interconnected), kiln size and type, fuel type and raw material.

1st-generation capture technologies

Post-combustion capture with amines is the obvious first-generation technology for cement plants. Norwegian cement manufacturer Norcem have tested an amine for CO₂ capture from the flue gas in their on-site CCS test centre in Brevik with satisfactory results. Generally speaking, for cement plants, it will depend on the amount of heat required for drying of the raw meal whether a cement plant will have available waste heat that can supply part of the heat required for amine regeneration.

2nd generation capture technologies

Key process advances could include Chilled Ammonia Process (CAP) capture, advanced amine capture process configurations, oxy combustion capture (with cryogenic ASU), membrane assisted CO₂-liquefaction, end-of-pipe post-combustion Calcium looping and entrained-flow Calcium looping. These are discussed below.

1. Chilled Ammonia Process (CAP) is a solvent technology perceived as 1st-generation technology for power plants and other CO₂ sources with CO₂ concentrations below 20%. The technology has never been tested for concentrations as high as what could be relevant for cement plants (up till to 35%). Such testing will be done in synthetic flue-gas flows of 1 tonne/day in the ongoing H2020 project CEMCAP.
2. Although oxy combustion using cryogenic ASU and other commercial technologies can be seen as a first-generation CO₂ capture technology for coal-fired power plants with the definitions employed in this report, this is not quite the case for cement plants. Components need to be tested and designed specifically for cement plants. CEMCAP will test oxy-fuel burners, calciner and clinker cooler for cement plants, and the results will be fed back to the ongoing ECRA CCS project and be used in the design of a oxy-fuel cement demonstration plant.
3. Calcium looping capture. Post-combustion capture of CO₂ emissions from the cement plant exhaust gases, after material pre-heating, with subsequent cooling and grinding of CaO is a 2nd generation capture technology for cement plants. ITRI's high-efficiency calcium-looping technology pilot (Heclot) in Korea is planned to capture 1 ton CO₂ per hour. Tests with high

make-up rates will be done up to 200 kW_{th} in the CEMCAP project, continuing work undertaken by the University of Stuttgart [63]. Also, exploratory work on more integrated concepts of calcium looping will be investigated at TRL4, involving the CO₂ capture step directly integrated in the raw meal pre-calcliner systems and particle sizes directly suitable for the clinker burning process (30-50 µm), meaning that no subsequent grinding of CaO particles is necessary. This is believed to make the Ca-looping capture technology more efficient for cement plants.

4. Membrane-assisted CO₂ liquefaction is considered to be a 2nd generation technology and is a concept suitable for higher CO₂ concentrations than those found at power plants. The principle is to apply bulk separation of CO₂ up to a concentration of ~60%, through the use of polymeric membranes, followed by compression, cooling and condensation of CO₂. The concept needs to be demonstrated, but should be possible to quickly advance to TRL6 since it can be realized with a combination of commercially available components (polymeric membranes, compressors, expanders, heat exchangers, phase separators). Initial testing to define optimum interface between membranes and CO₂ liquefaction, and confirm the operability of the CO₂ liquefaction technology will be done in CEMCAP. New membrane materials with high performance (permeance and selectivity), a technology currently at TRL5, is also being assessed as 2nd generation capture process within the cement industry.

3rd generation capture technologies

1. Amine-impregnated polymeric sorbents have been tested in the Norcem CCS project. CO₂ absorption occurs at 70°C and desorption at 110°C. The test phase in real cement plant flue gases is ongoing at a scale corresponding to 600-1600 SLPM.
2. Fixed-site carrier membranes have been tested on-site at the Norcem cement plant in the Norcem CCS project for 6 months. The core technology has proved to be functional, but the membrane module design needs improvements. Test results have proven to be satisfactory enough for the technology to proceed to a second test phase at Norcem.
3. O₂ production with high-temperature ceramic membranes has to date not been evaluated for integration in cement plants.

3.6 Emerging CO₂ capture technologies in the Refinery Industry

With the exception of the H₂ plant, CO₂ is emitted in flue gases from a larger number of different units throughout the refinery/petrochemical plants with fairly low CO₂ concentrations, typically in the order of 3–12% CO₂. Combined stacks can have a CO₂ content of up to 15% emitting in the order of 1 Mtpa [27, 64]. Because of the resemblance with the power sector flue gasses it is expected that the opportunities for applying CO₂ capture technologies in the refinery sector will follow the development in the power sector. Post-combustion capture with amines is thus the obvious first-generation technology for retrofits of existing refineries. Other technologies like

chemical and physical absorption, adsorption, and membranes are regarded as 2nd or 3rd generation capture technology.³²

Demonstration projects on hydrogen projects with CCS has commenced at Port Arthur (VPSA), Scotford (ADIP-X amine)³³ and at Port Jerome applying the Air Liquide Cryocap technology (CPU-derived technology).

3.7 Comparative assessment of emerging CO₂ capture technologies

Cost and energy use reduction remain essential criteria when assessing future CCS technologies. However, this report tries to go well beyond, by introducing in the assessment of emerging technologies some parameters that are considered highly relevant in the current energy and industrial markets where CCS is expected to operate:

- Cost reduction potential (Capex & Opex),
- Energy efficiency or efficiency penalty reduction
- Operational flexibility,
- Health, Safety & Environment (HSE),
- Retrofitability,
- Materials Availability.

We are aware of the uncertainties that are inherent to a comparative assessment of emerging technologies using all these categories. Even parameters of purely quantitative character (like CAPEX, OPEX or full system energy penalties) cannot accurately be estimated for emerging technologies as it well known that advocates of new technologies tend to under-estimate these parameters in early stages of the development of the technologies. Having said this, an assessment of the overall cost structure of the novel capture system is usually possible once the proof of concept (TRL 4-5) has been established. This estimation of CAPEX will depend on the nature of the construction material (functional and structural) of the equipment, the complexity of the capture process, the expected scale and the size of the main elements (which in turn depends on the kinetics of the capture process, e.g., residence times, CO₂ loading capacity of solvent or sorbent, etc.).

OPEX is directly affected by the efficiency penalty as well as the cost of replacement of the capture functional material (i.e. the degradation rate or stability of solvent, sorbent, oxygen carrier, CO₂ carrier, or membrane material).

The energy efficiency of the overall capture plant process depends not only on inherent thermodynamic aspects of the chosen CO₂ separation system, but also on the level of heat integration. Therefore, the efficiency of any new capture system has to be assessed under a

³² <http://ieaghg.org/education/19-ccs-resources/technical-workshops/523-ccs-in-process-industriestate-of-the-art-and-future-opportunities>

³³ <http://www.shell.ca/en/aboutshell/our-business-tpkg/upstream/oil-sands/quest.html>

holistic system level perspective. The criterion “operational flexibility” attempts to indicate whether a certain capture technology is capable of operating in load-following mode within a short response time, e.g. daily cycling up and down or, to put it simply, the system’s ability for rapid switching on and off. This is an issue that has only recently been considered by developers of emerging technologies.

HSE evaluates the different emission and degradation risk of the materials used in various capture systems and eventual toxic waste disposal.

The criterion “retrofitability” indicates whether a technology can be integrated into an existing, already operating plant at a later stage, thereby making no statement about the level to which integration is feasible and assuming that there are no space restrictions. It should also be noted that capture technologies which can be retrofitted to existing and relatively modern equipment will likely enter the market earlier than technologies which require a completely new built plant.

“Materials Availability” addresses a potential shortage of either rare or non-commercial materials needed in the novel capture system. ‘Non-commercial’ refers to an as yet non-existing manufacturing capacity or supply chain. Some emerging capture technologies require materials which today have no commercial supply chain, e.g., Metal Organic Framework (MOF), or other sorbent or functional materials (i.e. membranes or O₂ carriers in chemical looping). Many of these materials are synthesized in university labs on a milligram or gram scale and tested on lab bench scale for limited life times. In case of promising results at lab scale, the next logical step is the testing on larger scale and/or longer operating times. This up-scaling step often suffers from the non-availability of these materials in larger amounts, thus on the scale of kilograms or even tons, at least not at reasonable cost.

In order to progress towards the final assessment of technologies, a process of expert judgement among the authors and reviewers of this Report has been followed to build Table 3.3. In this table, each family of emerging technologies discussed in previous sections is represented by a couple keywords at the top of each column and all the assessment criteria referred to such technology are listed in the different table lines. Each cell is then given a colour (green, yellow, red) representing the main strengths (green) and weaknesses (red) of emerging CO₂ capture technologies with respect to the established benchmarks of 1st-generation technologies discussed in Section 2. A final row mentions the industrial environments where we perceive these technologies can best fit when taking into account their reviewed characteristics.

In assigning colours to the individual cells, the following set of criteria has been adopted (to avoid a final table filled with all green cells):

- For each category of technologies, we refer only to the most developed version (i.e. highest TRL). Usually, “promising” versions of these technologies are also being considered at lower TRL, but these cannot be assessed as present.
- While all 2nd and 3rd generation technologies might bear significant improvement potential, it is difficult to achieve a reliable assessment of technologies below a certain TRL status due to their lack of sufficient maturity. Therefore, no assessment of technologies with a TRL lower than 4 has been attempted.

- When there is a large uncertainty in a certain assessment parameter a red colour has been given.

The overall target in this assessment is therefore to identify the main strengths and weaknesses of emerging CO₂ capture technologies when deployed at the necessarily large scales required in the power and large industrial sectors.

Table 3.3. Traffic light table for emerging separation processes for CO₂ capture (process with TRL>4 only) with regards to assessment criteria Green means improvement potential compared to benchmark, today's 1st-generation demo plants. Yellow means indifferent, same or similar level and red means worse (or very uncertain) than benchmark. Yellow/green means could be better but in worst case similar than benchmark.

Process	Solvent based processes		Solid sorbent processes		High temperature solid looping systems		Membrane systems		
Separation Technology / Assessment criteria					Chemical looping	Calcium looping	Polymeric (post)	Ceramic (Oxy)	Metallic (pre)
Cost CAPEX	Yellow		Yellow		Green	Yellow	2) Yellow	Yellow	Red
Cost OPEX	Yellow		Green		Green	Green	Green	Yellow	Green
Efficiency penalty (thermodynamics, T- and P- level)	Yellow	Green	Yellow	Green	Green	Yellow	Green	Yellow	Green
Degradation solvent, sorbent, membrane	Yellow		Yellow		Yellow	Green	Yellow	Yellow	Yellow
Operational flexibility (on/off)	Yellow		Green		Yellow	Yellow	2) Green	2) Yellow	2) Yellow
HSE (waste, toxicity)	1) Yellow		1) Green		Yellow	Green	Green	Green	Green
Retrofitability ³⁾	Green		Green		Red	Green	2) Green	Red	Red
Materials availability (abundance, manufacturing chain)	Yellow		Yellow		Red	Yellow	Green	Red	Red
FOAK cost	Green		Yellow		Red	Red	Yellow	Red	Red
Applicability, most suitable to	Power, NG processing, Steel, Refineries, other		Power (pre combustion), Steel, Refineries		Power (solid fuels), Refineries	Power (post combustion, solid fuels), Cement	Power, NG processing, Cement, Steel	Power (oxy pre combustion)	Power (pre combustion), Refineries

Notes for Table 3.3:

- 1) All solvents or solids containing amino-groups might show due to operation conditions deamination³⁴ reactions which can lead to nitrosamine formation or degradation.
- 2) Depends very much on process integration of the membrane system. For example the retrofitability of polymeric membranes in a post-combustion configuration in general is possible, however, the feasibility in a detailed set-up which might require several membrane stages, compressors or vacuum pumps has to be individually assessed [65, 66].
- 3) The retrofitability criterion is a yes or no criterion, therefore only green or red.

We summarise below some comments on the decision process that has been followed to provide the colour codes of Table 3.3.

3.7.1 Solvent based processes

Solvent based post-combustion technologies are considered the current benchmark for CO₂ capture technologies due to their commercial availability and the substantial experience with this technology from a large number of pilot plants, including experiences gained from the first commercial plant at Boundary Dam. A number of different aqueous amine/ammonia solvent technologies are being offered commercially, but it is at present difficult to judge the relative performance of technologies from different vendors. Management of solvent degradation and emission control, namely handling of nitrosamines, has been a challenge for amine based CO₂ capture technology, these issues are being managed but there may be room for further improvements in terms of having the most cost efficient emission control technology.

All currently emerging solvent capture technologies can be considered as refined versions of existing 1st-generation amine/ammonia based solvents which try to overcome some of the particular weaknesses of 1st-generation solvents. While precipitating and enzyme catalysed enhanced solvents speed-up the absorption kinetics in order to reduce CAPEX for the absorber, other approaches like encapsulated solvents and ionic liquids try to reduce/avoid steam co-evaporation, the main energy consuming step in the capture process, in the stripper where CO₂ recovery occurs.

All emerging solvent capture technologies show selective improvements within the process, e.g. faster absorption kinetics or no volatility, less co-evaporation etc. However, these selective improvements in parts of the process come all along with trade-offs at other parts of the process, thus compensating or levelling the achieved benefits, or require additional equipment which increases cost.

At the current status it is not foreseeable whether these emerging solvent developments will lead to an overall net improvement of the process compared to the available 1st-generation amine/ammonia solvents.

³⁴ Removal of an amine group.

Amine/ammonia technology is likely to see gradual improvements in terms of optimal solvent formulations, individual process optimization and heat integration within the respective power and industry process to which it is applied.

For applications outside the power sector and gas processing industry there is less experience with amine technology. Development of solvent technology should also address optimal solutions for other than specific power applications. Key issues are likely to be optimal heat integration, and the management of various impurities in the flue gas, as amines are sensitive to SO_x and other oxidizing pollutants leading to amine degradation.

Solvent based capture technologies are best suited for continuously operated processes due to the high inertia of large amounts of liquid and the temperature profile required in the stripper for CO₂ recovery. Quick shut downs, ramp-ups are not optimal and will enhance operation cost. Very low CO₂ concentrations like in the flue gas of natural gas power plants (3-4 vol.%) require large absorber columns and the treatment of large diluted volume streams which lead to higher specific cost per tonne of CO₂ than for more concentrated CO₂ flue gas streams e.g. from a coal power or cement plant.

One way to reduce equipment volume at low CO₂ concentrations is more effective contacting surfaces, eventually by the means of nano-engineered surfaces, and faster cycles. Another approach is to develop abundant, lower cost material for the construction of capture plants which keep cost of even huge plants low.

3.7.2 Solid sorbents processes

Solid sorbent batch processes for large-scale continuous flue gas treatment will require more than one batch reactor, eventually multiple batch reactors, depending on the cycling time which entails higher CAPEX cost.

PSA and VPSA processes show at least an order of magnitude higher cycling times compared to TSA processes and greater operational flexibility with respect to power/industry plant output variations as the pressure build-up and vacuum generation can be turned on and off with relatively short lead time. TSA lacks operational flexibility for the same reason solvents do, due to the heat supply for the stripping off of CO₂.

Solid sorbent capture processes have the potential for lower net energy consumption (lower efficiency penalty) compared to solvent based capture processes.

Improvements are anticipated from novel material developments and novel process configurations. Ideal sorbent materials that are being sought would ideally look for those that show a high affinity to CO₂ (high CO₂ selectivity) but at the same time no affinity to other polar molecules like water. Materials showing also a strong affinity towards steam (a major component in any combustion process), achieve low purity of CO₂ in the separation process and high energy consumption in the CO₂ recovery process, as the adsorbed steam has to be recovered as well. This causes a similar inefficiency of the CO₂ recovery process as the steam co-evaporation that occurs in solvent capture processes. Highly CO₂ selective materials therefore possess a reduction potential for OPEX due to the lower regeneration energy (in the absence of H₂O).

The advantage of solid sorbent processes in order to lower heat requirements (CO_2 recovery) is the huge variety of potentially available highly-active surface adsorption materials, ranging from activated carbon to Metal Organic Frameworks (MOF), which can be precisely designed to the target molecule.

To achieve fast cycles (minimum cycling time) and minimize pressure drop in PSA, VPSA and RWA structured packings or monoliths need to be developed. Solid sorbent capture systems show a clear benefit with respect to HSE and waste minimization, as no aqueous solvents or toxic compounds are released.

3.7.3 High temperature solid looping systems

The potential for the highest efficiencies achievable with Chemical looping combustion systems is recognised in Table 3.3 with the only full green light on the energy penalty cell. However, this is only valid if CLC can adapt and operate at similar temperature and pressure conditions as in the reference system without capture. Chemical looping combustion has developed only recently to TRL5-6 for atmospheric pressure solid fuel combustion systems while high efficiency high-pressure systems linked to NGCC are not considered in the table because they remain at $\text{TRL} < 3$. Efficiency penalties can be extremely low for CLC systems, as long as fuel conversion is high and blower consumption for high solid circulation and inventories in CFB's is moderate.

The potential for low CAPEX in CLC systems at atmospheric pressure (green box in Table 3.3) exists if it is experimentally confirmed that the CLC system can closely resemble the commercial Circulating Fluidised Bed (CFB) boiler for solid fuels, despite their substantial differences in solid circulation rates, bed inventories and nature of the circulating materials. These differences justify a red colour for a FOAK plant. OPEX can also be very low if the performance as O_2 carriers of natural occurring minerals is demonstrated in stable pilot trials, but material availability for large pilots may be an issue if this is not the case (i.e. when synthetic oxygen carriers are needed in large quantities). CLC systems cannot be retrofitted to existing power plants and require new plants to be built.

In post-combustion Ca-looping, the post-combustion concept has been demonstrated in several pilots at TRL5 and 6, while pre-combustion concepts remain at $\text{TRL} < 3$. Applying Ca-looping as post-combustion capture technology to an ordinary coal power plant requires effective energy recovery in a new power cycle linked to the oxyfired CFB calciner. The need for an additional steam cycle to generate power increases the total CAPEX (in €) with respect to other post-combustion capture systems, while the specific CAPEX (in €/kWe), the specific OPEX and the energy penalties, is relatively low and remains competitive as a result of the capture system generating additional electric power. However, a partial yellow colour is given to efficiency penalty cell, as an ASU is still required to run the oxy fired calciner in the most mature CaL technology (other options under development to avoid air separation units are still at $\text{TRL} < 3$). The availability of sorbent precursor (limestone) is very high and the purge of solid material (rich in CaO) can find uses in power (i.e. desulphurisation) and cement plant environments. Cost of a FOAK could be relatively low because the tight similarity of CaL with CFBC boiler technology. However a red/yellow represents the increased uncertainties when designing interconnected system respect to single loop CFBC designs.

3.7.4 Membrane based separations

Post-combustion polymeric membranes systems could exhibit low energy requirements for the CO₂ separation. This justifies the green colour for OPEX although pressure drop can be an issue. The major cost for membrane systems are capital costs associated with compressor or vacuum pumps needed, and the membrane material (€/m²). Separation of power plant flue gases with low CO₂ concentration and large volume streams, generally requires large membrane areas in a single stage process, or several membrane stages. As the membrane cost could contribute to 50-60% of the system equipment cost, CAPEX was assessed in a yellow colour in Table 3.3. It will be important that new materials are designed to minimize the size and cost of the membranes, as well as the auxiliaries for compressors and vacuum pumps.

The number of membrane stages to achieve a certain CO₂ purity is affected by the CO₂ selectivity of the membrane while the size is determined by its permeance. However, post-combustion polymeric membrane systems create opportunities with respect to operation flexibility as they can be switched off and on, similar to gas power plants. In addition, the technology does not involve aqueous solvents or toxic compounds and does not need regeneration steps.

Upon meeting their performance expectations, e.g. such as high CO₂/N₂ selectivity, high permeance etc., membranes might become an attractive capture technology for gas power plants. Within the challenge for commercial applications, the stability and lifetime of membranes are of great importance. Potential clogging, fouling and cracks, as well as their sensitivity towards flue gas impurities will be determining factors – frequent membrane substitution would drive up OPEX. A given sensitivity of membranes towards other flue gas components determines the flue gas cleaning requirements and might therefore as well affect CAPEX and OPEX.

Metallic H₂-separation membranes for pre-combustion have reached a certain level of maturity in terms of H₂ permeability and selectivity. Ceramic O₂-selective membranes for integration in oxy-fuel processes are less developed and potentially more CAPEX intensive. OPEX can be low because of the low energy penalty, provided that the performance and stability of these membranes at their typically high operating temperatures are demonstrated. While retrofitting of an ASU unit installed in an existing plant is feasible with the membrane system replacing a cryogenic ASU unit, it is not possible to retrofit an already operating power plant with pre-combustion Pd membrane technology. In addition to challenges related to membrane availability and manufacturing value chain, this justifies a red colour for a FOAK plant.

4 Transport technology

4.1 Transport needs

Volumes of captured CO₂ will grow significantly over the coming decades, reaching the tens of megatonnes range at country level and for heavily industrialised regions between 2030 and 2050 [67]. For comparison, the largest CCS projects currently in operation capture, transport and store volumes typically in the order of 1 Mtpa. The transport of CO₂ for EOR purposes in the US is considerably more significant and in the order of tens of megatonnes per annum.

Transport and storage of these large volumes requires transport and storage networks that utilise economies of scale by linking several sources and sinks of CO₂. While today's one-on-one type of CCS projects represent the proving ground for CCS technologies, new developments will be required for the networks of the future.

Transport of CO₂ by pipeline onshore over long distances and over a range of pressures and temperatures is a well-established technology. Small-scale transport of CO₂ by ship and the onshore loading and offloading of CO₂ at ports is an established and commercial technology, but will require substantial upscaling to be relevant for CCS (both for ships and storage). Offshore unloading of CO₂ directly into subsea wells via buoys or platforms will require substantial technology development (heating and/or intermediate storage offshore) and further demonstration.

Table 4.1. 1st-generation Technology Readiness Levels

Technology	TRL	Comment
Pipeline transport	9	Based on US EOR, Quest and Boundary Dam Limited experience in European context: more densely populated
Shipping (port to port)	7	Small-scale LPG vessels (semi-refrigerated) demonstrate concept Large scale to be reached yet: ships and loading / unloading facilities
Shipping (port to offshore facility)	4-5	Further development required: impact of batch-wise injection on injection system, low-temperature flexible hoses, offshore buffering requirements, ship design

4.2 CO₂ pipeline transport experience

4.2.1 Operating pipeline projects

Bulk transportation of naturally occurring, and to a lesser extent, anthropogenic CO₂, is an established practice in the US where the main business driver has been to facilitate Enhanced Oil Recovery (EOR) rather than carbon dioxide sequestration. There are over 7,000 kilometres of pipelines in North America transporting significant volumes of CO₂ from natural reservoirs to oil fields (60 Mtpa in 2010) [68], with an increasing volume of CO₂ from industrial plants such as the facility at Port Arthur, Texas. The largest network supplies

Permian Basin operators in Texas and New Mexico, which have been injecting CO₂ for 40 years. The existence of these businesses gives confidence that transportation of CO₂ in dense phase is already at high TRL level. However, there are a number of important topics that need to be understood, before CO₂ large-scale transportation is applied in a wider European context.

- If not purified, anthropogenic CO₂ could potentially contain impurities that cause the product to behave differently in contact with materials (pipelines, seals etc.) and cause movement of phase boundaries potentially affecting transportation efficiencies. The impurities emitted from power plant capture in particular will result in different CO₂ compositions from those currently transported by pipelines in the USA. However, the CO₂ produced by almost all currently available capture techniques has a purity of >99% [69]; with sufficient dehydration to levels below about 250 ppm of water, impurities at these concentrations can be handled using carbon steel pipelines and injection wells [70]. The exception to this is CO₂ from oxyfuel systems and natural gas processing, which contains relatively high levels of air components or gas (several percentiles), which may need to be removed prior to transport and storage. The 'non-condensable' impurities (N₂, O₂, CH₄, Ar and H₂) have a relatively strong effect on the amount of compression [71].
- Water, as an impurity in the CO₂, has the strongest effect on transport and storage. Removing water to sufficiently low concentrations prevents corrosion and hydrate formation, also prevents inter-species reactions between impurities within the CO₂. Water content can be reduced by multi-stage compression and water knock-out systems and chemical dryers.
- CO₂ received into a network from multiple sources creates complexity for control and operations that needs to be understood through transient analysis.
- Immersing an intelligent pig into a pipeline containing dense phase CO₂ can expose it to the carbon dioxide atmosphere, and CO₂ can diffuse into the electronic components and the materials on which they are mounted, in the same way that it can diffuse into elastomers. Once the pig is removed from the trap it is depressurised, Rapid Gas Decompression (RGD) can take place, with damage resulting to the components within. Not only does this result in the loss of the electronic equipment, but also of the information collected, both of which are expensive. Operators in the USA are designing CO₂-compatible pigs, but a design that allows re-use in the same way that pigs are for other fluids has yet to be proven. Thus whilst prototypes have been demonstrated in the operational environment of dense phase CO₂, a reliable system has yet to be qualified.
- Standards applied for pipelines in remote areas of the USA are not necessarily appropriate for application in the more densely populated environment that can be expected in Europe. This is an important consideration in the context of Quantitative Risk Assessments (QRA's), differing expectations of safety levels and public acceptance in general. ISO 27913 provides guidance on transportation standards.
- Design Life of Assets comprising networks and other shared infrastructure may be greater for CCS operations than they are for EOR requiring different materials choices and/or standards of stewardship. That said, the USA Permian basin pipelines, developed originally by Shell, have been in place since the 1980s.

On-shore pipelines transporting CO₂ in vapour phase are currently also in use. In the Netherlands about 400 ktpa CO₂ (of which 300 ktpa from the Shell Pernis Refinery) is supplied to 500 greenhouses in vapour phase, re-using an existing 85 km 26" diameter pipeline between the Rotterdam industrial area and port of Amsterdam. This 'OCAP' pipeline is currently operating at about 20 bar(g) and is also used for buffering/storage of CO₂³⁵.

The only off-shore CO₂ pipeline worldwide was installed by Statoil in Norway, during 2005. This pipeline was installed by (un-)reeling, recognizing the challenging environment of the Barents Sea. CO₂, co-produced with the natural gas stream from the Snøhvit field, is separated at the Hammerfest LNG Plant on Melkøya Island and then transported, injected and stored in an aquifer about 2,600 meters below the seabed. Since April 2008, dry CO₂ is transported through a 153 km 8" Carbon Steel off-shore CO₂ pipeline and injected into the reservoir using a single subsea well at 330 meter water depth. Approximately 700 ktpa of CO₂ can be stored.

4.2.2 Planned projects

CCS holds investment potential for the development of transportation networks serving the many geographic clusters of CO₂ emitters. The concept of multi-user transportation networks is an important development on the journey towards developing a cost competitive CCS solution for carbon abatement. The benefits of economies of scale and the security provided by shared infrastructure are well understood through the development of gas, electricity, water and telecoms networks. A number of CCS networks have been considered across North West Europe which also raises the possibility of the North Sea being developed as a shared storage resource, raising the prospect of further economies of scale.

In the UK, the Yorkshire and Humber region has one of the highest concentrations of carbon dioxide emitters in the UK. Work on a multi user pipeline with a capacity of up to 17 million tonnes per annum in the region was well advanced, aiming to see carbon dioxide captured from this 'cluster' transported by pipeline and safely and permanently stored in geological formations beneath the North Sea³⁶. This development, known as the White Rose CCS project [4], was intended to start from a state-of-the-art coal-fired power plant equipped with full carbon capture and storage technology. This starter project was intended to prove CCS technology at commercial scale and demonstrate it as a competitive form of low-carbon power. The recent decision by the UK Government to withdraw funding for CCS Commercialisation has put this vision in jeopardy.

The Teesside region (Teesside Collective) aims to become Europe's first CCS equipped industrial zone. The Teesside Process Industry Cluster is one of the largest in the UK and includes a range of chemical, petrochemical and energy companies. The CO₂ emissions are an inherent part of many of the processes being utilised on Teesside³⁷.

³⁵ Information about the OCAP pipeline can be found at www.ocap.nl/files/Ocap_Factsheet2012_UK.pdf.

³⁶ See <http://www.ccshumber.co.uk/>.

³⁷ Blueprints for deployment of CCS in the Teesside industrial area can be found at <http://www.teessidecollective.co.uk/category/reports-publications>.

In Scotland, plans have been developed for a proposed full-chain 570 MW Carbon-Capture-Storage (CCS) coal-gasification power station located in Grangemouth. The proposed power station could be fitted with CCS technology designed to capture 90% of CO₂ emissions which would then be transported via existing on-shore pipelines and existing sub-sea pipelines for permanent geological storage 2 km beneath the North Sea. The aim was to link up with the offshore pipeline from the Peterhead CCS Project. Up to 10 million tonnes of carbon dioxide emissions could be captured from the Peterhead Power Station and transported by pipeline offshore. When connected together, through existing natural gas pipelines, the CO₂ transportation system in Scotland would be capable of taking CO₂ from the central belt of Scotland where most Industry and population is situated [72]. The withdrawal of funding for CCS commercialisation by the UK Government has significantly delayed the realisation of this vision.

The combined region of Rotterdam/Antwerp, with pipeline connections to Ijmuiden, Amsterdam and potentially the Ruhr Area in Germany would assemble the largest CO₂ cluster in Europe by far. In the Netherlands the Rotterdam Capture and Storage Demonstration Project (ROAD) is an initiative of Uniper (previously E.ON Benelux) and ENGIE Energie Nederland (previously GDF SUEZ Energie Nederland). ROAD plans to capture part of the CO₂ from a new power plant at the Maasvlakte and store the captured CO₂ in a depleted gas reservoir under the North Sea. ROAD aims to demonstrate the technical and economic feasibility of CCS and how it can be deployed on a large scale for power plants and energy-intensive industries. The knowledge and experience acquired within ROAD can be instrumental in the commercial introduction of CCS. The first infrastructure will be designed to facilitate the next phase of transport and storage in the region.

4.2.3 Potential development

An integrated connected network throughout the North Sea and around the Baltic will grow from these regional cluster projects. Other disconnected networks will develop in Eastern and Southern Europe as dictated by concentrations of emissions clusters and storage locations. The development of large, connected networks has been the subject of several studies³⁸.

The development of a large-scale north-west & central European CO₂ transport infrastructure was studied as part of the CO2Europipe Project, financed under the EU FP7 framework [67]. An inventory of large emission sources was established, assuming realistic economic scenarios. The captured CO₂ volumes were linked to potential storage locations (either depleted oil and gas fields or aquifers), for 3 different scenarios: on-shore & off-shore storage (Reference Scenario), off-shore storage only and an EOR scenario. By 2030 the transport network is expected to grow to 14,500 km (Reference Scenario) or even 21,000 km (Off-shore storage only & EOR scenario) in order to store 360 mtpa of CO₂. In order to store about 1,200 Mtpa by 2050, the transport system length should increase to 25,000 km (reference scenario) or even 33,000 km (both other scenarios). This is comparable with the

³⁸ For example, see [67], [126], [127]).

existing oil/products transmission network in Europe (35,000 km), but smaller when compared with the European gas transmission network having a length of 130,000 km in total. It can be concluded this is technically feasible, but the cost for development of this CO₂ transportation network is significant: about € 55 billion at current cost level for the Reference Scenario by 2050. This increases to even € 75-80 billion for the other scenarios, as the storage locations are more distant (off-shore storage only and CO₂ used for EOR). These findings are reasonably consistent with figures published in studies performed by other parties [73, 74].

Similar studies have also been performed for the US and Canada [75], showing the extent of the CO₂ network and associated costs.

4.3 Status of Pipeline technology

Transport by pipeline is an existing proven technology. The major considerations for designing CO₂ pipelines are:

- Transport capacity, which is related to number, size and location of (future) carbon capture plants and storage sites/well locations, onshore or subsea pipeline route options, ambient conditions such as soil, air temperature and (prevailing) wind conditions, geographical features and populated areas defining the pipeline route options and total length, burial requirements, variation in elevation, and options for compressor and/or pump stations along the onshore pipeline route or at injection points;
- Selection of standards applicable for pipeline design and operations;
- Selection of pipeline route corridors ensuring safe operations transporting CO₂ (risk reduced to As Low As Reasonably Practicable: ALARP), especially onshore nearby populated areas with elevation changes present (low lying areas);
- The compatibility of the CO₂ mixture in relation with material selection – corrosion (dehydration requirements for carbon steel), risk of fracture propagation (wall thickness, material grade and toughness requirements) and phase behaviour/transition during blowdown (low temperatures); the presence of impurities in the CO₂ can also have an impact on the behaviour of the pipeline material itself in the event of an uncontrolled escape, for instance, impact from earthmoving equipment. This is described in Annexe II, and it may be concluded that phenomena exist which have yet to be fully understood before CO₂ pipeline design and construction can be described as TRL9.
- Research has been carried [76] out into the way in which these impurities react when in an atmosphere of dense phase CO₂ with some surprising results. For example, experiments have been carried out with dense phase CO₂ containing 300 ppmv water, 350 ppmv O₂, 100 ppmv SO₂, 100 ppmv NO₂ and 100 ppmv H₂S. The CO₂ and the impurities were continuously injected in the test autoclaves and the consumption rate of the impurities was measured. The experiments showed that the carbon steel corroded and that elemental sulphur formed together with a liquid phase containing sulphuric and nitric acid. The potential for the deposition of elemental sulphur is of particular concern, as this has the potential to reduce flow, restrict valves, block down-hole injectors and blind the pores in the storage strata. Potential interactions of which a designer should be aware have been summarised in Table A1

of ISO 27913³⁹. The impurity with the most impact, because it seems to facilitate numerous other reactions, is water. As a general rule, if the moisture content of the CO₂ can be kept below 50 ppmv, then the potential for interactions between it and other impurities, or between the impurities themselves would seem to be significantly reduced.

- Transient phenomena such as depressurization which could lead to substantial cooling, resulting in low temperatures and potential for formation of hydrates (having free water present) or dry ice.

4.3.1 Phase Behaviour

It is important to bear in mind that CO₂ does not behave like water, hydrocarbon liquids, chemical liquids or methane, and varying the levels of impurities in the CO₂ will affect the phase behaviour. Understanding the phase diagram is critical, as under specific operating conditions (e.g. pressure reduction or blowdown) the fluid enters the two-phase regions (liquid and gas). Experience, research and design together highlight the importance of avoiding operating CO₂ pipelines in the two-phase region, although moving into two-phase flow cannot always be avoided. Depressurising a CO₂ filled pipeline or vessel can take much longer than for a natural gas and low temperatures resultant from Joule-Thompson expansion could potentially result in brittle fracture and crack propagation.

Most long distance CO₂ transportation pipelines are operated in dense phase. Operating in gas phase gives least operational complexity, e.g. the OCAP pipeline mentioned in Section 4.2.1 is operated at 20 bar. But operating in gas phase means that, in order to get reasonable throughput, large diameter pipelines are required, possibly also with booster compressors, increasing construction cost and thus transportation costs (per ton of CO₂ transported) substantially [77].

Operating in dense phase results in increased throughput for the same diameter but if a system is shut down and temperature falls the contents can convert to two phase, depending on temperature and pressures levels. Two-phase flow at start-up can lead to slugging of liquid CO₂ in the pipeline, therefore start-up should always be performed in a controlled manner to avoid potential damage to the pipeline.

Avoiding two-phase flow can be achieved by designing systems to operate well above the critical point by controlling the outlet pressure, even under shut down conditions, which means the pipeline is operated at high pressure over the full length. An overview of operating conditions of current and planned CO₂ pipelines is provided by IEAGHG [78].

4.3.2 Contamination and Material Selection

CO₂ pipelines require adequate dehydration of the CO₂ to prevent corrosion of carbon steel pipelines and specified fracture toughness levels of steel, or alternatively the installation of crack arrestors to minimise the impact of running ductile fracture in the unlikely event of a pipeline failure. Future technologies requiring research include alternative pipeline materials

³⁹ ISO 27913 'Carbon dioxide capture, transportation and geological storage – Pipeline transportation systems'

like CO₂ compatible composites which also have the potential for lower installation costs (reels with couplings without on-site welding).

Although the TRL level for transport by pipeline is high and indicative of a proven and commercially available technology (TRL 9), specific individual components could be at a much lower level. This will create a demand for focussed R&D to improve these sub-system components. Components of particular interest include the following.

- Measurement of constituent components in the individual and combined product streams. One of the operational concerns with regard to pipeline technology is the need to ensure product composition compliance (See Annexe III). CO₂ captured from industrial processes will contain small amounts of impurity which could have arisen from one of two sources:
 - The process by which the CO₂ was separated out (the exception being cryogenic processes where discrete separation based on the boiling points of the component gasses is possible). For instance, if a chemical solvent process is used, small amounts of the solvent (such as an amine) will be carried over into the CO₂ during regeneration.
 - The technology from which the CO₂ has been produced. For instance, CO₂ captured from post-combustion sources may contain CO, N₂, SO_x, or NO_x. Very often the captured CO₂ will contain remnant amounts of water or O₂.
- One process upset from one source can upset a larger part of a network. From an operator's perspective real time measurement is the ideal condition to assist safe and efficient management of the transportation system. This condition does not exist at present for all constituent components. The measurement process is further complicated if there is a need to extract samples in dense phase and then reduce the pressure and state to vapour phase prior to measurement. The need for and desirable frequency of CO₂ composition monitoring will depend on the system's sensitivity to CO₂ composition variations.
- Metering of volumes to the required fiscal standards is hampered by a lack of calibration facilities for the various metering technologies. Metering accuracy may be affected by impurities and techniques used for natural gas, such as ultra-sonic flow meters, may not be suitable for CO₂. Metering of flow in a pipeline undergoing two phase flow would be extremely unreliable. It will always be the intention of pipeline designers and operators to operate in single phase, but operating upsets may occur.
- The measurement of CO₂ flow is possible using a number of techniques: once the composition, temperature and pressure is known it is possible to calculate the mass flow to a level of accuracy sufficient for fiscal monitoring, generally accepted to be around $\pm 1\%$. In the context of flows of 4 Mtpa, knowing this to within 20,000 tonnes may not provide sufficient confidence for carbon accounting, and the accuracy may need to be improved.

4.3.3 Compression

A significant cost in CCS transportation systems will be for compression. Transporting CO₂ in dense phase or liquid is more efficient (requires smaller diameter pipeline) than in gas phase. Compressing to well above the supercritical pressure of 73.8 bar will mean that in spite of frictional losses the CO₂ can arrive at the end of the pipeline in dense phase.

Compression will heat up the CO₂, and in order to increase throughput, density may need to be increased by cooling the compressed CO₂ before entering the pipeline. In order to transport dense phase CO₂ through very long pipelines, pump stations (rather than compression stations) can be installed every 100-150km to maintain the flow and pressure.

Compressor design will need to be optimised depending upon the range of levels of impurities anticipated. Significant economies could be gained by:

- Improving the compression process, considering the typical large compression ratios required to bring near atmospheric CO₂ from the capturing process into dense phase for efficient transportation;
- Capturing waste heat (integrate with power plant or localised CHP);
- Improved models for thermodynamic properties of CO₂ rich mixtures, such that design and operation can be optimized.

Compression and transportation of pure CO₂ have been conducted in North America for over 40 years for enhanced oil recovery (EOR or Enhanced Gas Recovery), in remote areas and at pressures of typically 80 – 180 barg. There is increasing experience in North America related to the transportation of CO₂ containing impurities resulting from the combustion or chemical processing for carbon capture; examples are the Great Plains pipeline to Weyburn and the new capture projects that will come on line in 2016, such as the Kemper County IGCC plant. The future of CO₂ transport needs to take account of the need to transport CO₂ with impurities, in large diameter pipe at lower pressures (between 20 and 150 barg) sometimes near to densely populated regions. A recent report from IEAGHG highlights the impact of CO₂ purity on pipeline design (e.g., size and compression requirements) [79].

In Europe, and specifically in the North Sea region, the primary drivers for a preference for offshore pipeline transport over transport by ship are that:

1. transportation distances from onshore sources to prospective North Sea storage sites are relatively short;
2. bulk transmission is more economical than individual point to point transportation systems, economies of scale are in developing transportation from clusters of emitters;
3. Pipelines avoid the need for intermediate (near-shore) storage and cryogenic operations as needed at a ship loading point.

4.3.4 Economies of scale

The unit cost of transporting CO₂ by pipeline decreases as scale increases. Both use and scale are important. Optimising location and size of early CO₂ infrastructure can reduce the incremental cost of transportation and storage substantially for later projects and facilitate future CCS deployment. Some examples of projects developing pipelines into networks and the advantage this brings are given in 4.2 above. Examples of cost analyses and economies of scale can be found in [77] and [80].

4.3.5 Standards

An international standard is currently in development, PSE/265 Carbon Capture Transportation and Storage - BS ISO 27913 and geological storage - Pipeline transportation

systems⁴⁰; the standard is due for release in 2016. The recommended practice formulated by DNV, DNV-RP-J202⁴¹, was used as the starting point for the ISO standard.

The objective of the international standard is to provide requirements and recommendations on certain aspects of safe and reliable design, construction and operation of pipelines intended for large-scale transportation of CO₂ that are not already covered in existing pipeline standards such as ISO 13623, ASME B31.4, EN 1594, AS 2885 or other standards. The International Standard is written to be a supplement to other existing pipeline standards for natural gas or liquids for both onshore and offshore pipelines. The international standard specifies additional requirements and recommendations not covered in existing pipeline standards for the transportation of CO₂ streams from the capture site to the storage site where it is primarily stored in a geological formation or used for other purposes (e.g. for EOR or CO₂ use).

The standard applies to:

- rigid metallic pipelines;
- pipeline systems;
- onshore and offshore pipelines for the transportation of CO₂ streams;
- conversion of existing pipelines for the transportation of CO₂ streams;
- pipeline transportation of CO₂ streams for storage or utilisation;
- transport of CO₂ in gaseous-, and dense-phases.

Issues that are specific to CO₂ transport by pipeline and that need further development include those mentioned in Section 4.2.1. The mechanisms that determine hazards of accidental release from pipelines and associated safety distances for CO₂ pipelines are yet to be fully understood [81, 77].

For on-shore pipelines validated computer simulation packages (e.g. PHAST) are available to make an assessment of plume dispersion following a release of CO₂. These assessments are sometimes refined using CFD techniques. However, no equivalent packages are available to assess the dispersion characteristics following an off-shore release.

4.4 Transport by ship

4.4.1 Ship transport in operation

Shipping of CO₂ has been established, but experience to date is only limited to smaller carriers. Both Yara (vessels managed & operated by Larvik Shipping AS) and Anthony Veder have been operating small dedicated food-grade CO₂ carriers having a capacity of 900-1250 ton, for decades. Pressurized CO₂ (18 bar(g)) is transported at a temperature of -40°C. For transport of large volumes CO₂ a significant scale enlargement of these carriers is

⁴⁰ Information about the standard is available at <https://www.iso.org/obp/ui/#iso:std:iso:27913:dis:ed-3:v1:en>.

⁴¹ The DNV recommended practice is available at <http://rules.dnvgl.com/docs/pdf/DNV/codes/docs/2010-04/RP-J202.pdf>.

required, which has been established for LNG/LPG shipping. It is rather unlikely that existing gas carriers will be converted for CO₂ transport, as only a limited number of specialised gas carriers for LPG/ethylene meet the pressure and temperature conditions, as required for CO₂. Furthermore it is yet to be studied in more detail how the cold CO₂ can be heated and injected intermittently from the gas carrier into the injection well to optimize the shipping logistics, or whether costly intermediate cold and pressurized storage (and subsequent heating) is required to ensure a more stable injection rate into the well.

4.4.2 Planned projects

Transport by ship is considered to be a cost-effective solution for the full-chain CCS project that is being developed in Norway⁴². This 'Norwegian CCS Initiative' is about capturing CO₂ at one or more onshore emission point(s), transporting it to offshore locations where it is stored in a saline formation or a depleted field. Although pipeline transport could become a viable alternative, depending on such parameters as CO₂ volume and transport distance, ship transport is considered the more cost-effective option, offered as a commercial service by several providers. Some elements of the ship transport element in the CCS chain may require technology development, such as offshore offloading and offshore injection.

4.4.3 Potential development

The Norwegian CCS Initiative is currently the only CCS project considering ship transport. However, ship transport has certain advantages over transport by pipeline and could play a key role in the early phases of CO₂ transport. Ship transport could evolve as part of large-scale CO₂ transport in several ways.

- 1) As a temporary solution, prior to the establishment of a CO₂ pipeline, either one source-one sink, or before an additional connection to an existing offshore pipeline infrastructure. Such a scenario assumes that ship transport could be used during an initial phase when the volumes of CO₂ are relatively small, but where a later phase of larger CO₂ volumes would justify the construction of a pipeline.
- 2) As a permanent transport solution when distances are too long and/or CO₂ quantities to be transported are too small, or when several storage sites may become necessary during the lifetime of the CO₂ emission source.
- 3) As part of a mixed system, in which pipelines and ships are combined. This was considered for CO₂ from the industrialised areas in the Netherlands, Belgium and Germany [82].

The Norwegian CCS Initiative could perhaps at this moment be regarded as an example of the first scenario. Gassnova has the aim to realize facilities by 2020, although the date of commencement of shipping is not clear. Following this initiative, ship transport may begin to include hubs for loading/offloading of liquid CO₂ either along the North Sea and Baltic coast initially, or even offshore in the future. In case more loading / unloading hubs are developed,

⁴² See <https://www.regjeringen.no/contentassets/3652c303169e46e7815617adab685710/gassnovas-pre-feasibility-study.pdf>.

a shipping network can start to develop, with ships shuttling between loading and unloading sites.

As CCS progresses from demonstration via early deployment beyond 2020 to widespread deployment beyond 2030, the number and size of ships transporting CO₂ will increase as required, depending on the amount of CO₂ to be transported from coastal areas where no offshore pipeline infrastructure is available. In order to optimize the logistics chain and reduce cost, ships that are capable of transporting both CO₂ and LPG⁴³ may be relevant to put into operation in cases where it is of interest to transport hydrocarbons back to the area from where the CO₂ is collected.

The NORDICCS project (concluded end of 2015) has conducted CCS case studies of several CO₂ emission points and storage sites in the Nordic region (Iceland, Norway, Denmark, Finland, Sweden)⁴⁴. Regarding CO₂ transport, the overall conclusion is that ship transport is likely to be the most economical solution for transporting CO₂ from individual emission sources in most investigated cases, due to the small CO₂ quantities and in some cases also long transport distances. Also, for CO₂ clusters, CO₂ transport by ship has been found to be the most economical solution, at least in the ramp-up phase of a CCS cluster.

A Nordic initiative to evaluate the prospects of CO₂ transport by ship is also under consideration. In this scheme, CO₂ from large CO₂ point sources in the Skagerrak / Kattegat region to the south of Oslo is chilled and transported in liquid form to offshore storage locations. There are some minor formations that have been evaluated for CO₂ storage in the Baltic sea (e.g. Faludden, with very limited storage capacity), but it is likely that most CO₂ from the Nordic countries except Iceland but including Finland and Sweden will be transported by ship for storage in the North Sea. In a similar vein, CO₂ captured and aggregated at sea ports in Antwerp, Hamburg, Le Havre or at the mouth of the Thames, Tyne, Humber and Mersey in the UK may be shipped to other ports for transfer to pipelines to offshore storage via buffer storage at the receiving port. A recent study suggests that offshore offloading at the storage site could be feasible [83].

4.5 Status of shipping technology

Much necessary shipping technology can be considered to be well established, but not at the scale/volumes required. Several aspects will need further development.

The shipping technology concept is adequately demonstrated through the operation of LPG tankers although few dedicated liquid CO₂ tankers exist (semi-refrigerated)⁴⁵. Scaling up of these vessels to meet the expected volumes of CO₂ that would be emitted by a typical power station will require a significant effort.

The port to port shipping option could consist of four different elements; 1) the onshore terminal at an onshore collection hub for intermediate storage of the liquefied CO₂ 2) loading

⁴³ Or possibly LNG, but then the requirements on CO₂ traces remaining in the tanks will be more stringent.

⁴⁴ [Recommendations on CO2 transport solutions](#), NORDICCS deliverable D20.

⁴⁵ A detailed list of existing fleets can be found in <http://www.sccs.org.uk/images/expertise/misc/SCCS-CO2-EOR-JIP-Shipping.pdf>.

to the vessel(s), 3) the offloading terminal and intermediate storage facility, and 4) the onshore pipeline which will connect the offloading port facility with the pipeline network.

The implementation of a ship transport chain depends on the location of the loading and unloading sites. In an analysis of the cost of CO₂ transport [84], ZEP considers a number of ship transport options; [85] describes in detail the technical set-up of a ship transport link to an offshore offloading site.

4.5.1 Vessels

The technology to build ships for CO₂ transport is demonstrated and available. In Norway, ammonia producer Yara has two ships certified for CO₂ transport (capacity 1800 metric tonnes/ship) in operation today; three more ships are in operation by Larvik Shipping, with a capacity of between 900 and 1200 t. In The Netherlands, Anthony Veder operates a CO₂ vessel with a capacity in the same range. These ships transport food-grade CO₂; the ships are probably too small for the CCS industry.

IM Skaugen is a Norwegian shipping company that operates larger vessels, designed to be able to transport pressurized liquids, such as NH₃, liquefied light hydrocarbons, ethylene and LNG. Typical size is 8000 to 12,000 m³. One of the IM Skaugen ships with a capacity of 10,000 m³ is also certified for ship transport of liquid CO₂. Generally speaking, adapting such liquid carriers (operating typically up to 8 bara) for CO₂ transport can be done at relatively low cost. This option offers flexibility in terms of carrier use, reduces owner risk, and implies that when ship transport of CO₂ is envisaged during an initial operation phase of a CCS project, they can be used for other purposes later on if the CO₂ transport is converted to pipeline. Attention must be given to the requirements that will be put on carriers transporting CO₂ with impurities, and whether the steel qualities used can accept such impurities. The EU FP7 IMPACTS project recently provided the data that allow accurate calculations of the effects of the most relevant impurities on the phase behaviour of a CO₂ mixture (see, e.g., [70]).

Design of CO₂ ships may in the future comprise CO₂ heating prior to injection if the CO₂ is delivered to a hub where this is not integrated. A recent study suggested that sufficient heating and compression facilities can be put on board a ship, although a system with offshore temporary storage would be a lower-cost solution [83].

Compressed CO₂ transport (75 bar, 25 °C) has the advantage of requiring little (or no) heating during offloading. However, this technology remains to be demonstrated for large-scale CCS and most studies suggest liquefied CO₂ transport to be the most feasible [86]. In semi-refrigerated ships the CO₂ is kept in the liquid phase on the saturation line by a pressure higher than atmospheric pressure and a temperature lower than the ambient temperature. An additional advantage of transporting CO₂ under these conditions is that it has the highest density possible in these conditions in the liquid state, resulting in a lower unit cost for transportation. Semi-refrigerated ships are usually designed for a working pressure of 5 to 7 bar and operate at low temperatures (-48°C for LPG, -104°C for ethylene and around -50°C for CO₂). Boil off is reported in the literature at 3-4% per 1000 km; Vermeulen [85] describes how the boil-off gas can be contained within the tanker, avoiding the need to release CO₂ to the atmosphere.

The most common type of semi-refrigerated ship is the LPG tanker. The largest semi-refrigerated LPG tankers currently under construction and in operation can transport approximately 20,000 m³. Such vessels generally have 2 to 6 tanks, and each tank may have a capacity of 4,500 m³. CO₂ ship transport studies consider ships with capacities in the range of 20 – 50,000 m³ [85, 87, 83]. CO₂ shuttle tankers suitable for offshore offloading need to be built, as there is currently not a market for such vessels. It is believed that existing shuttle tankers for oil transport could be modified to accept limited amounts of CO₂. However, for large-scale operation (over 1 Mt/yr), specialized vessels will be required.

4.5.2 Loading and Unloading Facilities at Ports

The loading and unloading facilities consist of the quay/jetty and the loading/unloading system. The loading/unloading system at the quay/jetty transfers liquefied CO₂ from the storage tanks to the ship and vice versa. The storage tanks should have a capacity of at least one tanker. The loading/unloading system includes all the necessary piping between the tanks and the ship, as well as pumps, loading and offloading arms and a return line for CO₂ vapour generated at the ship.

The CO₂ ships currently in operation prove that loading and unloading facilities are commercially available. The step to the scale that is required for large-scale CO₂ transport and storage remains to be demonstrated.

4.5.3 Intermediate Storage Facility

Food grade CO₂ is stored as liquid in semi-pressurized storage tanks at -50 °C. Semi-pressurized storage is common for other liquefied gases such as LPG and ethylene. The most common methods are: semi-pressurized spheres, semi-pressurized cylindrical tanks (bullets), or underground storage in caverns (but not as liquid).

Due to the potential for liquid CO₂ to form a snow-like solid during expansion, care must be taken in the entire process (process plant, storage and loading and unloading) to avoid this. There is little knowledge regarding the thermodynamics of the formation of CO₂ snow with impurities present. In the liquefaction of CO₂ at low temperatures, non-condensable impurities like N₂ and Ar will mostly be separated from the liquid, whereas condensable impurities like H₂S or SO₂ can remain. This knowledge will be essential before a Safety Case can be made for the bulk storage of impure CO₂.

4.5.4 Gasification, Heating and Compression

In order to transfer CO₂ into long distance transport pipelines, the CO₂ stored in tanks/buffers and/or delivered by ship will require pressurisation (by pumps) and heating.

A recent study into the requirements of heating and compression for ship-based transport suggested that technically and practically feasible solutions could be found, for most offshore storage types, including depleted fields and saline formations [83]. The results suggest that offshore ship-based conditioning of the CO₂, prior to injection, is feasible. However, as mentioned above, the study found that a set-up with temporary offshore storage has advantages for both operations and costs. Further work is needed, such as the detailed design of dedicated systems and ships.

4.5.5 Offshore unloading

Delivering liquid CO₂ offshore in the North Sea and injecting heated CO₂ into wells requires some innovation. Ship to ship transfer with current technology can only take place in relatively calm weather, whereas the industry will require quick offloading turnaround in all weathers if possible. Ship to floating dock or fixed dock is more tolerant of a range of weathers, current and swell. In order to achieve full availability, current mooring and connection systems should be developed and demonstrated in realistic weather and sea state conditions. Vermeulen [85] and Brownsort [88] discuss several options that have been put forward in recent studies.

The offloading facility may need a buffering capacity of at least double the size of the visiting tankers. The need for offshore buffering (temporary storage) capacity will depend on the design of the injection system [88]. Facilities with heaters, compression, filters, meters and monitoring equipment all of a suitable scale have not yet been developed.

Flexible hoses are another element of the offshore offloading system that need testing and verification. Flexible hoses are being used for LPG and LNG in conditions comparable to those expected for CO₂, but their suitability for CO₂ is yet to be tested [88].

Ship transport may lead to intermittent injection, with associated thermal and pressure cycles imposed on the injection well. Research is needed into the impact of such batch-wise injection on the well system. There may be a trade-off between avoiding batch-wise injection through local buffer storage and adapting the design of the injection well. Skagestad *et al.* [86] assign this issue the highest R&D priority.

4.5.6 Benefits and Limitations of Ship Transportation

Some unique benefits of CO₂ transportation using ships include the following.

- Shipping can be a cost-effective transportation option especially for smaller projects with low volumes and projects that are still at an embryonic stage, and/or for projects having large transport distances.
- Short delivery time of CO₂ ships from order can offer a competitive advantage.
- Shipping offers the flexibility of using the ships in several projects and therefore the ship operators can have full utilization of the ship.
- Ships can be certified for transport of several other pressurized liquids in addition to CO₂, (NH₃, light hydrocarbons, LNG, ethylene), which reduces owner's risk.
- Ships offer the ability to collect CO₂ from existing industrial sources with moderate capital costs compared to new pipelines.
- Transportation capacity can be increased at relatively low capital cost by adding further ships to the system.
- Shipping of liquid CO₂ at large scale is feasible with known technologies and can provide a transportation system that is flexible in terms of space and time.

On the whole, ship transport offers an alternative to pipeline transport that has a lower financial risk and that may be more easily investable.

There are some issues that need to be demonstrated for the shipping option; at present no technological showstoppers have been identified.

- The effects of batch-wise injection on the injection system must be investigated. Related to this issue is the need for offshore buffer storage, which could also provide a location for the facilities for conditioning the CO₂ prior to injection.
- Offshore offloading systems are to be demonstrated, especially for more severe weather and sea state conditions.
- The impact from impurities in CO₂ on the selection of steel quality must be verified. For transport of pure CO₂, the technology is at TRL 7. If impurities are present in the CO₂ that is to be transported and stored, the phase behaviour of the mixture may affect the design criteria of the shipping chain elements.

4.6 Transport network

The operation of pipeline networks and hubs for CO₂ is an established technology in the United States within the EOR industry. Therefore, there is not considered to be a technology gap in the development of pipeline networks.

Nevertheless, for pipeline network operation there is a lack of validated modelling experience with CO₂ pipelines; in this respect, the presence of impurities in the CO₂ should be taken into account. Other issues include the ability of the pipeline network to act as a storage vessel (short-term storage reserve) and the operation for increasing and decreasing the pressure in the pipeline with minimum impact of two-phase flow; the requirement for intermediate storage in the pipeline network; the effect of uncertainties in the geophysical properties of the storage site and the operation of the store under varying CO₂ flow rates and phases.

The availability of well proven tools for modelling of transient CO₂ flow is limited. At least one tool for transient modelling of oil and gas flow has been modified to handle CO₂ [89], however this model is currently not available commercially⁴⁶. Reliable engineering tools for modelling of CO₂ injection will aid in improving the operating envelope, giving better utilization of capacity. This is especially true for concepts which rely on frequent connect/disconnect operations such as ship-based transport, where a good understanding of the transient system response is important.

Another challenge in the operation of pipeline networks is uncertainty surrounding the variation in specifications of CO₂ that may be encountered in the system. Although the importance of CO₂ specification has been mentioned in other sections of this report, with respect to the design of the pipeline, the variation that could be accommodated in the specification should be considered and the restrictions that these could place on 'late entrants' into a pipeline network. In this respect the on-line metering and monitoring of the CO₂ stream entering the transportation system becomes critical. Technologies will need to be developed to monitor the variations in CO₂ composition for a number of critical

⁴⁶ gPROMS from PSE can model the entire CCS chain, in both dynamic and static mode.

components (e.g. water, hydrogen, nitrogen, oxygen) to ensure the integrity and operability of the transport and storage system. It has been concluded that current capture systems provide CO₂ of sufficient purity for CO₂ pipeline systems with standard carbon steel, provided that dehydration at the system inlets ensures the absence of free water at all times [70]; it is noted that oxyfuel systems form the exception, as these produce the least pure CO₂. Brunsvold *et al.* [70] suggest that in general it is more cost-effective to remove impurities at the source, rather than to deal with downstream effects. The purity of CO₂ from current capture systems is already sufficiently high for transport systems with standard carbon steel pipelines to allow some variation in CO₂ composition in the system. The EU FP7 IMPACTS project has contributed to the database of CO₂ mixtures properties that is maintained at NIST⁴⁷, with which the properties and behaviour of real CO₂ mixtures in transport and storage systems can be predicted.

If at high pressure to avoid two-phase flow, CO₂ pipelines do not need a minimum flow rate, although higher flow rates have better asset utilisation. Care should be taken at high flows to avoid static electricity build-up in the fluid. It is important to maintain flow in a single phase, but this can already be achieved by effective control systems.

4.7 Summary

As noted in Section 4.1, CO₂ transport is well-established technology, with significant development required only for large-scale ship transport. The sections above list a number of technological gaps that are summarised in Table 4.1, with an indication of need, cost and agent for delivery or cooperation.

⁴⁷ Available at www.nist.gov.

Table 4.1. Transport challenges and R&D gaps.

Section	Technology	Must have / Nice to have	Development Cost	Who
4.3.1	Contaminants affect CO ₂ phase behaviour and reactions with materials	Must have	Low	Research and Industry
4.3.2	Alternative pipeline materials	Nice to have	Low to medium	Multi-industry and research organisations
4.3.2, 4.5.6	Measurement of constituent components – real time measurement of contaminants	Must have	Low to medium	Research and Industry
4.3.2	Extract samples in dense phase - new sampling technique or gas chromatograph at high pressure	Nice to have	Low	Research and Industry
4.3.3	Compressor design – optimise for range of CO ₂ duties and CO ₂ quality	Ongoing	Medium	Industry share experience and research
4.3.4	International standard in development	Happening	Low	Research and Industry cooperate
4.5.1	Scaling up CO ₂ ships	Must have	High	Shipping industry
4.5.1	Optimise design of ship and of offshore buffer storage (if any)	Must have	Low	Shipping industry
4.5.2	Loading/unloading facilities at ports for liquid CO ₂ – confirm safe range of operation and build into design	Must have	High	Shipping and HC industries
4.5.3	Dry ice formation with impurities – range of specific lab studies	Must have	Low	Research and gases from air industry
4.5.5	Offshore unloading – ship to platform or to satellite in rough sea: mooring, flexible hoses	Must have	Very high	Shipping and HC industries
4.5.5	Offshore buffering, pre- injection heating, compression	Must have	Very high	HC industry and research
4.5.5	Understand impact intermittent injection on injection system	Must have	Very high	HC industry and research
4.5.6	Modelling and operating with transient flow in complex pipeline network	Must have	Low	Transfer from natural gas industry and liquid transport

5 CO₂ injection and storage technologies

5.1 Storage technology needs

The projected development of CCS, as described in Section 4.1 implies that large-scale storage is required to store the CO₂ from a wide range of capture projects. Similar to transport, benefits from economies of scale can be by obtained by linking several sinks of CO₂ in a network, ensuring continuity of storage capacity and decreasing the risk for capture facility operators. While today's one-on-one type of CCS projects represent the proving ground for CCS technologies, new developments will be required for the storage networks of the future.

Section 5.2 describes the set-up and performance of existing CCS projects, which have already proven CCS as a feasible and commercially available technology. Section 5.3 discusses the potential to develop current CCS technologies, to match the needs of future CCS infrastructures.

5.2 Performance of existing (and planned) storage projects in Europe

The IPCC Special report on CO₂ capture and storage [25] already stated that CO₂ injection and storage technology largely thrives on the experience built up from oil and gas exploitation, including long experience with natural gas storage and with injection of CO₂ for enhancing the recovery of oil. The IPCC report refers to two large-scale CO₂ storage projects offshore, in the North Sea and the Barents Sea and one onshore, in Algeria, demonstrating that CO₂ storage technology is available. Since the 2005 IPCC report, several new projects have provided additional evidence of the operational status of CCS as emission reduction technology [4]. Next to the Sleipner and Snøhvit projects several smaller-scale transport and/or storage projects are or were operating in Europe. Some of their design and operational characteristics are listed in Table 5.1.

5.2.1 Dedicated CO₂ storage pilots and demos

The first large-scale CO₂ storage activity, the offshore Sleipner CO₂ storage project, started injection in 1996 and is still ongoing offshore Norway. This commercial scale project with an annual storage volume of about 0.85 Mt, which is injected via one well, has the longest track record of CO₂ storage globally. In this project CO₂ is captured from the natural gas produced from the Sleipner gas reservoirs and is re-injected in a deep saline aquifer, the top of which is at a depth of 800 m. The reservoir properties are excellent with exceptionally high permeability-height (Kh – a measure of injectivity) and good pressure connectivity within the aquifer. Figure 5.1 shows data from the Global CCS Institute CCS projects database that highlights that operational projects sample a wide range in reservoir depth and reservoir quality.

Two more large-scale CO₂ storage projects started up in 2004 in Algeria and in 2008 in the Barents Sea, known as the In Salah CO₂ storage and Snøhvit CO₂ storage projects, respectively. In both projects, like in the Sleipner project, CO₂ is captured from the natural gas production stream and is re-injected in a deep saline aquifer. Predictable and reliable

pressure management in aquifer storage structures is a critical requirement. For In Salah a configuration with three horizontal injection wells was chosen. After lowering the injection pressure in 2010, injection at In Salah was suspended in 2011 [90].

Injection at Snøhvit was originally into the Tubåen formation, halted when pressure built up faster than predicted [91]. Injection was diverted into the Stø Formation from 2011. A second Stø Formation injection well is being evaluated.

In November 2015 CO₂ injection operations started as part of the QUEST project in Canadian province Alberta. About 1 Mt CO₂ is to be injected annually through 3 wells in a deep saline aquifer. The milestone of the first million tonnes stored was reached in August 2016 [92].

Table 5.1. Overview of operational CO₂ transport and injection projects in Europe; the list includes storage projects at a scale above about 100 kt of CO₂ stored, in Europe.

	OCAP (NL)	Ketzin (GE)	K12-B (Offshore NL)	Sleipner West (Offshore NO)	Snøhvit (Offshore NO)	Lacq (FR)
Operational	2005	2008	2004	1996	2008	2010
Source of CO₂	Shell/ Abengoa	Linde/ Schwarze Pumpe	Engie K12-B	Statoil Sleipner	Statoil/ Snøhvit/ Melkoya	Total/Gas oxycom- bustion
Compression at source	Yes	N/A	N/A	N/A	Yes	Yes
Pipeline inlet pressure (bar)	20	N/A	N/A	N/A	80 - 150	27
Pipeline inlet temp (°C)	Ambient	N/A	N/A	N/A	Liquid	-
Distance (km)	85	0	0	0	153	27
Flow rate kt/yr	400	15	up to 20	850	400 - 700	Up to 43
Cumulative CO₂ (kt)	~3000	67	100	>16000	>2000	51
Compression at site	N/A	Yes	Yes	Yes	Yes (2- stage compressio n)	Yes
Wellhead pressure (bar)	N/A	60	50 - 55	~65	80-200	>40
Wellhead temp (°C)	N/A	35	60 - 80	25	4	40
Injection well	N/A	Ktzi201	K12-B6	16/9-A-16	7121/4F-2H	RSE-1
Formation/Field	N/A	Stuttgart	Rotliegend	Utsira	Tubaen (2008- 2010) Stø (2011-)	Mano/ Rousse
Storage depth (m)	N/A	630	3800	>800	2500	4500
Info	OCAP	KETZIN	K12-B	SLEIPNER	SNOHVIT SNOHVIT2	LACQ
Reference	[93]	[94]	[95]	[96]	[91]	[97]

Figure 5.2 shows injection rates used by various CCS projects; large-scale projects typically use injection rates of about 1 Mtpa.

A few more large-scale storage projects are expected to be on stream in the next two years. The Illinois Industrial CCS project in the USA is planned to be on stream early 2016 and will inject on average 1 Mt CO₂ per annum into a deep saline aquifer. This storage project is a scaled up version of the large pilot injection in the Illinois Basin Decatur Project. This pilot

started in 2011 and has injected more than 1 Mt by the end of 2014. A major step forward in scaling up will be the Gorgon CO₂ Injection Project which is expected to start up in 2017. Capturing 3.4 to 4 Mt of CO₂ annually from a gas production stream, the project will inject the CO₂ via 8 to 9 wells in a deep saline aquifer under Barrow Island off the coast of Australia. Next to the injection wells three pressure management production wells have been planned.

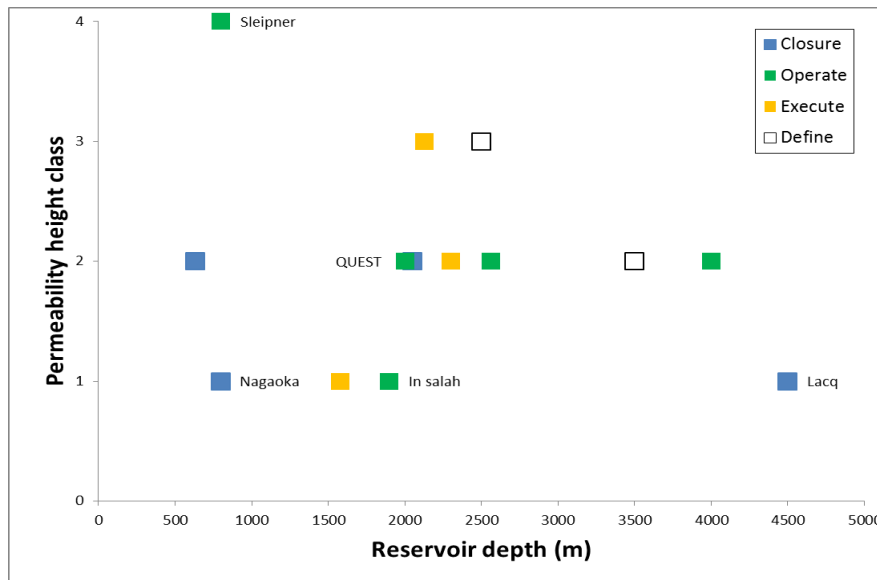


Figure 5.1. Depth of reservoirs versus reservoir permeability-height ($k \cdot h$) for selected storage pilots and demos; $k \cdot h$ classes: 1 = Low ($< 10^3$ mD·m), 2 = Medium ($10^3 - 5 \cdot 10^4$ mD·m), 3 = High ($> 5 \cdot 10^4 - 10^5$ mD·m), 4 = Very high ($> 10^5$ mD·m) (see Appendix 2 for used data). Storage projects cover a wide range of values of permeability-height (which is a measure of the injectivity of the reservoir). Some CCS projects are highlighted. See Annexe IV for the data used.

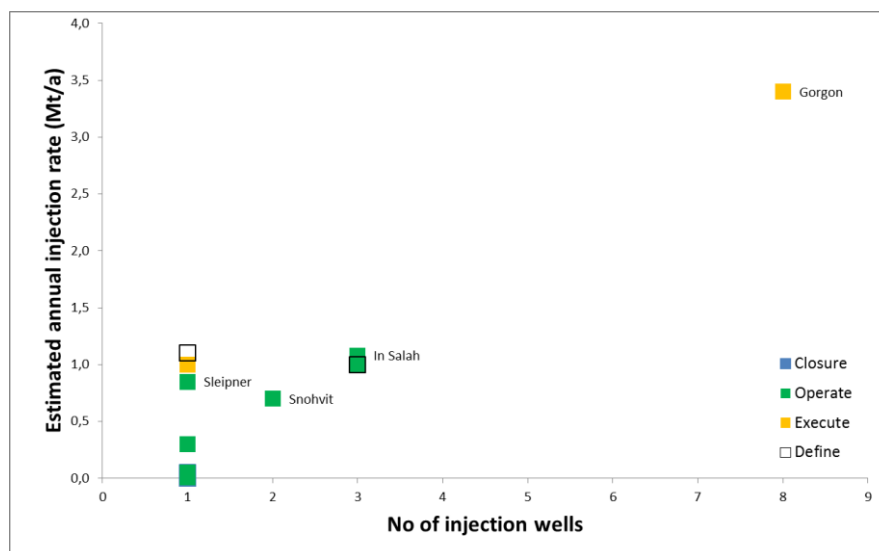


Figure 5.2. Relation between number of wells and estimated annual injection rate for selected storage pilots and demos and their lifetime stage in 2015 (see Appendix 2 for data used). See Annexe IV for the data used.

All of the aforementioned large-scale dedicated CO₂ storage activities are in deep saline sandstone aquifers. Several pilot projects have been developed in other storage media, e.g. in depleted gas reservoirs in sandstone [95] and in carbonate rock [98], in a carbonate aquifer [99] and in basalt rocks (Carbfix-Sulfix projects and the Hellisheidi industrial project⁴⁸). Storage in basalt is an emerging technology which is based on mineralisation of the injected CO₂. These pilot projects have TRLs between 5 and 7 (Table 2.2). A few pilot projects already have ceased injection and are now in the phase of evaluation before dismantling and abandonment, like the Ketzin Pilot project in Germany and the Lacq project in France.

Storage costs are highly variable, depending on the type of reservoir, geographical location and re-use of well infrastructure [24, 22]. The ZEP study [84] showed that the costs of onshore storage range from 1 to 12 EUR/tCO₂ whereas offshore storage costs vary between 2 and 20 EUR/tCO₂. More recent studies on storage costs onshore resulted in a smaller range of costs between 6 and 13 EUR/tCO₂ [22].

The time taken to start storing in a reservoir from site characterisation to first injection will be at least 5 years and on average 10 years, each site appraisal requiring substantial investment partly depending on available legacy data (e.g., [100]). Depleted oil and gas fields may have shorter lead times because of the existing data from HC exploitation. On the other hand legacy wells may need more attention to ensure integrity. A study for the UK offshore showed that the lead time from identification to FID could be reduced to 2 to 4 years for storage prospects with a high level of already existing information [101].

5.2.2 CO₂-EOR projects

CO₂-EOR is a mature technology in the onshore USA since the mid-seventies. Large projects have been developed and are in operation in the USA, Canada, Brazil, China and the Middle East; good overviews are available from MIT⁴⁹ and GCCSI⁵⁰. In Europe, CO₂-EOR is deployed in Eastern Europe (Hungary, Croatia) and Turkey. CO₂ is injected to mobilise remaining oil by reducing viscosity, swelling the oil and changing relative permeability. The CO₂ will break through at production wells and is produced with the oil, separated and often re-injected. Natural gas produced with the oil and CO₂ may be separated and then used as fuel or sold provided the concentration and volume are large enough, otherwise it is re-injected with the CO₂. Onshore CO₂-EOR involves a large number of wells, kilometres of flow lines and significant processing equipment for the treatment of produced fluids.

⁴⁸ See, for the Carbfix-Sulfix and Hellisheidi projects, see http://www.globalccsinstitute.com/sites/www.globalccsinstitute.com/files/content/page/122975/files/The_CarbFix-SulFix_Project.pdf

⁴⁹ The MIT site can be found at https://sequestration.mit.edu/tools/projects/index_capture.html; the site was discontinued as of October 2016.

⁵⁰ The GCCSI projects database can be found at <https://www.globalccsinstitute.com/projects/large-scale-ccs-projects>.

Studies suggest that over the project's lifetime, CO₂-EOR operations store about 90% of the acquired CO₂ [102, 103]. Operating EOR projects provide an opportunity to develop monitoring programmes that verify CO₂ storage (e.g. [104]). In the USA two of the DOE partnerships, PCOR and SECARB, are now monitoring EOR projects to verify that CO₂ is stored securely during the EOR operations. Also the Weyburn project in Canada has undergone an extensive storage demonstration programme (e.g. [105]). Learning from CO₂-EOR operations has the potential to drive cost reduction in CCS.

5.2.3 Summary

The development of a wide range of CO₂ storage projects proves that CCS technology is available. Technology development is currently ongoing, through the same projects, as operational issues are encountered and solved, and as new solutions are deployed and proven. New projects help to bring down costs through learning and knowledge sharing.

This is the main conclusion from the overview of current projects: CO₂ storage is an available and proven technology. However, to meet the needs of future, large-scale storage operations will be required that connect multiple capture plants with large-scale storage reservoirs or clusters of reservoirs, new solutions. The next section discusses those needs and the developments needed.

5.3 Development potential for injection and storage technology

Even though injection and storage technology for CO₂ stored in aquifers and oil reservoirs for EOR is proven, technology improvements are required to apply the technology on a large scale, to reduce the cost and to making the processes more efficient.

The following sections address potential technology development to meet the needs of future large-scale, linked storage and storage networks.

5.3.1 Storage portfolio management

Whilst investigations by a number of countries around the North Sea, e.g., UK⁵¹, Norway⁵² and the Netherlands⁵³ indicate that abundant storage is available, efficient exploitation of this theoretical pore space will require site investigations to be undertaken in a timely manner to ensure the stores are available when needed. The time from the start of appraisal of individual storage sites and first injection is in the range of five to ten years; the recent study of the development of five potential storage sites offshore UK also came to this conclusion.⁵⁴ The long development time of operational storage reservoirs suggests that some de-risking (testing, permitting) of storage reservoirs is needed to promote the development of CO₂

⁵¹ See <http://www.co2stored.co.uk/home/index>.

⁵² See <http://www.npd.no/Global/Norsk/3-Publikasjoner/Rapporter/PDF/CO2-ATLAS-lav.pdf>.

⁵³

See

<http://www.globalccsinstitute.com/sites/www.globalccsinstitute.com/files/publications/35621/independent-assessment-high-capacity-offshore-co2-storage-options-opt.pdf>.

⁵⁴ See <http://www.eti.co.uk/project/strategic-uk-ccs-storage-appraisal>.

capture and transport projects. Pre-commercial characterisation of effective storage capacity and of sustainable injection rates is crucial for wider deployment of CCS following the first demonstration projects, as already suggested (e.g. [106]).

In the case of depleted hydrocarbon reservoirs the available information and knowledge from the production period provides the basis for storage appraisal. In the case of large virgin saline aquifers, storage appraisal is more challenging, as in general less information is available. In hydrocarbon deposits the size of the accumulation is appraised by drilling wells which are also required for the extraction of the hydrocarbons. For CO₂ storage in saline aquifers it is necessary to understand the connectivity within the store over long distances, however cost constraints preclude the drilling of many wells during evaluation/appraisal. Technological developments, potentially redeploying techniques from groundwater reconnaissance and other similar subsurface activities, have the potential to reduce the cost of appraising storage capacity.

The CO₂ might eventually only occupy 1% of the pressure-affected pore space (see, e.g., [78]). In this case the appraised storage pore space needs to be 100 times the volume of the CO₂ to be injected. The subsurface areal of a saline storage aquifer might be many times larger than that of even the largest known hydrocarbons reservoirs. Therefore, for saline aquifers in particular, technologies are needed for the management of large areal aquifers and stacked reservoirs to ensure their optimal use as a strategic resource both for individual MS and for Europe as a whole. In some large areal formations further optimisation is possible through development of integrated injection schemes across multiple injection locations. Aquifers will cross national boundaries and thus will be subjected to different regulatory regimes, ownerships and liabilities. In short, experience should be gained with developing and using saline formations for CO₂ storage, as these hold the largest storage capacity in Europe [107].

Additionally, the optimal time to use a depleted pressure hydrocarbon field is at the end of economic production or earlier where enhanced hydrocarbon production might be utilised. At this point knowledge of the field behaviour is at a maximum and infrastructure that may be converted for CO₂ injection is available. However, once a field has ceased production it is likely that infrastructure will be quickly decommissioned and wells plugged, reducing the opportunity for CO₂ storage at reduced costs. This requires defining cost-efficient ways of mothballing wells, facilities and pipelines⁵⁵, maintaining their capacity for future re-use.

5.3.2 Uncertainty, risk and liability

A review of the CCS project development efforts in the UK prior to the withdrawal of funding for the UK CCS competition in 2015 suggested that a major issue for operators in the CCS chain is the allocation of risk, liability and related premiums [108]. The risk of storage is related to the inherently limited knowledge of the properties of the subsurface and its response to injection of CO₂. While monitoring techniques are available to reduce this uncertainty by observing the behaviour of the CO₂ in its storage reservoir, a certain level of

⁵⁵ The recent ETI study in the UK suggests that re-use should focus on high-pressure pipelines (<http://www.eti.co.uk/project/strategic-uk-ccs-storage-appraisal>).

uncertainty will remain. The storage permit, along with the associated plans for monitoring and remediation activities, quantifies this level and describes how the storage project deals with this uncertainty throughout its lifetime. This uncertainty results in a certain risk of storage that needs to be shared among the parties in the CCS chain, along with the risks associated with other elements of the CCS chain.

In the case of storage in depleted HC reservoirs, the production history has resulted in a large body of information and knowledge; the uncertainty about the suitability of the reservoir for CO₂ storage will be smaller than in the case of a saline formation that has not been exploited previously.

As discussed by Gibbs [109], there is a need to develop iterative modelling that, from the monitoring data, derives the behaviour of CO₂ in the subsurface and updates the model of the storage complex. During the lifetime of the injection process, such modelling will result in increasingly reliable models of the subsurface and of the fate of the CO₂ plume, with ever decreasing uncertainty. Towards the end of the injection process, this will form the basis for site closure (see also Section 5.3.5). As described by Jenkins et al. [110] for current CO₂ storage projects, such modelling is currently performed on a qualitative basis; a quantitative approach is needed and would help build confidence in storage operations.

5.3.3 Drilling, completing and operating wells

Well drilling and completion technology is the most important cost driver in oil and gas industry. Increased subsurface understanding with integration of multiple disciplines and real time data support is key to secure the best possible drainage strategy and for optimised well construction.

The key will be to develop low cost drilling techniques. The experience in the oil and gas industry with identifying hydrocarbon prospects and developing them in a portfolio of producing hydrocarbon fields will be of great use. Innovative drilling technologies such as steerable casing and liner drilling solutions and managed pressure drilling are being introduced for the extension of the drilling envelope. Revolutionary technologies such as “fishbones” or multi-laterals installed as an integrated part of the bottom hole design have been developed, which could also be deployed in CO₂ storage.

If CO₂ is being injected into a low pressure environment, like a depleted pressure reservoir, CO₂ injection cools well tubing and annulus fluids [111]. In addition, if a well is allowed to back flow, or when CO₂ is produced with enhanced production of oil, CO₂ expansion can cause significant cooling at surface. Most oil and gas field equipment has been designed with high temperatures in mind – as a result there is R&D potential to extend the operating envelope and improve current equipment to sustain lower temperatures for specified time intervals and activities. The injection strategy at the Goldeneye project was designed to avoid low injection temperatures in the depleted Goldeneye gas field.⁵⁶ Injection into the

⁵⁶ https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/531394/11.133_-_FEED_Summary_Report_for_Full_CCS_Chain.pdf.

P18-4 depleted gas field in the Netherlands offshore was also designed around avoiding low temperatures in the well and reservoir.⁵⁷

Transported and injected CO₂ will need as much water to be removed as practically possible to minimise corrosion [70]. Water will also need to be removed to minimise reactions with other impurities in the CO₂, and to prevent the formation of hydrates. Most projects are likely to use corrosion resistant steel but this will increase the capital cost of the project. Seals at valves and joints will need specific materials that are CO₂-compatible (for example with minimum molecular ingress to avoid RGD upon decompression). One specific area is the well bottom hole casing materials in contact with brine/ CO₂ and other chemicals and materials in the formation. Another technology development area is specific CO₂ well tubular materials where the industry can build on the extensive knowledge in the O&G industry and the CO₂ EOR industry. Material research is required to expand the operational envelope of well completions for CO₂ injection.

Well Plugging and Abandonment (P&A) of offshore wells has been carried out for many decades but is always a hot topic for the industry. New technologies are being developed for more cost efficient operations. The Norwegian Oil and Gas Association has developed a roadmap for new P&A technologies which include drillpipe conveyed tools for optimised casing milling and rigless solutions for offline well work with use of wireline and coiled tubing. Examples are optimised perforation, well washing and cementing technologies to avoid pulling or milling of tubulars. Improved verification and logging methods for well diagnostics are also under constant development. Alternatives to cement for annular isolation such as creeping shale are being investigated. High-energy solutions for melting downhole components and tubulars to effectively create a volcanic type rock as a well barrier are being studied. CO₂ storage R&D on plugging and abandonment should line up with programmes for the oil and gas industry.

The Snøhvit project is thought to have experienced halite precipitation blocking the pores in the Tubåen formation [91]. This was countered by injection of a water based fluid. Testing of well productivity by water injection has the potential to damage the formation – clays can swell and block the pores. CO₂ has the ability to swell certain types of clay. Hence specific research is required to evaluate each potential storage reservoir, as part of the site characterisation phase in the site development.

The petroleum industry requires that fluids injected into hydrocarbon-bearing rock should have a maximum oxygen content of 10 ppmv so that pore blocking by Sulphate-Reducing Bacteria (SRB) does not take place. An injection of CO₂ containing significantly more oxygen than this was made into the Ketzin reservoir in Germany and loss of permeability resultant from SRB was quickly observed. Whilst this justifies a low level of oxygen-in-CO₂ if the maximum potential of the geological store is to be realised, there is no justification for the 10 ppmv figure, other than it works. Work is in hand to ascertain if there is an oxygen content “tipping point” at which SRB blooms, or whether the production of SRB is linear with oxygen content above a certain baseline. This work is due for completion in 2018, and will inform

⁵⁷

http://www.rvo.nl/sites/default/files/sn_bijlagen/bep/70-Opslagprojecten/ROAD-project/Fase1/4_Aanvragen/A-06-2-Aanvulling-opslagvergunning-kl-354540.pdf.

engineers, particularly those involved on oxy-fuel projects, what the permissible level of oxygen should be.

5.3.4 Pressure management for increasing capacity and injectivity

CO₂ injection can be divided into 1) saline formation injection or CO₂ injection for EOR where the pressures may be increased above initial formation pressure and 2) depleted pressure fields where the initial storage pressures are below that of the adjacent water saturated formation, but pressures steadily rise as CO₂ is injected⁵⁸. The common theme here is that CO₂ creates an increase in subsurface pressure in the storage zone; ultimately, the storage capacity is limited by pressure limits dictated by safety of storage in the reservoir.

In the case of saline aquifer storage using water production wells in order to manage pressures and minimise formation pressure increase may lead to better exploitation of the theoretically available pore space and, hence, lower overall storage cost. In CO₂ EOR and CO₂ storage with water extraction like in the Gorgon CCS project⁵⁹ the areal size of the pressure plume is constrained or controlled by water/oil extraction. In saline aquifer storage (like in Quest, and Sleipner) without water production wells the pressure plume is constrained by the geology and in case of a high-permeability aquifer with a large areal extent there will be a small pressure increase.

The deployment of water extraction wells opens up questions related to (i) development of strategies for the location and operation of water production wells, (ii) preventing breakthrough of CO₂ at the water production wells, (iii) monitoring of produced water qualities (iv). The disposal or cost-effective treatment of the produced water and potential re-use [112]. Finding the optimum configuration of injection wells and production wells (if any) is likely to be strongly case specific.

The common theme in the above is subsurface pressure management. Research is needed to operate in large extent storage formation and to manage clustered storage sites.

5.3.5 Low-cost monitoring and mitigation technology

Monitoring is a regulatory and operational requirement to demonstrate that an injection operation is performing appropriately and that there is no evidence of significant irregularities that might lead to the need to make changes in operation or take remedial actions. Many of the technologies used in CO₂ storage to establish baseline conditions (which may themselves evolve during the lifetime of the project) are mature and benefit greatly from continuous development in other sectors, notably the oil and gas industries. A large body of evidence has now been obtained from several key storage demonstrations of the wide portfolio of technologies available to monitor storage site performance. The applications of these technologies are described in detail in IEAGHG's monitoring selection tool (available

⁵⁸ The basalt storage mentioned in Section 5.2.1 would fall in the first category.

⁵⁹ See, e.g., <https://www.globalccsinstitute.com/projects/gorgon-carbon-dioxide-injection-project>.

online⁶⁰). However, storage operation will benefit from greater experience of optimal and efficient integration of a selection of the most appropriate tools in future projects.

Current CCS projects deploy oil field technology, such as time-lapse seismic surveys and pressure and temperature monitoring. The In Salah project showed how satellite interferometry can be used to monitor the CO₂ plume (see, e.g., [90]). There is large potential for cross over, learning and co-development from many other fields in monitoring technology to construct site-specific monitoring systems. Recently, the first CO₂ storage permit obtained under the EU CCS Directive proved that a monitoring system using current technology can be relatively simple [113].

Another key aspect for the improvement of monitoring technology lies in minimising the impact on stakeholders. Oil and gas technology – such as 3D seismic surveying – is often very intrusive onshore. For example vibroseis necessitates the driving of trucks across the countryside, through fields and crops. This is potentially acceptable for hydrocarbon exploration where it happens once – to locate the fossil hydrocarbons– but for CCS in aquifers this is required multiple times as the CO₂ plume expands. New techniques such as continuous source seismic (being piloted in Japan and Canada⁶¹), passive seismic or seismic interferometry, have the ability to increase the frequency and extent of seismic data collection (especially when coupled with permanent fibre-optic distributed acoustic sensors) while also dramatically reducing the stakeholder impact.

Monitoring groundwater quality is a mature technology and can be automated at low cost. Similarly, whilst techniques for monitoring atmospheric CO₂ concentrations are relatively mature, further technological developments are needed to develop efficient low-cost integrated monitoring systems that can track CO₂ migration in the shallow subsurface and quantify the rate of atmospheric emissions in the unlikely situation of CO₂ leakage. Technologies for detection of elevated atmospheric CO₂ concentrations include eddy covariance, laser-based atmospheric CO₂ concentrations, permanent monitoring of soil gas compositions and fluxes, which have been demonstrated as being useful at a number of pilot sites but would require further improvements in terms of efficiency, robustness and integration for wider deployment [114]. However, these techniques have no application offshore. Improvements in monitoring efficiency can also be found in dedicated, ‘on-demand’ monitoring [115], that measures discriminating characteristics of CO₂ seeping into or out of the near-surface zone to prove its origin.

Monitoring technologies have been demonstrated in a number of large-scale demonstration projects globally to be effective at the detection of CO₂ in a range of storage types such as saline formations and operating and depleted hydrocarbon fields. Nevertheless, opportunities still exist to reduce costs, improve detection limits and resolutions, particularly through the use of permanent installations on the seabed or down well. The use of mature technologies such as sonar and multi-beam systems for bubble detection require further demonstration of their applicability in a range of credible leakage scenarios. Similarly, whilst the use of Autonomous Underwater Vehicles (AUVs) offers significant potential for the

⁶⁰ <http://ieaghg.org/ccs-resources/monitoring-selection-tool1>.

⁶¹ See <http://rmc.usc.edu/assets/002/96013.pdf>.

detection of CO₂ leakage in seawater columns, further demonstration under prolonged operation in the North Sea is needed (see., e.g., [116]). This challenge is taken on by the EU H2020 STEMM-CCS project⁶². Other permanently installed monitoring technologies should also be tested to develop low-cost but robust offshore leakage quantification technologies. Quantification of the flux of CO₂ from a leak still requires further technological development and demonstration. Technologies for the detection of proxy or pre-cursor indicators of leakage (including novel tracers and displaced fluids) should also be demonstrated. Most of these techniques can only be effective if they can detect against often naturally highly variable background fluctuations [70]. A research challenge is to develop monitoring techniques which do not require extensive measurement of natural background fluctuations, viz. to find indicators which are unique to the injected CO₂ stream.

A promising approach is to develop advanced methods for time lapse seismic acquisition and potentially the development of combined techniques such as seismic and gravity or seismic and Controlled Source Electromagnetics (CSEM). IEAGHG [114] also suggest that the improvements in monitoring are to be found in combining individual techniques.

Recent developments, as shown by the Shell Quest commercial scale project in Canada, which is injecting over 3,000 tonnes per day, include fibre optic sensing down the whole length of the well and line-of-sight surface CO₂ detection using laser absorption⁶³. The technologies employed by Quest have further development potential, for example the sensitivity of optical fibres for seismic acquisition is increasing rapidly. In time it should be possible to use these for micro-seismic detection as well as vertical seismic profiles. Quest has a suite of MMV technologies for demonstration from which future projects can select the most effective and efficient to satisfy their MMV requirements⁶⁴.

While new monitoring techniques are being developed, there is a need for a methodology to develop site-specific, efficient and effective monitoring systems. These should be focused at the storage site's aspects associated with the highest residual risk, i.e. the risk that remains after careful site selection and development and injection strategy design. Storage operators will have to demonstrate to the relevant authorities that the proposed set of monitoring techniques is sufficient to assess the storage risk throughout the lifetime of the injection process. Towards the end of the injection process, the monitoring system should provide the data to prove the system's stability and to indicate when site closure and handover to the authorities can be initiated. This methodology is linked to the uncertainty discussed in Section 5.3.2.

As with monitoring technologies, mitigation technologies can be applied from other sectors, most particularly from the oil and gas production industry. Here well workover technologies are continuously improving from which future CO₂ storage operations will naturally benefit. Future technology development can be expected in the areas of plume steering and management of 'thief' zones and high permeability zones to control migration. A particular area of future technology development is the optimisation of trapping mechanisms and the

⁶² See <http://www.stemm-ccs.eu/>.

⁶³ See <http://www.energy.alberta.ca/CCS/pdfs/CCSQuestReport2014.pdf>.

⁶⁴ Information available at <http://www.energy.alberta.ca/CCS/3848.asp>.

potential for reducing reservoir permeabilities in locations where this might be needed. An overview of mitigation techniques can be found in Gerdes [117], while Steeghs *et al.* [113] describe the corrective measures (mitigation) plan that is part of the P18-4 storage permit.

The closure of a CO₂ site and the subsequent monitoring period before transfer of responsibility to the competent authority depends on a thorough understanding of the storage performance. The techniques for closure at present are adopted from the oil and gas industry. Better understanding of the risk can lead to a shortening of the post closure periods – reducing the exposure of operators and hence the cost of “insurance” or “liability provision”. Cost effective methods of closing wells permanently and also of monitoring post closure will also reduce the unit cost of storage; examples of the former include natural sealing techniques, which use, for example, subsurface salt or clay layers to permanently close the well bore.

5.3.6 Reducing costs and footprint of installations

CO₂ pipelines and CO₂ injection installations differ markedly from a hydrocarbon production facility. When hydrocarbons are produced oil, gas and water have to be separated. Because of this all the monitoring equipment has been designed to work on large manned facilities. The monitoring equipment is a small portion of the total cost.

When CO₂ is injected for EOR this means additional equipment on old oil production platforms to handle the injection wells, compression, distribution and more separation equipment to remove any produced CO₂ for reinjection. Much of the old production system will need to be replaced with corrosion resistant material. To address the issue of limited space on existing platforms for new equipment, work is underway in Norway in developing and demonstrating subsea compression and gas separation systems.

When dry CO₂ is injected in an aquifer structure the range of equipment required, new wells, compression, distribution, monitoring, measuring is likely to be much less than for a hydrocarbon facility for EOR. There may be a desire to make most or even all facilities normally unmanned, which further reduces the technical scope of the facilities. Monitoring equipment may make up a larger proportion of the total cost. If water production wells are required for pressure management more well slots will be needed and equipment to detect CO₂ in the produced water, but provided the water does not need treatment and can be dumped into the sea, the complexity of the installation is minimal.

When dry CO₂ is injected into depleted pressure fields, the original platforms and wells may be available for use and the deck space may be adequate for the incremental equipment required. In some cases compression and CO₂ heating may not be required, depending mainly on the injection temperature, the injection rate required, the number of wells and the final reservoir pressure desired and the reservoir depth.

Subsea wellheads for injection wells will also reduce the complexity of the offshore facilities, although well entry requires a rig which may limit the opportunity for several monitoring techniques to be employed. The challenge for CCS is to reduce operational cost of CO₂ storage facilities: develop minimal facilities, preferably unmanned, which could lead to lower operating cost, compared to Oil and Gas industry facilities.

5.3.7 Need for flexibility of CO₂ throughput

The first generation of storage systems are characterised by point-to-point projects developed using conservative assumptions and oil industry technologies. The scale is small from a commercial point of view, generally less than 50 Mt CO₂ stored. Follow-on capture projects will include both power and industry emission sources. In a power market that will increasingly be dominated by renewable energy sources, CO₂ supply from fossil-fuelled power is expected to be strongly intermittent; industry-based CO₂ supply will also have varying rates, depending on the industrial sector. When applied at large scale, storage technology will be applied in networks of linked storage sites and will have to be able to deal with intermittent supply of CO₂.

The key question is where to build capacity and redundancy into a system, which copes with volatility in supply and demand for CO₂. For example, should the storage have 100% availability in order to ensure that a connected power plant can always export CO₂ and sell clean electricity? How much does this additional capacity cost – potentially requiring networked storage across more than one site? Is it better for the power plant to either stop generating or potentially emit CO₂ for a short period? What delivers the lower system cost and how should commercial agreements and grid supply rules be structured so that additional cost can be driven out of the system? And how can these agreements evolve as a network grows and the consequence of interruption of a single source or sink has less effect on the whole?

Injection wells can, in general, take varying flow rates – from very low to a physical maximum, often dictated by the onset of strong tubing vibrations. At times a relatively low injection rate is enforced because of the high degree of Joule-Thompson cooling of the injected CO₂. Strong intermittency, for example system shut-ins on a daily basis, might lead to concerns about expansion and contraction on the injection tubing, on the casing, and on the cement bonds between the casing and the rock formation. Owing to the high cost of offshore well interventions operators take a conservative approach and try to minimise on/off cycles. Research into the effects on the well construction of intermittent injection could inform operators of the reliability envelope and has the potential to increase the ability of a single point-to-point system to adapt to changing rates.

For subsea equipment, the foreseen operating pressures and temperatures of CO₂ injection wells are within the range of current systems. Still, it is likely that some technical modifications will be required, to be able to handle the CO₂ stream. For intermittent injection with a large number of cycles, additional development may be required in order to ensure reliability of subsea installations. Valves, which would be operated for a higher number of cycles compared to during typical oil and gas service, may require some development.

Some types of storage system are more likely to experience down time than others. In general the more complex the system the more likely it is to trip or to require maintenance. As a result an EOR storage system might suffer more down time than an aquifer storage system with continuous supply of CO₂.

How to manage daily fluctuations from practices like ‘two shifting’ operating regimes have also been discussed and elements like buffer CO₂ tanks, or rich amine tanks debated. At this point in the development of the industry such measures are probably immature. The moment

a power station has more than one unit on capture, or two or more emissions sources are captured, the ability exists to alter commercial constructs to allow operators to manage the CO₂ export to all but eliminate periods of zero flow – rather going from low flow to high flow. This removes the need for additional infrastructure.

There is an opportunity for research into identifying the best or complementary combinations of captured emission sources and how to manage these to create the lowest cost of capture, transportation and storage infrastructure – taking full cognisance of the external constraints like wind power variability, cement plant work practices, and even public holidays or extreme weather conditions.

Currently the performance of well construction materials is not tested under daily thermal cycling. First generation projects are assuming steady injection. Materials science research can extend the operating envelopes of well materials and increase the responsiveness of storage systems.

5.3.8 Summary of development potential

For storage the question is mainly of an economic nature rather than technical, however there are several areas where further developments are required to prepare for future, large-scale storage, as well as for the transition period between demonstration and large-scale deployment of CCS.

Portfolio management

- Support pre-commercial storage appraisal
- Develop storage sites in saline formations
- Develop mothballing strategies for depleted hydrocarbon fields

Wells

- Develop and deploy lower-cost drilling technologies
- Investigate the impact of intermittent flow on the well system
- Develop dedicated well abandonment technology

Pressure management

- Develop a knowledge base on subsurface pressure management

Monitoring and mitigation technology

- Develop strategies leading to lower-cost, integrated monitoring systems
- Improve leakage detection and quantification of monitoring techniques

Cost reduction

- Reduce operational costs CO₂ storage sites
- For offshore sites, develop and test subsea technology

Flexibility of storage

- Develop approaches to ensure flexibility of storage

5.4 Discussion and summary

The discussion in the previous sections show that there is a need for further developments in the area of storage, to progress from the current demonstration phase into the transition to large-scale deployment of CCS.

Table 5.2 provides a summary of the main technology improvements for CO₂ injection and storage which have been brought forward in this report. They are grouped in two main categories: technology improvements for existing storage media and a smaller group with development of novel CO₂ storage media. The impact of each development for cost reduction, improving conformance and safety and expansion of the storage portfolio has been indicated. Also involved technology customer and providers have been mentioned.

Table 5.2. Improving technology for CO₂ injection and storage; Category (i) Cost, Conformance, Confidence and Safety of existing storage media and Category (ii) Expansion of the range of storage options with novel storage media. Low investment = 10⁶-10⁷ EUR; High investment = 10⁸-10⁹ EUR.

Area of main impact	Technology development	Investment need	Main actor(s) Buyer/provider
Improving performance for current CO₂ storage media			
Cost, Confidence	Improve well construction materials for low temperatures, different fluids & dynamic loading	Low-High	HC well service Co/ material research
Cost, Conformance	Improved metering technology for CO ₂ mixtures and CO ₂ mass balance, e.g. for EOR	Low	Oil OPCo, service Co
Cost, Confidence	Improve (transient) fluid dynamic modelling of CO ₂ mixtures, e.g. for low T & well backflow	Low	Storage OPCo/ flow modelling research
Expansion, Confidence	Modelling and management of water extraction aquifers	Low-high	Flow modelling & water treatment research
Expansion	Regional characterisation of aquifer injectivity & management of multi user storage formations under acceptable overpressure constraints	High	OPCo, storage org, geoscience & modelling
Expansion, Cost, Confidence	Governance and financing of multi-store locations, e.g. evolution, time-variable CO ₂ streams, liability, CCS chain and risk profile	Low	EU & MS regulators/ economics & business school research
Cost, Confidence, Safety	Improvement of well drilling ('smart drilling') & intervention, e.g. offshore CO ₂ cooling effects dissolution into elastomers	Low	OPCo, drilling service Co; synergy with HC exploitation and mining / drill rig simulator research
Cost, Conformance, Expansion	Improvement of marine environmental monitoring, e.g. sensors, autonomous under water vehicles for seabed profiling & characterization of natural fluxes	Low	OPCo, storage org/ environmental research
Cost, Confidence, Conformance, Expansion	Development of wireless long term pressure monitoring in plugged wells	High	OPCo, storage org, well service Co/ technical research

Area of main impact	Technology development	Investment need	Main actor(s) Buyer/provider
Cost, Expansion, Conformance, Confidence	Improvement of (spatial seismic) monitoring and data transmission techniques, e.g. lower cost, less intrusive and higher detectability of microseismics	Low-High	OPCo, storage org, geophysical service Co; synergy with HC exploitation / geophysical research
Confidence, Expansion	Improved modelling, characterization & management of microseismic risk, e.g. understanding fault behaviour	Low	OPCo, storage org; synergy with HC exploitation/ geomechanical and geoscientific research
Cost, Conformance	Develop methodology for site conformance assessment	Low	Geoscientific R&D, with storage org/regulatory bodies
Cost, Conformance	Field trials of CO ₂ tracer injection – especially noble isotopes of Xe	Low	OPCo, well service Co/ fluid dynamic modelling research
Cost, Expansion	Improved well leakage assessment, monitoring & management – e.g. shale squeeze & legacy wells	High	OPCo, storage org/regulatory bodies/ well and geoscientific R&D
Cost, Expansion	Governance and financing of mothballing HC wells and installations	Low	Mining authorities
Conformance, Confidence	Improving well plugging and abandonment, e.g. securing annular isolation	Low	Synergy with HC exploitation
Cost, Expansion	Minimizing compression costs for aquifers and EOR, e.g. offshore	Low	Synergy with HC exploitation
Developing novel CO₂ storage media			
Expansion	Shale storage – including pilots	High	
Expansion	Basalt storage pilots	High	
Expansion	Formations with non-standard caprocks – e.g. multiple baffles	Low	

6 Conclusions & Recommendations

CCS is known to be important in all GHG emission mitigation scenarios targeting 2 °C and essential in scenarios with long term targets of 1.5 °C as agreed in COP 21. In such scenarios, CCS is expected to compete and co-exist with other low carbon technology options in the power generation sector. In addition, about a quarter of global emissions stems from energy-intensive industries like steel, cement, refineries and other industrial sectors. These industries may be unable to reduce significantly their GHG emissions within the next 2-3 decades without CCS. Non-fossil alternatives are not yet commercially available and newly developing processes have to be brought in line with the lifecycle of the existing assets in order to prevent from additional economic burden.

The assessment of future CCS technologies carried out in this report has embraced not only the changing market conditions for fossil power plants caused by an increasing share of intermittent renewable power, but also the emerging importance of CCS for non-power industries. Furthermore, the assessment criteria of CCS technologies have been deliberately enlarged beyond typical cost and efficiency criteria to incorporate in qualitative form key factors like operational flexibility, retrofitability, HSE issues, materials availability etc. that will determine the economic viability and acceptability of the different process CCS options in a future CCS technology market.

As far as transport and storage is concerned, requirements for improvement of currently available technologies and, where the need was identified, the development of new technologies were derived from the projected growth of CCS. This growth will lead from currently demonstration and early commercial projects that can be typified as one-on-one projects, to increasingly interconnected transport and storage systems, in which economies of scale are obtained by sharing transport and storage structures.

Although this assessment of technology prospects and status has only been done qualitatively, it allowed us to highlight many common R&D priority areas for years to come, as described below.

6.1 CO₂ capture

6.1.1 R&D Challenges & recommendations for CO₂ capture

Some preliminary notes and observations with respect to the assessment of emerging capture technologies are the following.

- To enable quantitative, more precise cost and performance assessments of emerging capture technologies, it is important that these reach a sufficiently credible pilot scale testing at TRL 5-7.
- Capture technologies which have already achieved high TRL under certain boundary conditions, e.g. for power applications, cannot necessarily be classified with the same TRL under different boundary conditions for other industrial applications. However, it should be possible to build on existing pilot infrastructures experience and quickly adapt them to new, modified boundary conditions of different industrial sectors.

- Current solvent based capture processes are commercially available but there is a substantial scope to reduce their relatively high cost and efficiency penalty. They also display limited operational flexibility, which is increasingly required by power plants today. The development of capture processes allowing for (higher) operational flexibility (load following operation) without additional cost is therefore a key R&D challenge. Flexibility is a key requirement for of the transport and storage elements of the CCS chain (i.e., variable supply of CO₂).
- Technology improvements arising from R&D works need to be assessed on system (plant) level rather than focusing on isolated improvements with uncertain impact on the overall efficiency penalty and cost of CCS.
- An open R&D challenge is the continuous development of new functional materials (solvents, sorbents, membranes, oxygen carriers for CLC) which:
 - are less sensitive towards the most abundant impurities in flue or process gases, e.g. steam, SO_x, NO_x, degradation/attrition which could prolong lifetime, thus reduce OPEX,
 - could enable fast adsorption/absorption kinetics or transport (permeance, diffusion) to reduce residence time, allowing for more compact capture equipment, hence lower CAPEX.
- Many new materials show apparently good results in CO₂ separation on lab scale. Testing under real process conditions, real flue gas conditions and compositions should be a R&D priority to confirm the actual potential of such materials, e.g. testing of capture technologies in steam free environment is artificial.
- There is a need to Intensify and support fast up-scaling of promising lab-scale capture technologies (TRL<3) in order to speed up its development and avoid stagnation on low TRL status. For example, many new materials are synthesized in labs and lack a commercial supply chain which makes their up-scaling costly.
- The type of application and fuel (coal or biomass vs natural gas) is known to favour some capture technologies with respect to others, both for power generation or industrial systems. Despite recent shift in interest towards natural gas in some regions, emerging technologies for solid fuels should remain in the portfolio of R&D priorities, as the CO₂ capture technology market is of global nature.
- Flexibility during operation of power plants is a major requirement that may alter substantially the viability of a particular CO₂ capture process route. This has only recently been addressed for 1st-generation technologies. Therefore, much has to be learned by sustained R&D on how flexibility requirements will impact the efficiency and cost prospects of emerging CO₂ capture technologies. Synergies of CCS systems, hybrid systems of capture technologies currently classified in different generations, as well as combinations with energy storage concepts at wider system level need to be investigated.
- New power cycles or enabling technologies to the power or industrial sectors have been left out of the scope of this report. It would be worthwhile to have a similar assessment on new power cycles and enabling technologies in another future ZEP report.
- Finally, it appears realistic to conclude that the sequence of generations in capture technologies is based on the assumption that 1st-generation technologies are deployed. The natural progression towards emerging technologies will only follow on

the realisation of this deployment. Therefore, specific R&D challenges closely linked to large demonstration projects will remain an important R&D priority.

6.1.2 Benchmarking of emerging technologies for CO₂ capture

Table 3.3 compares in a qualitative way the various emerging capture technologies according to the different assessment criteria introduced in this report.

- Nearly all emerging capture technologies claim a reduction potential with respect to CAPEX required by 1st-generation capture technologies. The current status of many emerging capture technologies still includes too many uncertainties to come to quantitative and precise conclusions. Under this premise however chemical looping shows currently the highest CAPEX reduction perspective.
- Technologies involving solid sorbents, looping processes and polymeric and metallic membranes show a legitimate potential to improve operational cost (OPEX) compared to 1st-generation solvents, due to the avoidance of co-evaporation of large amounts of water. The currently developing solvent alternatives focus on the improvement of particular parts within the capture process showing disadvantages or trade-offs at other parts of the capture/plant process. Therefore, the anticipated improvements on overall plant level might be marginal and be related rather to better process integration.
- With respect to process efficiency, most of the technologies assessed show an improvement potential. R&D, especially on lower TRL sub-part of the system, can still lead to certain improvements. Yet, overall process quantitative assessments are difficult and the possible outcome ranges from “better than existing 1st-generation solvents to indifferent”, thus equally good or bad (green/yellow colour). Chemical looping appears most promising and polymeric membranes show potential as they are already commercially applied to other boundary conditions, i.e. in natural gas processing. Polymeric membranes might be a good alternative for natural gas or other clean flue gas post-combustion applications, eventually compromising on other process parameters, such as CO₂ capture rate or in combination with other technologies (hybrid systems).
- Degradation of functional material appears to be a problem of almost all emerging technologies over time with calcium looping being the only exception. Therefore, different plant boundaries and operating conditions of specific applications will be determining on the suitability of particular capture technologies over others.
- Operational flexibility gained much importance in the power sector over the last years. Many gas and coal plants have to compensate for the intermittency of growing renewable electricity generation, stabilizing the grid and matching demand. That goes along with lower annual operational hours and faster operational load change of power plants including fast ramp-up’s and shut down’s. Hence, there is a need from the power sector for capture technologies capable to follow the load without extra cost beyond the additional capture cost. Promising emerging capture technology with respect to operational flexibility are polymeric membranes and likely solid sorbent processes (VPSA, PSA), conditional to the integration of these technologies in the overall process configuration.
- With respect to HSE and waste disposal, solid sorbents, calcium looping and membranes bear an advantage against current aqueous amine solvents. This is due to the volatility of amines requiring additional efforts/technical equipment to avoid amine emissions.

- With regards to retrofitability, chemical looping is not retrofitable as it is a new concept substituting a boiler or gas turbine in contrast to calcium looping which is applied as post-combustion capture technology. The same is true for any oxy-combustion related process e.g. oxy-ceramic membranes which require the recirculation of flue gas, difficult or too complex to be integrated to existing configurations without high investment
- Finally when it comes to availability, chemical looping as well as oxy-ceramic and metallic membranes might be the technologies that face the most critical challenges today.

6.2 Transport and Storage R&D challenges & recommendations

In contrast to capture technologies, transport and storage technologies rely to a high degree on commercially available equipment used in the oil and gas industry. Future development of transport and storage technology will mostly be of incremental nature, leading to improved performance and/or lowered costs of existing technology. There are some exceptions, which relate to transport by ship and storage in basalts which are both at low TRL levels today and can be considered as emerging technologies.

6.2.1 CO₂ transport

Transport of CO₂ by pipeline.

- This is a well-established technology and is commercially available, but issues relating to the avoidance of ductile fracture need better understanding.
- Minor issues exist around the modelling of transient flow in pipelines, across platforms and into wells. Recent developments in databases of physical CO₂ mixture properties, advancements are required in software that is capable of performing transient flow calculations.
- In transport networks, the management of the quality of CO₂ becomes an issue, when mixing of streams of different quality could affect the performance of the system. The required knowledge about the relation between CO₂ quality and the behaviour of the CO₂ in the system has advanced considerably in recent years, allowing CO₂ quality effects to be taken into account.

Transport of CO₂ by ship.

- This is well established but for large-scale CCS ship transport needs to be scaled up and the potential implications of transporting impure CO₂ need to be considered. CO₂ carriers exist, but larger ships will be required; the same can be said about loading and unloading facilities at ports. Offloading offshore, near the injection location requires some technology development and demonstration, such as flexible hoses and mooring systems.
- Ship transport to offshore storage locations may lead to batch-wise injection. The effect of intermittent injection, with pressure and temperature cycling, on injection wells needs to be investigated. An on-site buffer storage could remove some of the intermittency.
- The design of CO₂ carriers and that of a possible buffer storage remains to be optimised and demonstrated; the optimisation relates to the location of and power source for facilities to condition the CO₂ prior to injection.

6.2.2 CO₂ storage

- The required operational flexibility holds for the whole CCS chain including CO₂ injection and storage, in particular in the early stages of CCS development from demonstration to early deployment where the dependence on single sources for a reliable continuous supply will dominate availability of CO₂. Systems analysis of the whole chain is necessary to evaluate where the capacity for flexibility is to be built most cost-effectively, e.g. flexible, cost-effective capture technology, in buffering and in networking to stabilize transport grid and storage load.
- Research including full-scale demonstration is required on expanding the operational envelope of injection wells and subsea equipment under repetitive cycles of pressure and temperature changes, particularly for injection into low pressure stores like depleted pressure gas fields.
- Approaches for effective storage portfolio management are necessary to efficiently exploit the available pore space, e.g. in large areal extent aquifers, to shorten the appraisal lead time and to timely expand the infrastructure for injection of CO₂ including mothballing of existing infrastructure.
- Sufficient storage capacity must be assured before investors can decide on financing CCS. A good starting point for tackling this research item is the work done for the UK sector.
- Pressure management for increasing the capacity and injectivity, e.g. by using water production wells; research is to be directed to strategies for water production, the breakthrough of CO₂ and water treatment. In 2016 US DoE has selected two projects on technologies for the production of usable water from CO₂ storage sites (EWR).⁶⁵
- Lower-cost monitoring and mitigation technologies which are cheaper than current technologies from the oil and gas industry. Combined techniques such as seismic with gravity or seismic with Controlled Source Electromagnetics (CSEM) with less impact on the earth's surface; for tracking CO₂ in the shallow subsurface and atmosphere and water need further development. Technology development should also be directed to less invasive leakage mitigation techniques and cost-effective methods for closing wells.
- There is a need to assess site conformance, i.e., the level at which the site behaves as expected, on a quantitative level. A methodology should be available to support operators and regulators in their assessment of the performance of the storage site: during storage operations, when unexpected events occur, and when preparing site handover to the competent authorities.

⁶⁵ <http://energy.gov/fe/articles/energy-department-selects-projects-demonstrate-feasibility-producing-usable-water-co2>

Bibliography

- [1] International Energy Agency, "World Energy Outlook Special Briefing for COP21," OECD/IEA, Paris, France, 2015.
- [2] International Energy Agency, "Technology Roadmap Carbon Capture and Storage," Paris, France, 2013.
- [3] IEAGHG, "CCS Deployment in the Context of Regional Developments in Meeting Long-Term Climate Change Objectives (2015-TR3)," 2015.
- [4] Global CCS Institute, "The Global Status of CCS: 2015 Summary Report," Melbourne, Australia.
- [5] International Energy Agency, "Energy Technology Perspectives - Mobilising Innovation to Accelerate Climate Action," Paris, France, 2015.
- [6] C. Hendriks, P. Noothout, P. Zakkour and G. Cook, "Implications of the Reuse of Captured CO₂ for European Climate Action Policies - Final report," CLIMA.C.1/SER/2011/0033; ECUNL11593, 2013.
- [7] Z. Liang, W. Rongwong, H. Liu, K. Fu, H. Gao, F. Cao, R. Zhang, T. Sema, A. Henni, K. Sumon, D. Nath, D. Gelowitz, W. Srisang, C. Saiwan, A. Benamor, M. Al-Marri and H. Shi, "Recent Progress and New Developments in Post Combustion Carbon Capture Technology with Amine Based Solvents," *International Journal of Greenhouse Gas Control*, vol. 40, pp. 26-56, 2015.
- [8] R. Idem, T. Supap, H. Shi, D. Gelowitz, M. Ball, C. Campbell and T. Paitoon, "Practical Experience in Post Combustion CO₂ Capture using Reactive Solvent in Large Pilot and Demonstration Plants," *International Journal of Greenhouse Gas Control*, vol. 40, pp. 6-25, 2015.
- [9] M. Wang, A. Lawal, P. Stephenson, J. Sidders and C. Ramshaw, "Post-Combustion CO₂ Capture with Chemical Absorption: A State-of-the-Art Review," *Chemical Engineering Research and Design*, vol. 89, no. 9, pp. 1609-1624, 2011.
- [10] S. Mills, "Coal Fired CCS Demonstration Plants - IEACCC Report No. 207".
- [11] H. F. Svendsen, "State of the Art on Post Combustion Capture Technologies," in *7th CATO Symposium*, Amsterdam, NL, 2014.
- [12] F. Chopin, "Results of the CO₂ Capture Demonstration Facility at EDF's Le Havre Power Plant: Status of ALSTOM's Advanced Amines Process," in *PowerGen Europe*, Cologne, Germany, 2014.
- [13] K. Kadono, A. Suzuki, M. Iijima, T. Ohishi, H. Tanaka, T. Hirata and M. Kondo, "New Energy Efficient Processes and Newly Developed Absorbents for Flue Gas CO₂

- Capture,” *Energy Procedia*, vol. 37, pp. 1785-1792, 2013.
- [14] K. A. Hoff, E. F. da Silva, I. Kim, A. Grimstvedt and S. Ma'mun, “Solvent development in post combustion CO₂ capture-Selection criteria and optimization of solvent performance,” in *GHGT-11*, Kyoto, Japan, 2012.
 - [15] L. Raynal, P. A. Bouillon, A. Gomez and P. Broutin, “From MEA to demixing solvents and future steps, a roadmap for lowering the cost of post-combustion carbon capture,” *Chem. Eng. J.*, vol. 171, p. 742–752, 2011.
 - [16] D. Jansen, M. Gazzani, G. Manzolini, E. van Dijk and M. Carbo, “Pre Combustion CO₂ Capture,” *International Journal of Greenhouse Gas Control*, vol. 40, pp. 167-187, 2015.
 - [17] R. Stanger, T. Wall, R. Spörl, M. Paneru, S. Grathwohl, M. Weidmann, G. Scheffknecht, D. McDonald, K. Myöhänen, J. Ritvanen, S. Rahiala, T. Hyppänen, J. Mletzko, A. Kather and S. Stanley, “Oxyfuel Combustion for CO₂ Capture in Power Plants,” *International Journal of Greenhouse Gas Control*, vol. 40, pp. 6-25, 2015.
 - [18] G. Scheffknecht, L. Al-Makhadmeh, U. Schnell and J. Maier, “Oxyfuel Coal Combustion - A Review of the Current State-of-the-Art,” *International Journal of Greenhouse Gas Control*, vol. 5, pp. 16-35, 2011.
 - [19] R. Davidson and S. Santos, “Oxyfuel Combustion of Pulverised Coal - IEACCC Report No. CCC/168,” 2010.
 - [20] T. Lockwood, “Developments in Oxyfuel Combustion of Coal - IEA CCC Report No. CCC/240,” 2014.
 - [21] G. Magneschi, T. Zhang and R. Munson, “Water use in thermal power plants equipped with CO₂ capture systems. Global CCS Institute (publication in progress).,” Global CCS Institute, 2015.
 - [22] E. S. Rubin, J. E. Davidson and H. J. Herzog, “The cost of CO₂ capture and storage,” *International Journal of Greenhouse Gas Control*, 2015.
 - [23] CCS Cost Reduction Task Force, “Final Report,” 2013.
 - [24] ZEP, “The Cost of CO₂ Capture: Post Demonstration CCS in EU,” 2011.
 - [25] IPCC, “Special Report on Carbon Dioxide Capture and Storage,” Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)], Cambridge, UK and New York, USA, 2005.
 - [26] Global CCS Institute, “The Global Status of CCS,” Melbourne, Australia, 2014.
 - [27] IEAGHG, “Assessment of emerging CO₂ capture technologies and their potential to reduce costs (2014/TR),” 2014.

- [28] J. Abanades, B. Arias, A. Lyngfelt, T. Mattisson, D. Wiley, H. Li, M. Ho, E. Mangano and S. Brandani, "Emerging CO₂ capture systems," *International Journal of Greenhouse Gas Control*, p. 126–166, 2015.
- [29] L. Schoon and J. van Straelen, "Development of a precipitating carbonate technology for post combustion CO₂ capture," in *TCCS-6*, Trondheim, Norway, 2011.
- [30] D. Quyn, A. Rayer, J. Gouw, I. Indrawan, K. Mumford, C. Anderson, B. Hooper and G. Stevens, "Results from a pilot plant using un-promoted potassium carbonate for carbon capture," *Energy Procedia*, vol. 37, pp. 448-454, 2012.
- [31] J. Zhang, Y. Qiao, W. Wang, R. Misch, K. Hussain and D. Agar, "Development of an energy efficient CO₂ capture process using thermomorphic biphasic solvents," *Energy Procedia*, vol. 37, pp. 1254-1261, 2013.
- [32] L. Raynal, P. Briota, M. Dreillard, P. Broutin, A. Mangiaracina, B. Salghetti-Drioli, M. Politi, C. Lamarca, J. Mertens, M. Thielens, G. Laboriec and L. Normand, "Evaluation of the DMX process for industrial pilot demonstration - methodology and results," *Energy Procedia*, vol. 63, pp. 6298-6309, 2014.
- [33] S. Black, "Field Pilot Results of a Novel Biocatalyst-Enabled Process for CO₂ Capture," in *13th Annual Conference on Carbon Capture, Utilization and Storage*, Pittsburgh, USA, 2014.
- [34] US Department of Energy NETL, "Appendix B. Carbon Dioxide Capture Technology Sheets: Post combustion solvents, B-261," 2013.
- [35] S. Sjoström and J. Denney, "Evaluation of Solid Sorbents as a Retrofit Technology for CO₂ Capture," in *2014 NETL CO₂ Capture Technology Meeting*, Pittsburgh, USA, 2014.
- [36] J. Elliott, "Sorbent Based Post Combustion CO₂ Slipstream Testing," in *2014 NETL CO₂ Capture Technology Meeting*, Pittsburgh, USA, 2014.
- [37] G. Krishnan, "Pilot Scale Evaluation of an Advanced Carbon Sorbet-Based Process for Post Combustion Carbon Capture," in *2014 NETL CO₂ Capture Technology Meeting*, Pittsburgh, USA, 2014.
- [38] D. Marx, L. Joss, M. Hefti and M. Mazzotti, "Temperature Swing Adsorption for Post Combustion CO₂ Capture: Single and Multi-column Experiments and Simulations," *Industrial & Engineering Chemistry Research*, vol. 55, no. 5, pp. 1401-1412, 2016.
- [39] V. White, A. Wright, S. Tappe and J. Yan, "The Air Products Vattenfall Oxyfuel CO₂ Compression and Purification Pilot Plant at Schwarze Pumpe," *Energy Procedia*, vol. 37, pp. 1490-1499, 2013.
- [40] J. Strohle, M. Orth and B. Eppele, "Chemical Looping Combustion of Hard Coal in a 1MWth Pilog Plant Using Ilmenite as Oxygen Carrier," in *3rd International Conference*

on Chemical Looping, Goteborg, Sweden, 2014.

- [41] B. Arias, M. Diego, J. Abanades, M. Lorenzo, M. Diaz, D. Martinez, J. Alvarez and A. Sanchez-Biezma, "Demonstration of steady state CO₂ capture in a 1.7 MWth calcium looping pilot," *International Journal of Greenhouse Gas Control*, vol. 18, pp. 237-245, 2013.
- [42] F. van Berkel, C. Hao, C. Bao, C. Jiang, H. Xu, J. Morud, T. Peters, E. Soutif, J. Dijkstra, D. Jansen and B. Song, "Pd membranes on their way towards application for CO₂ capture," *Energy Procedia*, vol. 37, pp. 1076-1084, 2013.
- [43] P. Veenstra, M. Iyer, A. Nijmeijer, F. Geuzebroek, R. Moe and J. Saukaitis, "Integrated approach to CO₂ capture: Fuel gas decarbonisation," *Energy procedia*, vol. 63, pp. 2054-2059, 2014.
- [44] US Department of Energy, "Quadrennial Technology Review (Chapter 4: Advancing Clean Electric Power Technologies)," 2015.
- [45] J. Repasky, V. Stein, P. Armstrong, M. Quintrell, A. Maxson and M. Bartone, "Ceramic and Coal: ITM oxygen for power generation with reduced CO₂ emission detailed engineering study results," in *AIChE spring National meeting*, San Antonio, Texas, 2013.
- [46] J. Tennant, S. Maley and D. Bennet, "Development of ion transport membrane (ITM) oxygen technology for integration in IGCC and other advanced power systems," NETL, 2014.
- [47] A. Nalaparaju, S. Khurana, I. Farooq, A. Karimi and J. Jiang, "CO₂ capture in cation-exchanged metal-organic frameworks: Holistic modeling from molecular simulation to process optimization.," *Chemical Engineering Science*, vol. 124, pp. 70-78, 2015.
- [48] T. Proell, G. Schoeny, G. Sprachmann and H. Hofbauer, "Introduction and evaluation of a double loop staged fluidized bed system for post-combustion CO₂ capture using solid sorbents in a continuous temperature swing adsorption process," *Chemical Engineering Science*, vol. 141, pp. 166-174, 2016.
- [49] A. Gibson, E. Mangano, E. Shiko, A. Greenaway, A. Gromov, M. Lozinska, D. Friedrich, C. Campbell, P. Wright and S. Brandani, "Adsorption Materials and Processes for Carbon Capture from Gas-Fired Power Plants: AMPGas," *Industrial & Engineering Chemistry Research*, vol. 55, no. 13, pp. 3840-3851, 2015.
- [50] D. Jansen, E. van Selow, P. Cobden, G. Manzolini, E. Macchi, M. Gazzani, R. Blom, P. P. Henriksen, R. Beavis and A. Wright, "SEWGS Technology is Now Ready for Scale-up!," *Energy Procedia*, vol. 37, pp. 2265-2273, 2013.
- [51] A. Iqbal, C. Beal, H. Andrus, B. Eppele, A. Lyngfelt and B. Lani, "Alstom's Chemical Looping Prototypes," in *37th International Technical Conference on Clean Coal & Fuel Systems*, Clearwater, FL, USA, 2012.

- [52] H. Hamers, F. Gallucci, P. Cobden, E. Kimball and M. van Sint Annaland, "A novel reactor configuration for packed bed chemical-looping combustion of syngas," *International Journal of Greenhouse Gas Control*, vol. 16, pp. 1-12, 2013.
- [53] E. Favre, "Carbon dioxide recovery from post-combustion processes: Can gas permeation membranes compete with absorption?," *Journal of Membrane Science*, vol. 294, pp. 50-59, 2007.
- [54] C. Casillas, K. Chan, D. Fulton, J. Kaschemekat, J. Kniep, J. Ly, T. Merkel, V. Nguyen, Z. Sun, X. Wang, X. Wei and S. White, "Pilot Testing of a Membrane System for Post-Combustion CO₂ Capture," in *NETL CO₂ Capture Technology Meeting*, 2015.
- [55] X. Hea, C. Fub and M.-B. Hägg, "Membrane system design and process feasibility analysis for CO₂ capture from flue gas with a fixed-site-carrier membrane," *Chemical Engineering Journal*, vol. 268, pp. 1-9, 2015.
- [56] T.-J. Kim, H. Vrålstad, M. Sandru and M.-B. Hägg, "Separation performance of PVAm composite membrane for CO₂ capture at various pH levels," *Journal of Membrane Science*, vol. 428, pp. 218-224, 2013.
- [57] A. Basile, L. Di Paola, F. Hai and V. Piemonte, *Membrane Reactors for Energy Applications and Basic Chemical Production*, Elsevier, 2015.
- [58] P. Veenstra, M. Iyer, A. Nijmeijer, F. Geuzebr, R. Moene and J. Saukaitis, "Integrated Approach to CO₂ Capture: Fuel Gas Decarbonisation," *Energy Procedia*, vol. 63, pp. 2054-2059, 2014.
- [59] J. Wheeldon and T. Wu, "Testing of Pre-Combustion CO₂ Capture Technologies at the National Carbon Capture Center," in *Gasification Technologies Conference*, Washington, USA, 2012.
- [60] R. J. Ciora, "Robust and Energy Efficient Dual Stage Membrane Based Process for Enhanced CO₂ Recovery (DE-FE0013064)," in *FY 15 Carbon Capture Peer Review*, 2015.
- [61] T. T. Norton and Y. Lin, "Ceramic-carbonate dual-phase membrane with improved chemical stability for carbon dioxide separation at high temperature," *Solid State Ionics*, vol. 263, p. 172-179, 2014.
- [62] VDI-RICHTLINIEN, "Emission Control Cement Plants," 3 2003. [Online]. Available: http://www.vdi.eu/uploads/tx_vdirili/pdf/9430282.pdf. [Accessed 17 10 2016].
- [63] H. Dieter, "Calcium Looping Post Combustion CO₂ Capture: A promising technology for emission free cement production," in *TCCS-8*, Trondheim, Norway, 2015.
- [64] DNV, "Global Technology Roadmap for CCS in Industry: Sectoral Assessment: Refineries (Report No./DNV Reg No.: / 12P5TPP-9)," London, UK, 2010.

- [65] T. C. Merkel, X. Wei, Z. He, L. S. White, J. G. Wijmans and R. W. Baker, "Selective Exhaust Gas Recycle with membranes for CO₂ capture from Natural Gas Power plants," *Industrial & Engineering Chemistry Research*, vol. 52, no. 3, p. 1150–1159, 2013.
- [66] A. T. Evulet, A. M. ELKady, A. R. Branda and D. Chinn, "On the performance of GE's dry low NO_x combustors utilizing exhaust gas recirculation for post-combustion CCS," *Energy Procedia*, vol. 1, no. 1, pp. 3809-3816, 2009.
- [67] F. Neele, M. Koenen, J. van Deurzen, A. Seebregts, H. Groenenberg and T. Thielemann, "Large-scale CCS transport and storage networks in North-West and Central Europe," *Energy Procedia*, vol. 4, pp. 2740-2747, 2011.
- [68] NETL, "A review of the CO₂ pipeline infrastructure in the U.S., report DOE/NETL-2014/1681," 2015.
- [69] C. Eickhoff, F. Neele, M. Hammer, M. DiBiagio, C. Hofstee, M. Koenen, S. Fischer, A. Isaenko, A. Brown and T. Kovacs, "IMPACTS: Economic Trade-offs for CO₂ Impurity Specification," *Energy Procedia*, vol. 63, pp. 7379-7388, 2014.
- [70] A. Brunsvold, J. P. Jakobsen, M. J. Mazzetti, G. Skaugen, M. Hammer, C. Eickhoff and F. Neele, "Key findings and recommendations from the IMPACTS project," *International Journal of Greenhouse Gas Control*, vol. In press, 2016.
- [71] B. Wetenhall, H. Aghajani, H. Chalmers, S. Benson, M. Ferrari, J. Li, J. Race, P. Singh and J. Davison, "Impact of CO₂ impurity on CO₂ compression, liquefaction and transportation," *Energy Procedia*, vol. 63, pp. 2764-2776, 2014.
- [72] P. Brownsort, V. Scott and S. Haszeldine, "Reducing costs of carbon capture and storage by shared reuse of existing pipeline—Case study of a CO₂ capture cluster for industry and power in Scotland," *Int. J. Greenh. Gas Control*, vol. 52, pp. 130-138, 2016.
- [73] ARUP, "Feasibility study for Europe-wide CO₂ infrastructure," 2010. [Online]. Available: https://ec.europa.eu/energy/sites/ener/files/documents/2010_10_co2_infrastructures.pdf. [Accessed 9 September 2016].
- [74] J. Morbee, J. Serpa and E. Tzimas, "Optimal planning of CO₂ transmission infrastructure: the JRC InfraCCS tool," *Energy Procedia*, vol. 4, pp. 2772-2777, 2011.
- [75] ICF International, "Developing a pipeline infrastructure for CO₂ capture and storage: issues and challenges," 2009.
- [76] A. Dugstad, M. Halseid and B. Morland, "Testing of CO₂ specifications with respect to corrosion and bulk," *Energy Procedia*, vol. 63, pp. 2547-2556, 2014.
- [77] M. Knoope, I. Raben, A. Ramirez, M. Spruijt and A. Faaij, "The influence of risk mitigation measures on the risks, costs and routing of CO₂ pipelines," *International*

Journal of Greenhouse Gas Control, vol. 29, pp. 104-124, 2014.

- [78] IEAGHG, "CO₂ pipeline infrastructure, report 2013/18,," 2014. [Online]. Available: www.ieaghg.org/docs/General_Docs/Reports/2013-18.pdf. [Accessed 9 September 2016].
- [79] IEAGHG, "Impact of CO₂ impurity on CO₂ compression, liquefaction and transportation," *IEAGHG report 2016-01*, 2016.
- [80] M. Knoope, W. Guijt, A. Ramirez and A. Faaij, "Improved cost models for optimizing CO₂ pipeline configuration for point-to-point pipelines and simple networks," *Int. J. Greenhouse Gas Control*, vol. 22, pp. 25-46, 2014.
- [81] J. Hébrard, J. Jamois, C. Proust, M. Spruijt, C. Hulsbosch-Dam, M. Molag and E. Messina, "Medium scale CO₂ releases," *Energy Procedia*, vol. 86, pp. 479-488, 2016.
- [82] Global CCS Institute, "Transport & storage economics of CCS networks in The Netherlands," 2013. [Online]. Available: <http://hub.globalccsinstitute.com/sites/default/files/publications/101121/transport-storage-economics-ccs-networks-netherlands.pdf>. [Accessed 9 September 2016].
- [83] R. De Kler, F. Neele and et al., "Transportation and unloading of CO₂ by ship – a comparative assessment, CATO report CCUS-T2013-WP09-D08," 2015. [Online]. Available: https://www.co2-cato.org/cato-download/3971/20160916_145008_CCUS-T2013-WP09-D08-v2016.04.09-CO2-Ship-Transpo. [Accessed 16 September 2016].
- [84] ZEP, "The cost of CO₂ transport," 2011. [Online]. Available: <http://www.zeroemissionsplatform.eu/library/publication/167-zep-cost-report-transport.html>. [Accessed 9 September 2016].
- [85] T. Vermeulen, "Overall Supply Chain Optimization - CO₂ Liquid Logistics Shipping Concept, Report number: 3112001," 2011. [Online]. Available: <http://decarboni.se/sites/default/files/publications/19011/co2-liquid-logistics-shipping-concept-llsc-overall-supply-chain-optimization.pdf>. [Accessed 9 September 2016].
- [86] R. Skagestad, N. Eldrup, H. Hansen, S. Belfroid, A. Mathisen, A. Lach and H. A. Haugen, "Ship transport of CO₂, Tel-Tek report no. 2214090," 2014. [Online]. Available: http://www.gassnova.no/no/Documents/Ship_transport_TelTEK_2014.pdf. [Accessed 9 September 2016].
- [87] B.-Y. Yoo, D.-K. Choi, H.-J. Kim, Y.-S. Moon, H.-S. Na and L. Sung-Geun, "Development of CO₂ terminal and CO₂ carrier for future commercialized CCS market," *In. J. of Greenhouse Gas Control*,, vol. 12, pp. 323-332, 2013.
- [88] P. Brownsort, "Offshore offloading of CO₂," 2015. [Online]. Available: <http://www.sccs.org.uk/images/expertise/misc/SCCS-CO2-EOR-JIP-Offshore-offloading.pdf>. [Accessed 9 September 2016].

- [89] T. A. Ruden, Z. Gang , M. Håvelsrud Selberg, T. Haugset, M. Langsholt, L. Liu and J. Amundsen, "Simulating Flow of CO₂ with Impurities in OLGA; Dealing with Narrow Phase-envelopes and the Critical Point," *Energy Procedia*, vol. 51, pp. 344-352, 2014.
- [90] P. Ringrose, A. Mathieson, I. Wright, F. Selama, O. Hansen, R. Bissell, N. Saoula and J. Midgley, "The In Salah CO₂ storage project: Lessons learned and knowledge transfer," *Energy Procedia*, vol. 37, p. 6226– 6236, 2013.
- [91] O. Hansen, D. Gilding, B. Nazarian, B. Osdal, P. Ringrose, J.-B. Kristoffersen, O. Eiken and H. Hansen, "Snøhvit: the history of injecting and storing 1 Mt CO₂ in the Fluvial Tubåen Fm," *Energy Procedia*, vol. 37, pp. 3565-3573, 2013.
- [92] Global CCS Institute, "Quest," 26 September 2016. [Online]. Available: <https://www.globalccsinstitute.com/projects/quest>. [Accessed 28 September 2016].
- [93] M. Ros, A. Read, J. Uilenreef and J. Limbeek, "Start of a CO₂ hub in Rotterdam: connecting CCS and CCU," *Energy Procedia*, vol. 63, p. 2691 – 2701, 2014.
- [94] S. Martens, R. Conze, M. De Lucia, J. Henninges, T. Kempka, A. Liebscher, S. Lüth, F. Möller, B. Norden, B. Prevedel, C. Schmidt-Hattenberger, A. Szizybalski, A. Vieth-Hillebrand, H. Würdemann, K. Zemke and M. Zimmer, "Geological Storage of CO₂ – Long Term Security Aspects," in *Joint Research Project CO₂MAN (CO₂MAN Reservoir Management): Continuation of research and development work for CO₂ storage at the Ketzin Pilot site*, Springer, 2015, pp. 1-32.
- [95] V. Vandeweyer, B. van der Meer, C. Hofstee, F. Mulders, D. D'Hoore and H. Graven, "Monitoring the CO₂ injection site: K12-b," *Energy Procedia*, vol. 4, pp. 5471-5478, 2011.
- [96] T. Maldal and I. Tappel, "CO₂ underground storage for Snøhvit gas field development," *Energy*, vol. 29, pp. 1403-1011, 2004.
- [97] TOTAL S.A., "Carbon Capture and Storage - The Lacq pilot - Project and injection period 2006 – 2013," Global CCS Institute, 15 September 2015. [Online]. Available: <http://www.globalccsinstitute.com/publications/carbon-capture-and-storage-lacq-pilot-project-and-injection-period-2006-2013>. [Accessed 19 July 2016].
- [98] S. Thibeau, P. Chiquet, C. Prinet and M. Lescanne, "Lacq-Rousse CO₂ capture and storage demonstration pilot : lessons learnt from reservoir modelling studies," *Energy Procedia*, vol. 37, pp. 6306-6316, 2013.
- [99] T. Kovacs, D. F. Poulussen and C. deDios, "Strategies for injection of CO₂ into carbonate rocks at Hontomin, GCCSI technical report,," 2015. [Online]. Available: <http://hub.globalccsinstitute.com/sites/default/files/publications/193428/strategies-injection-co2-carbonate-rocks-hontomin-final-technical>. [Accessed 9 September 2016].
- [100] SiteChar D1.2, "Draft site characterisation workflow, EU FP7 Sitechar project, report D1.2," 2011. [Online]. Available: <http://www.sitechar->

co2.eu/FileDownload.aspx?IdFile=974&From=Publications. [Accessed 9 September 2016].

- [101] Pale Blue Dot Energy & Axis Well Technology, "Progressing Development of the UK's Strategic Carbon Dioxide Storage Resource - A Summary of Results from the Strategic UK CO₂ Storage Appraisal Project, 48 p.," 2016. [Online]. Available: <https://onedrive.live.com/?authkey=%21ANk4zmABaDBBtjA&cid=56FC709A2072366C&id=56FC709A2072366C%211573&parId=56FC709A2072366C%211559&o=OneUp>. [Accessed 9 September 2016].
- [102] C. Fox, "CO₂ EOR carbon balance, Presented at the Annual CO₂ Conference Week," in <http://www.co2conference.net/2012/12/co2-eor-carbon-balance/>, Houston, Texas, 2009.
- [103] J. Stewart and S. Haszeldine, "Carbon accounting for carbon dioxide enhanced oil recovery, SCCS report," 2014. [Online]. Available: <http://www.sccs.org.uk/images/expertise/reports/co2-eor-jip/SCCS-CO2-EOR-JIP-WP2-Carbon-Balance.pdf>.
- [104] L. Melzer, "Carbon dioxide enhanced oil recovery (CO₂-EOR): factors involved in adding carbon capture, utilization and storage (CCUS) to enhanced oil recovery," 2012. [Online]. Available: http://neori.org/Melzer_CO2EOR_CCUS_Feb2012.pdf. [Accessed 9 September 2016].
- [105] S. Whittaker, B. Rostron, C. Hawkes, C. Gardner, D. White and J. Johnson, "A decade of CO₂ injection into depleting oil fields: Monitoring and research activities of the IEA GHG Weyburn-Midale CO₂ Monitoring and Storage Project," *Energy Procedia*, vol. 4, pp. 6069-6076, 2011.
- [106] ZEP, "Identifying and developing European CCS hubs," 2016. [Online]. Available: <http://www.zeroemissionsplatform.eu/downloads/1597.html>. [Accessed 9 September 2016].
- [107] T. Vangkilde-Pedersen, K. L. Anthonsen, N. Smith, K. Kirk, F. Neele, B. van der Meer, Y. Le Gallo, D. Bossie-Codreanu, A. Wojcicki, Y.-M. Le Nindre, C. Hendriks, F. Dalhoff and N. P. Christensen, "Assessing European capacity for geological storage of carbon dioxide – the EU GeoCapacity project," *Energy Procedia*, vol. 1, pp. 2663-2670, 2009.
- [108] CCSA, "Lessons learned - lessons and evidence derived from UK CCS programmes, 2008-2015," 2016.
- [109] M. Gibbs, "Effective enforcement of underground storage of carbon dioxide," *HWL Ebsworth Lawyers*, 2016.
- [110] C. Jenkins, A. Chadwick and S. Hovorka, "The state of the art in monitoring and verification – ten years on," *Int. J. Greenh. Gas Control*, vol. 40, pp. 312-349, 2015.
- [111] C. M. Oldenburg, "Joule-Thomson cooling due to CO₂ injection into natural gas

- reservoirs,” *Energy Conversion and Management*, vol. 48, pp. 1808-1815, 2007.
- [112] T. Buscheck, J. Bielicki, J. White, Y. Sun, Y. Hao, W. Bourcier, S. Carroll and R. Aines, “Pre-injection brine production in CO₂ storage reservoir: an approach to augment the development, operation and performance of CCS while generating water,” *International Journal of Greenhouse Gas Control*, vol. In press.
- [113] P. Steeghs, F. Neele, C. Gittins and M. Ros, “Drafting a monitoring plan for the ROAD project under the EU CCS Directive,” *Energy Procedia*, vol. 63, pp. 6680-6687, 2014.
- [114] IEAGHG, “Quantification techniques for CO₂ leakage, report 2012/02,” 2012.
- [115] T. Dixon and K. Romanak, “Improving monitoring protocols for CO₂ geological storage with technical advances in CO₂ attribution monitoring,” *International Journal of Greenhouse Gas Control*, vol. 41, pp. 29-40, 2015.
- [116] J. Blackford, J. Bull, M. Cevatoglu, D. Connelly, C. Hauton, R. James, A. Lichtschlag, H. Stahl, S. Widdicombe and I. Wright, “Marine baseline and monitoring strategies for carbon dioxide capture and storage (CCS),” *Int. J. Greenh. Gas Control*, vol. 38, pp. 221-229, 2015.
- [117] K. Gerdes, “Carbon dioxide capture for storage in deep geologic formations – results from the CO₂ capture project,” CO₂ Capture Project, 2015. [Online]. Available: http://www.co2captureproject.org/reports/CCP3v4_full_version.pdf. [Accessed 19 July 2016].
- [118] G. C. Institute, “Large-sale CCS rojects database,” 2016.
- [119] S. Thibeau, “Personnal communication,” 2016.
- [120] F. Neele, H. Quinquis, A. Read, M. Wright, J. Lorscheid and D. Fernandez Poulussen, “CO₂ Storage Development: Status of the Large European CCS Projects with EEPR Funding,” *Energy Procedia*, vol. 63, pp. 6053-6066, 2014.
- [121] SCCS, “Optimising CO₂ storage in geological formations; a case study offshore Scotland,” University of Edinburgh, Edinburgh, 2015.
- [122] G. Ortiz, T. Kovacs, D. Fernandez Poulussen and C. de Dios, “Hontomin reservoir characterisation tests - final technical report,” GCCSI, 2015.
- [123] A. Hosa, M. Esentia, J. Stewart and S. Haszeldine, “Injection of CO₂ into saline formations: Benchmarking worldwide projects,” *Energy Procedia*, vol. 89, pp. 1855-1864, 2011.
- [124] IEAGHG, “Integrated Carbon Capture and Storage Project at SaskPower's Boundary Dam Power Station (2015/6),” 2015.
- [125] K. Goto, K. Yogo and H. Takayuki, “A review of efficiency penalty in a coal-fired power

- plant with post-combustion CO₂ capture,” *Applied Energy*, vol. 111, p. 710–720, 2013.
- [126] Element Energy, “One North Sea – A study into North Sea cross-border CO₂ transport and storage,” 2010. [Online]. Available: <http://www.element-energy.co.uk/wordpress/wp-content/uploads/2010/08/OneNorthSea.pdf>. [Accessed 9 September 2016].
- [127] Y. Forward, “A carbon capture and storage network for Yorkshire and Humber,” 2008. [Online]. Available: [http://www.ccsassociation.org/docs/2008/Yorkshire Forward – A Carbon Capture and Storage Network fo Yorkshire and Humber June 08.pdf](http://www.ccsassociation.org/docs/2008/Yorkshire%20Forward%20-%20A%20Carbon%20Capture%20and%20Storage%20Network%20for%20Yorkshire%20and%20Humber%20June%2008.pdf). [Accessed 9 September 2016].
- [128] Z. Kapetaki, J. Simjanović and J. Hetland, “European Carbon Capture and Storage Project Network: Overview of the Status and Developments,” *Energy Procedia*, vol. 86, pp. 12-21, 2016.

Annexe I

List of Commercially Available Solvent (Amine) for Post-Combustion CO₂ Capture

Table A.1.1. List of Commercially Available Solvent (Amine) for Post-Combustion CO₂ Capture

Developer	Solvent Name / Trademark	Types	Reported KPIs (based on coal PP - flue gas)	Comments	TRL
Aker Solution	Just Catch Process	Mix amine		<ul style="list-style-type: none"> Performance evaluated at TCM Mongstad (~250 tpd) pilot plant. Mobile pilot plant test completed or on-going at NCCC (AL, USA), Brevik (Norway) and Klemenstrud (Norway). Assessed in SSE's Longannet (UK), Norcem's Brevik (Norway), Enel's Porto Tolle (Italy) FEED study 	7-8
Fluor	Econamine FG+	MEA		<ul style="list-style-type: none"> Licensed to several plants worldwide.⁶⁶ Significant operational experience in capturing CO₂ from GT flue gas (i.e. Bellingham CHP) Performance evaluated at TEPCO's Kawasaki (~120 tpd), EOn's Wilhelmshaven (~70 tpd), ENEL's Federico II (~60 tpd) pilot plants, etc... Assessed in the ROAD's Maasvlakte (Netherlands) FEED study 	7-8

⁶⁶ <http://www.eppsa.eu/fluor.html>

Developer	Solvent Trademark	Name /	Types	Reported KPIs (based on coal PP - flue gas)	Comments	TRL
GE (Alstom)/Dow Chemicals	Advance Process based on UCARSOL 3000 solvent	Amine (AAP) Dow's FGC	MEA/ Chilled ammonia	2.3 – 2.4 GJ/t ⁶⁷	<ul style="list-style-type: none">Development based on other Dow's solvent for CO₂ removal used in the NG processing industry.Performance evaluated at EDF's La Havre (~25 tpd) pilot plantAssessed in the PG&E's Belchatow (Poland) FEED study	7-8
Hitachi	H3 family of solvent		Mix Amine	H3-1 Solvent: ⁶⁸ 2.5 -2.8 GJ/t	<ul style="list-style-type: none">Performance evaluated at Saskpower's Shand (120 tpd) pilot plantMobile pilot plant test stopped; these took place at various Electrabel's and EON's power plants in Europe (5 MWth slip stream).	7-8
HTC Energy	Pure Thermal-Kinetics Optimisation (TKO) CO ₂ capture process based on RS Family of Solvent		Mix Amine	RS2 Solvent: ⁶⁹ ~2.4 GJ/t	<ul style="list-style-type: none">Based on University of Regina's solvent development programme using the pilot plant at Boundary Dam (now decommissioned).Performance recently evaluated at SSE's Ferrybridge (~100 tpd) pilot plantAssessed in the BEPC's Antelope (Dakota, USA) FEED study	7-8

⁶⁷ <http://pennwell.sds06.websds.net//2014/cologne/pge/slideshows/T2S3O20-slides.pdf>

⁶⁸ http://www.psa.mhps.com/supportingdocs/forbus/hpsa/technical_papers/Technology%20Option%20For%20Clean%20Coal%20Power%20Generation%20with%20CO2%20Capture.pdf

⁶⁹ Based on the performance of the BD pilot plant.

Developer	Solvent Name / Trademark	Types	Reported KPIs (based on coal PP - flue gas)	Comments	TRL
MHI	KM-CDR based on KS family of solvent	Process Hindered Amine	2.4 – 2.8 GJ/t	<ul style="list-style-type: none"> Licensed to several plants worldwide. Performance recently evaluated at TCM Mongstad (~250 tpd) and Plant Barry (~500 tpd) pilot plants. Assessed in EOn's Kingsnorth (UK) FEED study Plant under construction – NRG's WA Parish Petra Nova (TX, USA) Power Plant with flue gas slip stream - equivalent to 240MWe. Expected to be in service by 2017/2018. 	8-9
Shell Cansolv	Cansolv based on DC103 / DC201 solvent	Solvent DC103 / DC201 Tertiary Amine with Promoter	Design Basis for BD aims to achieve ~2.5 GJ/t ⁷⁰	<ul style="list-style-type: none"> Capable of selective or sequential SO_x, NO_x and CO₂ removal Performance recently evaluated at TCM Mongstad (~250 tpd), EOn's Heyden (~100 tpd), RWE's Aberthaw (~50 tpd) pilot plants Assessed in the SSE's Peterhead (Scotland) FEED studies. Large-scale demonstration plant in operation – Saskpower's Boundary Dam (Saskatchewan, Canada) – capturing CO₂ from flue gas of 110MWe lignite fired power plant 	8-9

⁷⁰ http://www.platts.com/IM.Platts.Content/ProductsServices/ConferenceandEvents/2014/pc465/presentations/18DevinShaw_SHELLCANSOLV.pdf

Annexe II

Avoidance of running ductile fracture

Running Ductile Fracture (RDF) is also called 'shear' fracture. This takes place when cracks resulting from an initiating defect grow along the length of a piece of pipe at a rate faster than the decompression velocity of the fluid being carried. The phenomenon is recognised as being complex. The presence of some impurities within the CO₂, particularly N₂, but also H₂, H₂S and O₂ can affect its decompression velocity, making RDF more of a possibility.

It is possible, using a combination of material properties, to predict theoretically the point at which a crack in a pipeline will run. This utilises the Batelle Two Curve Method (BTCM), which is a theoretical tool designed to envelope the results from a large number of experiments involving a number of different fluids, some sub-cooled liquids, others gaseous. This matches the fracture-speed curve (the driving force) with the pipe toughness or resistance curve. When these two curves are tangent, the minimum level of fracture toughness for fracture arrest is defined. Fracture arrest of pipe depends on a combination of Charpy, the flow stress of pipe material ($\bar{\sigma}$)⁷¹, the diameter and pipe wall thickness.

A series of tests using Natural Gas and air was carried out and further evidence was gathered to suggest that the BTCM was not always conservative. As a result of this potential lack of conservatism, it was decided to carry out a number of full-scale burst tests using dense phase impure CO₂ with a composition typical of what might be expected in a post-combustion capture situation. Table A.2.1 shows the arrangements for these.

Table A.2.1: Full-scale burst tests using impure CO₂

Source	Pipe details Diameter (inches)	Wall thickness (mm)	Material	Predicted, required CV-value for crack arrest	Test layout
DNV JIP CO₂ pipetrans	16	6.2, 8, 9.5, 12.7	X60 (X42)	<100J due to small pipe diameter	Crack should arrest due to wall thickness (stress)
National Grid	36	25.4mm	X65	>100J	Crack should arrest due to toughness

Some of these tests indicated crack propagation at $\geq 270\text{J}$ and arrest at $\approx 300\text{J}$. The results could be enveloped by a line that suggested that if the arrest stress could be reduced from 0.3 to 0.265 $\bar{\sigma}$, then the crack would not 'run'. Other tests indicated crack propagation at $\geq 246\text{J}$ and arrest at $\approx 350\text{J}$. These results could be enveloped by a line that suggested that if the arrest stress could be reduced to 0.243 $\bar{\sigma}$, then the crack would not 'run'.

⁷¹ Flow stress, $\bar{\sigma}$, is the greater of ($\sigma_y + 69\text{MPa}$) or 0.5 ($\sigma_y + \sigma_{\text{uts}}$)

For impure CO₂, when predicting Running Ductile Fracture using the Battelle two-curve method, it appeared that, in order to ensure that the design is conservative, it would be necessary to apply an additional margin of ≥ 1.2 to envelope all of the test results. However, this would result in a $\geq 20\%$ increase in wall thickness and steel cost. The Modified Batelle Two Curve Method (MBTCM) was derived, applying a 1.2 factor to the arrest stress. Clearly this would have implications for pipeline design, increasing pipeline wall thickness, adding weight. A comparison has been made with BSPD8010 Part 1 for the example of API5L grade X65 steel. Typical figures for this steel are:

$$\sigma_y = 448 \text{ N/mm}^2,$$

$$\sigma_{uts} = 531 \text{ N/mm}^2.$$

$$\text{So } \bar{\sigma} = 489 \text{ N/mm}^2$$

BTCM indicates Arrest Zone at $0.3 * 489 = 146.7 \text{ N/mm}^2$

MBTCM (for impure CO₂) indicates Arrest Zone at $146.7/1.2 = 122 \text{ N/mm}^2$

BS PD 8010 requires a design factor of 0.3 to be applied to σ_y (448 N/mm^2)

Allowable hoop stress, $\sigma_{ah} = 448 * 0.3 = 134 \text{ N/mm}^2$.

Conclusion: in this case, BS PD 8010 would require a design factor of < 0.27 to match MBTC.

A final test was planned, and, to the surprise of the participants, the result showed that the crack had run when the stresses were within the Arrest Zone even with the 1.2 factor applied. No metallurgical or other evidence has provided a satisfactory explanation for this, nor have any errors in the execution of the test been identified that would explain this. In recognition of this, when writing the ISO Standard ISO27913 on CO₂ transportation, it was decided to address the matter by requiring that *“Where the combination of pipeline materials and CO₂ 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”*.

Annexe III

CO₂ composition measurement

There are a number of reasons why the measurement of the CO₂ composition in a pipeline system is important, which would include:

- Quality Assurance for the pipeline operator to ensure that the impurities remained within design values: this is particularly important if the CO₂ is derived from a number of different sources, even more so if there is potential for reactions to take place between the impurities themselves.
- Demonstration of compliance with internationally agreed legislature, e.g. London and OSPAR treaties, EU CCS Directive.
- Fiscal measurement of the CO₂ to know accurately the amount of carbon being transported for storage: the presence of nitrogen, for instance, could lead to over-estimating the carbon.
- Trend analysis, which could indicate potential problems with upstream equipment (e.g. a gradual increase in water content could result from mechanical deterioration in a dehydration plant)

Work was carried out by the National Physics Laboratories in 2013 to look at the practicability of measuring the composition of impure CO₂ at up to 201bar pipeline transporting 2000 tonnes/hour through a 30" pipe. A composition that would meet the requirements of ISO27913 Table A1 was assumed. Work was carried out to investigate possible impurities that could be present in the CO₂ from fossil-based electricity generation, including pre-, post- and oxy-combustion options, threshold levels, and likely maxima thereof. Industrial information was added from a series of Workshops.

Their conclusion was that no off-the-shelf equipment was currently available, and that certain fundamental problems required solutions. Of these two main challenges were identified.

Phase changes; avoidance of condensation of species

Most in-situ analysers will need to correct measurements for temperature and pressure, which means that there is a potential issue with the phase of the CO₂ stream being measured. It is noted that impure CO₂ is more complex, as the phase diagram can change significantly dependent on the proportion of the impurities present. The preference is to make measurements in the area of the phase diagram where the density of the CO₂ mixture does not strongly depend on its pressure and temperature.

Interference of the impurities

Using spectroscopic techniques, difficulties are encountered with CO₂ swamping the population, and reducing discrimination between species. Figures A.3.1 and A.3.2 illustrate this point.

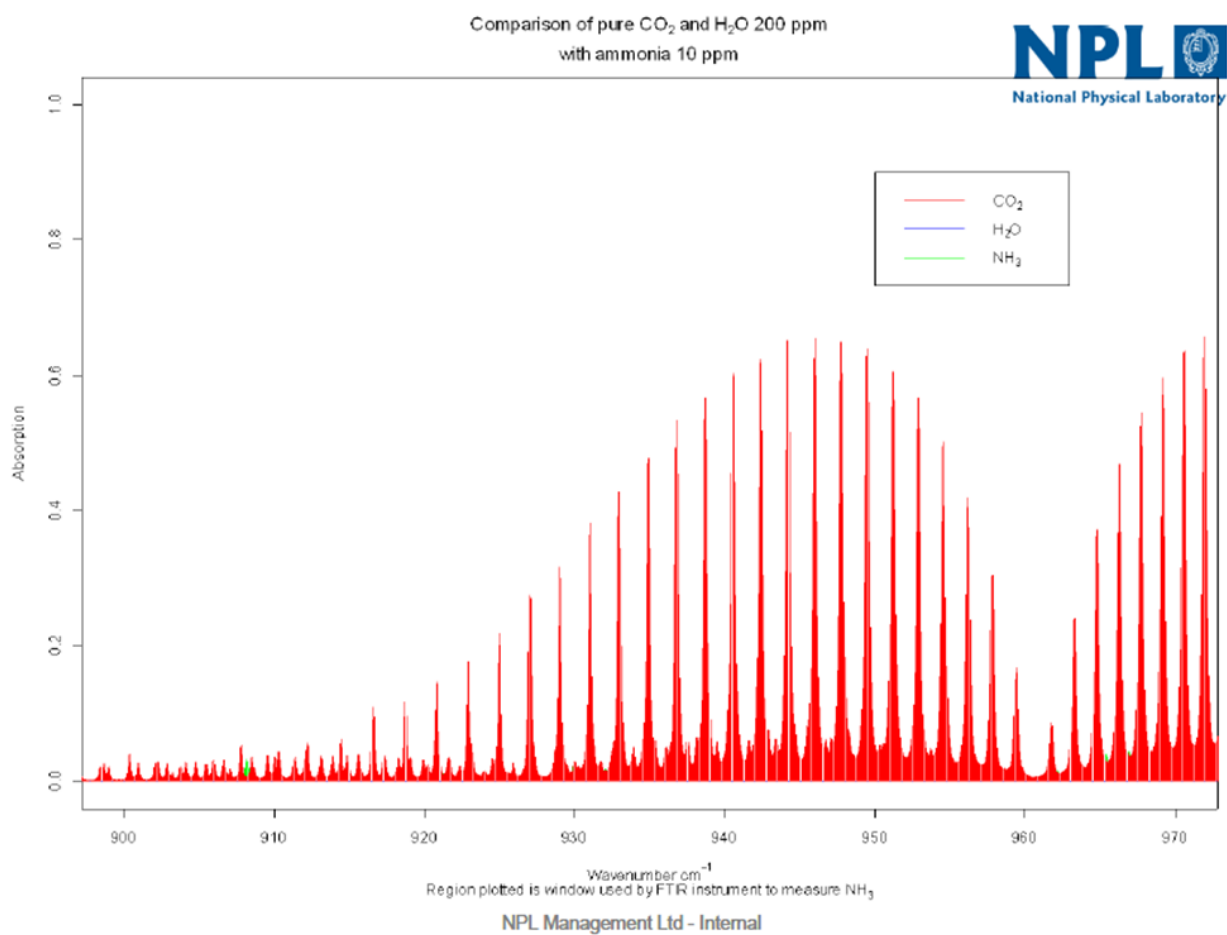


Figure A.3.1: Spectra from CO₂ mask those from 200ppmv of H₂O and 10ppmv NH₃ (ringed in green).

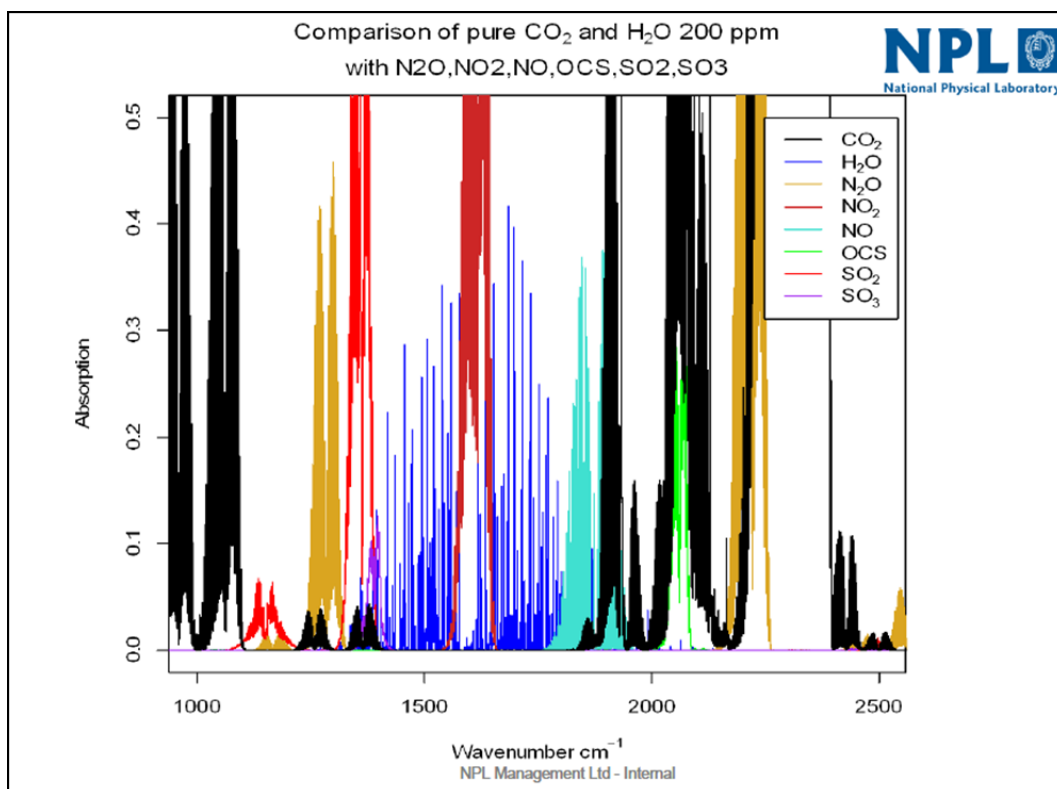


Figure A.3.2: Spectroscopic comparison of pure CO_2 and H_2O with N_2O , NO_2 , NO , COS , SO_2 and SO_3

Atomic weight coincidence

The atomic weights of CO and N_2 are very close (28.0101 and 28.0134 respectively), and the equipment struggled to discern the difference of less than 0.012%. Figure A.3.3 illustrates this.

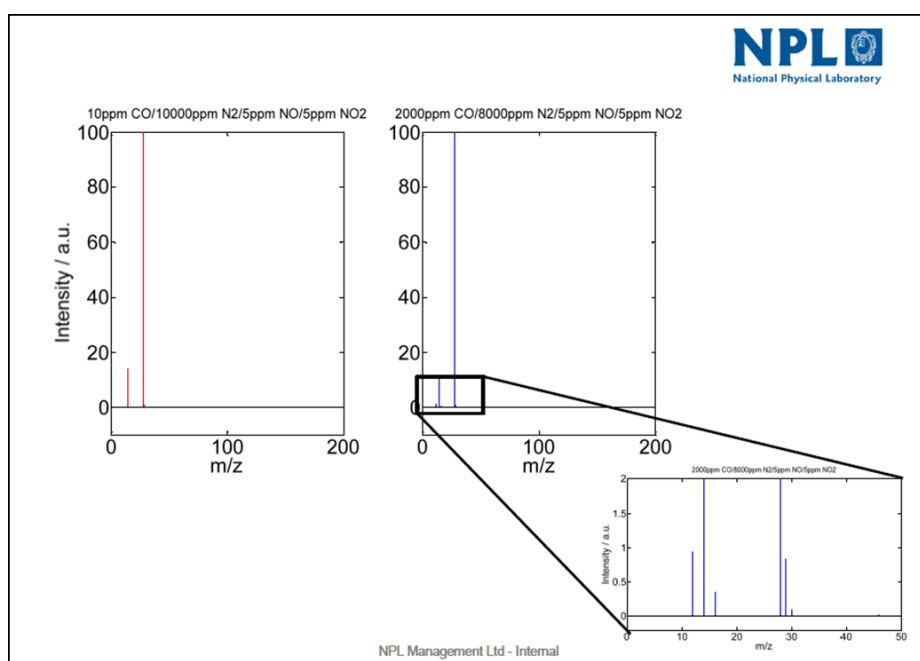


Figure A.3.3: The CO/N_2 Issue

Another problem to compound this is the natural existence of isoplogues within the CO₂, examples of which are ¹³C (typically found at about 370ppm) and ¹⁸O compounds, which mean that even “pure CO₂, when subjected to detailed analysis, cannot be assumed to be homogenous.

Work at the UK PACT⁷² Project has considered the measurement of impure CO₂ composition. They use Fourier Transform Infrared Spectroscopy (FTIR) and/or stack analysers to assess the composition of the CO₂. FTIR has been found excellent for in-process monitoring, but the product outlet is troublesome, because of the high absorbance of CO₂ in the infra-red.

The PACT facility does not use the main absorbance peak at 2200-2400 cm⁻¹, but rather a tiny peak in the 900-1050cm⁻¹ range. This has been found to be acceptable for high concentrations, whilst also providing sensitivity for other compounds. For very low concentrations they have discovered that the main peak for the analysis area can be set up to go down to concentrations of 100ppm or less.

One of the key problems is that interferences and absorbency overlap between compounds, and the fact that in mixtures these compounds could interact and their concentrations therefore shift. For example, most calibration is usually carried out in a nitrogen atmosphere (which is not active in the Infra-Red (IR) part of the spectrum), but there is no reason why the calibration atmosphere could not be carried out in CO₂ for a CCS application. However, that part of the analysis area where the CO₂ absorbs strongly would inevitably be lost.

The FTIR analyser used at the PACT facility has a 5m path, which it is good in terms of sensitivity for smaller compounds. Cell paths of 2.5m, 7.5m or 10m are used: the higher the path the higher the sensitivity/signal to noise ratio. Conventional stack analysers often use a short cell path and focus on the main peak of CO₂ where a better signal to noise ratio can be obtained, other component within the gas is sacrificed as a results. It is possible to install a specific analyser for each component for specific concentration ranges, but that does limit the user to these components, and thus does not highlight any unknown impurities, which a full scan FTIR analysis would do.

Depending on where peaks fall it is potentially possible to benefit from a wider spectral range: the PACT facility is 900-4500cm⁻¹, but ~450-8000cm⁻¹ is possible, depending on construction, source, and detector.

The CO₂ would require separate analysers for homonuclear diatomic molecules such as O₂, N₂ and H₂, as these are not active in the IR range.

PACT in the UK have also used Gas Chromatography Mass Spectrometry (GCMS), but no longer do so because of the issues discovered by NPL (see above), and also because they found GCMS to be unsuitable for on-line process monitoring.

⁷² PACT (Pilot-Scale Advanced CO₂-Capture Technology) is a collaborative activity between the Universities of Cranfield, Edinburgh, Imperial College London, Leeds, Nottingham and Sheffield. It forms part of the UK Carbon Capture and Storage Research Centre (UKCCSRC) jointly funded by the Department of Energy and Climate Change (DECC) and the Engineering and Physical Sciences Research Council (EPSRC).

In conclusion, analysis using FTIR has been found to be the best solution for composition monitoring. The equipment would have to be calibrated for at least the main species within the CO₂. Calibrations would ideally be carried out on mixtures as well (in cylinders or synthesised on site) to account for possible interactions between the components themselves not just the CO₂. A separate O₂ analyser at least, would be required, and ideally something like GCMS to help with the unknown species that might appear, and a gas calibration set-up to add calibrations for such (unknown species) when/if they come up.

The technology has clearly been validated beyond the laboratory, and is therefore at least TRL4 and has arguably, at least in part been validated in a relevant environment. It may therefore be optimistic to describe it as TRL 5.

One barrier to this proving an attractive field for commercial development could be the likely low volume of sales for this equipment worldwide (perhaps 20 in the next 10 years), which does not justify the sums of money necessary for commercial companies to make the necessary investment.

Annexe IV

Data used in Figure 5.1 and Figure 5.2.

Dedicated geological storage pilots and demos; based on GCCSI database [118] and expanded with information from [119], [97], [120], [121], [122], [123].

Project name (click on project name for link to full description)	Project lifecycle stage	Country	Operati on start date	Status 2016	On-/ offshore	Storage medium	Reservoir lithology	Reservoir depth (m)	Reservoir thickness (m)	Permea bility (mD)	Permea bility height*	No of injection wells	Estimat ed annual injection rate (Mt/a)	Injecti on volum e (Mt)	TRL
Nagaoka CO ₂ Storage Project	(Post-) closure	JAPAN	2003	CEASED 2005	ON	SAQ	Sandstone	800	60	6	low	1	0,0050	10 kt	6
Carbfix & Sulffix CCS Pilot Project	(Post-) closure	ICELAND	2012	CEASED 2012	ON	MIN	Basalt	400	400			1	0,0003	0.3 kt	5
Lacq CCS Pilot Project	Closure	FRANCE	2010	CEASED 2013	ON	GAS	Carbonate	4500	130	5	low	1	0,0150	51 kt	7
Ketzin Pilot Project	Closure	GERMANY	2008	CEASED 2013	ON	SAQ	Sandstone	630	40	750	medium	1	0,0160	67 kt	7
CO2CRC Otway Project Stage 1	Closure	AUSTRALIA	2008	CEASED 2009	ON	GAS	Sandstone	2050	31	50-1600	medium	1	0,0500	65 kt	7
Don Valley Power Project	Define	UNITED KINGDOM	2020	FEASIBILITY	OFF	SAQ	Sandstone						1,5		9
Rotterdam Opslag en Afvang Demonstratieproj ect (ROAD)	Define	NETHERLA NDS	2019-20	LICENSE	OFF	GAS	Sandstone	3500	24	207	medium	1	1,1000		9
Spectra Energy's Fort Nelson CCS Project	Define	CANADA	2019 GCCSI estimate	FEASIBILITY	ON	SAQ	Carbonate	2100					2,2		9
White Rose CCS Project	Define	UNITED KINGDOM	2020-21	FEED / ON HOLD	OFF	SAQ	Sandstone						2,0		9
Peterhead CCS Project	Define	UNITED KINGDOM	2019-20	FEED / ON HOLD	OFF	GAS	Sandstone	2500	82	790	high	3	1,0000		9
Gorgon carbon dioxide capture project	Execute	AUSTRALIA	2017 GCCSI estimate	CONSTRUCT	ON	SAQ	Sandstone	2300	500	20-30/ 30-100	medium	8	3,4000		9
Illinois Industrial Carbon Capture and Storage	Execute	UNITED STATES	2016	CONSTRUCT	ON	SAQ	Sandstone	2130	300	225	high	1	1,0000		9

Project name (click on project name for link to full description)	Project lifecycle stage	Country	Operation start date	Status 2016	On-/offshore	Storage medium	Reservoir lithology	Reservoir depth (m)	Reservoir thickness (m)	Permeability (mD)	Permeability height*	No of injection wells	Estimated annual injection rate (Mt/a)	Injection volume (Mt)	TRL
Project															
CO ₂ Capture, Transport & Storage TDP	Execute	SPAIN		TESTING	ON	SAQ	Carbonate	1580	133-165	0.015-1.8	low	1		<100 kt	6
In Salah CO ₂ Storage	Operate	ALGERIA	2004	ON HOLD	ON	SAQ	Sandstone	1900	29	5	low	3	1,0000	3.8	9
Sleipner CO ₂ Storage Project	Operate	NORWAY	1996	ONGOING	OFF	SAQ	Sandstone	800	250	5000	very high	1	0,8500	15.5	8
Snøhvit CO ₂ Storage Project	Operate	NORWAY	2008	ONGOING	OFF	SAQ	Sandstone	2560	60	450	medium	2	0,7000	3	8
Quest	Operate	CANADA	2015	ONGOING	ON	SAQ	Sandstone	2000	46	20-50	medium	3	1,0800		9
K12-B CO ₂ Injection Project	Operate	NETHERLANDS	2004	ONGOING	OFF	GAS	Sandstone	4000	350	20	medium	1	0,0100	90 kt	6
Illinois Basin Decatur Project	Operate	USA	2011	ONGOING	ON	SAQ	Sandstone	2130	300	225	high	1	0,3000	1 Mt (2015)	8
Shenhua Group Ordos CCS Demonstration Project	Operate	CHINA	2011	ONGOING	ON	SAQ		2500				1	0,0500	155 kt (2013)	7
Hellisheidi industrial scale gas capture and injection project	Operate	ICELAND	2014	ONGOING	ON	MIN	Basalt						0.005		6

Annexe V

Network Technology – Future CCS Technologies Temporary Working Group

Name	Affiliation
Filip Neele (Network Technology chair)	TNO
Markus Wolf (Lead)	GE
Zoe Kapetaki (Co-lead)	GCCSI
Ton Wildenborg (Co-lead)	TNO
List of contributors	
Carlos Abanades	INCAR
Rahul Anantharaman	SINTEF
Pascal Audigane	BRGM
Andy Barwick	National Grid
Stefano Brandani	University of Edinburgh
Andy Brown	Progressive Energy
Dominique Copin	Total
Eirik Falck da Silva	Shell
Robert de Kler	TNO
Gelein de Koeijer	Statoil
Kristina Fleiger	VDZ GmbH Germany
Chris Gittins	TAQA
Earl Goetheer	TNO
Wim Guijt	Shell
May-Britt Hägg	NTNU Norway
Kristin Jordal	SINTEF
Sigurd Løvseth	SINTEF
Halvor Lund	SINTEF
Wilfried Maas	Shell
Jonathan Pearce	BGS
Tim Peeters	Tata Steel
Thijs Peters	SINTEF
Julia Race	University of Strathclyde
Adam Richards	National Grid
Philip Ringrose	Statoil
Matteo Romano	Politecnico di Milano
Stanley Santos	IEAGHG
Günter Scheffknecht	University of Stuttgart
Sylvain Thibeau	Total
Owain Tucker	Shell
Martin van Sint Annaland	Eindhoven University
List of reviewers	
Peter Brownsort	SCCS / Edinburgh University
Keith Burnard	IEAGHG
Andrew Cavanagh	Statoil
Hannah Chalmers	SCCS / Edinburgh University
James Craig	IEAGHG
Tim Dixon	IEAGHG
Maria-Chiara Ferrari	SCCS / Edinburgh University
Wim Guijt	Shell

Gareth Johnson	SCCS / Edinburgh University
Lisa Joss	Imperial College
Jasmin Kemper	IEAGHG
Enzo Mangano	SCCS / Edinburgh University
Marco Mazzotti	ETH Zurich

January 2017