



TECHNICAL GROUP

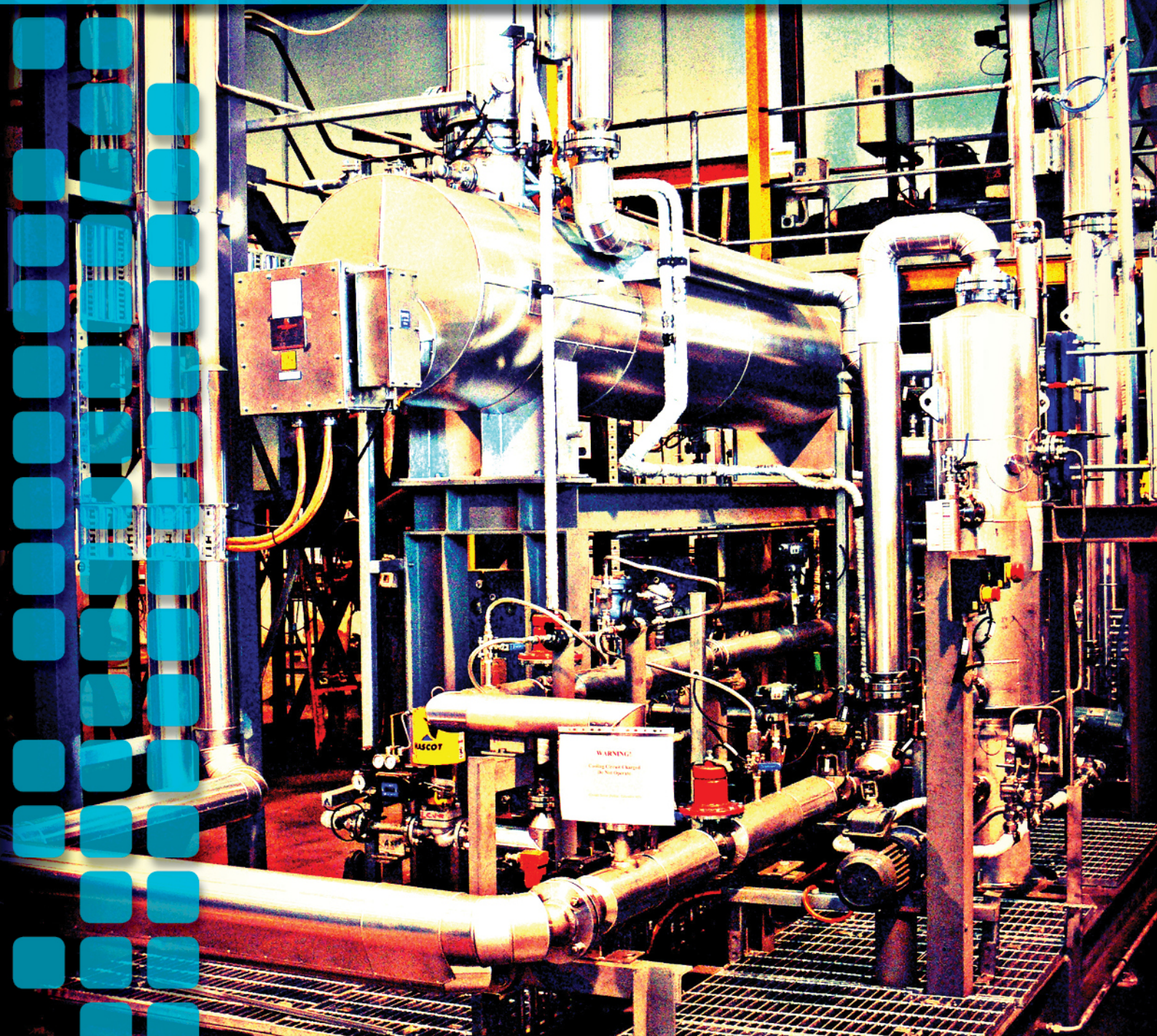
Final Report by the CSLF Task Force on CCS Technology Opportunities and Gaps

Background

At the September 2011 CSLF Ministerial Meeting in Beijing, a Task Force was formed to investigate CCS Technology Opportunities and Gaps. The Task Force mandate was to identify and monitor key CCS technology gaps and related issues, to determine the effectiveness of ongoing CCS RD&D for addressing these gaps, and to recommend any RD&D that would address CCS gaps and other issues. This document is the Final Report from the Task Force.

CCS Technology Development Gaps, Opportunities and Research Fronts

Prepared for the CSLF by The CRC for Greenhouse Gas Technologies (CO2CRC)





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1. Executive Summary

It is now clear that climate change management involving CCS deployment will be less expensive than alternative strategies (see IEA 2013 and ETI 2013). To realise and enhance the full potential of CCS at a global level, continued technology development is essential.

In recent years, a strong field of CCS science and engineering has emerged. At a high level there are no major technology gaps. CCS has been and can be deployed. The focus of technology development is now on driving down costs and securing more efficient operational, monitoring and regulatory outcomes.

This report sets out some of the key technical issues and research fronts in CCS technology and identifies opportunities and gaps relevant to policy makers and technology development strategists. The report is complemented by a global listing of pilot plant projects in both capture and storage. The high level observations and recommendations to the CSLF concerning CCS technology are:

Capture and Integrated Combustion

1. A number of capture technologies are available today (mostly solvent-based) and deployed on large scale demonstrations or industrial processes; capture costs can be expected to fall substantially by 2025-2030, particularly if promising technologies are moved through the development pathway.
2. There is a need to continue to support 2nd and 3rd generation technology development, from pilot to large scale demonstration¹, to secure the lowest cost technologies for the future, noting the lead times can run to decades. Adsorbents and membranes are likely to play a big role.
3. For all capture technologies, improvements must focus on all dimensions: (1) materials, (2) equipment, (3) impurity handling/tolerance, (4) process design and heat integration, and (5) environmental impact.
4. Retrofit of current coal-fired power stations can result in much lower cost of electricity than closing viable stations and building new low emission coal-fired stations.
5. More work is required on the flexible operation of power plants with CCS, synchronised with electricity market prices and links to renewable energy production.
6. For oxyfuel technologies; on coal combustion the technology is mature, but for natural gas combustion an important new technology field is opening up. The latter will play a big part linked to the new role of shale gas. New turbine design is an important R&D front. Lower cost oxygen will benefit all oxyfuel technologies.
7. Chemical looping is an important emerging technology for some industrial processes such as cement manufacture and also for fluidised bed combustion of coal; moving the technology to larger scale is a priority.

¹ In USA, EU, China, Korea, Japan, competitions allow prospective capture technologies to compete for funding for large scale demonstration projects.

CO₂ Transport

The technology for transport of CO₂ is well established, with over 6,500 km of CO₂ pipelines in the US transporting 48 – 58Mt/yr. There are however still technology improvement opportunities, with the key points being:

1. Transport pipeline technology is mature and available; however, some technology improvements are needed to get costs down and increase safety, including managing and designing for variations in CO₂ composition in multiple source hubs (includes understanding equations of state and operational implications), fracture propagation control, corrosion control and CO₂ dispersion modelling for safety case and risk assessment purposes.
2. Large scale transport of CO₂ by ship offers promise and needs to be demonstrated at scale.
3. Experience is needed in planning, designing and implementation of large-scale CO₂ transport networks, including hubs and multiple points of capture.

Storage

A significant established body of technology from the oil and gas industry has combined with the research and demonstration on CCS over the last 10-15 years to underpin a strong consensus that safe CO₂ storage is possible today. New knowledge will be gained from the numerous larger scale deployments underway. This will fine tune the technology for large scale deployment. Key research and improvement areas are:

1. Modelling the CO₂ behaviour, this is a vital element of storage research and technology integration. The main development issues require:
 - a. Fundamental research, laboratory work and data gathering on physical and chemical parameters to better underpin detailed modelling of fluid flow behaviour, chemical reactions and geomechanical outcomes;
 - b. More integrated dynamic models of fluid flow, geochemistry and geomechanics running on very large computers;
 - c. The ability to build robust basin scale fluid flow models for operators, regulators and governments involved in resource allocation and resource conflict resolution;
 - d. Modelling and strategies associated with the hydraulic integrity of intra-formational seals and faults, and the number and thickness of cap rock required; and
 - e. Developing stronger models and underpinning data sets on possible migration pathways (fault, seal, strata/structure), to improve risk management.
2. Improvements to optimise operational effectiveness and storage efficiency include:
 - a. Development of strategies to optimise drill patterns and angles for CO₂ injection and pressure management to increase injectivity and control the behaviour of the CO₂ plume;
 - b. Understanding induced seismicity and development of pressure management strategies to avoid minor induced seismic events and the potential to compromise cap rocks;
 - c. Approaches to enhance residual trapping, in-situ mineral trapping and mineralisation and also injection strategies for storage in low-permeability rocks;
 - d. Development of methodologies to manage high permeability thief zones and differential pressure effects that can reduce efficient reservoir use; and

- e. Understanding of fines migration, mineral dissolution and precipitation and the effects of subsurface microbes that could compromise operational efficiency and storage resource effectiveness.
3. Development (based on oil and gas industry practice) of internationally consistent standards for:
 - a. Storage site characterisation methodologies;
 - b. Storage efficiency factors; and
 - c. Capacity estimation and reporting standards.
 4. Technology and risk management strategies to mitigate or manage unintended CO₂ migration, including:
 - a. Well integrity, including developing CO₂ resistant well cement and simulation modelling of migration through wells;
 - b. Mitigation strategies, such as pressure management, and profile modification²;
 - c. The attribution of leaked CO₂ and associated measuring and accounting issues; and
 - d. Strategies to give even greater confidence in long term storage.

Monitoring, Measurement and Verification (MMV)

MMV continues to be a vital part of CCS technology development, as it underpins operational decisions as well as the relationship with regulators and the community. Some key observations and recommendations are:

1. Establish technologies and methodologies for offshore (sub marine) MMV, as a significant portion of global storage capacity is offshore;
2. Improve onshore and offshore MMV technology and models:
 - a. The whole package of geology between the storage reservoir and the surface, to assess the timing and possible modes of potential CO₂ movement and to inform remediation and mitigation strategies;
 - b. CO₂ plumes in the subsurface, particularly with respect to the relationship between CO₂ saturation and plume resolution; and
 - c. MMV in aquifers which cover large areas, where specific plume movement may be more difficult to precisely predict, particularly in laterally unconfined aquifers.
3. Continue work on controlled release calibration and natural analogues; these experiments are important for CO₂ detection and accounting;
4. Develop an agreed methodology and language for dealing with what will be the principal result of most monitoring – a null result;
5. Continue the rapidly evolving trend to continuous, high resolution, low cost, low impact subsurface monitoring;³

² This involves modifying the strata in certain zones with agents such as gels and surfactants to change the flow rates of CO₂

6. Continue to develop new seismic interpretation and inversion techniques for enhanced CO₂ detection including:
 - a. Quantitative interpretation of 4D seismic, including 4D inversion (deterministic, stochastic, etc) and 4D full-waveform inversion;
 - b. Using changes in seismic attenuation and seismic anisotropy of the rocks;
 - c. Integrating reservoir & seismic modelling with 4D seismic into the closed loop prediction/correction workflow and improving signal sensitivity with new data analysis algorithms;
 - d. Using rock physics data and models to enhance fundamental understanding of CO₂ injection-related changes in the rock properties;
 - e. Deployment of permanent sources, massive buried receiver arrays; and
 - f. Combining active as well as passive seismic methods and novel processing algorithms.

7. Develop and/or improve:
 - a. Subsurface (down well) solid state detectors for CO₂ and ensure that they can be deployed for long periods of time in the subsurface; and
 - b. A portable low cost C-14 detection system (CO₂ from fossil fuels has no C-14 content).

Building Technical Knowledge Capability and People

The broad deployment of CCS will require a significant pool of technically skilled people as well as continuing growth and dispersion of the CCS technology knowledge base. Governments are encouraged to:


1. Continue R&D and technology development to both develop the knowledge base and to train engineers and scientists in CCS technologies.
2. Stimulate international collaboration by:
 - a. Supporting researchers to travel and join smaller collaborative research projects involving exchange of researchers and complementary work programs;
 - b. Allocating resources and funds for researchers to contribute to, or buying a stake in consortia of international researchers around larger demonstration projects where particular teams can bring a unique or complementary set of skills; and
 - c. Involving industry, government and researchers in international CCS projects.

Industry dynamics associated with exploration and technology development

One of the most pressing problems for global CCS deployment at scale is getting the requisite amount of exploration started when there is a weak price on carbon. The lead times from initiating exploration through approvals and construction will often be as long as 10-15 years. This has implications for the degree to which CCS can contribute to 2050 targets and the rate of technology development⁴. Governments are encouraged to:

³ The extent to which this is required on any specific project will depend on the cost, the proponent's needs, the stage and status of their project and the relationship to regulators and local communities.

⁴ If exploration is slow, large scale deployment will be slow, which will in turn slow learning-by-doing for current technologies and market pull for the next generation of technologies. Conversely, if governments

- 
1. Start the identification and pre-competitive data generation of prospective storage basins, making assessments of the likely realistic storage capacity.
 2. Either start exploration or incentivise the private sector to start exploration.

In summary, governments around the world now have a technology at their fingertips that can be deployed to manage carbon emissions, but the rate of take-up and the associated improvements in technology needs to be incentivised. There are profound role-of-government lessons from the development of the nuclear industry and SO₂ scrubbing in the US and also from the global LNG industry. Governments played a decisive role in both the development and the diffusion of these technologies. Governments must continue to be involved in the same way in CCS development; where the diffusion and take-up of the technologies is strongly driven by the credibility of incentives for industry to invest in commercial scale projects and technology development.

incentivise the market to act, with carbon prices, taxes or mandates, the result will be synergistic for both exploration and discovery of storage capacity and also for technology development. The result will be lower costs, which will in turn drive the market dynamics more strongly.

2. Introduction


This document identifies the key research fronts in CCS technology being pursued today and highlights some of the high-level global gaps and opportunities required to move technology forward to facilitate the deployment of safe, low cost CCS to attempt to stay within the IEA’s ‘2°C scenario’ (2DS). It provides additional information on CCS technologies to support the 2013 CSLF Technology Road Map (TRM) and supplement the comprehensive carbon capture and storage status report by SINTEF (2013). Understanding where the key research fronts and prospects are can be helpful in seeing the challenge ahead. This document is also supported by a compilation of the major capture and storage pilot plants around the world (see Appendices A - B).

Technology Horizons			
Technology Development Status	Definition	Paradigm	Time Horizon to commercial deployment
First generation technologies or Horizon 1	Technologies in operation today that are the subject of further improvement through research and learning by doing	“Improvement of current technology”	In large scale operation today
Second generation technologies or Horizon 2	New technologies, tested at bench scale, that offer significant operating cost/ performance or environmental benefits	“Highly prospective new technologies proven at bench scale”	10-15 years
Third generation technologies or Horizon 3	Early stage, potentially game changing technology concepts that have only limited theoretical or laboratory work	“Paradigm shifting technologies offering major improvements”	15-25 years

Table 1: Technology Horizons

The global effort on CCS is moving to large scale demonstration where current technologies are being pushed to successfully demonstrate large scale CCS. This is supported by a small (relative to the magnitude of the problem) but growing base of scientists and engineers and an increasing level of research, development and pilot scale demonstration. This scientific and research effort will be vital to fine tuning and improving the current technologies (first generation technologies) for immediate deployment

The lead times on technology development in the energy and resources sphere are long, often running for 20-30 years. The research front associated with CCS technology development will be with us for many decades as the technology is developed, deployed and improved. It is thus important for the CSLF to note the second and third generation technologies that offer the potential to ensure technology is developed to reach 2050



targets with the lowest cost to global communities. (Note that table 1 overleaf provides definitions of each generation or horizon of technologies.)

Achieving significant cost reductions will not only require a vigorous and sustained level of research and development but also a substantial level of deployment where further learning and improvements can develop. A critical part of the equation will be the need for a market pull for CO₂ technologies.

In assessing current CCS technologies, it is helpful to understand the position of the technologies on the generic technology learning curve or “Grubb” curve (Figure 1). The concept of the curve is that most technologies follow the curve in their development as they progress to commercial application. Firstly, as the technology matures, the accuracy of performance of cost estimates tends to improve, but there is also a learning effect as more and more units are deployed that drives down the cost. In Figure 1 the key areas of CCS technology are plotted on a generic curve. It should be noted that those in black are the current technologies that will continue to improve.

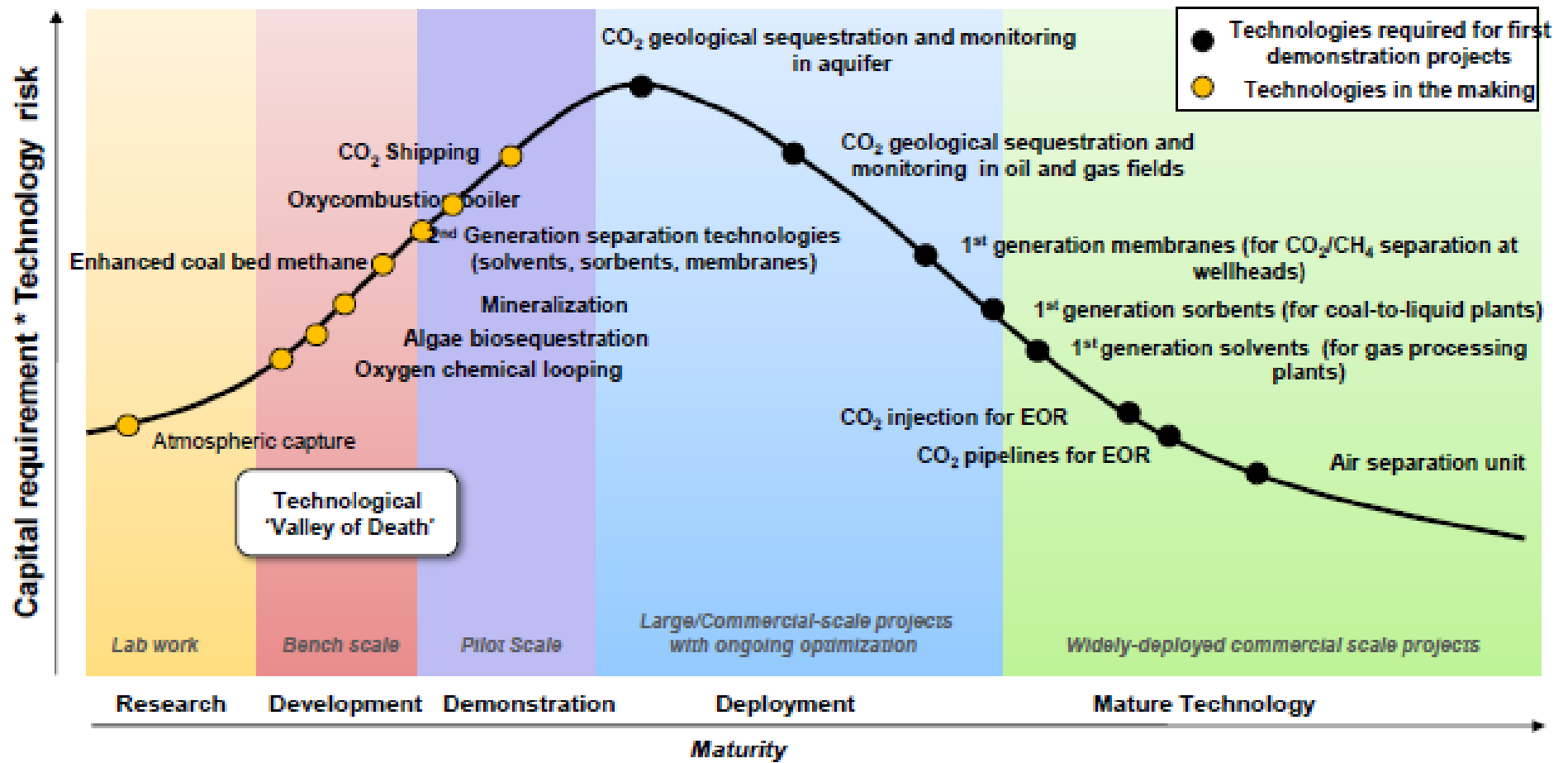


Figure 1 - Understanding the status and pathways of CCS technology on the Grubb Curve

From "Leading the Energy Transition: Bringing Carbon Capture & Storage to Market" SBC Energy Institute 2012

3. CO₂ Capture Technologies

Significant CO₂ emissions from stationary sources, which can be mitigated using CCS, come from power generation and industrial processes. The condition (pressure, temperature, flow, concentration) in which the CO₂ is available for separation varies with the stationary emission source. For example, in natural gas processing the CO₂ is at significantly higher pressure and sometimes concentration than in the flue gases of thermal power stations, which influences the choice of technology. A summary of the emission sources and relevant CO₂ capture technologies is given in Figure 2.

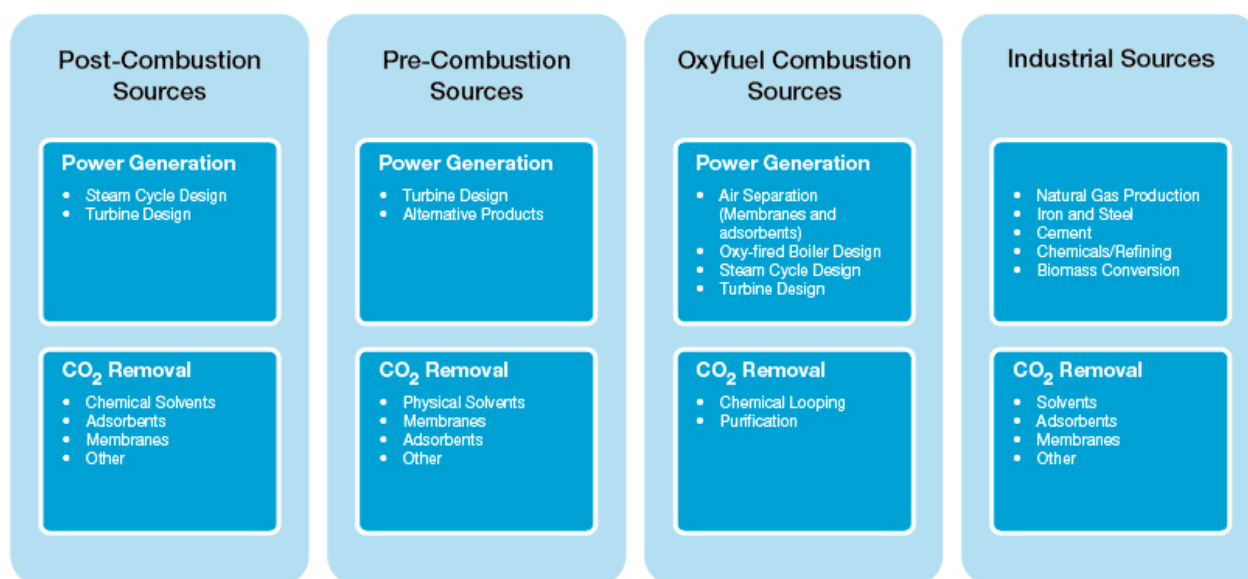


Figure 2 - CO₂ Emission Sources with CO₂ Capture Options

The three leading capture technologies for CO₂ capture are currently (i) solvent absorption, (ii) membrane separation and (iii) gas adsorption. There is significant research, pilot plant and engineering activity in these areas. Other technologies, such as hydrates/cryogenics, hybrid technologies and chemical looping are also emerging as having potential for CO₂ capture but do not have the same commercial foundation in gas processing as solvent absorption, membrane separation and gas adsorption.

To accelerate the large scale deployment of CCS by 2050 to meet the requirements of the 2DS scenario (IEA 2012), significant advances in CO₂ capture technologies must occur. The technologies which are available today and are likely to be implemented in the larger scale demonstration projects by 2020 are termed first generation. Technologies that are likely to be commercially available by 2030 and 2050 are termed second and third generation technologies, respectively.

In terms of power generation, first generation capture technologies reduce the absolute efficiency of the power station by 10-15 percentage points, where the absolute efficiency of the power station is the ratio of the electricity produced to the energy available in the fuel source based on higher heating value (HHV). Second generation and third generation capture technologies are expected to significantly reduce the impact of this energy penalty on the power station. To progress from first generation to second generation and then to third

generation innovation needs to occur holistically within the following themes to enable the significant reduction in costs required.

1. Materials: improved separation efficiency and reduced material cost
2. Equipment: reduced size, cost and footprint
3. Impurity handling/tolerance: improved durability, reduced size, cost and footprint
4. Process design and heat integration: efficient flowsheet design with reduced energy penalty through reduced steam/heat and direct electric power requirements and integration with the power station
5. Environmental impact: CO₂ removal without any other negative environmental impacts
6. Water consumption: CO₂ removal with minimal water use

These themes are discussed in the following sub-sections in relation to emerging next (second and third) generation capture technologies for the various emission sources.

3.1. Solvents

3.1.1 Materials

Solvent technologies are well established for removing CO₂ from gas streams and have been used commercially for several decades in the oil and gas, chemical and refining industries. First generation solvent technologies are ready for application to pre and post-combustion capture along with capture from industrial sources, but they have significant energy penalties and high costs.

The challenge for next generation solvents is to find materials which will result in much lower regeneration energies and have a low cost. Next generation solvents, which will be most relevant to post-combustion capture, include advanced amines and amino acids, carbonate systems (including precipitating carbonates), solvent blends, immiscible liquids and ionic liquids. A summary of the next generations of competing solvent materials is given in Figure 4. The specific challenges for these solvents are also presented here along with prospective areas for future research.

Figure 3 presents an example of cost reductions that can be achieved from changing the solvent material (from a first generation monoethanol amine (MEA) and state of art (SOA) amine to a second generation precipitating carbonate system). The waterfall diagram presented here also shows other process improvements, which are discussed under the subsequent themes.

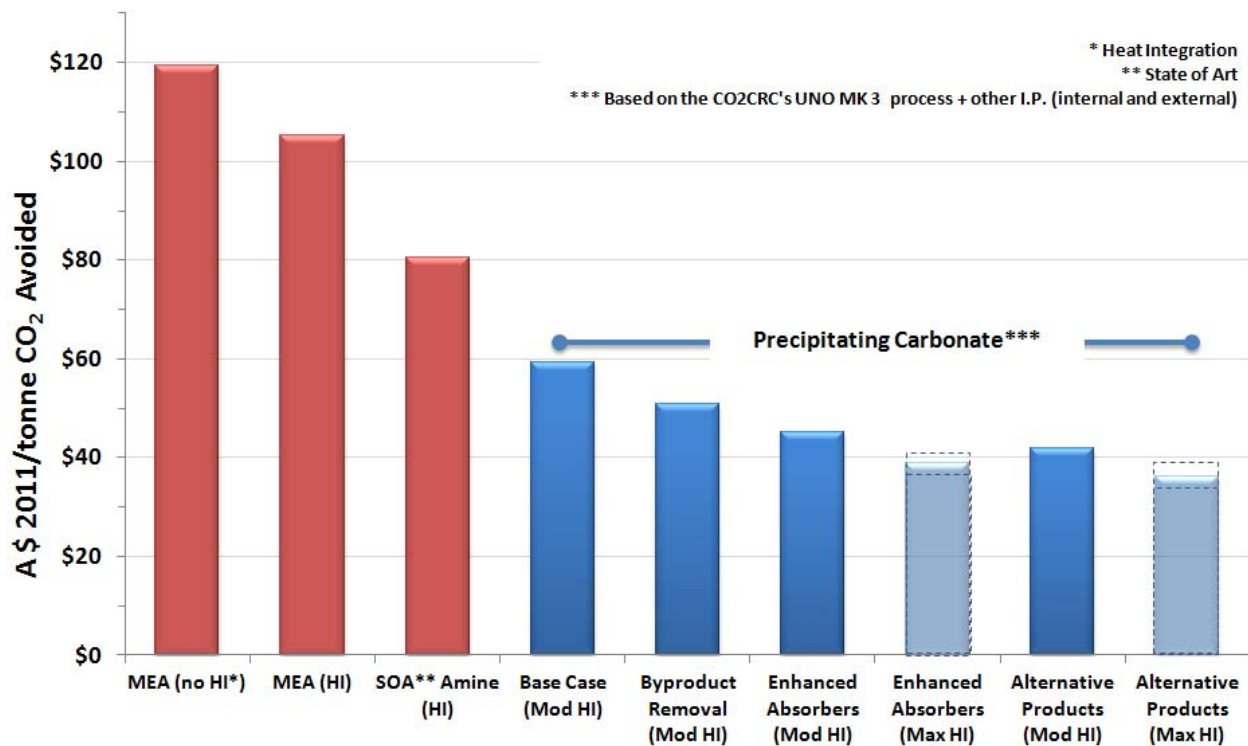


Figure 3 - Impact of Process Improvements using the UNO MK 3 Solvent Process as an Example.

Further details on the UNO MK 3 process used as the example here can be found elsewhere (Anderson et al 2012). The example presented here is based on retrofitting CCS to an Australian brown coal power station.

The first big improvement in the cost occurs through changing the process from a standard amine-based solvent process (shown in red) to an advanced solvent process (UNO MK 3 shown in blue) that allows multi-component capture, uses a less expensive solvent and has a smaller regeneration circuit. Further improvements are then made by producing fertiliser products (second blue column) from the SO_x and NO_x impurities in the flue gas.

Solvent Absorption - Materials

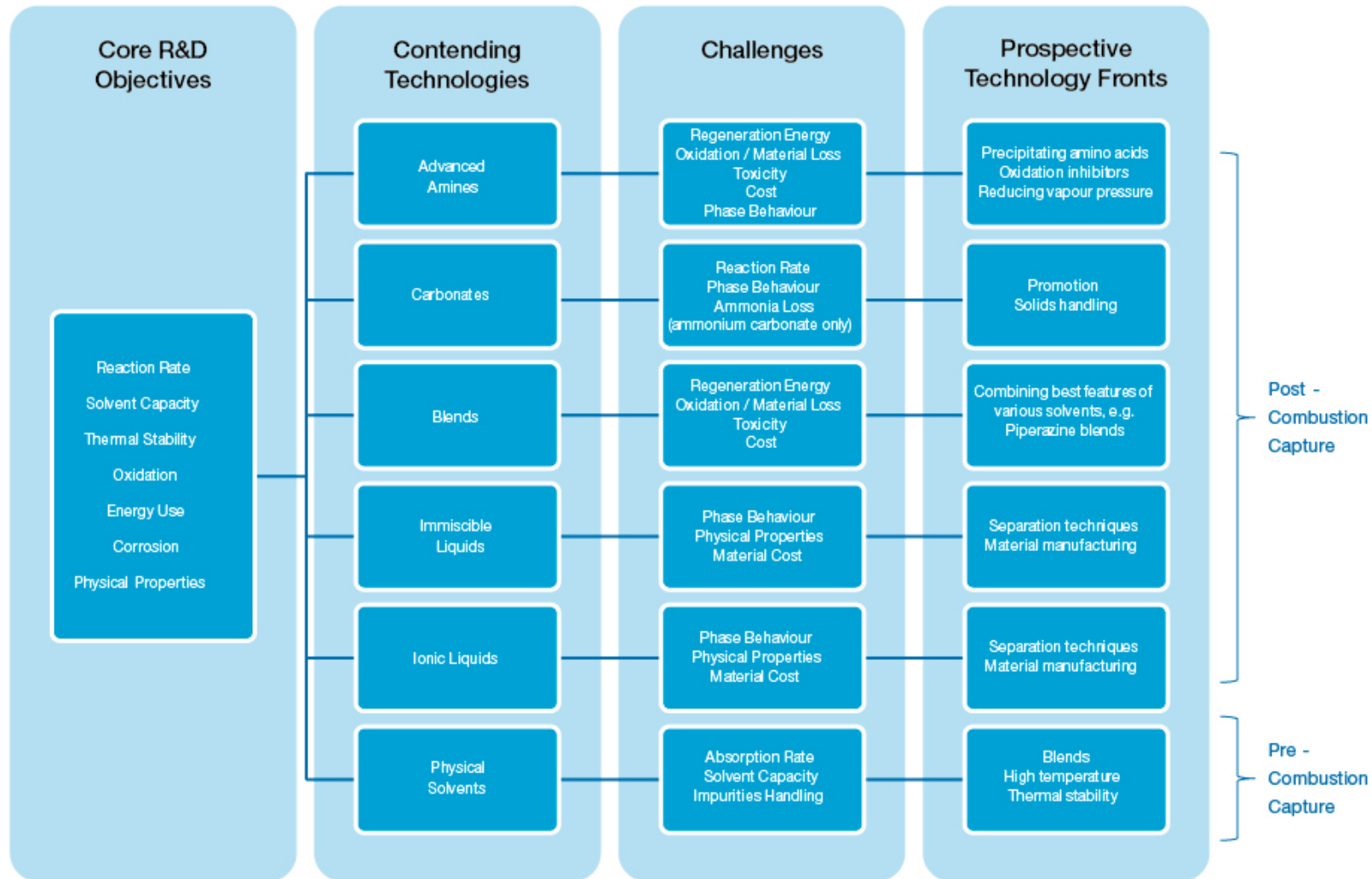


Figure 4 - Next Generation Solvent Materials, Prospective Technology Fronts

3.1.2 Equipment

The largest equipment items in solvent absorption processes are the absorber and regeneration columns. Improvements in the height and size of these columns are needed to enable significant reductions in capital cost. An example of such an improvement is a concentric column design (Hooper et al 2008), which combines the two columns into one and includes construction using alternative materials to steel. An indication of the possible cost reduction for this particular equipment was shown previously in Figure 3. A summary of the next generation equipment for solvent absorption is presented in Figure 5.

Solvent Absorption - Equipment

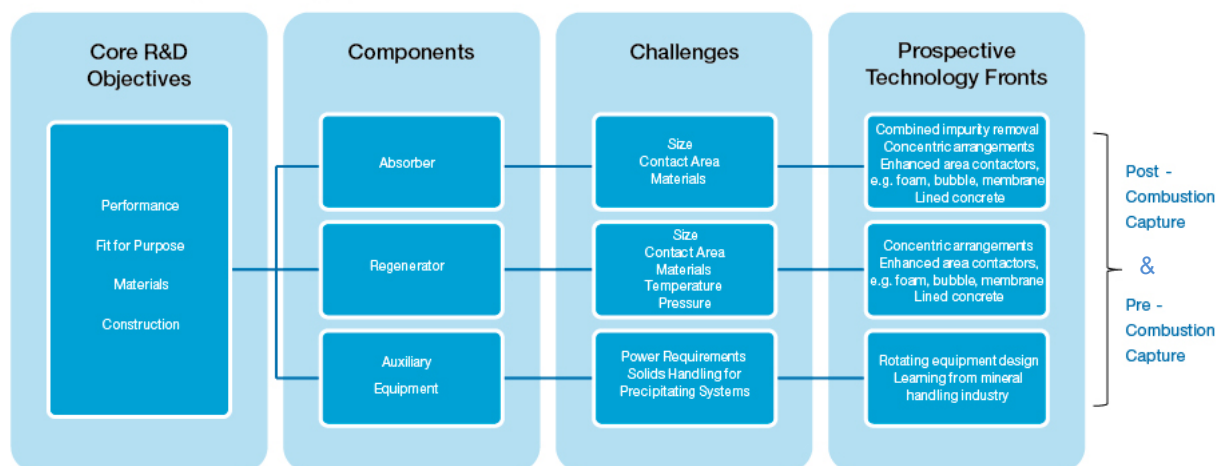


Figure 5 - Next Generation Solvent Absorption Equipment, Prospective Technology Fronts

3.1.3 Impurity Handling/Tolerance

Traditional amine-based solvents degrade in the presence of SO_x , NO_x and oxygen due to a reaction of the amine with these components which produces heat stable salts along with other degradation compounds such as nitrosamines. While power stations in the USA and Europe are fitted with flue gas desulphurisation (FGD) units, further treatment is often required to remove the SO_x and NO_x to the even lower levels tolerated by the amine-based solvents.

Solvent absorption processes that do not require any pre-treatment to remove impurities prior to absorption will be advantageous. In particular, solvents which are primarily inorganic materials will be tolerant to oxygen along with the SO_x and NO_x present in post-combustion capture applications.

CO2CRC's UNO MK 3 process for example does not require any pretreatment of the flue gas and produces a valuable fertiliser byproduct from the SO_x and NO_x impurities.

3.1.4 Process Design and Heat Integration

The impact on the cost of CO_2 avoided using heat integration for solvent absorption was demonstrated previously in Figure 3 by the difference in the first two red columns (impact of moderate heat integration) and the dark blue and light blue bars (impact of maximum heat integration).

The standard way of reporting the energy usage for solvent processes is the energy required by the regeneration process (e.g. ~ 4 MJ/tonne CO_2 removed). For the promotion of CCS, it may be more

useful to present the energy usage following heat integration. As part of the ETIS project, CO2CRC determined that following heat integration, the energy requirement of the three main capture technologies (solvent absorption, membrane separation and gas adsorption) is very similar at 1 GJ/tonne of CO₂ captured (Qader et al 2011a).

3.1.5 Environmental Impact

A major challenge facing the next generation of solvents is the environmental impact when considering CCS in wide scale deployment. While the global warming potential of the power station will be reduced, amine-based solvents degrade, which when emitted to the atmosphere, significantly increase the environmental impact of the power station as shown through other environmental indicators such as human toxicity potential (Merkewitz et al 2009). This is mostly due to the formation of nitrosamines from the reaction of secondary and tertiary amines with NO_x (Statoil 2010). In response to this issue there is currently a lot of research activity in improving the environmental impact of amine-based solvent processes.

The established method for assessing environmental impact is Life Cycle Assessment (LCA), which is a practice set out by ISO Standards 14040 to 14042. LCA deduces the environmental impact of a process based on all the inputs and outputs to and from the process and has been used as an assessment tool for the environmental impact of various MEA-based solvent processes (Schreiber et al 2012). Along with the negative impacts on the environment from amine-based solvents, the results of these LCA also show that if carbon dioxide from the additional power required to operate capture facility is not avoided, the capture efficiency drops from 90% capture to 60%-75% capture.

3.2 Membrane Separation

3.2.1 Materials

First generation materials such as cellulose acetate and polyimides are well established for commercial separation of CO₂ using membranes in the natural gas industry where the available system pressure is high.

The development of membrane technologies for post combustion capture is focused on improved materials that have moderate CO₂/N₂ selectivities (30-50) and high permeabilities (>1000 GPU). These process conditions have been shown to provide the smallest energy penalty (Ho et al 2008, and Merkel et al 2010). Emerging candidate membrane materials include the Membrane Technology & Research (MTR) Polaris[®], polymers of intrinsic microporosity (PIMs) (Guiver & Moo 2013) and thermally rearranged polymers (Park et al 2010). Facilitated transport systems, such as those based on poly vinyl alcohol (Deng et al 2009 and Zou & Ho 2006) or room temperature ionic liquids (Bara et al 2010) also show promise. There is also significant research effort being directed to mixed matrix membranes, which combine the best features of adsorbent technology into a membrane format.

Other active areas of development for membrane technologies in the application of pre-combustion capture include the development of membrane reactors for the water gas shift process, and palladium based membranes for hydrogen separation. In addition, ion and oxygen transport membranes for air separation are being developed for oxyfuel and pre-combustion applications.

Figure 6 presents a summary of next generation of materials for membrane separation.

Membrane Separation - Materials

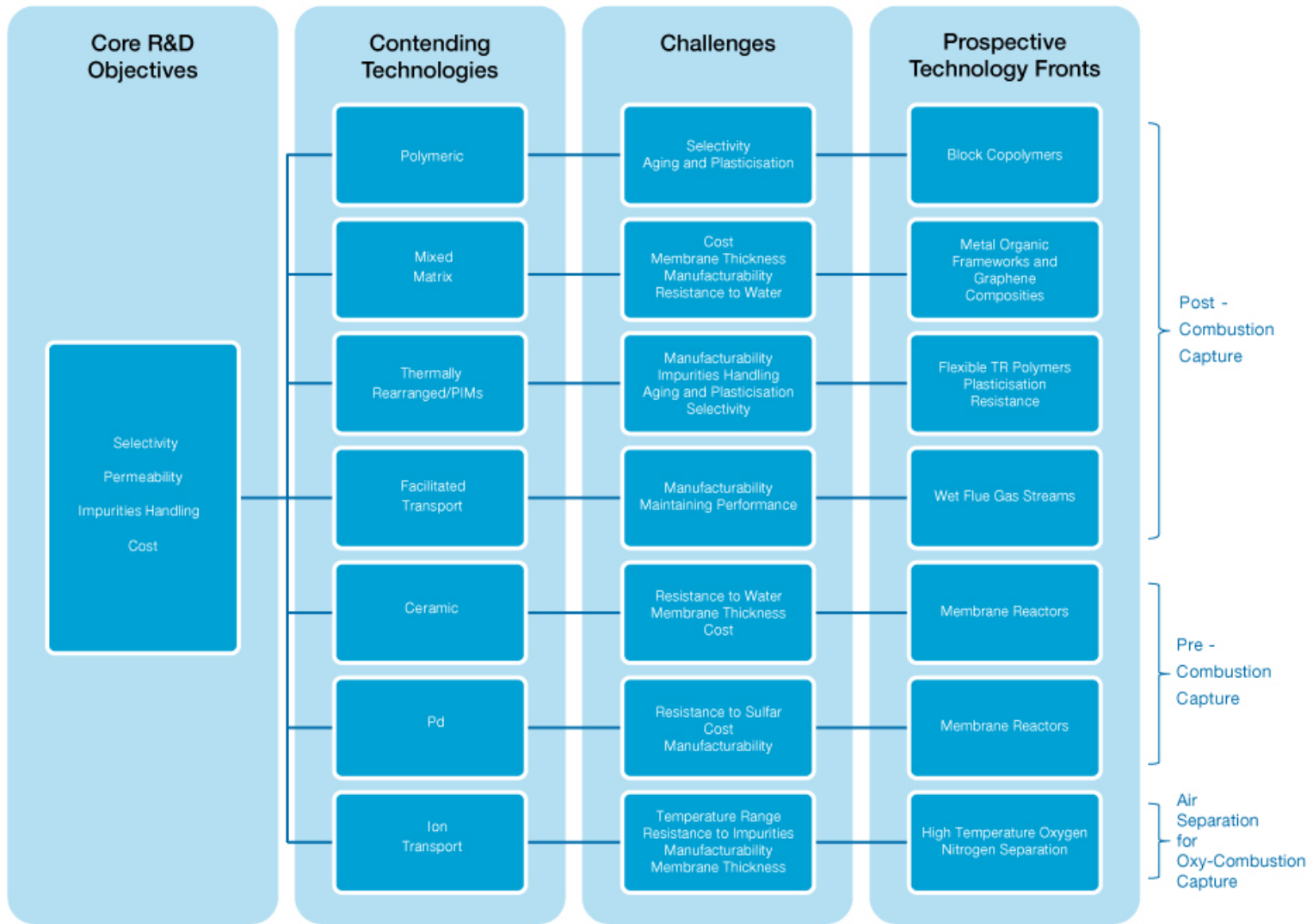


Figure 6 - Next Generation Membrane Materials, Prospective Technology Fronts

3.2.2 Equipment

For the application of post-combustion capture, the challenge facing the next generation of membrane equipment design is the need to develop low pressure drop, countercurrent flow modules. While spiral wound membranes may provide the best resistance to fly ash fouling, which can increase pressure drop, they are not able to accommodate countercurrent flow arrangements. For this reason, MTR have recently trialed the use of plate and frame arrangements. Other groups are focusing on hollow fibre modules, which can provide a good mix of pressure drop, fouling resistance and countercurrent flow.

A further mechanism for reducing equipment costs is to utilise membrane contactors. In this case, a standard gas sorption solvent is contained within a hollow fibre membrane module. Such an approach provides a dramatic reduction in equipment foot print and reduces issues with foaming and flooding. However, performance can drop over time due to membrane pore wetting, which reduces the mass transfer coefficient. Pore wetting can also be induced by unbalanced pressure drop control during startup and shutdown and so elaborate pressure drop control mechanisms may be required.

Most process flowsheets for post combustion capture incorporate a vacuum on the permeate side of the membrane. As membrane technology reaches a larger scale, research will be required to develop the necessary large scale vacuum pumps. The flue gas will be wet, so these are likely to be ring type pumps.

A summary of the next generation equipment for membrane separation is presented in Figure 7.

Membrane Separation - Equipment

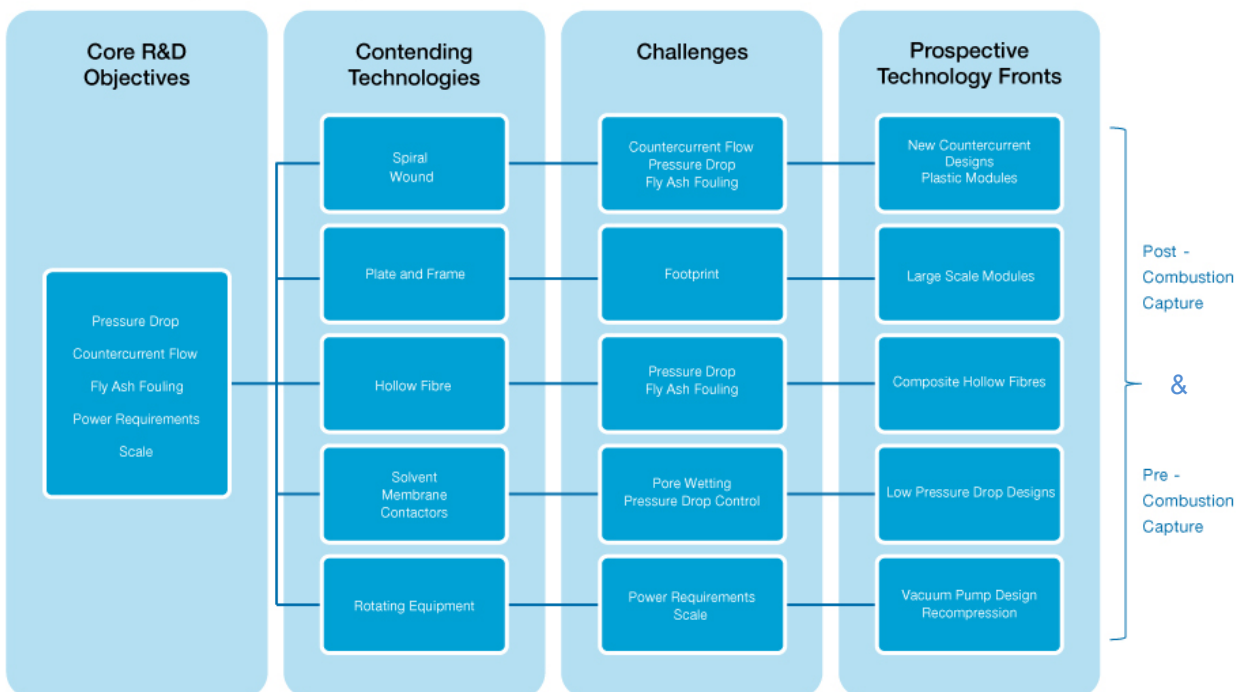


Figure 7 - Next Generation Membrane Separation Equipment, Prospective Technology Fronts

3.2.3 Impurity Handling/Tolerance

To avoid pretreatment, membrane materials will need to be tolerant to water along with oxygen and sulphur and nitrogen compounds. Most polymeric membrane materials show resistance to these compounds, which increases their attractiveness for post combustion applications. The only limitation is the requirement to maintain the level of condensable impurities (such as water) at around 10°C below the dew point. This is readily achievable using a simple cycle of cooling, knockout and reheat.

In the post combustion application, membrane materials if placed upstream of pretreating equipment such as flue gas desulphurisation (FDG) or a direct contact cooler (DCC) will also need to adequately handle fly ash compounds. Initial work by CO2CRC indicates that dry fly ash does not reduce membrane permeability, but the presence of water and fly ash together can be an issue. Fly ash will add to pressure drop concerns within the membrane module.

Resistance to water and sulfur compounds is an issue with many inorganic membranes targeted at pre-combustion capture applications. Zeolite membranes often show poor resistance to water and Palladium membranes are readily compromised by sulfur. The use of mixed matrix membranes which combine both inorganic and organic elements within one structure will also suffer from these issues.

3.2.4 Process Design and Heat Integration

Of all of the technologies reviewed in the National Energy Technology Laboratory (NETL) study published in March 2012, the MTR membrane process, which represents a next generation process, provided the lowest cost of CO₂ avoided for post combustion capture from black coal (NETL 2012). The reduction in energy penalty is achieved through the use of the combustion air feed to the boiler as a sweep gas flow to a countercurrent membrane module. A downstream cryogenic separation is used to reach the necessary CO₂ purity. Work by CO2CRC has shown that further benefits may be gained by enriching the oxygen content of this combustion air feed.

3.2.5 Environmental Impact


Unlike solvent absorption, there are no chemicals continuously used in membrane separation, which bodes well for low environmental impact. The environmental impacts will primarily come from the manufacture of the membrane materials and the energy required by the membrane separation process taken from the power station. Consideration will also need to be given to the ultimate disposal of the membrane elements; currently these are sent to landfill.

3.3 Gas Adsorption

3.3.1 Materials

Like solvent absorption and membrane separation, gas adsorption is also a well established technology in the natural gas industry, although generally used for gas dehydration rather than CO₂ removal.

The developments of new adsorbent materials, which have high selectivities and high adsorption capacities, along with process improvements make gas adsorption a promising technology for next generation capture technologies. Promising adsorbent materials for next generation capture include



alumina, zeolite, activated carbon, metal organic frameworks, organic-inorganic hybrids and dry regenerable sorbents.

A number of these materials fall under into the broad category of solid sorbents (Samanta et al 2012 and Sjostrom & Krutka 2010). Solid sorbents are currently in use at pilot scale demonstration at sizes up to 10 MW (Park et al 2011). Specifically, next generation solid sorbents, which may be most relevant to post-combustion capture, include carbonates and solid amines. For pre-combustion capture, oxides such as magnesium oxide and calcium oxide may be more relevant.

The challenges associated with these materials relate to selectivity, capacity, kinetics, oxidation, and thermal stability along with the ability to handle impurities and water, regeneration and mechanical strength. Materials will need to be developed with modified compositions and surface chemistry to meet these challenges.

Figure 8 presents a summary of next generation of materials for gas adsorption.

Gas Adsorption - Materials

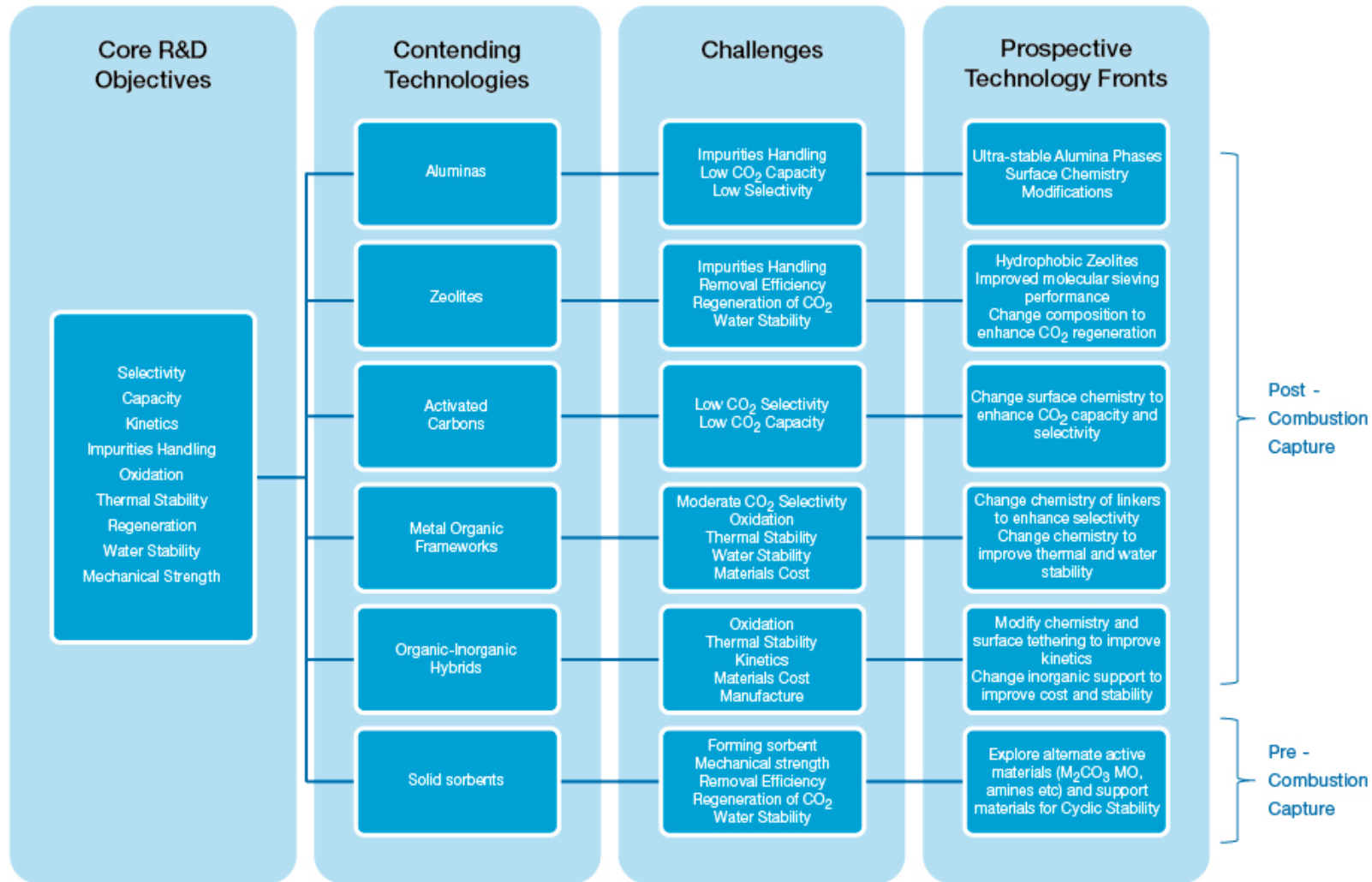


Figure 8 - Next Generation Gas Adsorbent Materials, Prospective Technology Fronts

3.3.2 Equipment

For gas adsorption technologies, equipment improvements will be imperative in the areas of gas/solid contact, regeneration and rotating equipment (e.g. vacuum pumps).

The possible configurations for contacting CO₂-containing gas streams with solid sorbents are fixed bed, fluidised bed, and moving bed. Compared with the other contactor arrangements, fluidized bed contactors have the advantages of (i) excellent gas-solid contact due to vigorous agitation of sorbent particles, (ii) minimum diffusional resistance, (iii) uniformity of temperature, and (iv) faster overall kinetics. Fluidised bed tests have been successfully conducted for the removal of CO₂ from flue gases (at a scale of 0.5 MW) for more than 700 hrs of continuous operation (Park et al 2011). Several regeneration options are available when using adsorbents to capture CO₂. Pressure Swing Adsorption (PSA) is common in cases where the feed is already at pressure (such as pre-combustion capture) or when the high energy costs associated with pressurising a low pressure feed are more than offset by improvements in system performance and capital costs.

Post-combustion capture from low pressure flue gas streams do not benefit from pressurising the feed stream. Instead, vacuum must be applied to the bed to remove the CO₂. This vacuum swing adsorption process (VSA) is appropriate for small scale capture plants and current research must address the very low vacuum levels needed (5kPa) to regenerate the bed and recover CO₂ at sufficiently high purity for sequestration. Other options for bed regeneration include thermal swing processes. Low quality heat can be used to regenerate the adsorbent bed either in the form of steam purge or hot CO₂ purge. The former is used in the TDA Advanced CO₂ Absorber.

The TDA Advanced CO₂ Absorber is a next generation adsorbent process reported in the 2012 NETL Report (NETL 2012). This process resulted in costs only slightly higher than those reported for the MTR membrane process (NETL 2012). The KIER “Dry Sorbent CO₂ Capture Process” has been trialed at 0.5 MWe and is the first pilot plant to show the feasibility of CO₂ capture technology using dry sorbent spheres (Park et al 2011, 2012, Yi et al 2013).

The drawbacks of the thermal regeneration process is the large time scale needed for heating and cooling the porous adsorbent – future research efforts must be directed at reducing this time scale so that larger size TSA units become practical.

Hybrid schemes employing thermal assisted vacuum swing adsorption processes are promising options for future adsorption based technology. All of these gas adsorption processes need appropriate materials with good CO₂ capacity, selectivity and thermal stability as well as tolerance to impurities and water.

A summary of the next generation equipment for gas adsorption is presented in Figure 9.

Gas Adsorption - Equipment

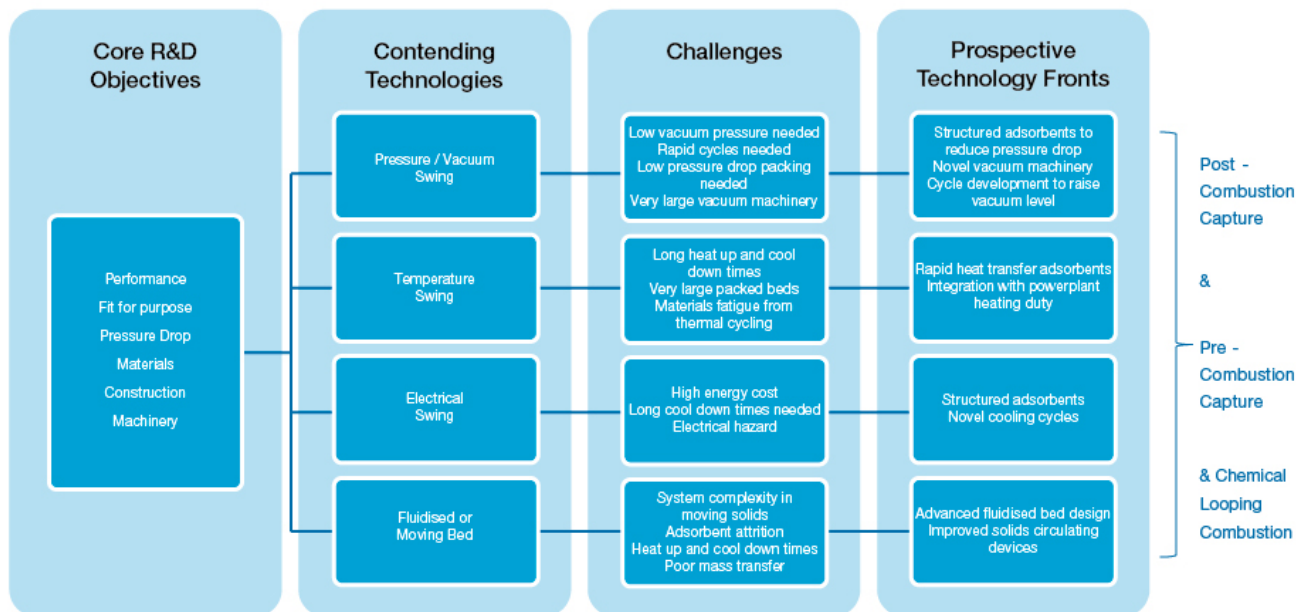


Figure 9 - Next Generation Gas Adsorption Equipment, Prospective Technology Fronts

3.3.3 Impurity Handling/Tolerance

Like membrane separation materials, gas adsorption materials will also need to be tolerant to various impurities including water.

Potential materials include ultra-stable alumina phases, hydrophobic zeolites, activated carbon, metal organic frameworks, organic-inorganic hybrids and solid sorbents.

Solid sorbents which are primarily inorganic materials will be tolerant to oxygen along with SO_x and NO_x present in post-combustion applications. However, water does influence the carbonation and regeneration reaction for alkali carbonate sorbents (Lee et al 2011).

3.3.4 Process Design and Heat Integration

The energy penalty for adsorption-based processes primarily comes from the heat required for temperature swing regeneration and/or the power required to drive vacuum regeneration. Reductions in the energy penalty can be made by using waste heat for regeneration and/or by reducing the pressure swing required. The next generation adsorbent process reported in the NETL study was the TDA Advanced CO_2 Absorber. This process resulted in costs only slightly higher than those reported for the MTR membrane process (NETL 2012).

3.3.5 Environmental Impact

Like membrane separation, there are no chemicals continuously used in gas adsorption, which also bodes well for low environmental impact. The environmental impacts will primarily come from the manufacture of the adsorbent materials and the energy required by the gas adsorption process taken from the power station. If the adsorbent materials are manufactured from organic materials, then the environmental impacts of degradation products such as nitrosamines may be an issue.

3.4 Chemical Looping Processes

Chemical looping processes are based on chemical reactions that take place in two different reactors and a reactive solid that is circulated between the reactors, thus the name looping. Different chemical looping processes are being studied or applied in small scale for application to CO₂ capture. They all appear attractive alternatives to other CO₂ capture systems, mainly due the potential lower energy penalty. However, none of the technologies have been proved at scales much larger than laboratory scale or small pilot and they all need further research or upscaling.

3.4.1. Chemical Looping Combustion

Chemical Looping Combustion (CLC) is an approach that is usually placed in the oxy-fuel category. It utilises a solid carrier, usually a metal oxide, which is able to adsorb oxygen from air and release it in the presence of a gaseous fuel such as natural gas. The oxidation takes place in what is commonly referred to as the air reactor and subsequent reduction takes place in the fuel reactor. The exhaust from the air reactor is N₂ and trace gases in air, from the fuel reactor CO₂ and H₂O. The net amount of heat generated over the two reactors is the same as oxygen during normal combustion. Some advantages of CLC over other technologies are:

- Almost pure CO₂ is ready for storage after condensation of the fuel reactor flue gas
- N₂ is removed before combustion
- Greater safety - combustion takes place without the presence of free gaseous oxygen.
- The energy penalty will be lower than other technologies, as there is no need for a separate air separation unit nor for scrubbing systems.

Some remaining challenges for CLC include:

- Finding an optimal metal oxide
- Developing reliable looping systems
- Obtaining efficient heat integration
- Application to solid fuel.

Comprehensive reviews of the status of CLC can be found in Adanez et al (2012), Pröll & Hofbauer (2011) and Bozzuto (2012)

3.4.2. Chemical Looping Reforming

Chemical looping can also be applied in a pre-combustion mode, as auto-thermal Chemical Looping Reforming, often referred to as CLR (Adanez et al, 2012 and Pröll & Hofbauer, 2011). CLR differs from CLC in that it is operated at understoichiometric conditions, i.e. insufficient air is added to the air reactor to completely oxidise the fuel. In addition, steam is added to the fuel reactor along with the fuel. The output of CLR is H₂, CO₂, CO and H₂O. Benefits and challenges for CLR are as for CLC.

3.4.3. Calcium Carbonate Looping

Calcium Carbonate looping (Blamey et al, 2010 and GCCSI 2013) can be used as a post-combustion CO₂ capture solution. Flue gas is fed to a carbonator with calcium oxide (CaO) that reacts with the CO₂ in the flue gas to form calcium carbonate (CaCO₃). The CaCO₃ is transferred to a calciner to which is then added air, heat and fuel. Advantages of the calcium looping process are:

- The output from the calciner is high purity CO₂.
- The exothermic heat of the CO₂ absorption reaction is recovered for use in steam generation, which reduces the energy penalty.
- The raw material (CaO/CaCO₃ found for example in dolomite and natural gypsum) is abundant and inexpensive.

Remaining work includes improving and understanding the reactivity of the sorbent, and research activities are needed to improve sintering of the sorbent and overcome challenges related to attrition and fragmentation of the sorbent and ash fouling in the calciner. Taiwan inaugurated the world's largest carbon capture plant employing calcium looping process technology in June 2013.⁵ Operating at one metric tonne of CO₂ per hour, it is reported that 90 percent of CO₂ produced during the cement manufacturing process is captured and requires less than 20 percent additional energy. There is potential to increase the scale of activity.

3.4.4. Sorption Enhanced Reforming (SER)

This process also uses CaO as an absorbent (Blamey et al, 2010). Fuel (natural gas or syngas from a gasifier) and steam is fed into the carbonator (or reformer), CO₂ is absorbed by the CaO to become CaCO₃, which in turn is transferred to the calciner (or combustor). Here air or oxygen is added, possibly with some fuel, and calcinated to CaO, which is returned to the carbonator under the addition of heat. Output from the carbonator is H₂-rich syngas and from the calciner CO₂-rich exhaust. The hydrogen can be used as fuel or for electricity production, thus this version of calcium looping can be regarded as a pre-combustion solution. Benefits and challenges are basically as for calcium carbonate looping.

SER has been patented for use in combination with a solid oxide fuel cell (SOFC) to produce electricity. Waste heat from the SOFC is used in the SER process, so that an overall efficiency of > 80% is claimed (ZEG Power 2013).

3.5 CO₂ Compression

Another example of significant equipment improvement is Ramgen "Shockwave" Compression. Ramgen Compression is expected to use less power and be less expensive than traditional in-line compression, which will again improve the cost of CO₂ avoided (Dreher et al 2011).

A summary of the next generation equipment for CO₂ compression is presented in Figure 10.

⁵ The plant was built in collaboration with Taiwan Cement Corp Situated in Sioulin Township, Hualien County—a cement production hub for Taiwan. Source : Taiwan Today 12 Jun 2013 <http://taiwantoday.tw/ct.asp?xItem=206192&CtNode=436>

Compression - Equipment

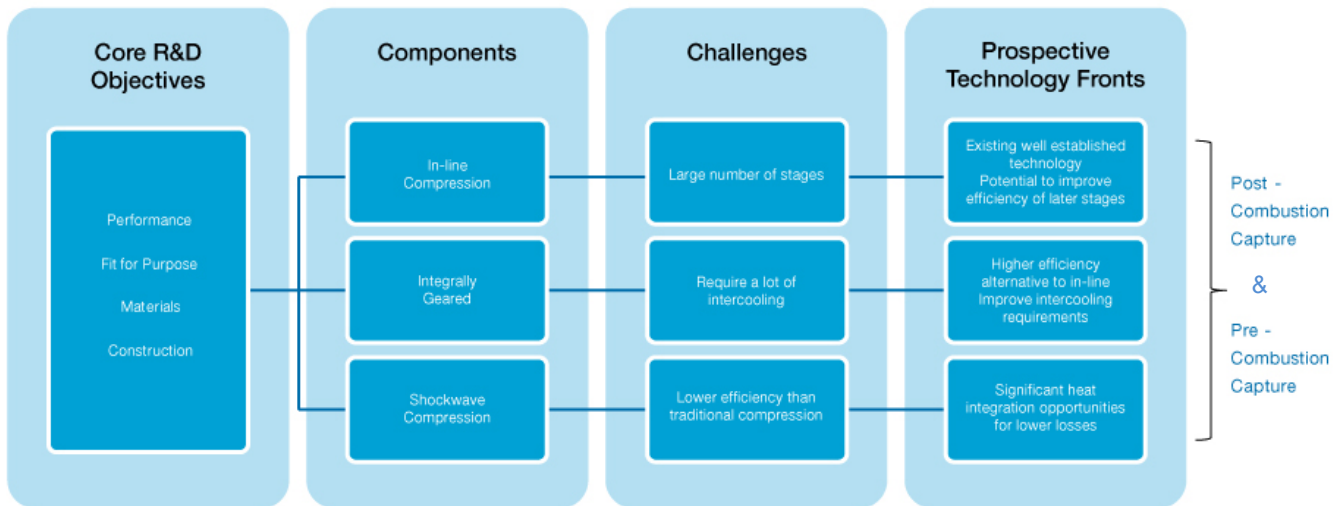


Figure 10 - Next Generation Compression Equipment, Prospective Technology Fronts

3.6 Future Directions

3.6.1 Technology Development Status at 2013

Figures 11, 12 and 13 show the current status of the technology development for solvent absorption, membrane separation and gas adsorption, respectively, using the generic Grubb Curve format (SBC Energy Institute 2012).

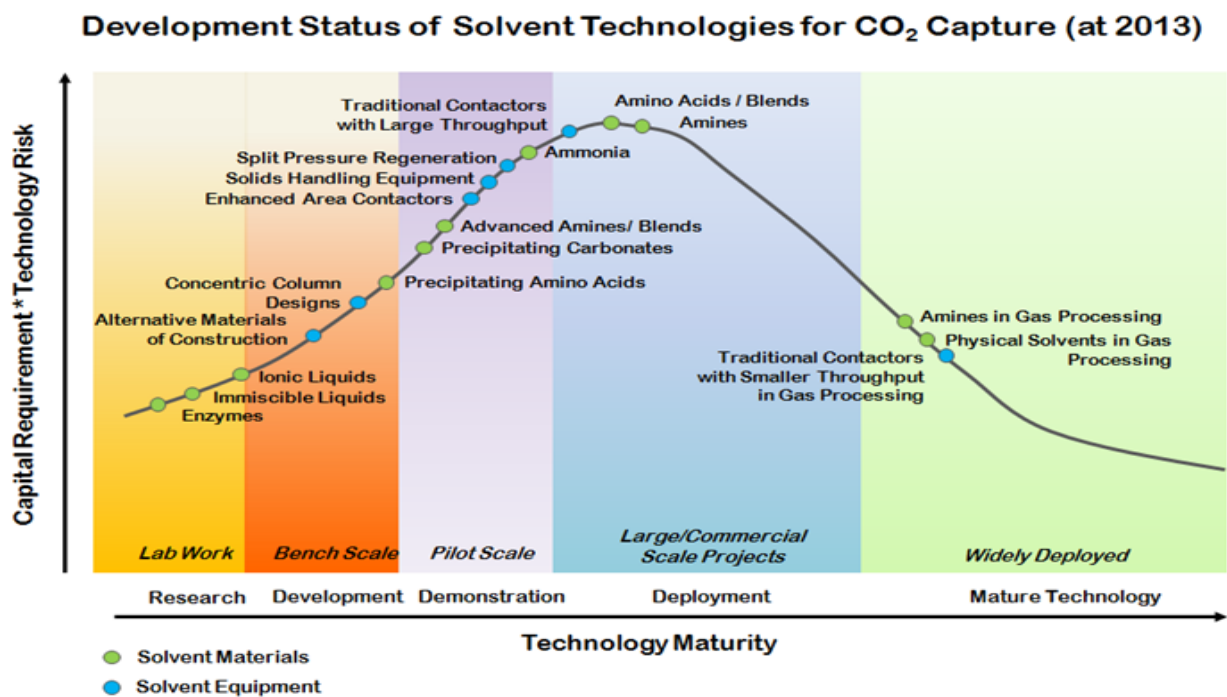
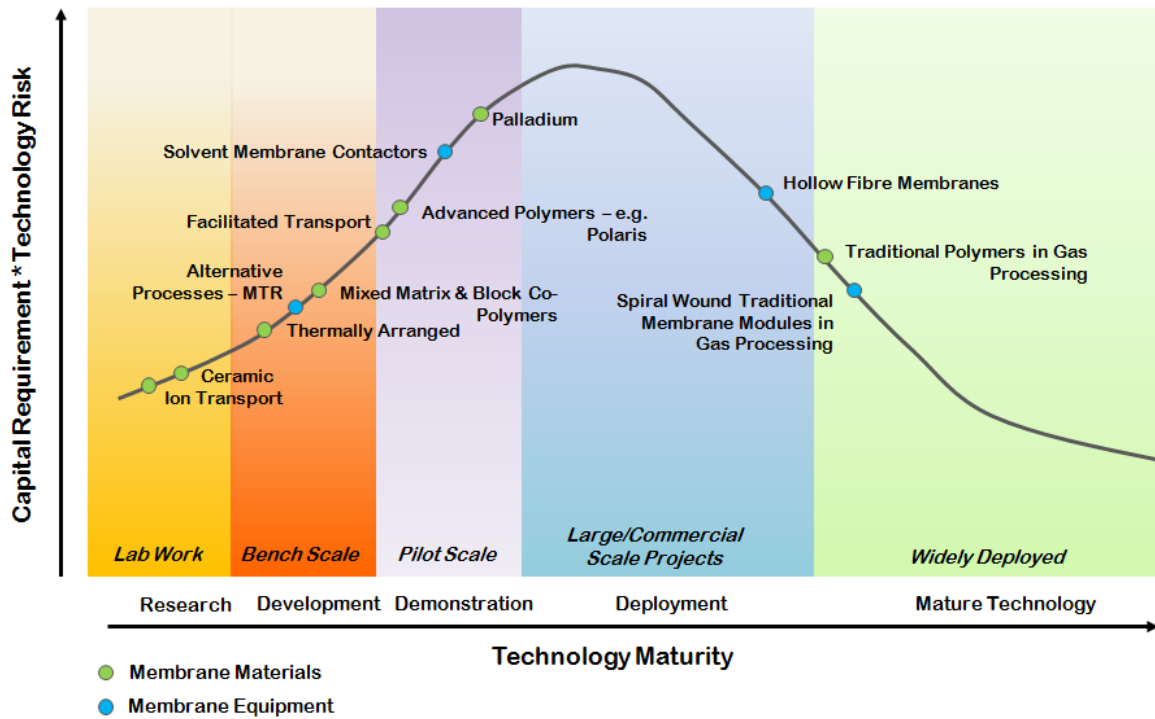


Figure 11 - Current Status of Solvent Absorption Technology

Development Status of Membrane Technologies for CO₂ Capture (at 2013)



Reference: Grub Curve from SBC Energy Institute 2012

Figure 12 - Current Status of Membrane Separation Technology

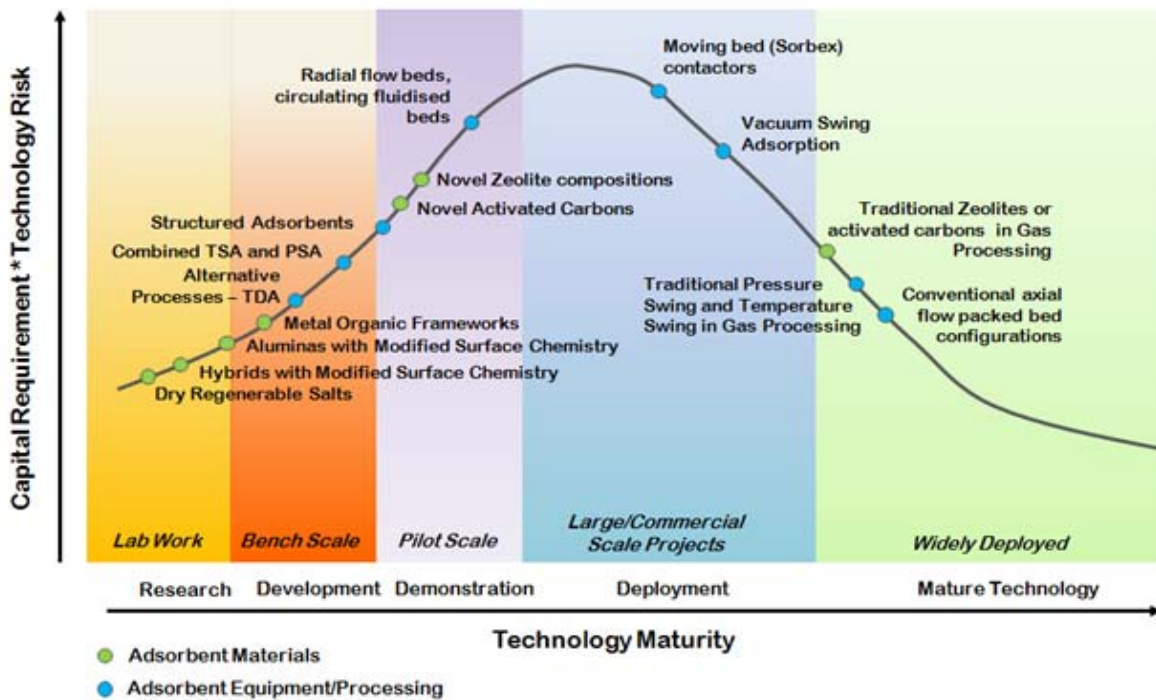


Figure 13 - Current Status of Gas Adsorption Technology

3.6.2 Technologies Beyond 2030

The larger scale CO₂ capture technologies in application beyond 2030 are likely to still be within the leading fields of solvent absorption, membrane separation and gas adsorption because of the research activities in these areas today. Other technologies such as cryogenics and chemical looping may be starting to appear although probably on a smaller scale and potentially associated with more advanced power generation systems such as pre-combustion and oxy-combustion capture.

The CO₂ separation materials used as part of solvent absorption, membrane separation and gas adsorption that will be employed beyond 2030 will be highly efficient, have low energy use and be tolerant to impurities. In addition, the CO₂ capture process will be highly integrated with the emission sources (such as power stations) to minimise overall energy losses. The combined characteristics of future CO₂ capture technologies should enable the significant cost reductions required.

Finally, CO₂ capture technologies beyond 2030 will have a low environmental impact such that installation of the CO₂ capture facility and reduction of the greenhouse gas emissions does not create other environmental problems (such as existing amine-based solvent absorption processes would do).

3.6.3 CCS Implementation Pathways

In addition to the technical innovation required to reduce costs, appropriate funding mechanisms are necessary to pull the technology forward from lab and pilot scale through to large scale development. This needs to be done through suitable policy frameworks which allow commercial progression in a timely manner.

The pathway of retrofitting existing power stations with carbon capture is considered to be important for the uptake of CCS. Retrofit pathways will be discussed further in Section 3.6.4. In addition, allowing flexibility in the design of carbon capture facilities such that the technology can be upgraded in future will also play a role in accelerating CCS as discussed further in Section 3.6.5. Finally, a list of the current pilot plants demonstrating CO₂ capture is given in Appendix A.

3.6.4 Retrofit and Flexible Operation with Energy Market Pricing

Retrofitting post-combustion CCS to existing power stations can provide important capital cost savings for the implementation of CCS. Studies completed by CO₂CRC suggest that retrofitting CCS to existing brown and black coal pulverised power stations may result in levelised costs of electricity (LCOE) 40% lower than new build power stations with CCS. This is due to the reduced capital requirements from using existing power generation equipment and the potential to effectively use waste heat to reduce energy penalties. While retrofit may not be possible in all cases it should be given serious consideration. Retrofitting capture may incorporate a repowering component that is designed as an integrated capture solution.

Retrofitting/repowering with CCS is being demonstrated such as projects like Boundary Dam. However, over time, it is expected that new build power stations with CCS will ultimately provide the most efficient solutions.

Modeling of post-combustion capture operating in environments where electricity markets are established, giving variable pricing, indicates that having the ability to change the rate of CO₂ capture can substantially lower the average cost of capture. For example, at times of the day with high electricity prices in an environment with low to moderate carbon prices it may make sense to stop capture and take as much value from the higher electricity prices, paying the penalty to emit more CO₂. At times of very low electricity prices, capture plant would be operated at full capacity to avoid the carbon prices.

3.6.5 Avoiding Technology “Lock-In”

Large scale CO₂ capture facilities which will be built in the coming decade are likely to use first generation capture technologies. These technologies may bring large energy penalties to the associated power stations or industrial sources depending on how they are configured, e.g. heat integration opportunities. The nature of basic absorption/stripping designs is such that new and improved solvents are likely to be able to be used in first generation plants. This is likely to avoid, or limit, so called technology ‘lock-in’. More elaborate new generation solvents (such as those using phase change) and novel technologies such as membranes and adsorbents will undoubtedly require different equipment configurations. Should this be an issue proponents may wish to consider the implications of these alternative generations technology in defining emissions reduction pathways.

3.6.6 Pilot Plant Facilities

Pilot scale trials are critical to taking the technology to the next stage. A list of the pilot plants demonstrating CO₂ capture are given in Table 1 in Appendix A. Several of the demonstration sites are now working together on collaborations.

Key Observations and Recommendations to the CSLF on Capture Technologies

1. A number of capture technologies are available today (mostly solvent based), deployed on large scale demonstrations or industrial processes; capture costs can be expected to fall to US substantially by 2025-2030, particularly if promising technologies are moved through the development pathway.
2. There is a need to continue to support 2nd and 3rd generation technology development, from pilot to large scale demonstration⁶, to secure the low cost technologies for the future, noting the lead times can run to decades. Adsorbents and membranes are likely to play a big role.
3. For all capture technologies improvements must focus on all dimensions: (1) materials, (2) equipment, (3) impurity handling/tolerance, (4) process design and heat integration and (5) environmental impact.
4. Retrofit of current coal-fired power stations can result in much lower cost electricity than closing viable stations and building new low emission coal-fired stations.
5. More work is required on the flexible operation of power plants with CCS synchronised with electricity market prices and links to renewable energy production.
6. Capture on natural gas combustion, an important new technology field, is opening up. This will play a major part linked to the new role of shale gas. Flue gas recirculation, low flue gas pressures and high oxygen contents will all be important research areas, as will oxyfuel combustion (see next chapter). New turbine design is also an important R&D front.

⁶ In USA, EU, China, Korea, Japan, competitions allow prospective capture technologies to compete for funding for large scale demonstration projects.

7. Chemical looping is an important emerging technology for some industrial process such as cement manufacture and also for fluidised bed combustion of coal; moving the technology to larger scales is a priority.

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4. Oxyfuel Combustion Technology for Coal- and Gas-Fired Power Plant

4.1 Introduction

Oxyfuel combustion for power generation with CO₂ capture is the use of oxygen and recycling of part of the flue gas instead of air as oxidant to the fuel. This results in a flue gas with very high CO₂ and H₂O concentration therefore requiring physical separation to deliver the specified purity of CO₂ for transport and storage.

With a number of research activities on Oxyfuel Combustion Technology (OxyCT), particularly for coal-fired plant application, this technology has reached a significant level of maturity. However, for the application of this technology to gas-fired power plant, it is still considered to be at an early stage of development.

This section of the report will cover the status of the technology and the identification of the gaps and opportunities for both coal and natural gas.

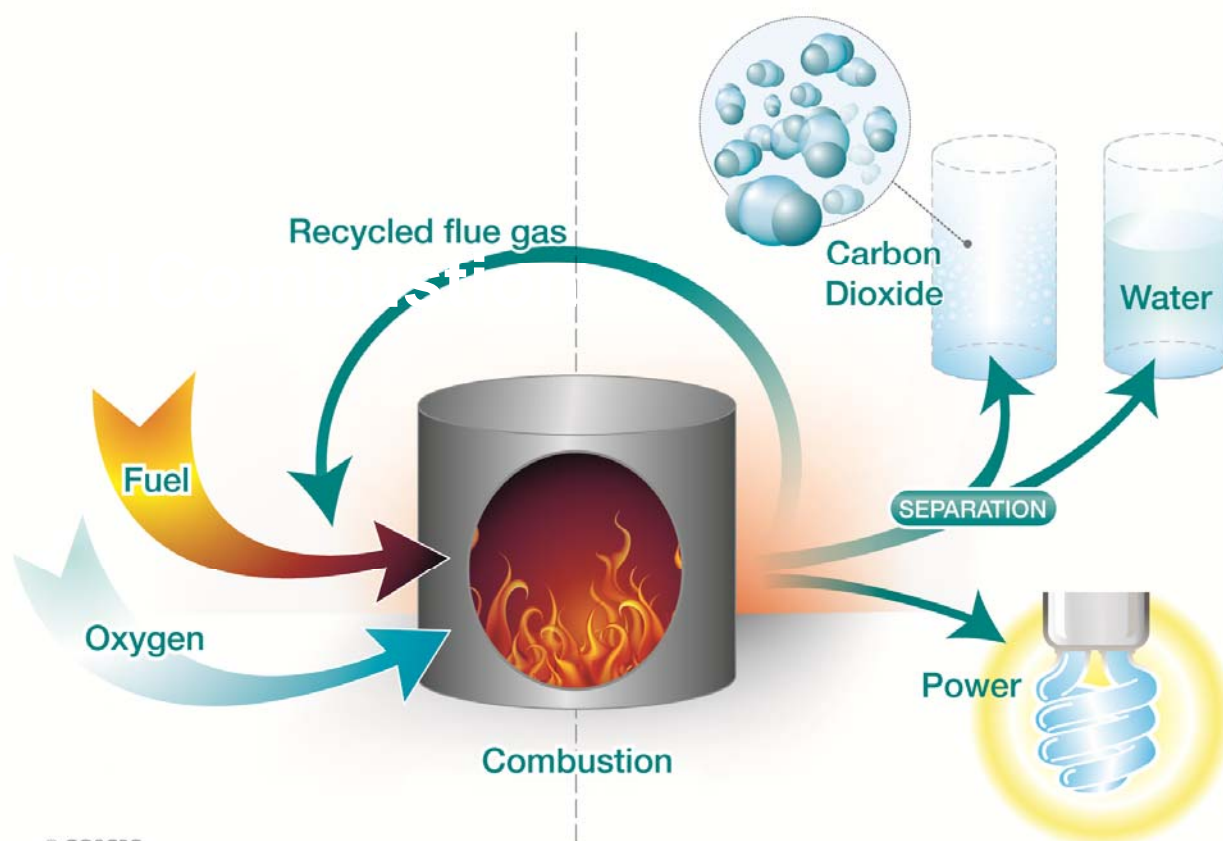


Figure 14 - Diagram showing the main components of Oxyfuel combustion technology

4.2 Oxyfuel Combustion for Coal Fired Power Plant

In the past ten years, significant RD&D investment has been made in the development of oxyfuel combustion technology for coal-based power production. The technology has reached a significant level of maturity and the next step is for it to be demonstrated in a large scale plant in order of 100 to 300MWe to benefit from learning by doing. This should provide the opportunity for the technology to develop enhanced efficiency and achieve lower cost and risk.

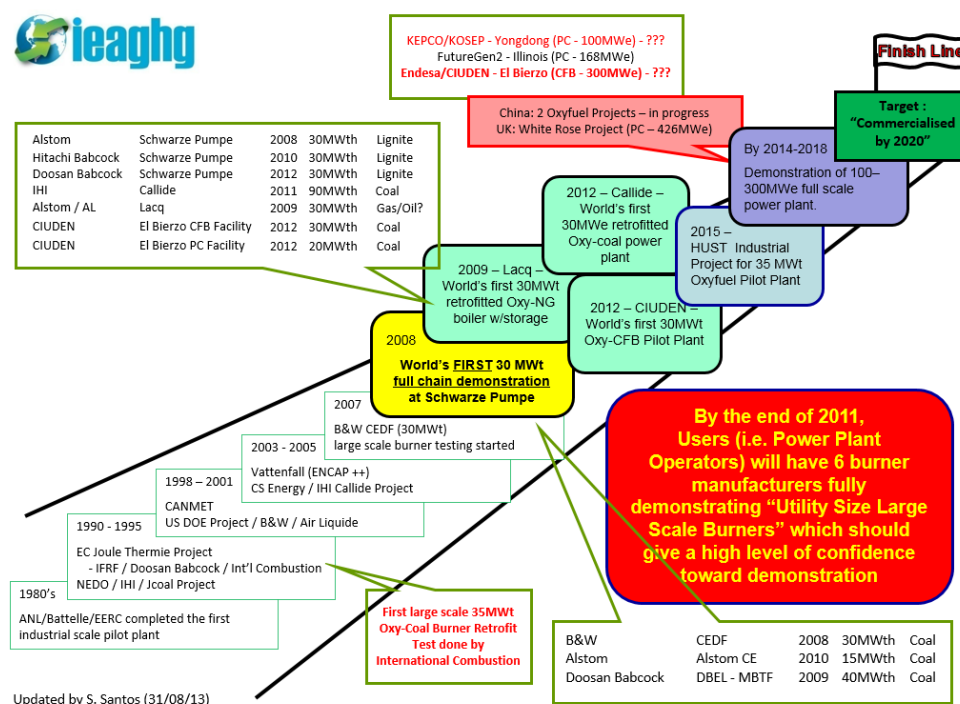


Figure 15 – Oxyfuel Combustion Technology - Timeline to Commercialisation [1, 2]

According to DOE/NETL reports [3-8], OxyCT has the potential to deliver the highest efficiency and lowest cost of CO₂ capture for coal-fired plants. A number of recent pilot and demonstration projects have shown OxyCT offers lower technology risk because the plant components are primarily conventional equipment modified for operation in oxyfuel mode. It can be retrofitted using existing plant and equipment, and output can be increased by heat integration [9-22]. The oxygen production and the CO₂ processing unit contribute to ~50-60% and ~30-40% of the total energy penalty respectively [6-7, 23-24]. Furthermore, this technology has the potential to reach near zero emissions and achieve greater than a 98% CO₂ capture rate [25-30]. One of its benefits over post-combustion capture on coal is that there are no new solvents or chemicals to be used within the power plant; therefore it, does not require low pressure steam extraction for solvent regeneration.

Technology development of Oxyfuel Combustion can be broadly divided into five key areas [2, 9]:

- Fuel preparation (particularly important for lignite to enhance efficiency)
- Boiler design and operation
- Oxygen Production
- Flue Gas Processing
- CO₂ Processing Unit (CO₂ Purification Unit/Gas Processing Unit)

Work done at Vattenfall's Schwarze Pumpe facility [31-41] has demonstrated that all components of this technology could be adapted to any coal fired boilers. Intensive RD&D activities worldwide over the past decade have succeeded in engaging a good number of OEMs that could provide commercial offerings of this technology.⁷

With the Vattenfall experience and the success at the Callide Power Station in Australia (demonstrating an Oxyfuel Boiler at 90MWth / 30MWe) [20-22], it is clear that not only is the technology proven, but it could be retrofitted to just about any coal fired boiler.

Additionally, the demonstration of the largest oxy-CFB boiler (30MWth) at CIUDEN's Technology Development facility expands the range of options for oxyfuel combustion coal fired power plant with CO₂ capture [42-44].

Successes at various large scale pilot facilities worldwide have provided a good basis toward scaling up of this technology to the 100 – 300 MWe scale.

For the new build power plant option, it is preferred to have a demonstration scale at 250-300MWe – as this is the smallest coal-fired boiler that is viable to provide steam at supercritical condition (a pre-requisite for any future plant for 600-1000MWe).

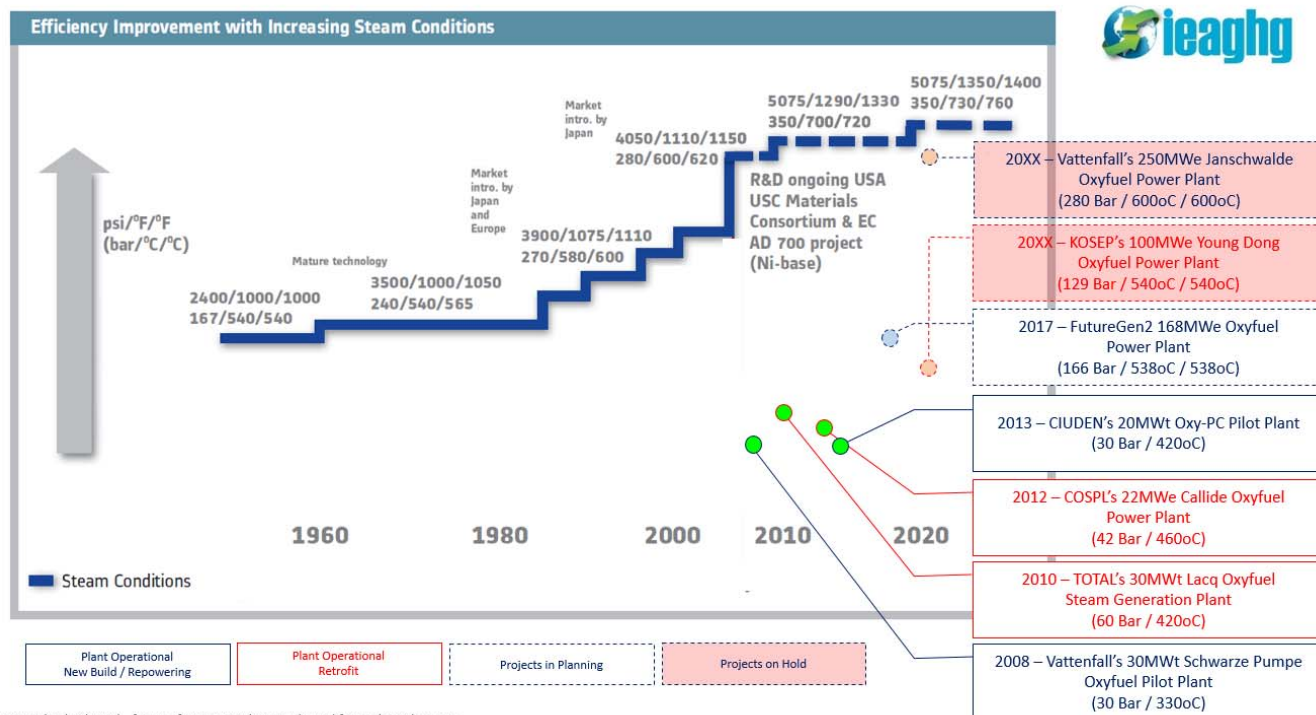
For the retrofit case, the experience from the Callide Oxyfuel Project is an important cornerstone for the demonstration of this technology. This project has proven that this technology could be retrofitted to an existing coal fired power station. Achievement of 10,000 operating hours at the Callide Power Plant by 2014 will be a major milestone, as this could be used as a reference to the various components of this technology by the participating OEMs. Work at Callide Power Station will be further enhanced if Young Dong Project in South Korea retrofitting a 125MWe coal fired power plant with oxyfuel combustion technology is implemented.

The next step in the development of oxy-CFB technology would be to demonstrate at a scale of 100-300MWe. This should provide opportunities to demonstrate the modular nature in the design of CFB boilers and its scale up principle which could be applicable to the scaling up of any oxy-CFB boilers. In addition, research work done under the O2Gen project in Europe involving the use of a lower flue gas recycle rate and higher oxygen concentration in the boiler could provide fundamental understanding in the development of next generation oxy-CFB boilers that could potentially reduce capital cost.

⁹ Note: there are six boiler manufacturers (Alstom, B&W, Doosan Babcock, Foster Wheeler, Hitachi and IHI) and four industrial gas companies (Air Liquide, Air Products, Linde and Praxair) capable of offering a suite of technologies that could demonstrate oxyfuel technology at the large demonstration scale.

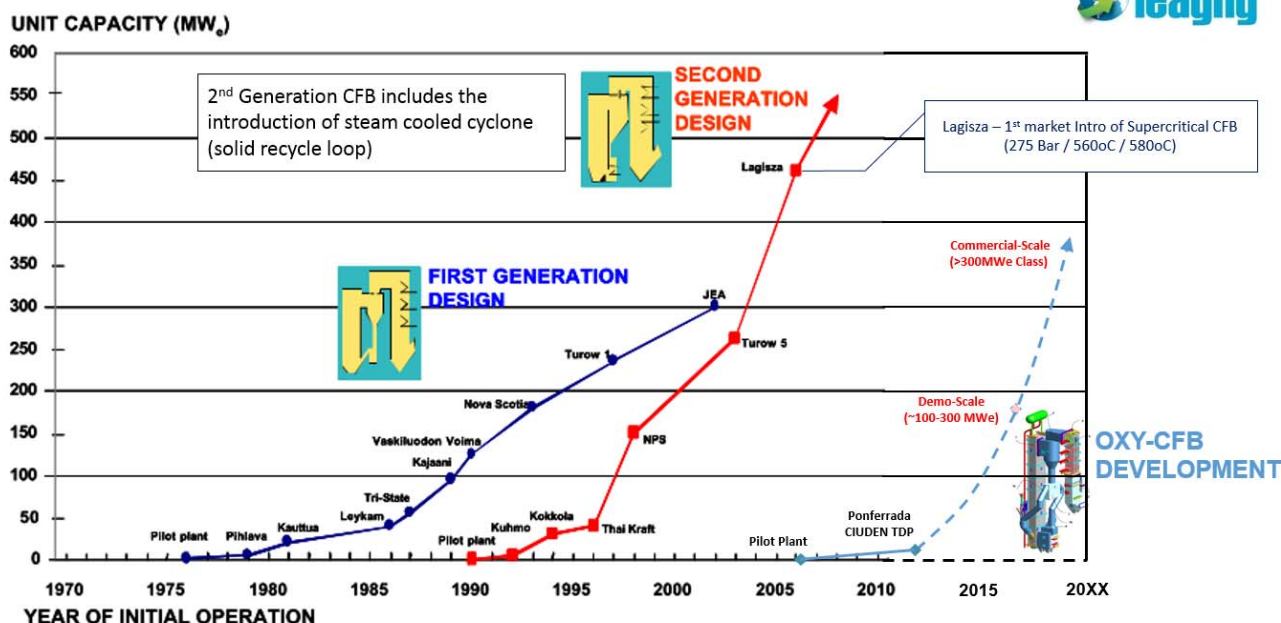
4.2.1 Development of Oxy-PC and Oxy-CFB Boilers

Development of PF and CFB boilers for coal fired power generation evolves over time from their demonstration to commercialisation (as illustrated in Figures 16 and 17).



S. Santos (31/08/2013) - figure of steam conditions adapted from Alstom's paper

Figure 16 – Development pathway of PF coal-fired boiler – also depicting the current status of oxyfuel combustion boiler development (Figure adapted from [45]).



S. Santos (31/08/2013) - figure of CFB development adapted from Foster Wheeler's paper

Figure 17 – Development pathway of CFB coal-fired boiler – also depicting the current status of oxy-CFB boiler development (Figure adapted from Foster Wheeler paper) [46].

It is expected that the development of Oxy-PC and Oxy-CFB will follow a similar development path to their air-fired counterpart. Thus, it is difficult to classify what is second or third generation technology as the overall technology concept is established on a learning by doing trajectory. Likewise, several designs and components used by conventional air-fired PC/CFB boilers are to be adapted to the Oxy-PC/CFB Boilers design and operation.

Figures 16 & 17 also illustrate the current status of the development in both Oxy-PC and Oxy-CFB boilers in relation to the air-fired counterpart. To reach commercialisation, the learning curve is expected to be steep.

Additionally, it should be noted that, unlike other leading capture technologies, development of oxyfuel combustion is “all or nothing”. One cannot just work with a slip stream of flue gas. The whole boiler needs to be changed.

The development pathway will be based on the coal types used resulting in variation to the design of the boiler and downstream flue gas processing units. (i.e. FF/ESP, de-SO_x and FGC) [11-13]:

- Lignite (various tests completed via projects at Vattenfall’s Schwarze Pumpe pilot plant)
- Sub-bituminous coal (various tests completed via projects by Alstom at CT, USA; Doosan Babcock at Renfrew; B&W at Ohio)
- Bituminous coal (various tests completed via projects by Vattenfall, Callide, and all the OEMs)
- Semi-anthracite/Anthracite (various tests completed or underway at CIUDEN’s TDP facility)

Areas for future development of this technology (for boiler), where development is always related to and based on a clear understanding of the combustion characteristics of the coal or other solid fuel, include:

- Coal with high Sulphur and Chlorine
- Coal blending
- Co-firing with biomass (from virgin to torrefied class; from easy to difficult)
- Co-firing with petcoke

Controlling the combustion is an important area of continued work. Oxyfuel has opened up several options for controlling the combustion including the control and location of oxygen and flue gas recycle injection, and flame stability at low flue gas oxygen. Use of warm flue gas recycling is another promising area of development as a way of improving efficiency. These are all optimisation issues that offer opportunities for improved performance and reduced maintenance, but by and large they will be vendor specific developments.

In terms of power generation, Vattenfall has reported that Janschwalde’s 250MWe Demonstration Plant could achieve 36% net efficiency – a penalty of ~8% as compared to power plants without capture [47].

Materials

For the first generation of Oxyfuel Combustion technology applied to coal or other solid fuels, the main consideration is the combustion characteristics of the fuel and the optimization of design and operation associated with that fuel [10, 11]. For the demonstration and first generation oxyfuel boilers, it is expected that conservative designs based on known boiler tube materials currently used by their air-fired counterpart will be deployed. Operation of the boiler (i.e. heat extraction rate) will be adjusted according to the dew point temperature of the resulting flue gas. Current development will focus on flue gas processing (of the recycled flue gas) to remove SO_x, NO_x, halogenated compounds, and water to reduce risk of material failures due to

corrosion. It is expected that future generation oxyfuel boilers will merge its development to the development of advanced USC boilers followed by their air-fired counterpart.

One key research areas is related to the development of materials used in advanced USC boilers. This includes research into the reliability of boiler tubes operating under oxyfuel combustion conditions (i.e. with very high concentration of acid components such as NO_x, SO_x, HCl, in the presence of high water content).

Some laboratory/pilot scale tests [48-51] have indicated that Austenitic steel and Ni-based alloys have experienced high oxidation rate under oxyfuel combustion particularly in the presence of both high Chlorine and SO_x (SO₂/SO₃) concentration. Likewise, metal carburisation of the boiler tube is another concern. Several material tests subjected to real or simulated oxyfuel flue gas conditions provided mixed results for both issues. Hence the mechanism that promotes higher oxidation rates or initiates carburisation under oxyfuel conditions seems to remain un-clarified, and understanding these mechanisms is necessary to develop boiler tube materials for advanced USC steam parameters (i.e. 300 bar / 700°C).

Equipment

The main focus of development is in the understanding of the combustion characteristic of the fuel operating under oxyfuel combustion conditions. Equipment (i.e. coal mill, burners, boilers and other auxiliaries) used by current air-fired boilers will be adapted to the operation of oxyfuel combustion. To achieve this, several research activities have been undertaken. Key areas of R&D include the following [9-22]:

- Understanding the coal devolatilisation and char combustion properties. (important for combustion control and flame stability);
- Modeling heat transfer (radiative and convective heat transfer);
- Evaluating the slagging, deposition, fouling propensity of the coal ash;
- Understanding NO_x and SO_x formation mechanisms;
- Development of low NO_x burners (important for reducing CO emissions);
- Evaluating in-furnace SO_x removal (i.e. adsorbent injection);
- Understanding the fate of trace elements (essential to establish Hg balance); and
- Development of burner scaling methodology for oxyfuel combustion application.

Many of these issues have been addressed by various R&D activities undertaken in the past ten years [9-22, 31-38]. Understanding of the fundamentals has been achieved with confidence, meaning that this technology is ready for demonstration. Nonetheless, just like any new build, re-powering or retrofit projects for coal-fired power plants; these are very fuel-specific properties which would require continuous evaluation even during the commercialisation of the technology.

Today, there are three large scale facilities that are capable of testing different PC burners at commercial scale (i.e. burner size of 20MWth and above); these include Alstom's CT facility (a platform for tangential firing boilers); the B&W OH facility (for wall fired boilers); and the Doosan Babcock Renfrew facility (for wall-fired boilers) [2, 16-17, 38, 52]. There are two large scale pilot plants (Vattenfall's Schwaze Pumpe; CIUDEN's Ponferrada facilities) demonstrating the full chain oxyfuel combustion technology [30-44]. One small demonstration plant (Callide Power Station) operating a full scale boiler; two trains of ASU; and a train of CPU processing 18% of the CO₂ rich flue gas from the boiler [20-22].

It has been established that the basic principles used in designing conventional coal-fired boilers and burners are also applicable to the design of oxyfuel combustion boilers [9-24]. Future work will follow the development

of advanced ultra-supercritical PC-fired boilers to higher temperatures and pressure (i.e. 300 bar / 700°C). Most of this work is related to material development as briefly described in the previous section.

Process Design and Heat Integration

There are several options where flue gas could be recycled to the boiler, dependent on the sulphur content of the coal. It has been suggested that the use of warm recycle of the flue gas contributes to some efficiency gains.

4.2.2 Development of Air Separation Units for Oxyfuel Combustion

The oxygen demand for oxyfuel combustion coal-fired boilers could be the largest among any large oxygen consumers today. Only cryogenic air separation unit could meet such demand. Other oxygen production technologies currently being developed are not mature enough to replace the cryogenic ASU.

The cryogenic air separation unit is considered one of the mature technologies within the CO₂ capture chain. For conventional ASU, it would be difficult to achieve any major improvement to the efficiency of this process. However, ASUs for oxyfuel combustion applications that deliver oxygen with low purity (i.e. 95 – 97% O₂) and low pressure (i.e. 1.2 to 1.8 Bar) have opened up opportunities for a step change improvement in energy efficiency [53-57]. It is expected that advanced ASU cycles using three columns or dual reboilers will be deployed as part of the development pathway.

Key to the development of the air separation unit is the demonstration of a large scale single train ASU (i.e. in the range of 5,000 to 10,000 TPD O₂). Today, the largest operating ASU is 3900 TPD O₂. A contract has recently been awarded to build the largest single train ASU at 5,250 TPD O₂ in India for gasification application. This is expected to be operational by 2015. This kind of commercial deployment will naturally feed into the development of large scale single train ASUs for oxyfuel combustion application, which should help reduce capital and operating costs.

Materials

Cryogenic air separation unit is a mature technology. Therefore, the main focus of the work is related to equipment and process improvement [57].

Nonetheless, development of novel oxygen production is currently on-going. In this area of research, the main focus is on the development of membrane and ceramic materials for high temperature oxygen production [58]. This is being developed in various labs and pilot scale facilities.

Equipment

The main cost and energy penalty of the ASU is the main air compressor (MAC). A 5,000 TPD oxygen plant requires approximately 700,000 Nm³/h of air. Although compressor manufacturers are confident of being able to design and manufacture these large compressors, the long term reliability of an ASU with these large compressors remains to be proven.

Future development will focus on further improvement of the main air compressor's efficiency (i.e. improved impeller design); and capability of wider turndown range for operating flexibility. Current compressors are limited to 75-80% turndown [53, 57].

Some of the key areas of development where improvements to the equipment could potentially provide efficiency gains and reduce capital cost include the following [53, 54, 57]:

- Improvement to the Front End Purification Processes. (i.e. packing selection for Direct Contact After Cooler – that could reduce pressure drop and minimise vessel diameter).
- Improvement to the main heat exchanger (i.e. use of brazed aluminum heat exchanger with larger core sizes and lower pressure drop).
- Improvement of the distillation column (i.e. use of high capacity structured packing that will lead to low pressure drop and smaller diameter).
- Improvement to the reboiler design (i.e. use of improved Thermosyphon reboiler design).

The selection of an appropriate ASU cycle is an important aspect of the delivery of an optimised CAPEX and OPEX air separation unit for oxyfuel combustion application.

Process Design and Heat Integration

Process design and cycle selection of the ASU is an important step in optimising the CAPEX and OPEX of the cryogenic oxygen production [53-57]. Generally, the leading options involve the use of either the three columns cycle or the dual reboilers cycle. In these advanced ASU cycles, energy consumption is achieved by reducing the pressure and the amount of process air needed to be compressed by the MAC.

Heat integration with the power plant is possible. Heat from the air compressor could be used for pre-heating boiler feed water. Published data has indicated that integration of an ASU to the Power Plant could lead to some efficiency gains [59].

Consideration of the use of waste nitrogen is another aspect where potential energy savings could be gained. However, this is a very site specific condition that would require available waste within the site (this could be applicable to industry such as steel mills).

4.2.3 CO₂ Processing Unit (CPU)

The CO₂ processing unit or CPU is the purification of the CO₂-rich flue gas before its delivery to the storage site.

Development of the CPU could be sub-divided into three key areas of research activity, namely [25-30]:

1. Pre-treatment of the CO₂ rich flue gas from the oxyfuel boiler (i.e. removal of SO_x, NO_x, particulates, Hg and water).
2. Use of an auto-refrigeration cycle using impure CO₂ as refrigerant.
3. Development of the process for additional recovery of CO₂ from the CPU vent.

The main challenge to the development of the CPU is the absence of established specifications for the CO₂. The design of the CPU (process and equipment) is governed by the amount of non-CO₂ components that will be allowed to be co-captured with the CO₂ for transport and storage.

On this basis, the following should be noted:

- CO₂ from the CPU will be expected to be bone dry (from < 1 to 10 ppm) as this is a process requirement for the cryogenic separation (i.e. removal of non-CO₂ components mainly consists of O₂, N₂ and Ar).
- Any NO_x and SO_x in the CO₂ rich flue gas are removed during the CO₂ compression.

- The paper published by Air Products [25, 27] recognising the reaction of NO_x and SO_x in the presence of oxygen and water producing sulphuric acids and nitric acids during compression (i.e. classic lead chamber reaction) is an important development of the previous decade that led to the development of wide variety of processes to remove these acidic components. For the purpose of simplicity, this removal process could be classified as the front end pre-treatment unit of the CPU. Depending on the technology vendors, the design of the NO_x and SO_x removal unit is also dependent on the design of the Flue Gas Processing Unit (i.e. Flue Gas Desulphurisation and Flue Gas Condenser) of the OxyCT.
- Removal of oxygen governs the overall process design of the cold box (i.e. main CPU cycle). This will be based on the principle of cryogenic separation. For oxyfuel combustion, a range of purity from 95% to 99.999% CO₂ could be designed for. Cost difference between 95% and 99% could be minimal depending on what could be offered by the technology vendors [59].
- Mercury⁸ is an operational issue to the cryogenic separation process (i.e. it could cause damage to any aluminium base equipment – BAHX, valves and expanders). It is expected that any forms of mercury are removed down to undetectable limit (i.e. this is analogous to the standards used in NG processing).

Materials

The development of the CPU should follow the same approach to its industrial or food grade CO₂ production counterpart. Therefore, like the ASU, the main focus of work is related to equipment and process improvement.

Equipment

Like the ASU, it is also expected that the CO₂ compressor takes up the majority of the cost and energy penalty of the process.

Unlike the other two leading capture technologies (i.e. post- or pre- combustion CO₂ capture); the CO₂ compressor is an integral part of the CO₂ processing unit. For the CO₂ compressor, centrifugal type compressor is expected to be the leading choice. The compressor used prior to the removal of NO_x and/or SO_x would require sour service. Ramgen Compression may not be applicable to oxyfuel combustion.

The use of CO₂ as a refrigerant is considered a mature technology. However, engineering data (particularly with the use of impure CO₂) is required. There are several CPU cycle patented by Air Products, Air Liquide, Praxair, Linde and Alstom [15, 25-30, 60-61]. Refrigeration is provided by using JT expansion valves (expanding impure CO₂). However, some OEM suggested the use of Expanders to recover energy during the refrigeration process. This will need further development to reduce capital cost. Demonstration of this technology in large scale operation is necessary.

Oxyfuel combustion technology could be designed to recover greater than 98% of the CO₂ emitted from the power plant [25-30]. This will involve additional equipment capturing CO₂ and/or O₂ from the vent of the CPU.

⁸ The removal of mercury is not a major concern for oxyfuel combustion as the majority of the oxides of mercury will be removed by the FF, FGD and FGC. Additional removal of mercury will be expected during the sour compression of the flue gas. Nitric and sulphuric acid are good reagents in capturing both elemental and oxidised mercury. Furthermore, a mercury guard bed will be installed in the CPU. The only problem encountered so far is the credibility of the Hg measurement techniques used conventionally which is significantly affected by the acidic components of the oxyfuel flue gas, resulting in inaccurate readings.

Most of this additional equipment is commercially available and mature, however it would require large scale demonstration. The process used to capture the additional CO₂ is described in the next section.

Process Design and Heat Integration

The process design for the removal of SO_x and NO_x prior to the cryogenic removal of the inert gases is dependent on the OEM vendors. The main principle in the development of the process is to take advantage of the tendency to convert any NO to NO₂ during compression. NO₂ could act as catalyst for the conversion of SO₂ to form SO₃ in the presence of water and oxygen. There are a number of vendor's approaches⁹:

- Air Products [25, 27, 41, 62] proposes the use of the Sour Compression Process (based on lead chamber reaction) to knock out 99% of the SO_x as H₂SO₄ and remove at least 95% of NO_x as HNO₃ and HNO₂ during the compression of the CO₂ rich flue gas.
- Linde [28-29, 63] proposes the use of the LICONOX process whereby 99% of the SO_x is initially removed at the FGD and/or FGC. The cleaned gas is compressed to 15 Bar to convert NO to NO₂; and then NO₂ is removed using an alkali wash (based on NH₃ water or NaOH). This would result in the removal of at least 95% of NO_x as spent salts of nitrite and nitrate. An option to reduce the salt loading is possible by preheating the salt solution to 60°C therefore reducing the spent salt of nitrite to N₂ and H₂O.
- Praxair [30] presented two possible options for pretreatment of the flue gas. The first option uses sulphuric acid wash to recover nitric acid. This would result to a clean gas containing 50-100 ppm SO_x and less than 50 ppm NO_x. The second option uses activated carbon to adsorb any SO_x and NO_x resulting to dilute acid during regeneration of the bed; with the resulting cleaned gas consists of less than 10 ppm of NO.

The separation of inert gas and CO₂ requires cryogenic separation. Different CPU cycles have been proposed by various OEM vendors [15, 25-30, 60-61]. The main development is based on an auto-refrigeration cycle using impure CO₂ as refrigerant. The design of the cycle is based on the required final O₂ content in the CO₂. Lower purity would require a simple flash separation column while higher purity requires the use of a distillation column.

The process design for capturing additional CO₂ from the CPU vent is dependent on the technologies developed by different OEM vendors. As discussed earlier, the additional capture would result in a high capture rate of greater than 98% and this also minimises the impact of the air ingress. Some of the processes presented by the different OEM vendors are described below:

- Air Products proposed the use of a CO₂ membrane ("Prism") where the permeate, consisting of CO₂ and O₂, is recycled back to the boiler. It is claimed that with this equipment installed, the oxygen requirement from the ASU could be reduced by 3-5% [25, 27].
- Linde proposed the use of PSA to further recover CO₂ from the vent gas of the CPU. The CO₂-rich gas recovered is recycled back to the dehydration unit of the CPU, while the remaining gas could be fed into the front end purification unit of the ASU. It is claimed that energy consumption of the CPU will increase by 6% as compared to the CPU without PSA installed. However, Linde have not reported the possible savings that could be gained in the ASU [26, 29].

⁹ Currently, there is no clear winner among the different technologies proposed by different OEM vendors. Technology is at the pilot stage. The main gap for development requires engineering data for scale up.

- Praxair proposed the use of VPSA to recover CO₂ from the vent of the CPU. The CO₂-rich gas recovered is recycled back to the sour CO₂ compressor just after the FGC. Praxair has yet to report on the performance of this process [30].

Heat integration with the power plant is dependent on the technology choice. For example, Air Products proposes the use of heat from the power plant during the expansion of the vent gas from the CPU to produce electricity, while waste heat from CO₂ compression could be used to pre-heat boiler feed water for the power plant [25].

4.2.4 Impurities and its Tolerance

The handling of impurities is an integral part of the oxyfuel combustion technology.¹⁰ From a holistic point of view, the removal of non-CO₂ components is defined by the following requirements: namely (a) removal of acid components in the flue gas prior to its recycling to the boiler to prevent any issues related to corrosion and carburization; (b) removal of the non-CO₂ components governed by the process requirements of the CPU; and (c) removal of the non-CO₂ components as defined by the requirements of transport and storage.

4.2.5 Environmental Impact Atmospheric Emissions & Water Pollutants

Oxyfuel combustion results in a near zero emission power plant; with regard to atmospheric emissions, CO emission is the only concern for the oxyfuel combustion coal fired power plant. It should be noted that the amount of CO produced is generally lower than its air fired counterpart. But CO concentration at the CPU vent could exceed the current concentration limit set in some jurisdictions; eg the EU Large Combustion Plant Directives. CO could be removed at the CPU vent using Catalytic Converters¹¹ [64]

As water is removed from the flue gas of the boiler, therefore it is expected that all the trace elements and acid components would end up in the waste water treatment plant of the power station. This is dependent on the technology choice for the flue gas processing unit and CPU.

¹⁰ For Post-Combustion Capture – the main concern related to the allowable O₂ content in the CO₂ (~100 to 300ppm for MEA) has yet to be addressed. For Pre-Combustion Capture – the main concern related to allowable H₂ and H₂S content in CO₂ and will also need to be addressed. Additionally, debate on the acceptable water content limit of the CO₂ is still on-going. Both concerns mentioned above are defined by the requirements of the transport and storage.

¹¹ CO has similar cryogenic properties to N₂, therefore it will just go straight to the vent. Depending on the regulatory framework regarding CO emissions this could be diluted using waste nitrogen from ASU as the cheapest option.

Technology and Engineering Fronts for Oxyfuel Combustion

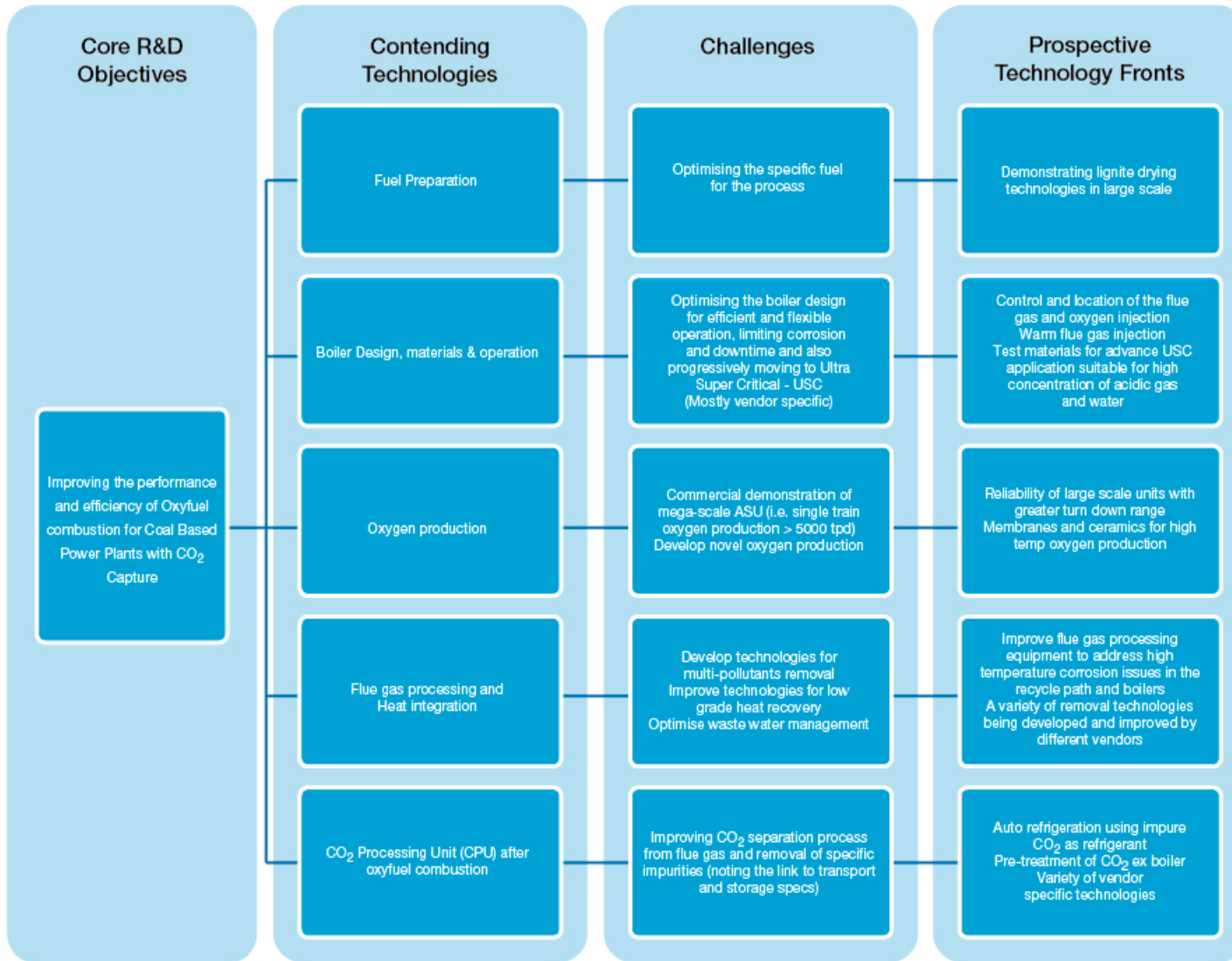


Figure 18 - Technology and Engineering Fronts for Oxyfuel Combustion for coal based Power Plants with CO₂ capture

4.3 Oxyfuel Combustion for Gas-Fired Power Plant

The emergence of shale gas has provided a strong driver for developing oxyfuel combustion technologies for gas-fired power plants.

Typical oxyfuel cycles would have the following features:

- Generally based on close to stoichiometric combustion using nearly pure oxygen mixed with recycled flue gas or steam;
- The working fluid mainly consists of CO₂ or water (or mixtures of both);
- Combustion would require pressurised oxygen between 10 to 300 bars, and oxygen purity ranging from 95 to 98% - depending on the type of GT cycle and the combustor design of the turbo machinery used; and
- If fired with natural gas, the CO₂ processing unit mainly consists of separation of water and CO₂. The amount of NO_x present in the flue gas depends on the GT combustor design and the purity of oxygen used. However, if fired with syngas (i.e. coal based oxyfuel combustion), the CO₂ processing unit requires removal of trace compounds such as SO_x and NO_x.

From the literature, there are several cycles proposed or under development. Examples of oxyfuel cycles using CO₂ as working fluid include the MATIANT [65, 66], Coolenerg [67], and COOPERATE [68, 69]. On the other hand, cycles using water as working fluid include CES Water [70-73] and Graz cycles [74]. Other hybrid cycles which don't require an ASU for oxygen production include the use of Chemical Looping [75-77] and AZEP cycle [78-79]. Additionally, research using ITM and OTM technologies for oxygen production are being evaluated.

For the purpose of analysing gaps in knowledge, only the oxyfuel cycles with advanced development (i.e. technology maturity toward large scale pilot demonstration) will be assessed and this is limited to the CES water cycle.

4.3.1 Current State of Development of CES Water Cycle

Clean Energy System (CES) Water Cycle [70-73]

The CES Water Cycle was developed using the principles of the rocket engine where the rocket engine's combustor is adapted to provide the main gas generator for the oxyfuel cycle.

Figure 19 shows the combustor/gas generator providing the working fluid to the steam and gas turbines; and Figure 20 presents the simplified process flow diagram of a 200MWe oxyfuel gas-fired power plant.

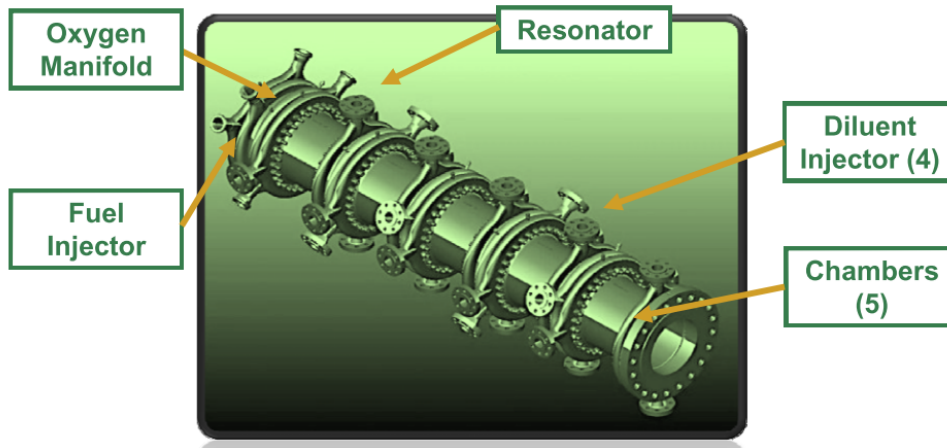


Figure 19 - 200MWth CES Combustor / Gas Generator (GG)

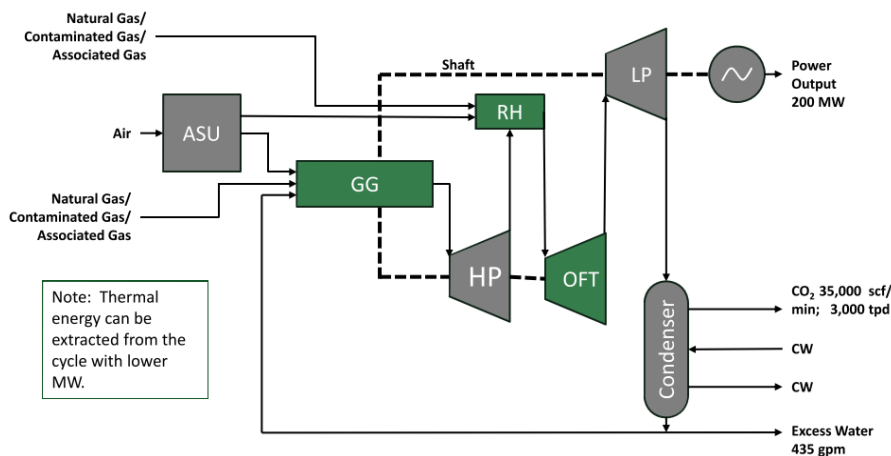


Figure 20 - Process flow diagram of the 200MWe Oxyfuel Gas Fired Power Plant

Typical working fluid generated by the combustor is about 80% water and 20% CO₂. The initial temperature of the combustor (i.e. first chamber) is maintained between 1650 and 1750°C; and the operating pressure is generally in the range of 50 to 100 bar. Temperature is moderated in the cooling chamber downstream of the combustor/gas generator by water or steam injection to match the operating inlet temperature of the high pressure (HP) steam turbine (normally between 500-610°C for current generation steam turbine, and up to 760°C for future generation steam turbine). The pressure ratio of the current generation HP steam turbine is about 5. The working fluid is reheated in an external combustor to provide a working fluid with a turbine inlet temperature (TIT) matching the capabilities of the intermediate pressure (IP) gas turbine or OFT. Typical TIT could be in the range of 700 to 1750°C depending on the operating inlet turbine temperature of the modified gas turbine to be used. The heat from the exhaust of the gas turbine is recovered via HRSG and the steam generated by the HRSG is delivered to the low pressure (LP) steam turbine; or the exhaust of the OFT could be used as the working fluid for the LP steam turbine (if temperature matches the operating temperature of available steam turbine).

CES has successfully developed and demonstrated the gas generator and modified GE J79 aeroderivative gas turbine (also known as OFJ79) providing a nominal power output of 40MWe. The nominal 220MWe is also demonstrated based on the modified Siemens SGT900 (also known at OFT900 or SXT150) gas turbine.

Future development of this technology includes (but not limited to) the following:

- Having demonstrated all the main components from 12 to 42 to 220MWe, the technology has reached the early commercial stage. The next step would be to demonstrate and validate its economic feasibility based on a large scale full chain power plant with CO₂ capture (having its own PPA).
- The potential to improve the efficiency of the CES Water Cycle technology depends solely on the development of two main components namely: development of the HP steam turbine operating at 760°C and the oxyfuel gas turbine with operating parameters similar to the H and J class gas turbine (i.e. with TIT at 1500°C). This should be followed by development of the gas turbine that could operate at TIT of 1760°C.
- Demonstration of this technology using gaseous fuel other than NG. This should benefit industrial users that could use low BTU off-gases or coal-based systems using gasifiers to produce syngas.

4.3.2 Oxygen Production

In the near term, it is expected that cryogenic ASU would be the only option to meet the demand of the oxygen required by the oxyfuel combustion NG fired power plant with CO₂ capture (for 220MWe using CES water cycle would require ~4600TPD O₂). For the CES Water Cycle, oxygen is delivered at pressure between 50 to 100 bar with O₂ purity ranging from 95 – 99% depending on the specification of the CO₂ to be delivered for transport and storage.


Consequently, ASU technology used in coal-based oxyfuel combustion power plant is not the same as the ASU technology to be used by the gas-based oxyfuel combustion power plant. The overall energy consumption is strongly dependent on the delivery pressure of the oxygen.

To improve efficiency of the oxygen production delivered by the ASU, the use of pumped LOX (PLOX) technology is required to deliver the oxygen at the pressure required by the process. Scaling up the LOX pumps to reduce cost is important to the development of the ASU for gas-based oxyfuel combustion power plants. Currently, the largest pump can only deliver up to 800 tpd.

4.3.3 CO₂ Processing Unit

For NG gas-fired oxyfuel combustion power plants, the CO₂ processing unit (CPU) is determined by the CO₂ specification required for transport and storage. Primarily, the main process consists of the dehydration of the CO₂ rich flue gas. However, one of the main factors that will govern the final design of the CPU will be the limits to oxygen and other inert gases (primarily Ar) in the CO₂ content. Given that operation of the gas-fired oxyfuel combustion power plant is nearly stoichiometric, it is feasible to remove residual oxygen content by catalytic combustion using hydrogen. This means that cryogenic separation of the inert gases may not be necessary. However, if there is a stringent requirement to remove Ar, the trade-off between the removal of Ar by using a cryogenic CPU process and the use of high purity O₂ should be evaluated.

For integrated coal gasification-based gas-fired oxyfuel combustion power plant, the CPU would require an additional pre-treatment process to remove trace elements such as NO_x and SO_x. The trade-off between removing sulphur compounds (as H₂S, COS, etc) in the syngas vs. its removal (as SO_x) at the CPU pre-treatment processes is a necessary evaluation step. Likewise, it is expected that removal of Hg would be done by pre-treatment of the syngas using sulphur impregnated activated carbon.



In general, the only environmental concern with respect to atmospheric emission will be related to the allowable CO emissions. This is strongly dependent on the operation of the burner of the combustor. Addressing this issue would be similar to how CO is removed in coal based oxyfuel combustion power plant.

Key Observations and Recommendations to CSLF on Oxyfuel Combustion

1. For Oxyfuel coal combustion the technology is mature; large scale (100-300MWe) plants are required to get both full scale up knowledge and also reduced costs from “learning- by-doing”.
2. Oxyfuel combustion of natural gas is an important new field that may well play a big part in CCS beyond 2030; improved turbine design is an important development dimension.
3. Air separation units are available to produce the oxygen required for both coal and natural gas combustion, but reducing the cost of oxygen production would have a major effect on overall Oxyfuel technology cost reduction.

Technology and Engineering Fronts for Oxyfuel Combustion

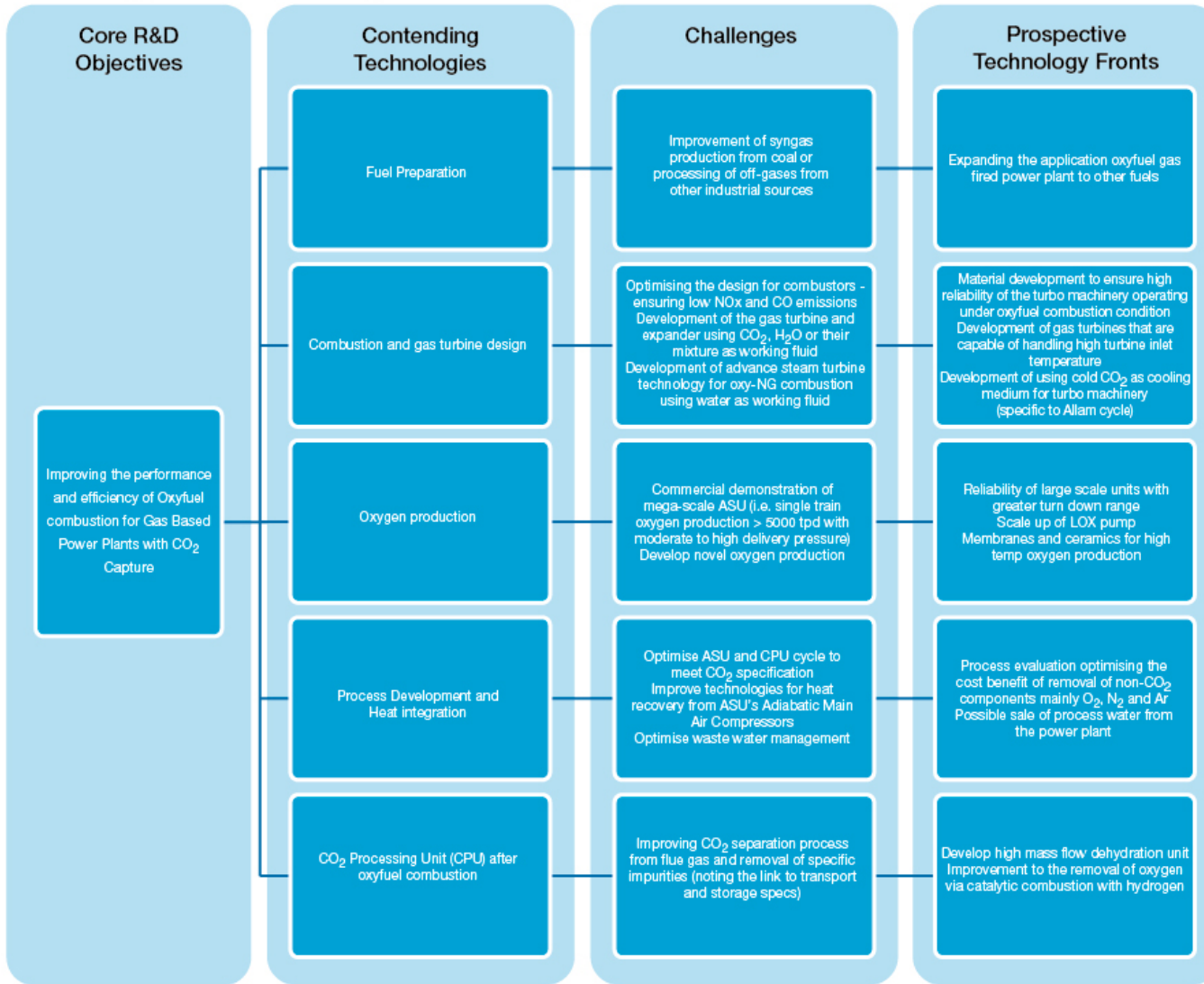


Figure 21 - Technology and Engineering Fronts for Oxyfuel Combustion for gas based Power Plants with CO₂ capture

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5. CO₂Transport Technologies

There have been a number of recent reports describing the status of transport technology for CO₂. The general overview is that the transportation of CO₂ is a mature technology:

5.1. Pipelines

In the US there are around 6500 km of onshore pipelines, representing 36 pipelines, transporting 48 – 58 Mtpa of mainly naturally sourced CO₂ for enhanced oil recovery purposes (GCSSI 2012). The first CO₂ pipeline built in the US was in 1964; over 40 years of operational experience has been gained (Energy Institute 2010). The longest CO₂ pipeline built in the US is the Cortez Pipeline at 800 km long and with a capacity of 20 Mt/yr (Demofonti & Spinelli, 2011)

The only offshore pipeline for CO₂ is part of the Snøhvit project in Norway. The pipeline is 153 km long and has been operational since 2008 (GCSSI 2012). The CO₂ is removed from natural gas streams and re-injected into the gas reservoir.

5.2. Road Tanker

CO₂ transportation by road tanker has been standard practice for over 40 years Each tanker can hold up to 20 tonnes of CO₂ (Energy Institute 2010).

5.3. Ship

LPG and LNG have been shipped around the world in tankers and it has been argued that there will be very little difference in transporting CO₂ this way (A.Verder). There are six ships, with capabilities in the range of 8,500 m³ to 10,000 m³, certified for carrying industrial and food grade CO₂ at optimum pressure and temperature for highest transport efficiency. This transport has led to the development and operation of a ship logistics system in Europe over the last twenty years. As an example of the industry's safety performance it has been estimated that more than 5,000 ship years have already been performed without a cargo related accident (Energy Institute 2010). These statistics go some way in highlighting that CO₂ transport via ship is a proven technology¹². Ship transport may be important in an initial market where trunk pipelines are not in place. Ships may also play a role in CO₂-EOR if CO₂ is needed for a limited time only. Preliminary designs have been suggested for up-scaled CO₂ tankers.

Preliminary feasibility studies on CO₂ shuttle shipping with direct injection of CO₂ from the ship (Chiyoda Corporation 2011) have shown promise as a technology that could offer shorter lead times for transport and storage of CO₂. There could be potential for this direct injection from the ship in areas that have multiple CO₂

¹² For ship transport, post-combustion capture will be penalised most as this would require external refrigeration for liquefaction. For pre-combustion, Selexol will be disadvantaged compared to Rectisol. Oxyfuel Combustion and the Rectisol process will be the most favourable for capture technology when ship transport is involved.

sources along the coast, such as Japan, and in areas where there are multiple smaller scale geological storage sites offshore.

5.4. Issues

CO₂ transport has been associated with pure or natural CO₂ that has been used for EOR. Transport of anthropogenic CO₂ (e.g. from Power Plants) will contain co-products not previously transported. Typical impurities generated from capture technologies not covered by EOR pipeline specifications include CO, NO_x, SO_x, H₂ and Ar. Other impurities that need to be considered are H₂S, N₂, CH₄, O₂ and the water content. These impurities affect the behaviour of the dense phase fluid, the preferred form of CO₂ for long distance transportation. The fluid's behaviour is described by equations of state which need improving for specific CCS applications.

Transport of CO₂ has been from single point source to single point-use/storage. For CCS pipelines the CO₂, whether from a single source or collected from a hub, may have a differing composition over time which would need to be controlled to an agreed fluid composition.

Anthropogenic CO₂ will contain impurities and be captured from a variety of sources. This may cause problems with composition and flow rate control and care will be required to avoid circumstances that could produce operational and safety problems.

All but one existing pipeline are onshore, and the majority of those onshore pipelines run through remote areas with a low population density. Pipelines running through more populated regions will have tighter safety requirements governing pipeline integrity.

Up-scaling of the infrastructure and transport technology required for large-scale, commercial projects. There are 6,000 km of CO₂ pipelines in the US compared to 490,000 km of natural gas pipelines (Energy Institute 2010). In Europe some estimates for the up-scaling required for CO₂ transport is between 30,000km – 150,000 km of pipeline, more than a 10-fold increase in pipeline lengths compared to current world wide installations (Energy Institute 2010). The infrastructure required for the transport of CO₂ will vary significantly between each CCS project, but research is underway to optimise the efficiency of these networks by clustering hubs of CO₂ emissions sources and developing CO₂ transport networks utilising existing pipeline routes or infrastructure corridors in Northern Europe and the North Sea (SCCS 2012) and Australia (Geoscience Australia 2013)

There needs to be a legal framework for the design, operation and maintenance of dense phase CO₂ pipelines, and other transport modes, which will set technical constraints.

In Australia, the Standard AS2885.1 Pipelines: Gas and liquid petroleum - Design and Construction, 2012 has an informative appendix covering CO₂ pipelines. However, there is some research indicates a need to improve the understanding of the safe and efficient design and operation of CO₂ pipelines. This relates to the prediction of CO₂ dispersion from potential leaks and to the equations of state for the range of compositions encountered.

Largely because of the public's unfamiliarity with CO₂ pipelines there may be challenges with public acceptance, which requires detailed work at the route selection stage of a project

5.5. Major International Research Programs on CO₂ Pipelines

EUROPE

European Commission Research Fund for Coal and Steel (RFCS) project: Requirements for safe and reliable CO₂ transportation pipeline (SARCO2)

- Project partners: CSM (Italy), CMFG (Germany), Europipe (Germany), Salzgitter Mannesmann Line Pipe (Germany), V&M Deutschland (Germany), Corinth Pipeworks (Greece), eni S.p.A (Italy), GDF Suez (France), National Grid (UK).
- Co-funded by the European Pipeline Research Group
- Project aim: develop specific requirements and design criteria of steel pipes for anthropogenic CO₂ transportation pipeline systems (including also crack arrestors and composite reinforced pipes) and create the basis for proposing European Guidelines for safe design and operation of anthropogenic CO₂ pipeline networks.
- Specific goals
- Definition of toughness requirements of base material to control running ductile fracture propagation
- Definition of requirements to control crack initiation event also considering corrosion and stress corrosion cracking phenomena
- Collect experimental data related to the release of CO₂ during a pipeline failure

Materials for Next Generation CO₂ Transport Systems (MATTRAN) project

- Newcastle, Nottingham, University College London (UCL), Leeds and Cranfield Universities
- Funded by the Engineering and Physical Sciences Research Council (EPSRC) and E.ON

IEA Greenhouse Gas R&D Programme, UK: COSHER (Carbon Dioxide, safety, Health, Environment and Risks)

- A Statoil/Gasunie initiative to establish a collaboration of European stakeholders to carry out a large scale CO₂ release experiments and measurements program to obtain data that can be used to improve and validate safety models for CO₂ pipelines

COOLTRANS (Dense Phase CO₂ PipeLine TRANSPORTATION) consortium

- National Grid (UK) funded project, started 2008 and about 50% complete
- £8 million
- Aim: establish and demonstrate the requirements for the safe design, construction, operation and maintenance of dense phase CO₂ pipelines to allow the development of a comprehensive safety justification for the onshore pipeline transportation of dense phase CO₂
- Project has 6 work streams:
 - Thermodynamic and flow characteristics of dense phase CO₂
 - Fracture control
 - Quantitative risk assessment

- Pipeline design and integrity
- Environmental and social impact studies
- Application of research findings

INTERNATIONAL

CO2PIPEHAZ Research Program: Quantitative Failure Consequence Hazard Assessment for Next Generation CO₂ Pipelines

- UCL, Leeds University, UK Health and Safety Executive (HSE), National Research Centre of Physical Sciences (Greece), Dalian University (China), INERIS (France) and GEXCON (Norway)
- Funded by the European 7th Framework

CO2PIPETRANS Joint Industry Project (JIP)

- Coordinated by DNV
- 15 international partners including operators, suppliers and regulators
- Aim is to close significant knowledge gaps through the collection of data mainly from experimental work and to then incorporate this into an update to the existing Recommended Practice for the Design and Operation of CP2 pipelines DNV-RP-J202

USA AND CANADA

Pipeline Research Council International (PRCI) [US based pipeline research group which is connected to the Energy Pipelines CRC] project on shock tube testing of dense phase CO₂ at the TransCanada Gas Dynamic Test Facility in Canada. This work was funded by a consortium including the Energy Pipelines CRC.

AUSTRALIA

Energy Pipelines CRC CO₂ Pipelines Research

- Funded by the Department of Resources, Energy and Tourism
- \$1.636m over 3 years
- Work being done by the University of Wollongong, Monash University, ANU, Acil Tasman and the consultants Peter Tuft and Phil Venton
- Developed the Appendix to AS2885 incorporated into the Standard in 2012
- Research projects with the aim of developing and filling gaps to allow a CO₂ pipeline to be designed and operated to AS2885:
 - Equations of state
 - Pipeline decompression
 - Modelling CO₂ dispersion
 - Determine limits for water content in CO₂ mixtures for safe transport in carbon steel pipe
 - Public safety, community consultation and organisational requirements for CO₂ pipelines

- Cost – benefit study of the application of the results of the research

Key Observations and Recommendations to CSLF on Transport

1. Transport pipeline technology is mature and available.
2. Large scale transport of CO₂ by ship offers promise and needs to be demonstrated at scale.
3. Fine tuning technology fronts include: managing and designing for variations in CO₂ composition in multiple source hubs (includes understanding equations of state and operational implications), fracture propagation control and CO₂ dispersion modelling for safety case and risk assessment purposes.
4. Experience is needed in planning, designing and implementation of large-scale CO₂ transport networks, including hubs and multiple points of capture.

5.6. References

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6. CO₂ Storage Technologies

CO₂ storage technologies are underpinned by well-established technologies used by the oil and gas industry. Fundamental research over many decades on the formation, movement and extraction of oil and gas has created an outstanding body of deep-seated knowledge. This has been applied and refined by industry around the world. Continued significant investment in next generation technologies has resulted in an oil and gas industry utilising very sophisticated technology that is continually evolving. This is the starting point for understanding and developing the technology associated with carbon storage (Benson and Cook, 2005; Ambrose et al, 2008).

The fundamental research in oil and gas behaviour in the subsurface is strongly informing the essential research and associated laboratory work in CCS. CO₂ has different properties to oil and gas and rather than extracting large volumes, the focus is on injecting significant volumes, this has implications for storage site selection, including understanding storage capacity, injectivity and containment potential at each site. A significant amounts of knowledge related to CO₂ can be gained from the science and technology associated with the injection and monitoring of CO₂ and other gases and liquids in enhanced oil recovery (Kaldi and Gibson-Poole, 2008). As in all operations, safety issues are reliant on specific parameters; in CO₂ storage these may be different to those conventionally used in the oil and gas industry.

This rapidly growing body of knowledge in the oil and gas industry, combined with the emerging laboratory and pilot scale studies in CO₂ storage (as well operating projects) gives immense confidence in the ability to safely store very large volumes of CO₂ in the world's sedimentary basins¹³. There is a strong consensus that safe CO₂ storage is possible today based on current technologies. This is reinforced by that fact that there are eight projects in operation globally and nine in the execution phase (GCCSI, 2013), noting that many of these are EOR projects.

There are however aspects where research and operational experience can optimise exploration regulatory and operational outcomes. This section looks at both the fundamental laboratory and pilot scale work on the behaviour of CO₂ in the subsurface (Fundamental knowledge in Table 2) that is underpinning the emerging technology of carbon storage, but also the application of large scale assessment, operations and monitoring (Applied Knowledge in Table 2). Large scale operations are creating both new knowledge in the applied space but will also define fundamental research needs to further improve operational deployment of CCS in the future. These are the typical dynamics of continuous improvement that occur in all large industrial processes.

¹³ It is to be noted that this report recognises that CO₂ storage in unconventional storage systems, such as basalts, shales, mudstones and carbonates is a research front. However, due to the very site specific nature of the geological storage of CO₂ within these unconventional systems and the long time frame for research and development of these sites, the report focuses on the more near-term research fronts in deep saline aquifers and depleted hydrocarbon reservoirs.

Fundamental Storage R&D	Applied Storage R&D				
	Basin Scale Analysis	Site Selection & Characterisation	Injectivity and Operations	Managing & avoiding migration variance	MMV and Accounting
Storage Geology <ul style="list-style-type: none"> • Top seal characterisation • Fault seal characterisation • Discontinuities & heterogeneity • Upscaling for large sites • Rock characterisation – caprocks & reservoirs • Saline aquifers/ depleted O&G reservoirs 	<ul style="list-style-type: none"> • Optimising storage resource • Managing imperfect data • Size of storage complex – resource conflict 	<ul style="list-style-type: none"> • Storage limits characterisation • Managing high uncertainty • Assessing structural traps vs stratigraphic traps • Hydrostratigraphy • Faults as trapping mechanisms • understanding confined and laterally unconfined aquifers 	<ul style="list-style-type: none"> • High permeability thief zones and profile modification • Operating relative to seal limits • Well bore orientation to optimise efficiency • Optimisation (number of wells, capacity & permeability) 	<ul style="list-style-type: none"> • Modelling release of trace elements • Induced seismicity risk 	<ul style="list-style-type: none"> • Appropriate / fit for purpose data acquisition for characterisation • Reduction of MMV surface footprint • Detection versus quantification of leakage and how accurate it is possible to be.
Subsurface CO₂ Behaviour <ul style="list-style-type: none"> • Appropriate modelling • Temporal / spatial changes in chemistry, pressure, stress prediction • Residual & solution trapping effectiveness • Geomechanical and hydrodynamic 	<ul style="list-style-type: none"> • Analytical solutions for fluid flow • Impacts outside storage complex • Dynamic capacity • quantify connectivity and continuity of intraformational baffles & seals- Hydraulic monitoring 	<ul style="list-style-type: none"> • Risk and uncertainty based modelling • Along fault leakage • Impacts of Mineral Associated Trapping (MAT) 	<ul style="list-style-type: none"> • Storage Management: <ul style="list-style-type: none"> - Optimising pore space resource - Optimising injection rates and maintaining reservoir integrity • E factor for storage efficiency • Leak-off Tests (LOT) to optimise injection 	<ul style="list-style-type: none"> • Pressure relief / management modelling • Geoen지니어ing/ 'plume steering' • Monitoring for brine displacement • Subsurface intervention 	<ul style="list-style-type: none"> • performance verification • MMV-based long term model forecast calibration • understanding the amount and saturation of CO₂ relative to geological parameters to visualise/recognise the plume.
MMV Technologies <ul style="list-style-type: none"> • Seismic & EM • CO₂ sensors atmosphere • Other geophysical • Tracers 	<ul style="list-style-type: none"> • Effective large scale assurance monitoring • Hydrodynamics • Methods for monitoring groundwater resources that command general consent 	<ul style="list-style-type: none"> • Effective baseline duration 	<ul style="list-style-type: none"> • Effective performance monitoring • Far field effect MMV • Lack of injectivity software 	<ul style="list-style-type: none"> • Above zone monitoring • Well integrity evaluation • Marine monitoring • Data sets for leakage models (natural systems) • Determining the origin of potential leakage • Data sets to calibrate & test behaviour of tracer / CO₂ in lab and field. 	<ul style="list-style-type: none"> • Developing continuous, high resolution low cost, low impact subsurface monitoring • Technology and methodologies for offshore (sub marine) & land surface MMV • calibrating M&V with controlled releases

Table 2: CCS Storage R&D Gaps/Opportunities: fundamental and applied technology

Table 2 sets out three key areas in fundamental storage research where opportunities for improvement in understanding have been identified:

- Understanding the geological basis and constraints for CO₂ storage
- Understanding CO₂ behaviour in the subsurface. This is relevant to both reservoir scale and basin scale issues associated with carbon storage (see Figures 22 and 23 for the prospective associated research fronts).
- Optimising and adapting current MMV techniques and developing new techniques specifically for CO₂ storage

The growing knowledge base from these three areas and the deep knowledge base from the oil and gas industry are the underpinnings of the applied technology required for carbon storage. The framework of applied stages of CO₂ storage project discovery and operation used in this report are:

- Basin Scale Assessment
- Site Selection and Characterisation
- Injectivity and Operations
- Management and Risk Assessment
- Measurement, Monitoring & Verification (MMV)

6.1. Fundamental laboratory and bench scale research on storage

This work is mainly associated with understanding CO₂ at the micro scale (interaction with pores and minerals in the reservoirs and seals – Ferer et al, 2002) which in turn is used to interpret CO₂ movement and behaviour at the core/log scale, the storage site scale and ultimately the basin scale. This fundamental understanding is essential for the proper prediction of CO₂ movement and stabilisation over both the short periods of time necessary for efficient operational management but also the longer periods of time in defining and delivering final safe storage.

The main areas of laboratory and pilot scale research and development are:

- Understanding CO₂ movement and fluid flow, geochemical and geomechanical interactions from the pore to basin scale, (including pressure effects) and applying these to commercial scale projects (see Michael et al, (2009), Michael and Underschultz, (2009) and Allinson et al, (2010) for summary reviews).
- Upscaling of CO₂ simulations e.g. upscaling of solubility, residual gas trapping, convective mixing or of vertical migration of CO₂ (see Ennis-King and Paterson, 2000).
- Defining geochemical and mineralogical interactions with rock and pore fluid; see Knauss et al, (2005); Kirste et al(2010).

All of the above have fundamental theory and micro modeling research fronts and rely on the underpinning data sets of phase interactions, chemical equilibria, and the kinetics of CO₂ mineral interactions. Often, data sets that have been developed for the oil and gas industry are used but they may lack specificity to CO₂ related research, or they may be restricted to areas of oil and gas exploration, and do not include areas where hydrocarbons are not present but which may have potential for CO₂ storage

6.1.1 CO₂ movement and fluid flow and geomechanical effects

This covers laboratory work on the interaction of CO₂ with pores and conduits in the rock, as this is vital to understanding safe storage and injection strategies. Key areas are:

- Understanding geomechanical effects of pressure and volume changes on the integrity of seal and reservoir rocks (eg Perkins and Gonzales, 1985; Hawkes et al, 2005; Zoback, 2007; Rutquist et al, 2008; Kvamme et al, 2009);
- Developing data sets to test geomechanical models for the risk of fault reactivation (can known faults be deliberately reactivated to test models...perhaps by using water rather than carbon dioxide).

6.1.2 Geochemical research and reaction modelling

Geochemical modeling is sufficiently well developed to enable speciation and saturation index calculation for complex aqueous solution compositions and their reaction with many mineral phases. More experimental and field data for single- and multi-mineral phase-aqueous solution systems are required to ensure reaction path models are representative of natural systems. Incorporation of kinetics of reactions introduces significant uncertainty because of the number of variables required to adequately represent the controls on rates and the reaction mechanisms (Kirste et al, 2010). However, the geochemical modeling of experimental, field and natural analogue data is being carried out and the uncertainty is recognised and can be addressed.

Critical research gaps, opportunities and prospective technology fronts include:

- Developing robust data sets to test models for convection of dissolved carbon dioxide reactions on large time scales (beyond what is possible in demonstration projects), based on analogues from natural systems and extrapolation.
- Developing detailed conceptual models of the geochemical system involving CO₂. Choices of reactant and product phases are often the product of the numerical model rather than experimental and observational data.
- Fine tuning mineral dissolution or precipitation thermodynamics (processes and rates are largely unknown in CO₂-brine-rock systems in real time). However, reviews of geological analog studies (eg Schacht, 2008, Wilkinson et al, 2009) may provide insights into these aspects.
- Develop models that consider convergent flow (partial penetration/skin effects), dissolution of CO₂ in brine, precipitation of carbonate minerals or drying effects.
- Produce more thermodynamic data, especially for Pitzer equation, formulation are required for saline solutions.
- Improving the understanding of the thermodynamic properties of mixed mineral phases (solid solutions) and poorly defined mineral phases like clays that are not well constrained.
- More experimental data sets associated with surface processes like adsorption and exchange that can act as a significant buffer to pH changes and can be repositories for cations that may be involved in mineral trapping. Many modeling codes include the ability to simulate adsorption and ion exchange making sensitivity analysis possible.
- Develop refined kinetic rate parameters for critical mineral phases, especially mixed mineral phases and poorly defined mineral phases such as clays. Dawsonite precipitation kinetics need to be investigated as this is one of the most common product phases of numerical simulations and yet is not a common phase observed in natural analogues or experiments (Duan et al, 2005).

- Reactive surface area – determination, calculation, estimation. The most common difficulty described in the recent literature is the selection of a value for the reactive surface area to include in rate equations.
- Surface reaction mechanisms and how they influence the rates of reaction is poorly understood and difficult to model.
- Precipitation nucleation and degree of supersaturation required for precipitation for many important phases is not well known.
- Upscaling of reaction kinetics from the mineral surface to the continuum scale of reactive transport modeling is poorly constrained.

For carbonate reservoirs there are some specialist geochemical considerations:

- Assessing the significance of carbonate mineral dissolution.
- Determining the risk of liberation of contaminants when or if carbonate dissolution occurs.
- Researching the potential of a chemical equilibrium developing between CO₂ & carbonate reservoirs.
- Improving the understanding of the impacts of migration associated trapping (MAT) for evaluating capacity

Key observations and recommendations on fundamental storage science and laboratory work

1. It is important to continue research, laboratory work and data gathering on physical and chemical parameters underpinning the detailed modelling of CO₂ fluid flow behaviour, chemical reactions with minerals and geophysical responses. This includes up-scaling simulations of solubility, residual gas trapping and fluid mixing. More precise fundamental metrics and algorithms are vital to large scale predictive models and hence robust modelling predictions.

6.2. Integrating fundamental research into site and basin scale models of CO₂ behaviour

A significant shortcoming relates to the lack of integrated fluid flow and sub-surface models which also bring together geochemistry and geomechanical dimensions of modeling. It is expected that, as the underpinning science and modeling improves, the application of CCS behaviour knowledge will be much more efficient and useful to operators and regulators alike (Bachu, 2008).

Critical issues include:

- The ability to more accurately model plume movement and plume stabilisation in laterally unconstrained saline aquifers, taking into account residual trapping dissolution of CO₂ and eventual sinking of heavy CO₂ charged water and mineralisation.
- More efficient models of fluid flow through complex strata stacks with varying permeabilities and intermediate partial seals at reservoir and basin scale. Today there is a limitation on the number of blocks (or grid) components in the models for computational reasons. The larger the blocks of rock in the models the more assumptions have to be made about the flux of CO₂ (rate and volume) through each block.

6.2.1 Basin Scale Assessment

Basin Scale Assessment is conducted as a high level assessment to evaluate a basin's potential for CO₂ storage. There are two dimensions of this, one is the assessment of the basin for specific storage sites, and the other is for regulators who need to consider optimising the use of the basin in the long term for CO₂ storage. This is relevant, for example in the North Sea, where a significant quantity of Northern Europe's CO₂ could be stored for centuries if the use of the basin is properly planned. Similarly, assessment of the Gippsland Basin of Australia (Gibson-Poole et al, 2006, 2007), has demonstrated that this basin could store most of Australia's emissions. This then influences the allocation of storage rights, the order of injection into different individual storage sites and, last but not least, the impacts on other commodities such as oil and gas extraction and potable water aquifers.

Many of the techniques and skills used by the hydrocarbon industry will be used for basin scale planning and assessment for a CO₂ storage project. However, there are new dimensions that are substantially different from the oil and gas industry. The eventual scale of injection is formidable and the associated pressure effects and resource conflict issues are not very often present in the oil and gas business, which is mostly about extraction and the drop in pressure. There are thus a number of new challenges involved when conducting a basin scale assessment and planning for large volumes of CO₂ storage.

Critical research gaps, opportunities and prospective technology fronts include:

- Optimise use of natural resources and determine the impact of a storage project in regard to current and future hydrocarbon projects and ground water interactions to avoid resource conflict in the subsurface.
- Improvements in hydraulic modelling and monitoring will be required to quantify the connectivity and continuity of intraformational seals and baffles at basin scale. Basin scale modelling will require high level assessment of the interplay between the petrophysical, geomechanical, hydrodynamic and geochemical properties of caprocks and faults (Kaldi and Gibson-Poole, 2008). Background data on this will often be lacking or will consist of old seismic data and wells from oil and gas activity.
- Models are needed to understand the interaction of basin-scale hydrodynamics with CO₂ migration.

- The ability to populate basin scale models with synthetic data is used by the oil and gas industry but needs to be improved for CO₂ storage. The data sets are improved and ground-truthed as more hard information becomes available from wells, seismic interpretation and interpretation of other geophysical data such as gravity and aeromagnetics (Spencer et al, 2010). One of the research fronts is to get better probabilistic determinations and confidence levels on specific sequences of rock that may act as seals, fluid flow or unintended migration pathways. This will aid in the selection of new wells or seismic surveys to improve confidence levels of key sequences likely to be used for storage.
- There also needs to be work on the best way to use or access data-sets not commonly acquired through standard petroleum industry acquisition methods in basin-scale assessment, but which may already exist or be more cheaply acquired than new seismic data. Airborne gravity and magnetics are examples that have occasionally been used by the oil and gas industry.
- Faults in the subsurface create special problems and sometimes opportunities. They need to be mapped and properly defined to establish whether they could act as migration pathways for CO₂ or as trapping mechanisms. More research and studies on the containment-enhancing role of faults need to be provided to the CCS community so that proponents, regulatory agencies and the public are aware that faults in a potential CO₂ reservoir could be beneficial.
- Incorporating tenement allocations into basin scale assessment for CO₂ storage projects so as to avoid possible conflicts of interest between proponents, regulatory agencies and the public. Basin modelling will also assist government agencies in the allocation of tenements.

Key Recommendations to CSLF on basin scale modelling

1. CO₂ modelling would benefit from the move towards integrated dynamic models of fluid flow, geochemistry and geomechanics (computational fluid dynamics is already well established in designing many complex industrial processes).
2. More work is required on the ability to build robust basin scale fluid flow models; this is an important basis for operators and regulators as well as for governments involved in resource allocation and resource conflict issues.

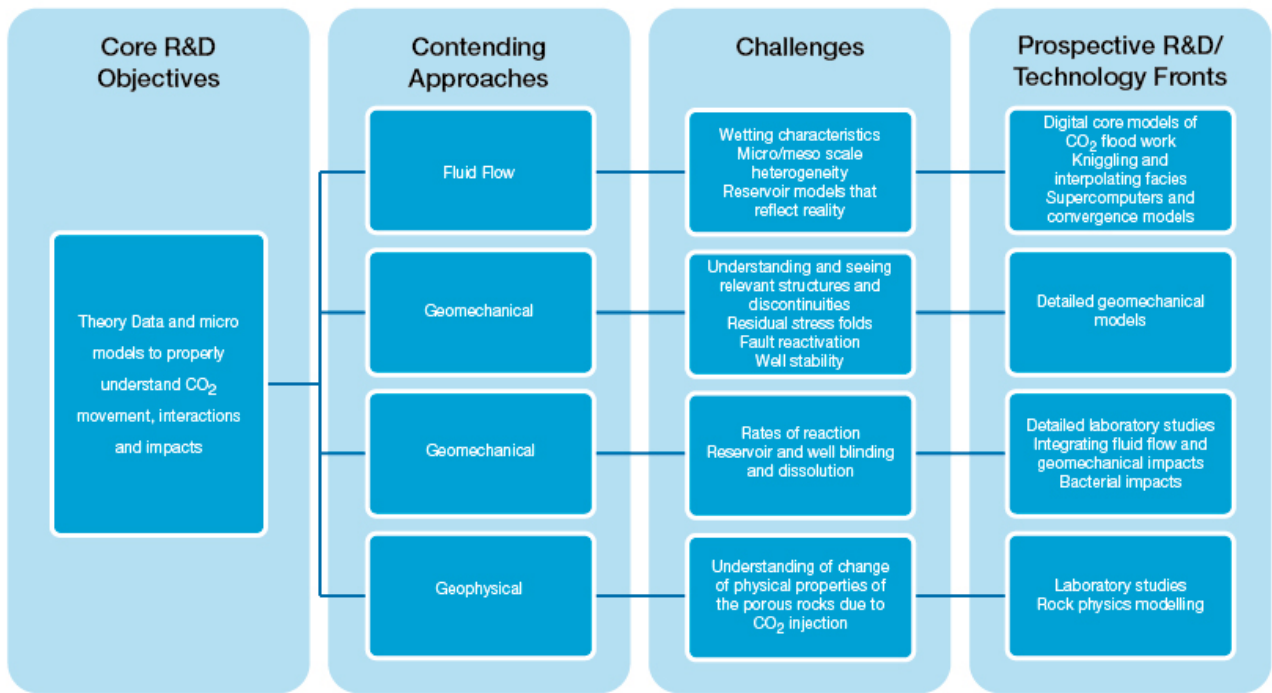


Figure 22 - Prospective Technology Fronts for Understanding CO₂ Behaviour in the Subsurface

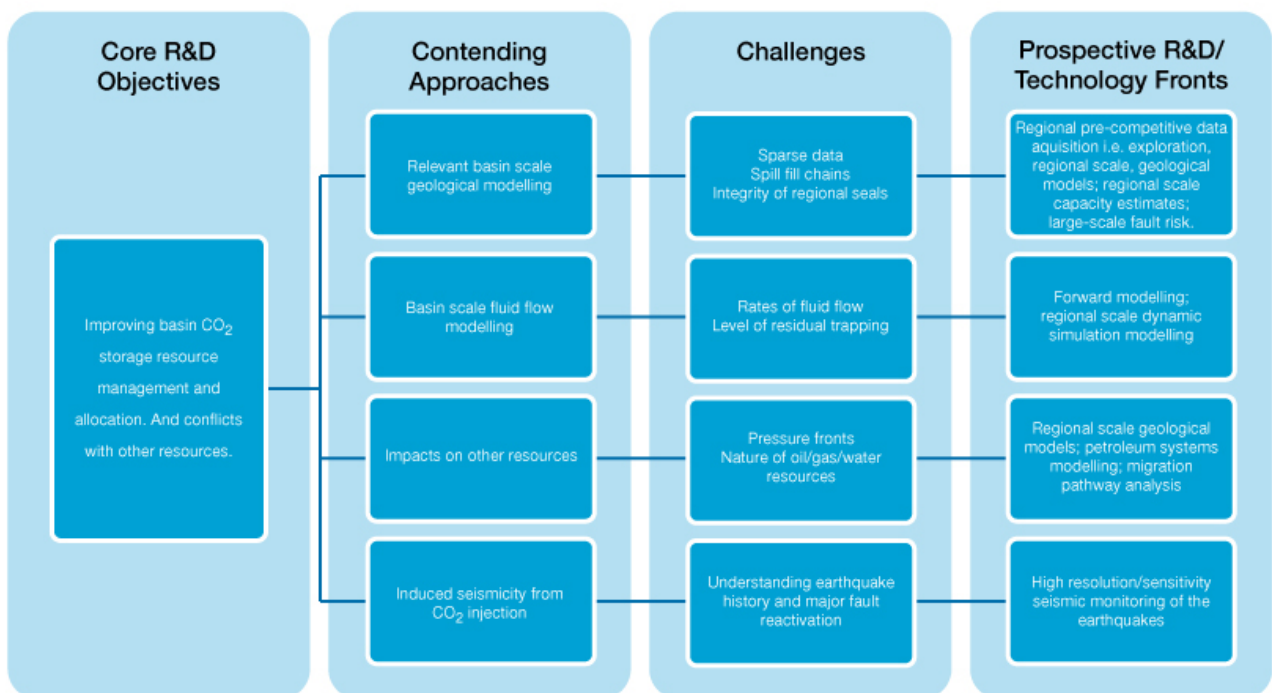


Figure 23 - Prospective Technology Fronts for Understanding CO₂ Behaviour & Impacts at Basin Scale.

6.3 Site Characterisation & Operation

6.3.1. Site Selection & Characterisation

The selection of storage sites suitable for significant volumes of CO₂ comprises mainly geological evaluation of the applicable storage system (e.g. saline formations, depleted or near depleted oil and gas reservoirs and/or coal systems) at various levels of detail. CO₂ site characterisation taps into a vast array of expertise in reservoir engineering, structural geology, sedimentology, stratigraphy, hydrogeology and geological modelling. Site characterisation requires greater detail than basin-scale assessment investigations and may involve re-evaluation of regional geology, generation of new data and/or updating of existing static geologic and seismic data, dynamic engineering data and numerical flow simulation models (Kaldi and Gibson Poole, 2008). An important aspect of site characterisation is the determination of acceptable versus unacceptable levels of uncertainty in order to determine the amount of risk associated with the site and the amount and type of additional data required to reduce the uncertainty (Vendrig et al, 2003; Bowden and Rigg, 2004; Streit and Watson, 2004). Three key factors that require further detailed evaluation at each specific storage site are: containment, capacity, and injectivity. These three factors encompass the fundamental elements needed to characterise any potential CO₂ geological storage site and are described in more detail below.

For greater understanding of the site selection and characterisation process, several opportunities for improvement of knowledge are:

- Researching and assessing the value of the different characterisation techniques for shallow and deep reservoirs to determine if different technologies are required or the same can be applied to both types of reservoir.
- Determining the optimum size of the characterisation “footprint” for site selection, i.e. how far away from the proposed storage zone will new data and deeper insights in geology be required.
- Evaluating the limitations of baseline surveys for characterising potential sites and determining when further detailed site characterisation will be required.
- Evaluating the significance of hydro-stratigraphy in site selection and characterisation.
- Comparing the significance of the evaluation of seal properties to the evaluation of reservoir properties for capacity and injectivity.

6.3.2 Capacity

Defining capacity of a storage site is a vital issue in CCS (Bachu et al, 2007; Bradshaw et al, 2007; Kaldi and Gibson Poole, 2008; Spencer et al, 2010). It is required in the initial work to determine if the injection volumes contemplated for “bankable” projects are realistic, so as to provide confidence (minimise risk) to operators, investors and regulators. The pore space is where the CO₂ is to be stored and so it becomes a resource; therefore calculating this space becomes an accounting issue. Much of the existing methodologies that address storage capacity estimation are based on the oil and gas industry’s Petroleum Resource Management System (PRMS) guidelines. *Storage capacity* is considered a resource, and as in petroleum accumulations and mineral deposits, categorised based on levels of certainty of resource availability (Allinson et al, 2010).

Because of uncertainties inherent in subsurface evaluation, exact quantification of geological properties is not possible and therefore storage capacity is always, at best, an approximation of the amount of pore space into which CO₂ can be injected. Hence, the likelihood of contingent and prospective storage volumes achieving commerciality is determined probabilistically, utilising high, low and best estimates.

All levels of capacity assessment involve mainly technical issues and, as the methodologies for estimation of capacity for CCS are still nascent, there are many opportunities to improve knowledge in certain key areas:

- Determining if different assessment methods are required to characterise depleted fields versus virgin saline formations.
- Distinguishing between the different assessment methods required in structural traps (folds and fault) versus stratigraphic traps.
- Developing a consistent methodology to define an Efficiency factor (E) for capacity estimation at various sites.
- Evaluating the suitability and effectiveness of the Petroleum Resource Management System (PRMS) of capacity estimation to be used as the standard methodology applied to all sites. This works on a net present value approach to the viability of a site and may need to take into account:
 - Incorporating lease boundary constraints and competing resource constraints into capacity estimations.
 - Improving understanding of scales in order to make capacity estimates for basins or regions.
 - Including source-sink matching in capacity estimates.

6.3.3. Containment

6.3.3.1 Hydrodynamics

The impact of hydrodynamics on the sealing capacity of top seals and faults has been discussed in the literature only with respect to hydrocarbon migration. With respect to CO₂ geological storage, little research has been published on this issue, though the IEAGHG report on *Pressurization and Brine Displacement Issues for Deep Saline Formation CO₂ Storage* (IEAGHG, 2010) as well as papers by Michael and Underschultz (2009) and Cavanagh and Wildgust (2011) have begun to address this gap.

Critical research gaps, opportunities and prospective technology fronts include:

- The most critical knowledge gap on this topic is the absence of data to calibrate analytical and numerical models and to quantify the impact of seal properties on reservoir pressure and capacity calculations.

6.3.3.2 Geochemistry

Chemical interaction between CO₂ and caprock may affect the mechanical strength and transport properties of the sealing formation, possibly inducing slip along currently sealing faults or creating pathways, allowing carbon dioxide seepage (Kaldi et al, 2011). However, very few studies attempt to couple chemical and mechanical processes occurring within the caprock as a result of CO₂ injection.

Critical research gaps, opportunities and prospective technology fronts include:

- Modelling of the hydraulic integrity of the reservoirs to quantify connectivity between the systems and continuity of intraformational seals and barriers is lacking. Collected data can then be integrated in predictive models of caprock integrity.
- Petrophysical, geomechanical, hydrodynamic and geochemical properties of both the reservoir and caprock are important to determine whether multiple reservoir/caprock and/or single reservoir/caprock systems can be utilised for safe, long-term storage. Very little work has been done towards

understanding the interplay between the combined effects of these properties on caprocks and faults for CO₂ systems.

6.3.4. Injectivity and Operational Issues

Injectivity refers to the rate at which CO₂ can be injected into a given reservoir interval and the ability of the subsequent CO₂ plume to migrate away from the injection well (Cook, 2012). For low permeability formations, numerical simulations show that there will be large pressure gradients near the wellbore, which will restrict the injectivity. Low injectivity potential for an interval might result in a site with otherwise excellent capacity and containment characteristics turning out to be uneconomic and therefore unsuitable for CO₂ storage. An example of this is the ZeroGen Project in Queensland, Australia (James et al, 2012). During CO₂ injection into a reservoir, the injectivity and nature of plume migration will depend on parameters such as the viscosity ratio, injection rate, permeability and relative permeability. These parameters will in turn depend on variables such as depositional environment and reservoir heterogeneity, stratigraphic architecture, post-depositional diagenetic alteration, structural dip, fault distribution and fault seal capacity, pressure distribution and the nature of the formation fluids (Kaldi and Gibson Poole, 2008).

Other critical operational issues relate to the ability to take the feedback and data from the early part of an operation and feed it back into the projected models for the future plume movement, pressure effects and related possible geomechanical impacts at the reservoir scale and the on seal stability. These kind of feedback processes are already well established in oil and gas industry practice and in geothermal energy but there will be considerable lessons that come from the early storage projects. These lessons will be vital to scale up to the multi-million tonne per annum operations that will be the next generation of storage projects starting in the late 2020s.

Critical research gaps, opportunities and prospective technology fronts include:

- The development of a low cost downhole solid state CO₂ detection method.
- Construction of a database for calibrating optimum wellbore parameters (e.g. diameter; perf zone) for injection into formations of various permeabilities, and thereby determining permeability cut-offs for injectivity.
- Managing high permeability intervals (“thief zones”) via profile modification.
- Establishing the parameters that control optimum wellbore orientation (vertical vs horizontal vs slant).
- Determining the relationship of optimal number and orientation of wells, capacity outcomes and permeability to optimise injectivity.
- Modelling injection-related pressure buildups and the effects of near-well boundary and far-field transients.
- Determining optimal injection rates to prevent blow-out (surface or subsurface).
- Lab-test the effects of injecting CO₂ with impurities (SO_x, NO_x, CO, and other exotic species) into the reservoir.
- Injectivity modelling is limited by software required versus software available and the inability to upscale from lab to field scale.

There is a lack of understanding of the full effects of pressure. There is a need to:

- Optimise injection rates while maintaining reservoir integrity.

- Optimise injection planning by calculating how and when to run Leak-off tests (LOT) and Extended leak-off tests (XLOT).
- Research the extent of pressure effects (near well-bore vs far field effects).
- Undertake research and calculations concerning the effect of pressure on induced seismicity.

6.3.5. Induced Seismicity

Seismicity can be induced by any industry that is injecting volumes of fluid or gas into the subsurface (e.g., CCS, geothermal and waste water disposal; Gerstenberger, et. al., 2013, Zoback and Gorelick, 2012; Avouac, 2012; Deichmann & Giardini, 2009; Holland, 2013; van der Elst, et al., 2013). Few induced earthquakes have been associated with CCS or other CO₂ storage sites, and those that have been recorded are small (i.e. micro-seismicity of $M \leq 2.0$; Gerstenberger, et al, 2013); however, the volumes of CO₂ injected have typically been small compared to what will be required for commercial scale CCS. Examples such as the Basel, Switzerland enhanced geothermal (EGS) project, which induced a magnitude 3.4 event, caused damage to the city and halted the EGS project (Deichmann & Giardini, 2009), indicate that appropriate mitigation and planning is required for a successful CCS industry. A key step in reducing the risk is appropriate selection of well characterised sites including understanding the response of the reservoir to injection. In addition, detailed monitoring of induced seismicity is an important mitigation measure and can also be used for understanding the behaviour of the subsurface and tracking the migration of the CO₂.

The understanding of the relationship between fluid injection and induced seismicity is in its infancy but some basic relationships such as a positive correlation between injected volume and maximum magnitude have been seen. Statistical predictive modelling tools are currently being developed and may prove to be useful in assisting mitigation of induced seismicity. Physics based numerical models are being developed in concert with the larger seismological community, but as of yet lack the necessary validation against observations. In the future, both types of modelling will likely be useful tools for reducing the risk of induced events.

While the available evidence indicates that the probability of inducing a large and damaging event is likely to be low, smaller non-damaging events may be detrimental to the reputation of the industry. Some key steps and knowledge gaps that can help reduce this risk are (Gerstenberger, et al, 2013):

- Availability of an across-industry induced seismicity catalogue.
- Understanding of fundamental induced seismicity relations.
- Realistic physics based modelling.
- Understanding of the impacts of scaling from pilot to production projects.
- A CCS Induced Seismicity Risk Management Protocol.
- Collaboration across industries including the wider seismological community.

Key Recommendations on Site Characterisation and Operation

1. Continue to build on oil and gas industry knowledge and integrate with emerging CO₂ storage data and concepts to develop internationally consistent:
 - storage site characterisation methodologies;
 - storage efficiency factor; and
 - capacity estimation and reporting standards.

2. Improving modelling strategies associated with the hydraulic integrity of intra-formational seals (this affects the interplay between reservoir and caprock qualities and the need for multiple or single caprocks in a given geological situation).
3. The industry needs to develop a downhole solid state CO₂ detection technology.
4. Development of methodologies to manage high permeability thief zones and differential pressure effects that can reduce efficient reservoir use.
5. Integrating modelling and operational experience to develop strategies to optimise drill patterns and angles for injection and also for pressure management, avoiding blow outs and induced seismicity.

6.4. Managing and Avoiding Migration Variance

Although there is now significant confidence in the science and technology associated with injecting large quantities of CO₂, consideration needs to be given to situations where some intervention is required to ensure that CO₂ is retained in the subsurface zones agreed with regulators. Ensuring well integrity is important, both for old wells in the plume area and for any new wells. Wells can be fixed and there is again considerable experience in the oil and gas industry on this.

The other dimension of managing and avoiding migration variance is where the plume moves in ways not predicted in the initial modeling. More work is required to build a knowledge base around working with or managing the CO₂ plume movement when there is significant variance to the projected models (Michael and Underschultz, 2009).

6.4.1. Wellbore Integrity

Slow, low-rate leakage is unlikely from injection wells as they will be managed with CO₂ interaction in mind, but leakage could happen from existing wells if they are not properly assessed and managed (Watson, 2009). The largest uncertainties and risks are old abandoned wells in the area of review as the state of completion may not be known (DOE/NETL 2013). The risk profile for projects should reflect the potential for long-term deterioration of wells and the movement of plumes to encounter leaking wells. Cement is key to reducing wellbore integrity issues – if the cementing is good (in terms of the role of centralisers and in design, quality and placement), the well is most likely to perform as expected. Certain cements have the ability to self-heal (in some circumstances).

Research gaps, opportunities and prospective technology fronts include:

- Wellbore integrity is mainly related to the long term risk profile, associated with the breakdown of materials such as cement stability in CO₂ and steel corrosion. Therefore there is a case for more research into the design of CO₂-resistant cements, best practices in well completions, well abandonment practices, detailed modeling of fluid-wellbore interactions, field-scale modeling of wellbore performance and remediation technologies.
- Better characterisation and simulation of CO₂ leakage rates through wellbore cement, to arrive at a better assessment of the overall risk of well leakage.

6.4.2. Migration (including unintended migration and leakage)

Unintended migration or movement of the injected CO₂ plume away from the injection zone and through the reservoir is a potential risk for storage projects. High permeability formations allow relatively fast migration of CO₂, lowering the proportion of the injected CO₂ plume trapped by structural, stratigraphic or migration associated trapping (MAT) mechanisms such as solution, mineral or capillary trapping (Macminn, et al, 2010). Thus higher permeability is ideal near the wellbore to increase injectivity, lower permeability is desirable outside the radius of influence of the wellbore to increase residence times and encourage the rate of residual trapping, dissolution and mineral trapping.

Research gaps, opportunities and prospective technology fronts include:

- Leakage needs to be defined;
 - Is “leakage” any movement of the injected CO₂ out of the intended target storage formation (ie movement from a regulated zone in the subsurface to a shallower non-regulated zone)?
 - Or is it movement through the seal?
 - Or is it appearance at the surface or in sensitive receptors such as potable aquifers?
 - Should leakage/unintended migration refer not only to CO₂, but also to any brines displaced by injection of CO₂?
 - Should the potential impact of leakage be defined?
 - Can the leakage be classified as “detectable” (but without major impact) or “significant” (having major impact)?

Some of the areas for further work in addressing the uncertainties include:

- Data sets are required to test leakage models, perhaps in natural systems.
- Better simulations of fault leakage rates of CO₂ and CO₂/gas mixtures to the surface (involving liquid to gas transitions, as well as characterisation of the fault properties etc).
- Integration of CO₂ leakage to the ocean floor with prediction of CO₂ migration in the ocean (along with predictions on how to monitor it).
- Data sets to calibrate and test reactive transport models.
- How can leakage be attributed and accounted (in terms of liability and impact on carbon credits)?
- Attribution (from interpretation of monitoring data) is not adequately understood;
 - integration of diverse data sets may be necessary, as is determining the source of the leakage, such as through wells, fractures, caprock, spills and migration.

6.4.3. Mitigation

There is little experience in developing and testing mitigation technologies. Theoretically, there are various potential solutions to the key risk associated with storage: the unintended migration of CO₂, including leakage to surface or to sensitive receptors (including water, oil, gas, coal or other resources). Barlet-Gouédard et al (2006) discuss mitigation options for wellbore leakage; and Kuuskraa (2007) considers the subsurface storage system and suggests options such as reducing the pressure in the storage reservoir from which the leak is occurring; increasing the pressure in the storage formation (generally a shallower reservoir) into which the

leak is occurring; or intercepting the CO₂ plume and extracting it from the reservoir. However, all of these potential mitigation methodologies are untested and must therefore be considered knowledge gaps.

Research gaps, opportunities and prospective technology fronts include:

- Can pressure management and geoengineering (“plume steering”) by changing the flow direction by selective water production and/or injection be implemented under real reservoir conditions?
- Is it possible to change interfacial tensions (hence relative permeabilities by using chemical treatments, such as surfactants, biofilms etc)?
- If “thief zones” (preferential permeability pathways) occur in the reservoir due to channels or fractures, can these be preferentially plugged via profile modification using foams or other blocking agents?
- What are the cost/benefit ratios for all of these technologies?

6.4.4. Risk Assessment

Risk assessment is a critical activity as part of the selection and characterisation of sites for long-term storage of CO₂ and, in particular, for the development of a risk management strategy. While geologic uncertainties or risks are highly site-specific, the main perceived risks are of potential leakage, induced seismicity and ground displacement, and their potential impact on health, environment, resources, and value (GCCSI, 2013). Risks associated with storage that may affect project feasibility are the timely identification of a suitable storage site, its adequate characterisation and public acceptance.

Storage-related risk assessments and risk management processes have matured as more projects approach final investment decisions. Projects in development have benefited significantly from knowledge dissemination of risk management plans and MMV programs from operational or near-operational projects, such as Sleipner, the IEAGHG Weyburn–Midale CO₂ Storage and Monitoring Project, In Salah, and the Gorgon Injection Project (GCCSI, 2013). It is notable that many of the smaller demonstration and R&D projects, e.g. the CO₂CRC Otway Project, Frio, Nagaoka, Lacq-Rousse, Ketzin, Cranfield, and a number of tests in the US Regional CO₂ Partnership program, have all contributed to monitoring knowledge through trialling a wide array of technologies.

Research gaps, opportunities and prospective technology fronts include:

- There are multiple risk assessment tools in the market place (eg Bow-tie; Tesla; RISQUE; BBN), but few equitable comparisons have been made concerning which tool is best.
- Although regulators are conversant with risk management, there may be some benefit in educating regulators about risk assessment in CO₂ storage.
- The application of risk assessment to site selection during the various stages of site selection and characterisation; i.e. what constitutes the boundary condition to permanently reject a particular prospective site?

6.5 Key Observation and Recommendations on Managing and Avoiding Migration Variance

- Risk management of potential leakage has matured as more projects are approved or move through to financial investment decision.
- More work is required on:

- Developing stronger models and underpinning data sets on possible migration pathways (fault, seal, strata/structure), to enhance risk management.
- Well integrity including developing CO₂-resistant well cement and simulation modelling of leakage through wells.
- Mitigation strategies, such as pressure management, and profile modification.
- The attribution of leaked CO₂ and associated accounting issues.
- Strategies to underpin the proof of 99% storage (IPCC definition) are required.

Key Recommendations to CSLF on Storage

1. Modelling CO₂ behaviour is a vital element of storage research and technology integration; developments required include :
 - Fundamental research, laboratory work and data gathering on physical and chemical parameters to better underpin detailed modelling of fluid flow behaviour, chemical reactions and geomechanical outcomes.
 - More integrated dynamic models of fluid flow, geochemistry and geomechanics running on very large computers.
 - The ability to build robust basin scale fluid flow models for operators, regulators and governments involved in resource allocation and resource conflict resolution.
 - Modelling and strategies associated with the hydraulic integrity of intra-formational seals and faults and the number and thickness of caprock required.
 - Developing stronger models and underpinning data sets on possible migration pathways (fault, seal, strata/structure) to enhance risk management.
2. Improvements to optimise operational effectiveness and storage efficiency, including:
 - Developing strategies to optimise drill patterns and angles for CO₂ injection and pressure management to avoiding blow outs.
 - Understanding induced seismicity and developing pressure management strategies to avoid minor induced seismic events and potential compromise of caprocks.
 - Approaches to enhance residual trapping, in-situ mineral trapping and mineralisation and also injection strategies for storage in lower permeability rocks.
 - Developing methodologies to manage high permeability thief zones and differential pressure effects that can reduce efficient reservoir use.
 - Understanding fines migration, subsurface erosion and precipitation and the effects of subsurface microbes that could compromise operational effectiveness.
3. Develop (based on oil and gas industry practice) internationally consistent standards:
 - Storage site characterisation methodologies.
 - Storage efficiency factors.
 - Capacity estimation and reporting standards.


4. More work is also required on technology and risk management strategies to mitigate or manage unintended CO₂ migration:
 - Well integrity, including developing CO₂ resistant well cement and simulation modelling of migration through wells.
 - Mitigation strategies, such as pressure management, and profile modification.
 - The attribution of leaked CO₂ and associated measuring and accounting issues.
 - Strategies to give even greater confidence in long term storage.

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7. Measuring, Monitoring, Verifying (MMV) and accounting

7.1 Key Issues in MMV

Much knowledge has been developed and tested with respect to measuring, monitoring and verifying (MMV) in both oil and gas projects as well as in active CCS demonstration projects. A very wide range of techniques is available for MMV, covering many types of geophysical investigation and environmental monitoring. A comprehensive recent summary is given in the IEAGHG report (Korre 2012). A useful distinction is between conformance monitoring – essentially checking and updating models of CO₂ migration – and compliance monitoring, demonstrating compliance with regulatory and societal requirements. The former is relatively unproblematic and builds on decades of related experience in hydrocarbon extraction. The latter is more complex and revolves around the issue of “no leakage” or “no impact”. While many monitoring tools are available, probably the key issue is the integration of monitoring and risk assessment, and the associated issues of regulatory consent and social license.

Feasible monitoring programs will have to be focused on agreed risks in a precise way, not attempting to prove “no leakage” but rather accepting that this is the conclusion that remains when a number of specific leakage mechanisms have been ruled out (Jenkins, C., 2013 IJGGC). Measurements of CO₂ and its effects in the near-surface and atmosphere need particularly careful handling in this context. Because CO₂ is so intimately bound up with ecosystem processes, there are large variations in the measurements that are unrelated to leakage of anthropogenic CO₂. Unless monitoring programs are carefully designed, with an agreed understanding between stakeholders about the sensitivity of the measurements to leakages and the likelihood of false alarms, such programs could become a focus of contention rather than reassurance.

The outstanding research problem in this area concerns the monitoring of ground water. This is an increasingly critical resource, often occurring at depths where measurements are difficult, boreholes expensive, and models limited in their application. Leakage into aquifers, although unlikely, might go undetected for a long time with currently feasible monitoring methods, and breakthroughs in this area would be important.

As global assessment of storage capacity continues it is clear that a significant quantity of the world’s storage potential is in the offshore environment. Although this domain has been pushed to the limits for oil and gas extraction, there are some issues relating to MMV of offshore CO₂ storage that would benefit from more work. Specifically there is a need to understand and plan for monitoring CO₂ in the marine environment, where complex ocean currents and seasonal variation make MMV more complex. The establishment of the approaches to baseline studies in the marine environment, and then leak detection and finally accounting, will all be necessary. A number of projects around the world have started on this, particularly in the North Sea, a loch in Scotland and in offshore Australia, Korea and Japan.

In both onshore and offshore areas MMV research increasingly needs to understand the whole package of geology between the storage reservoir and the surface. The modelling referred to in earlier sections will be vital to allowing modelling of both the modes of movement through the above reservoir package and how quickly CO₂ can move through it. Such models can then be used to inform the design of MMV strategies, both at the outset of a project and also for any refinements that might be necessary as experience with the particular storage site situation develops over years of injection experience and history matching.

7.2 Developing Sensing Technologies for CO₂

7.2.1 Seismic:

Time-lapse seismic is an established but rapidly evolving technology for monitoring subsurface changes caused by hydrocarbon production (Johnston, 2013). Compared to other geophysical methods, seismic has by far the highest spatial resolution and thus is the technology of choice for monitoring subsurface changes caused CO₂ injection (Lumley, 2010). Effectiveness of seismic monitoring depends on the ability to detect and interpret (qualitatively and quantitatively) the time-lapse seismic signal on the background of time-lapse noise. As such, the main challenges in the use of time lapse seismic monitoring are related to (1) understanding the time lapse signal; (2) ability to extract useful information (qualitative and quantitative) from it and (3) understanding and minimizing time lapse noise. Additionally, in petroleum industry, time-lapse seismic monitoring is usually accomplished through acquisition of repeated 3D seismic surveys at regular intervals (usually 6 to 12 months). In CCS context, the need for early detection of CO₂ leakage will likely require continuous monitoring over many years, which will need to be optimised with respect to cost and land impact.

Critical research gaps, opportunities and prospective technology fronts include:

- 1) The quantitative interpretation of 4D seismic data for CO₂ storage, including, 4D inversion (deterministic, stochastic, etc) and 4D full-waveform inversion. The utilisation of the changes in seismic attenuation and seismic anisotropy of the rocks

Currently the analysis of time-lapse seismic data is mainly based on the comparison of 3D images acquired at different times. This might not be the optimal method as each image contains its own artefacts. More promising are approaches that explicitly utilise the fact that many parameters of the subsurface remain unchanged, such as deterministic or stochastic constrained 4D inversion (Sirgue et al., 2010; Johnston 2013). Furthermore, the seismic inversion technology requires a number of simplifying assumptions (such an ideally elastic and isotropic earth). Thus it is important to explore other promising seismic attributes, such as the changes in seismic anisotropy and attenuation caused by geomechanical changes in the reservoir (Herwanger et al. 2011). Improving time-lapse signal sensitivity can also be achieved through the development of the new data analysis algorithms such as virtual source method (Bakulin et al. 2007; Dellinger and Yu, 2009), diffraction imaging (Alonazi et al. 2013), etc.

- 2) The integration of the reservoir and seismic modelling with 4D seismic into the closed loop prediction/correction workflow.

The principal objective of seismic monitoring is to verify and improve the predictions of CO₂ migration obtained from dynamic reservoir modelling (flow simulations). To this end, the time-lapse seismic modelling and inversion workflows need to be integrated with reservoir simulations. In such integrated workflow, the results of the seismic time-lapse analysis need to be compared with the seismic response obtained from reservoir simulation, and any observed differences be used to amend the reservoir model. Such close-loop workflows are known as seismic history matching and are still in their infancy (Johnston 2013, Pevzner et al. 2013).

- 3) Development of continuous (24/7) low-cost continuous seismic monitoring technologies.

As mentioned earlier, the deployment of time-lapse seismic monitoring of CO₂ storage will likely require continuous monitoring over the time of the project. This emerging technology can be achieved through the deployment of massive buried seismic receiver arrays, both downhole and near-surface. The use of permanent seismic receiver (buried underground or installed on the ocean floor) do not only allow for continuous recording but will also greatly improve the repeatability of the seismic signal

(reduce the time-lapse noise) (Bakulin et al. 2012, Berron et al. 2012, Dellinger et al., 2013; Shulakova et al. 2013). Furthermore, while capital expenses may be significant, in the long-term the permanent installations are likely to be cost-effective (Johnston, 2013). Further improvements in both coverage and cost are likely with the use of new developments in the sensing technology (e.g. iDAS) and deployment of fibre optic cables that can detect seismic waves (Daley et al. 2013).

Continuous monitoring will likely benefit from the development of permanently installed seismic sources (Meunier et al., 2001). Examples of permanent land seismic sources include SeisMovie developed by CGG and ACROSS developed by University of Tokyo (Kasahara et al., 2013). However monitoring of industrial size CCS projects will require a large number of permanent sources and hence substantial improvement of the technology as well as cost reduction.

Deployment of permanent receiver arrays opens the possibility of integrating active seismic monitoring with passive monitoring. Passive monitoring may include recording microseismic events caused by geomechanical changes in the subsurface, and the use of external noise sources for monitoring changes in the subsurface (e.g., using multi-channel analysis of surface waves - MASW) (Park et al., 2007; Delinger and Yu, 2009)

Continuous seismic monitoring is an emerging technology and will require development of novel processing algorithms directly benefiting from proper sampling along the 'slow time' axis.

- 4) Using rock physics data and models to enhance the fundamental understanding of CO₂-injection related changes in the rock properties for the different reservoir types (through both theoretical and laboratory research).

Successful geophysical monitoring of CO₂ sequestration is underpinned by the effect of CO₂ on physical properties of rocks. Thus, understanding of this effect is essential. While theoretical models of the effect of CO₂ saturation on rock properties are known, they need to be calibrated and validated using laboratory measurements (Wang and Nur, 1989; Shi et al., 2007, Lebedev et al., 2013). The standard ultrasonic measurements of elastic properties do not adequately represent the real seismic experiment due to differences in frequency, stress and/or temperature conditions. Thus the current challenge is in the advancement of the methods of measuring elastic properties of rocks at seismic frequencies and at in-situ P-T conditions. Such experiments are particularly important for situations where basic assumptions of standard theoretical relationships are invalid, for instance, for carbonate lithologies, where CO₂ may react chemically with the rock matrix. Furthermore, since laboratory measurements can only be performed on small core samples, theories need to be further developed to upscale the laboratory results to the reservoir scale.

MMV Seismic and Geophysical methods

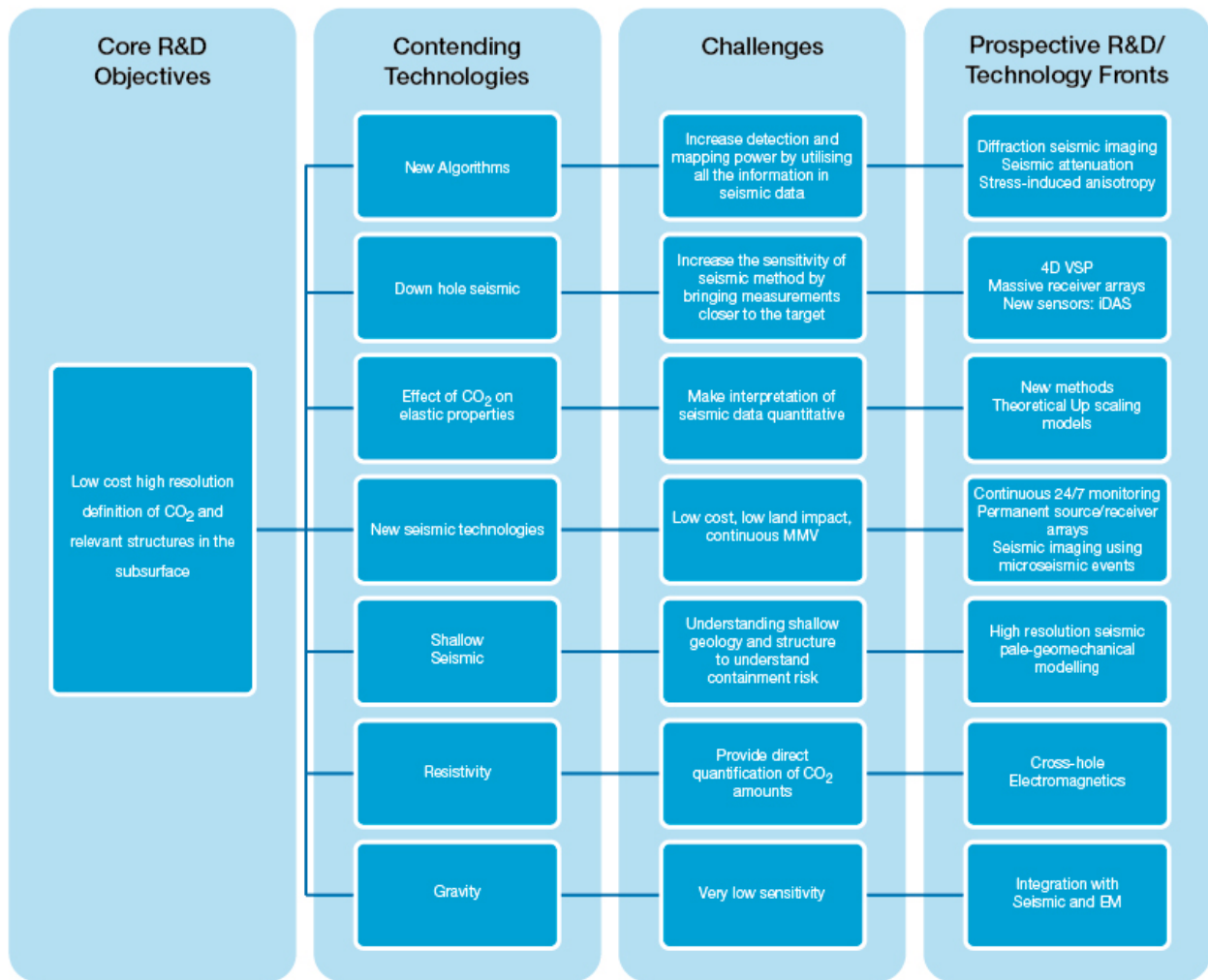


Figure 24 - Prospective Technological Fronts for Seismic and Geophysical MMV methodologies

7.2.2 Electromagnetic Methods

Electromagnetic (EM) methods are used to map electrical resistivity distribution of subsurface rocks. They are used in mineral and petroleum geophysics in borehole mode (resistivity logs), cross hole and surface modes. EM methods are attractive for CO₂ monitoring because CO₂ is electrically resistive compared to subsurface brines. That is, CO₂ injection into saline aquifers is typically accompanied by substantial changes in resistivity distribution. However, surface EM methods can suffer from low spatial resolution. Conversely, resistivity logs provide information only in the immediate vicinity of the wellbore. Thus for many circumstances cross-hole EM methods are the most promising for CO₂ monitoring (Harris and Pethick 2011, Swanepoel et al., 2012 Fabriol et al., 2011, Carcione et al., 2012). Pilot cross-hole EM studies have been conducted in a number of CCS projects: Ketzin, Nagaoka, Frio, Cranfield. One challenge is that wide spatial coverage of cross hole EM methods requires a number of suitably spaced wells. Another challenge of diffusive EM methods is their rapid loss of spatial resolution with distance between transmitter and receiver. However, results from time lapse EM monitoring can be significantly improved by integration with seismic methods, such as joint or cooperative seismic/EM inversion. This integration can be particularly useful as seismic can provide the structure while EM methods can be used to quantify saturation within a detailed seismically determined structural framework (Hoversten et al., 2003).

7.2.3 Gravity

Gravity methods are designed to map density of subsurface rocks, and are used mainly in mineral geophysics. These methods are attractive for CO₂ monitoring because density is linearly related to saturation. However, gravity has very low sensitivity, and thus is likely to be useful for monitoring only in downhole mode. A pilot study on the use of borehole gravity for CO₂ monitoring was conducted at Cranfield and produced promising results (Dodds et al., 2013). Due to the sparse nature of such observations, these methods will require integration with other geophysical methods, such as seismic and EM.

7.2.4 Down Hole Techniques

Wells for injection and pressure relief can provide access to the subsurface in or near CO₂ storage that can be used for pressure and temperature measurement as well as down hole seismic, electrical geophysics and even gravity detection. The value of these techniques is that they are in or close to the CO₂ and can thus give higher resolution and hence insights into early unanticipated CO₂ movement. They also offer the opportunity for integration of data sets (or inversion of data) to provide more detailed insights into the disposition of CO₂ plumes in the subsurface.

In addition to the above there are also refinements to the traditional down hole wire-line techniques developed by the oil and gas industry.

An important technique developed for CO₂ storage has been the down hole capturing of reservoir fluid to follow plume breakthrough from one hole to another for example. A valuable contribution to the field of CO₂ storage has been the development of solid state CO₂ detection methods¹⁴ that can be integrated with other down hole monitoring devices cemented into wells behind the casing for continuous longer term subsurface

¹⁴ E.g. Intelligent Optical Systems, Inc. (IOS) has developed an aqueous CO₂ monitoring system for deployment in water wells over long periods of time and a broad range of depths. Data are relayed in real time via network to a remote laboratory. This sensor has advantages over traditional CO₂ sampling, which requires transport of samples to the lab and increases potential for error and cost.

monitoring. Development here concerns ensuring that they can withstand the subsurface conditions for long periods of time.

7.2.5 Atmospheric Monitoring Techniques

The measurement and interpretation of atmospheric CO₂ concentrations and fluxes is a well-developed area of scientific research, especially for ecosystem studies. The difficulty for leakage detection is the large variations in the CO₂ background, because of the role of surrounding ecosystems in producing and consuming CO₂. Signals are also strongly diluted by atmospheric dispersion. With the current state of the art, atmospheric methods are useful for detecting leakages from small spatial areas, at ranges of a few hundred meters. Tracers are sometimes helpful in these cases but are expensive on industrial scales. A key advance would be a reduction in the cost of high-end measurement systems by a factor of 10.

Critical research gaps, opportunities and prospective technology fronts include:

- Improving and lowering the cost of C-14 detection, a natural tracer which is potentially important for monitoring CO₂. “Fossil” CO₂, resulting from burning fossil fuels, has essentially no C-14, whereas the isotope is naturally present in the atmosphere (it is created by cosmic rays). Currently the detection of C-14 in atmospheric samples is slow and very expensive, and a portable, affordable sensor would be a game-changer.

7.3 Key Research Issues in MMV

Research gaps, opportunities and prospective technology fronts include:

- Development of cheap, panoramic surface assurance techniques.
- Developing data sets to test and calibrate tracer/ CO₂ behaviour in lab and field.
- Better simulations of tracer effects in CO₂, especially density effects due to accumulation of relatively insoluble tracers at the front.
- Methods for monitoring groundwater resources that command general consent.
- Continuing to calibrate M&V methods with controlled releases.
- Determining how much atmospheric monitoring is required for commercial scale projects and which techniques are likely to provide the most consistent results.
- Quantifying the appropriate monitoring of leakage; including uncertainty associated with off-shore monitoring methods and approaches.
- Monitoring at depth, while expensive, may allow remediation before impacts occur in the shallow subsurface.
- Improve understanding of the amount and saturation of CO₂ relative to geological parameters to provide the ability to visualise/recognise the plume.
- Develop methodologies to determine the origin of potential leakage where complex interactions between CO₂, brine and mobilised hydrocarbons takes place (e.g. EOR projects).
- Develop new theoretical and analytical methods of attributing leakage.
- Detection versus quantification of leakage and how accurate it is possible to be; there may also be non-quantitative key indicators as precursors to escape from the storage reservoir.


- Assembling knowledge gained from controlled release sites will be essential to calibrating monitoring tools; these have not yet started to be incorporated into projects.
- Other needs include determining the variability of aquifer response to CO₂ – passage of plumes, pressure fronts, buffering capacity with respect to metals and understanding how a laboratory characterisation of potable aquifers is likely to be impacted by CO₂.
- Improve understanding of the differences between confined and laterally unconfined aquifers, as well as development of methods that can monitor large areas effectively. In the reservoir the plume may not be where predicted (as true reservoir complexity is rarely able to be accurately modelled).
- Improve understanding of physical and chemical transport processes (e.g. if secondary pooling were to occur, seismic could be effective for leakage monitoring). While there is no generic solution, it would be useful to compile information from existing projects to see how each have adjusted monitoring plans to suit site-specific conditions.

Key Observation and Recommendations on MMV Technology to CSLF

MMV continues to be a vital part of the CCS technology development, as it underpins operational decisions as well as the relationship with regulators and the community. Some of the key observations and recommendations are:

1. Establish technologies and methodologies for offshore (sub marine) MMV, as a significant portion of global storage capacity is offshore.
2. Improving onshore and offshore MMV technology and model:
 - a. the whole package of geology between the storage reservoir and the surface, to assess the timing and possible modes of potential CO₂ movement and to inform remediation and mitigation strategies,
 - b. CO₂ plumes in the subsurface, particularly with respect to the relationship between CO₂ saturation and plume resolution,
 - c. MMV in aquifers which cover large areas, where specific plume movement may be more difficult to precisely predict, particularly in horizontally unconfined aquifers.
3. Continuing work on controlled release calibration and natural analogues are important fronts for CO₂ detection and accounting research.
4. Develop an agreed methodology and language for dealing what will be the principal result of most monitoring – a null result.
5. Continue the rapidly evolving trend to continuous, high resolution, low cost, low impact subsurface monitoring.¹⁵
6. Continue to develop new seismic interpretation and inversion techniques for enhanced CO₂ detection including:

¹⁵ The extent to which this is required on any specific project will depend on the cost, the proponent's needs, the stage and status of their project and the relationship to regulators and local communities.

- 
- a. Quantitative interpretation of 4D seismic, including, 4D inversion (deterministic, stochastic, etc) and 4D full-waveform inversion,
 - b. Using changes in seismic attenuation and seismic anisotropy of the rocks,
 - c. Integrating reservoir & seismic modelling with 4D seismic into the closed loop prediction/correction workflow and improving signal sensitivity with new data analysis algorithms,
 - d. Using rock physics data and models to enhance in fundamental understanding of CO₂-injection related changes in the rock properties,
 - e. The deployment of permanent sources, massive buried receiver arrays,
 - f. Combining active as well as passive seismic methods and novel processing algorithms.
7. The following detectors either need further development or enhancement to be valuable to storage monitoring:
- a. Improving subsurface (down well) solid state detectors for CO₂ to be robust for long term down hole usage.
 - b. A portable low cost C-14 detection system (CO₂ from fossil fuels has no C-14 content).

MMV Methods within the reservoir

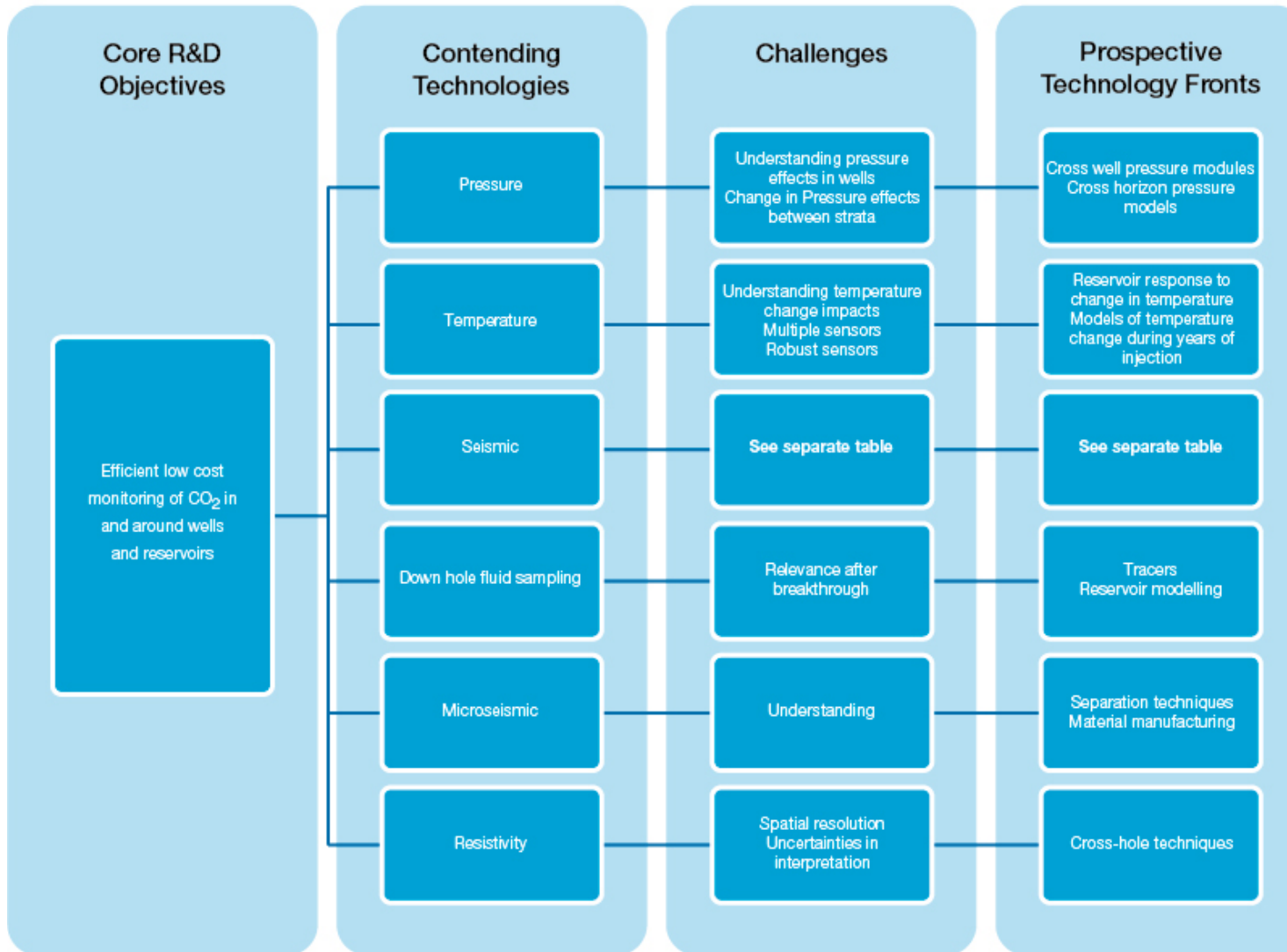


Figure 25 - Prospective technology fronts for MMV within the reservoir

MMV Methods outside of the reservoir – shallow and surface

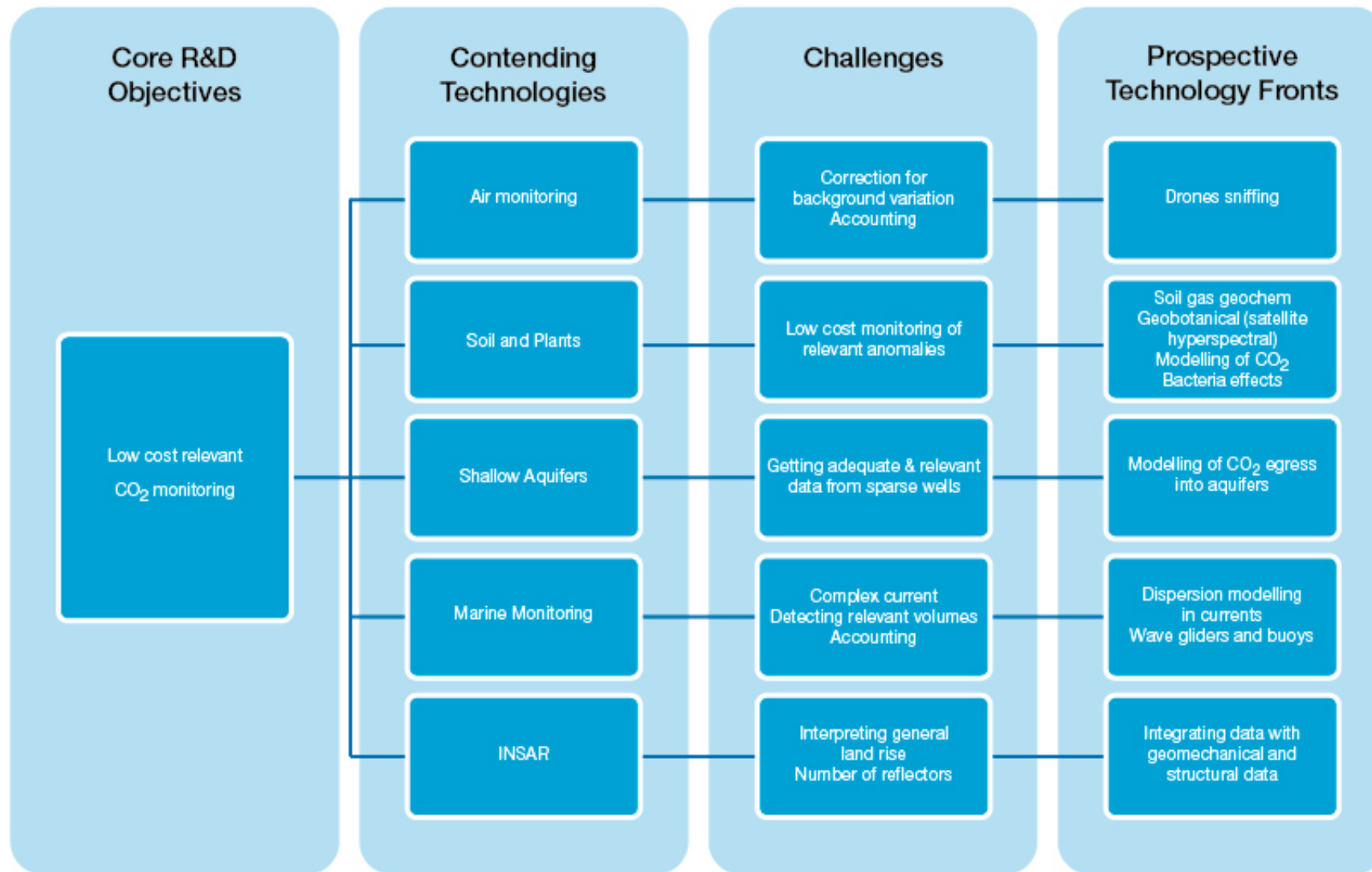


Figure 26 - Prospective technology fronts for MMV outside of the reservoir

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8. The role of Government in Technology Development, Exploration and CCS Industry Dynamics

8.1 Introduction

This chapter looks at some of the ancillary factors related to CCS technology development that require action if the global community is to meet 2050 targets with lowest costs and efficient outcomes. Although CCS technology is readily available and proven, the technology needs to be refined and costs driven down to ensure that CCS can reach its full potential. The research fronts identified in the earlier chapters of this document will continue to evolve as long as the drivers are there for the evolution of the technology.

Over the last ten years there has been a significant growth in CCS technology development; however the lack of global coherence and commitment to climate change action raises some questions about the future trajectory for the technology. Looking at the state of the technology and the associated industry dynamics, there is a need to:

- Deploy and fine tune the current (1st generation) technologies to get progressive learning and improvement by building larger scale pilots and demonstrations and fine tuning the technology from one project to another.
- Drive policies for stronger pull through to commercialisation of the 2nd and 3rd generation technologies to ensure that the benefit of these are realised in the future.
- Start significant regional exploration, discovery and characterisation of large capacity storage sites, factoring in the long lead times.
- Improve international collaboration to get better global outcomes from expenditure.

A variety of studies have shown that the prize associated with CCS deployment is huge in economic terms. However, the cost of climate change mitigation will double in the UK without CCS, adding £30 billion per year by 2050 to the cost of energy for the UK economy (ETI 2013). Furthermore, the cost of delaying CCS deployment will add a further £4 billion for every five year delay. These economic costs highlight the importance of continuing to drive the technology forward; starting the exploration for storage sites is essential.

8.2 Improving the Current Viable (1st Generation) Technologies

For the 1st generation technologies to get the benefit of learning by doing, more projects are required. The technology will only progress to lower unit costs if the cumulative investment or level of deployment progresses. It is thus essential to have incentives and policies to drive industry and/or governments to invest in more plants.

The early scale demonstration projects (see GCCSI 2012) and pilot projects (see Appendices in this document) have demonstrated that CCS technology to capture and store CO₂ is viable. The larger projects are deploying current off the shelf technologies and in the process identifying opportunities to reduce costs for subsequent plants. The aspirations for a planned roll out of CCS, as in many of the recent roadmaps (IEA, CSLF, UK), would see the 1st generation technologies following the incremental pathway seen in Figure 27.

This learning by doing is a well-established and understood pathway for technology development. It is however in stark contrast to the early phases of the search for breakthrough technologies, also seen in Figure 27.

For both pathways, there must be incentives and/or funding, or the technology progress will slowly falter or stop on its development path. If a significant lull in investment is sustained the technology can in some cases go backwards as industry knowledge is lost. In summary, to drive down the cost of the current batch of market available technologies, governments are advised to create the incentives and funding to drive more large scale CCS projects.

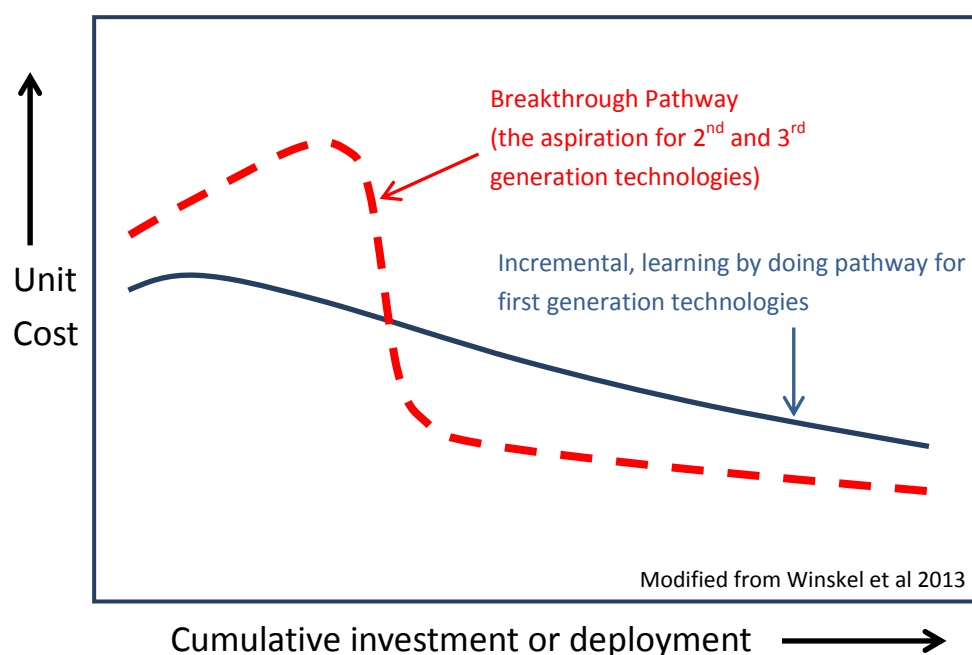


Figure 27 - Learning Curves for Incremental and breakthrough technologies

8.3. Drivers to Lower Costs Through 2nd and 3rd Generation Technologies

For the 2nd and 3rd generation technologies, that have the potential for much lower costs or greater efficiencies, longer lead times are required to bring the technology to the market place. It is also necessary to have the market or policy environment to drive these technologies forward. However, while there is a situation where there is no systematic price on carbon or sense of direction then there will be little incentive for the private sector to invest in the high risk, long term technology development associated with next generation technologies.

In the course of writing this report and talking to organisations that would normally develop and bring energy related technology to markets, it is clear that there is a reluctance to invest whilst there is little or no certainty in the policy environment; i.e. there is currently little or no market pull for the technology. Some companies have spent significant amounts on developing the first generation technologies for the market, only to find that there is virtually no market yet established that requires CCS. The result is that there has been little or no return on their initial investments and there is little appetite for further investment in second generation technologies with long lead times until the policy environment changes.

The technology push for next generation technologies is largely being driven by governments, where the comparatively low cost of the early phase of 2nd and 3rd generation technologies is moderate. Again, without the market incentives or significant investment by governments to pull these next generation technologies through to commercialisation, the technologies will struggle to get to the widespread pilot and demonstration phase and hence into the market. The current absence of strong global policy and market settings will slow down or negate the full and timely realisation of the next generation of low cost capture and storage technology that we will be needed in the 2030s and 2040s.

8.4. Exploration and Technology Development Dynamics

There is a significant body of rapidly evolving exploration technology in the oil and gas industry and this can be easily adapted to exploring for and defining carbon storage capacity. The oil and gas industry is also well acquainted with the exploration risks and timeframes, where exploration investment dynamics are fine-tuned around the rewards, risks and costs associated with exploration.

One of the most pressing problems for global CCS deployment at scale is getting the requisite amount of exploration started, when there is no price on carbon, to justify the exploration risk. Typically large scale carbon storage projects will take some 7-10 years or more from the time of the initial intent to explore, through to the discovery, definition, characterisation and approvals. There is little commercial incentive to start the design and construction of a major capture facility until the storage is well defined. Thus the lead times from initiating exploration through approvals and construction to getting CO₂ into the ground will often be as long as 10-15 years. This has implications for the degree to which CCS can contribute to 2050 targets. Figure 28 below shows the lead time effects of ramping up storage to 100Mtpa in a particular country or state; at a global scale the number will need to be an order of magnitude more than this.

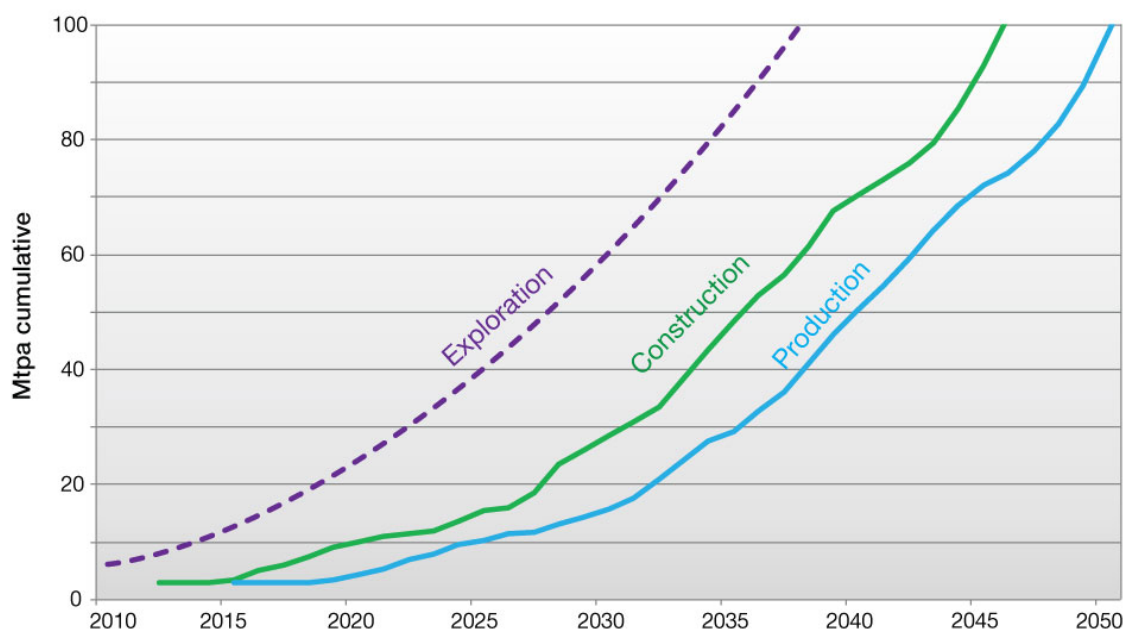


Figure 28 - Schematic diagram of exploration and production timing to reach 100 Mtpa by 2050

This “exploration dynamics” issue is one of the most important outstanding drivers for CCS deployment and it also has indirect links to technology development. The definition and characterisation of a large scale CCS

storage site can also cost several hundred million dollars (Chevron 2012). To make a decision to start exploration and discovery for any government or company is a big step. To get CCS deployment on a large scale requires industry to be incentivised and to have a clear idea of the forward trajectory for profitability. It is required at a scale that can be more easily driven by the private sector as many governments will not be able to summon the required skills, risk appetite and funds to underwrite the level of activity that is required. They would be better to create the market forces that will incentivise the private sector.

In a world where the incentives for carbon storage exploration are lacking and the market pull for technologies is weak or non-existent, the potential delays to technology development are significant. If exploration is slow, large scale deployment will be slow, which will in turn slow learning by doing for current technologies. Conversely, if governments are prepared to incentivise the market to act, with carbon prices, taxes or mandates, the result will be synergistic for both exploration and discovery of storage capacity and also for technology development, resulting in lower costs, which will in turn drive the market dynamics more strongly (see Figure 29).

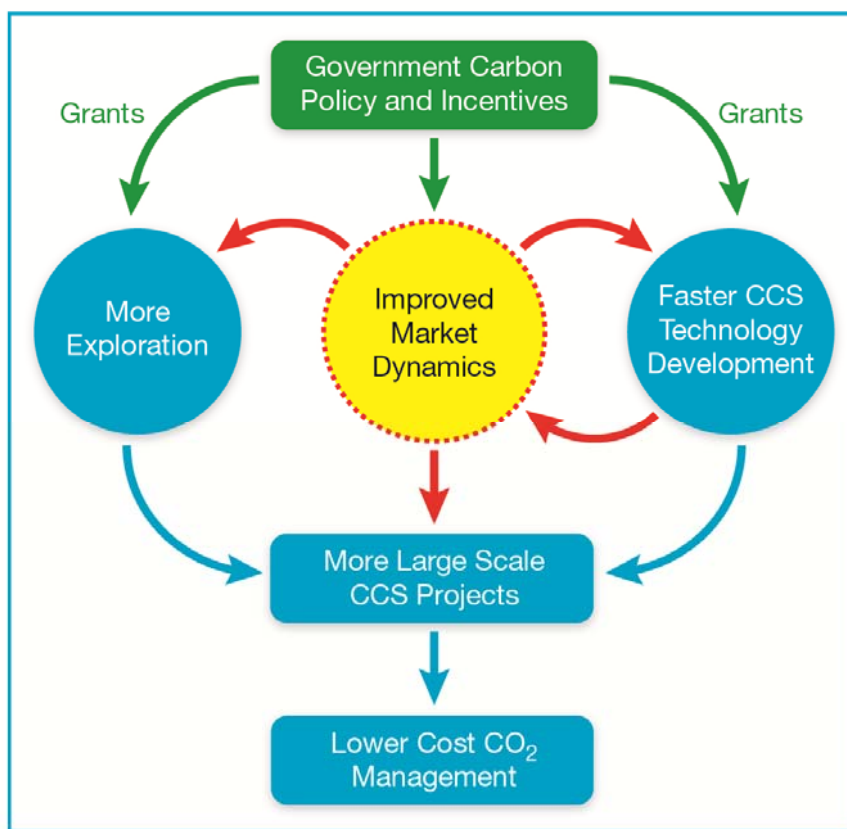


Figure 29 - System dynamics diagram showing the role of market dynamics driving exploration and technology development for CCS

In summary, governments around the world have a technology at their fingertips that can be deployed to manage carbon emissions, but the rate of take up needs to be incentivised. In this context it is useful to look at the role played by governments in the development of the nuclear industry in the US, the development and deployment of SO₂ scrubbing and also the global LNG industry. In all these cases the role of government, with long term vision and technology incentives, brought new technology into play, in a way that could not be achieved by the private sector in anything like the required timeframes (Rai, Victor and Thurber 2010). These authors concluded that “in these industries, governments played a decisive role in the development of the

technologies... and the diffusion of these technologies beyond the early demonstration and niche projects hinged on the credibility of incentives for industry to invest in commercial scale projects.”

8.5. International Collaboration

The logic behind enhanced international collaboration on CCS technology is compelling. There are consistent calls for global collaboration and some jurisdictions are actively encouraging it. de Conick et al (2009), set out the key justification for this and the IEA Technology Road Map (2013) and CSLF Technology Roadmap (2013) both call for more collaboration. Some of the key reasons underpinning international collaboration are that it can:

- a. Provide a strong basis for accelerated learning,
- b. Share the cost of learning, particularly where large or unique demonstration or operation facilities are available for technology development and learning,
- c. Drive globalisation of the learning, including to developing countries,
- d. Expand community and social awareness by leveraging knowledge and demonstration internationally,
- e. Assist in underpinning consistency in regulation and safety/environmental outcomes.

Some jurisdictions are actively encouraging their researchers to collaborate internationally; not only with travel funds but also by providing funds for a financial stake in international consortia working on particular trials or demonstrations. Many senior researchers have a natural network of international researchers by virtue of the field in which they operate. Collaboration can be a natural extension of this if the funds are available.

Collaboration is easier on the storage projects, but is more difficult for capture technologies where Intellectual Property (IP) issues can create difficulties, especially once the technology has reached a certain point on its development path and the IP has some incipient value. Collaboration on 2nd and 3rd generation technologies that are earlier in the development phase is easier.

Governments are encouraged to stimulate international collaboration by providing funds for:

- a. Researchers to travel and share their learning, insights and aspirations,
- b. Joining smaller scale projects, involving exchange of researchers and possibly complimentary work programs,
- c. Contributing to, or buying a stake in important consortia of international parties around larger projects where particular teams can bring a unique or complimentary set of skills to a research or demonstration project,
- d. Encouraging industry, government and researchers to collaborate around key projects, where the collaboration brings a range of commercial and technical perspectives to the research and technology development paths at hand.

International collaboration is considered to be a valuable approach to furthering the technology of CCS.

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Abbreviations and Acronyms

2DS	IEA ETP 2012 2°C scenario
Ar	Argon
ASU	Air Separation Unit
BAHX	Braised Aluminium Heat Exchanger
BTU	British thermal unit
CAPEX	Capital expenditure
CCS	Carbon Capture and Storage
CFB	Circulating fluidized bed
CH ₄	Methane
CLC	Chemical Looping Combustion
CLR	Chemical Looping Reforming
CPU	CO ₂ Processing Unit
CO	Carbon Monoxide
CO ₂	Carbon Dioxide
CO2CRC	Cooperative Research Centre for Greenhouse Gas Technologies
COS	Carbonyl Sulphide
CSLF	Carbon Sequestration Leadership Forum
DCC	Direct contact cooler
DOE	Department of Energy (USA)
EM	Electromagnetic
EOR	Enhanced Oil Recovery
ESP	Electrostatic precipitator
ETIS	Energy Technology Innovation Scheme (Australia)
FF	Fabric Filter
FGC	Flue Gas Condenser
FGD	Flue Gas Desulphurisation
GPU	Gas Permeability Unit
GT	Gas turbine
H ₂ S	Hydrogen Sulphide
HCl	Hydrogen Chloride
Hg	Mercury
HHV	Higher Heating Value
HI	Heat Integration
HP	High Pressure
HRSG	Heat Recovery Steam Generator
IEA	International Energy Agency
IEAGHG	IEA Greenhouse Gas Research & Development Program
InSAR	Inferometric synthetic aperture radar
IP	Intermediate Pressure
IPCC	Intergovernmental Panel on Climate Change
ITM	Ion transport membrane
JT	Joule-Thompson
kPa	Kilopascal
LCA	Life cycle assessment
LCOE	Levelised cost of electricity
LNG	Liquefied Natural Gas
LP	Low Pressure

LPG	Liquefied Petroleum Gas
LOT	Leak off test
LOX	Liquid oxygen pumps
MAC	Main Air Compressor
MAT	Migration associated trapping
MEA	Monoethanolamine
MMV	Measurement, Monitoring and Verification
Mtpa	Million tonnes per annum
MTR	Membrane Technology & Research
MW	Megawatt
MWe	Megawatt electrical
MWth	Megawatt thermal
N ₂	Nitrogen
NaOH	Sodium Hydroxide
NETL	National Energy Technology Laboratory (USA)
NG	Natural Gas
NOx	Nitrogen oxides
OEMs	Original equipment manufacturers
OFT	Oxy-Fuelled Turbine
OPEX	Operating expenses
OTM	Oxygen transport membrane
OxyCT	Oxyfuel Combustion Technology
PC	Pulverised coal
PF	Pulverised fuel
PIMs	Polymers of intrinsic microporosity
PLOX	Portable liquid oxygen pumps
PRMS	Petroleum Resource Management System
PSA	Pressure Swing Adsorption
RA	Risk assessment
RRRR&E	Reservoir, Rock Physics, Resolution, Repeatability & Economics
SER	Sorption Enhanced Reforming
SOA	State of Art
SOFC	Solid oxide fuel cell
SOx	Sulphur oxides
TIT	Turbine inlet temperature
TPD	Tonnes per day
TRM	Technology Road Map
TSA	Temperature Swing Adsorption
USC	Ultra super critical
VSA	Vacuum Swing Adsorption
XLOT	Extended leak off test

APPENDIX A: Table 1 – Pilot Plant Facilities Demonstrating CCS

Name	Name of Facility	Location	Company	Pilot MWe	Pilot t CO ₂ /d	Source	Key Research	Key Innovation	Key Learnings	Year of First Test
Solvents										
Akermin	National Carbon Capture Center, Plant Gaston	Alabama, USA	Akermin	0.01		Coal	Enzyme-catalyzed Potassium Carbonate	Biocatalyst delivery system		2012
Boundary Dam Pilot (1)	Boundary Dam Power Station		SaskPower		4		MEA, RS-2			2000
Castor (2)	Dong Energy	Esbjerg, Denmark	European Commission Funded, IFP-run	3	24	Coal PCC	Piperazine	MEA, proprietary solvents such as CASTOR-2	Solvent degradation	2008
CATO-2 CO ₂ Catcher (3)	CATO-2 CO ₂ Catcher	Rotterdam, Netherlands		0.4		Coal PCC	Amines			2008
CO ₂ Capture Plant Project / CSIRO (4)	Tarong	Tarong, Australia	CSIRO	0.1	2	Black Coal PCC	Advanced amines / piperazine	High rate of absorption		2008
CO ₂ Capture Plant Project - University of Texas(5)	SRO	University of Texas, USA	U. of Texas	0.1 to 0.5		Prepared flue gas	Advanced amines / piperazine	High rate of absorption		2010
CO ₂ Capture Plant Project – Southern Company/US DOE (6)	National Carbon Test Center, Plant Gaston	National Carbon Test Center, Alabama, USA	Southern Company / USDOE	0.5	10	Coal PCC	Multiple Technologies – solvents, sorbents, membranes	Technology dependent		2010
CO2CRC (7)	Hazelwood Power Station	Latrobe Valley, Australia	CO2CRC	2		Brown Coal PCC	Amino acids, potassium carbonate	Lower energy Impurity tolerance		2008
CO2CRC UNO MK 3 (8)	Hazelwood Power Station	Latrobe Valley, Australia	CO2CRC	0.05	1	Brown Coal PCC	Precipitating Process	Lower energy Impurity tolerance		2012

Name	Name of Facility	Location	Company	Pilot MWe	Pilot t CO ₂ /d	Source	Key Research	Key Innovation	Key Learnings	Year of First Test
CSIRO (9)	Loy Yang Power Station	Latrobe Valley, Australia	CSIRO		1	Brown Coal PCC	Conventional amine			2008
CSIRO (10)	Delta Electricity Munmorah Power Station	Munmorah, Australia	CSIRO		3	Black Coal PCC	Ammonia	Lower energy		2009
CSIRO (11)	Huaneng Beijing Cogeneration Plant	Beijing, China	CSIRO		3	Black Coal PCC	Conventional amine			2008
Dow Chemicals (12)	South Charleston	West Virginia, USA	Dow	0.5		Coal PCC	Amines			2009
Elcogas (13)	Elcogas Puertollano	Puertollano, Spain	Elcogas	5		Coal and Petcoke IGCC	Physical and Chemical Solvents			2010
ENEL (14)	Brindisi Power Plant	Cortemaggiore, Italy	ENEL	1.5		Coal PCC	Amines			2009
ERTF (15)	ERTF				1		MEA, RS-2			
First Energy (16)	Burger Plant	Shadyside, OH, USA	First Energy	1		Coal PCC	Ammonia	Lower energy		2008
Hitachi (17)	Tokyo Electric Power Station	Yokosuka, Japan	Hitachi	<1			MEA and advanced amines			1990s
ITC (18)	International Test Centre for CO ₂ Capture	University of Regina, Canada			1	Steam boiler	MEA and advanced solvents (including Econamine)			2000
KoSol Process for CO ₂ Capture (KPCC)	Boryeong Thermal Power Plant	Republic of Korea	KEPCO	0.1	2	Coal PCC	Advanced Amines	Low energy demand Less corrosion & degradation	Low energy demand	2010
KoSol Process for CO ₂ Capture (KPCC)	Boryeong Thermal Power Plant	Republic of Korea	KEPCO	10	200	Coal PCC	Advanced Amines	Low energy demand Less corrosion & degradation		2013

Name	Name of Facility	Location	Company	Pilot MWe	Pilot t CO ₂ /d	Source	Key Research	Key Innovation	Key Learnings	Year of First Test
MHI (19)	MHI Hiroshima R&D	Hiroshima, Japan	MHI		1	Coal PCC	Impurities testing on MHI's solvents such as KS1			2004
MHI (19)	Matsushima Thermal Power Station	Nagasaki, Japan	MHI		0.8	Coal PCC	MHI's solvents and process			2006
MHI (19)	Nanko Natural Gas	Osaka, Japan	MHI	0.1			MHI's solvents and process			1991
NETL (6)	National Carbon Test Center, Plant Gaston	National Carbon Test Center, Alabama, USA	NETL, Linde, BASF	1		Coal PCC	Advanced Amines	Lower energy demand, equipment integration		Beyond 2013
Neumann Systems Group	Colorado Springs Utilities Drake #7	Colorado Springs, CO, USA	Neumann Systems Group	0.5		Coal PCC	Absorber design/piperazine	Lower energy demand, lower footprint, lower cost		2014
Nuon (20)	Nuon Buggenum	Buggenum, Netherlands	Nuon			Coal and Biomass IGCC	Physical and Chemical solvents			2010
PGE (21)	Bechatow Power Station	Bechatow, Poland	PGE	20		Coal PCC	Amine			2014
Siemens (22)	E. ON's Power Station	Staudinger, Germany	Siemens	<1		Coal PCC	Amino acid salts	Low environmental impact Low energy demand		2009
Southern Company Services	Plant Barry	Alabama, USA	Southern Company Services, MHI	25		Coal PCC	Amine, Heat integration	Lower energy demand		2011
Technology Centre Mongstad, TCM (23)	Mongstad Cogen Pilot	Mongstad, Norway	Statoil	15		NG PCC	Chilled ammonia, amines			2012

Name	Name of Facility	Location	Company	Pilot MWe	Pilot t CO ₂ /d	Source	Key Research	Key Innovation	Key Learnings	Year of First Test
University of Kentucky Research Foundation	E.W. Brown Generating Station	Kentucky, USA	University of Kentucky, Hitachi	0.7	15	Coal PCC	Two-stage stripping, integrated cooling tower, Hitachi amine solvent	Lower energy demand		2014
Membranes										
Air Liquide (24)			Air Liquide	0.1	2		MEDAL hollow fibre membrane units	Sub ambient membrane operation		2011
CO2CRC (7)	Hazelwood Power Station	Latrobe Valley, Australia	CO2CRC							
Hybrid Membrane Absorption Process (25)	Midwest Generation Joliet Power Station	Illinois	GTI, Porogen, Aker	0.025	0.5		Porous PEEK membranes	Membrane contactors with carbonate and MEA solvents		2013
Media and Process Technology, Inc.	National Carbon Capture Center	Alabama, USA, Plant Gaston	Media and Process Technology, Inc.		50 lb/hr	IGCC	Membrane	Integrated WGS-membrane reactor		
MTR Polaris (26)	APS Cholla	Arizona, USA	MTR Incorporated	0.05	1	Brown Coal PCC	8" Polaris Modules	Spiral wound design with air sweep, novel polymers	Membrane retains performance in presence of SO _x , NO _x	2010
MTR Polaris (26)	National Carbon Capture Centre (NCCC)	Wilsonville, Alabama	MTR Incorporated	0.05	1	Coal PCC	9" Polaris Modules	Spiral wound design with air sweep, novel polymers		2011

Name	Name of Facility	Location	Company	Pilot MWe	Pilot t CO ₂ /d	Source	Key Research	Key Innovation	Key Learnings	Year of First Test
MTR Polaris (26)	National Carbon Capture Centre (NCCC)	Wilsonville, Alabama	MTR Incorporated	1	20	Coal PCC	Full scale Polaris Modules	Spiral wound and Plate and Frame Design		2013
MTR Proteus (26)	National Carbon Capture Centre (NCCC)	Wilsonville, Alabama	MTR Incorporated	500 lb/hrv		IGCC	Proteus Membrane Module	Spiral wound design, lower energy demand		2012 (smaller membranes tested in 2010 and 2011)
Nanoglowa (27)	Sines	Portugal		?	30 m ³ /hr	Coal PCC	Fixed site carrier membranes			
Nanoglowa (27)	Rutenberg	Israel		?	?	Coal PCC	Parker PPO hollow fibres			
Nanoglowa (27)	Scholven	Germany		?	?	Coal PCC				
Adsorbents										
ADA-ES	Plant Miller	Alabama, USA	ADA-ES	1	20	Coal-fired power plant slipstream	Solid sorbent, reactor design	Novel sorbent, lower energy demand		2014
CO2CRC (7)	Hazelwood Power Station	Latrobe Valley, Australia	CO2CRC	0.15	3	Coal fired power plant slip stream	3 BED VSA, Feed 1.3 atm, 75% CO ₂ purity, 70% recovery, wet flue gas handled	Multi-layered beds removed need for pretreatment and drying	Effect of HCl on feed blower, need for proper front end cleaning, need low pressure drop materials	2010


Name	Name of Facility	Location	Company	Pilot MWe	Pilot t CO ₂ /d	Source	Key Research	Key Innovation	Key Learnings	Year of First Test
Chubu Electric Power Co (28)	Not disclosed	Japan	Takamura	Not disclosed	7.44 Nm ³ /h.	boiler exhaust gas	4-bed, 8-step PSA; Feed: 13% CO ₂ CO ₂ purity 59% CO ₂ Recovery 91.6%	Evaluated NaA/NaX combination in 2 bed VSA; 1.2atm feed, 10kPa vacuum		2001
ECUST Plant (29)	Not disclosed	China	East China University of Science and Technology	?	50 Nm ³ /h	Coal fired power plant slip stream	3 bed VPSA; 80% CO ₂ purity with 80% recovery. Energy of 1.7-2 MJ/kg CO ₂ , vacuum level 7kPa	Have used a variety of cycles with 13X APG and 5A adsorbents from UOP	Front end water removal needed	2012
0.5 MW Dry Regenerable Sorbent Process (32, 33, 34)	KOSPO, Hadong Thermal Power Station	Hadong, Republic of Korea	KEPCO (solid sorbent) KIER, (process)	0.5	10	Coal PCC	KEP-CO ₂ P (K ₂ CO ₃ based-solid sorbents) and Dual fluidised-bed process	Solid sorbent CO ₂ Capture Process	Much less environmental impact (no volatile, less waste water & corrosion) and high thermal stability of sorbent	2010
10 MW Dry Regenerable Sorbent Process (35)	KOSPO, Hadong Thermal Power Station	Hadong, Republic of Korea	KEPCO (solid sorbent) KIER, (process)	10	200	Coal PCC	KEP-CO ₂ P (K ₂ CO ₃ based-solid sorbents) and Dual fluidised-bed process	Solid sorbent CO ₂ Capture Process		2013
NUS	Not disclosed	Singapore	National University of Singapore	0.15	3 TPD	Coal fired power plant slip stream	Not yet disclosed	Commissioning underway	Commissioning underway	2013

Name	Name of Facility	Location	Company	Pilot MWe	Pilot t CO ₂ /d	Source	Key Research	Key Innovation	Key Learnings	Year of First Test
TDA/ADA (30)	Not disclosed	USA	TDA Research, Inc., ADA Environmental Solutions	1kW slipstream	5 ACFM	Coal fired power plant slip stream	Circulating fluidized bed flow contactor, 90% CO ₂ recovery, low purity.	Uses low grade steam at 1.08atm and 110°C to regenerate – pilot used electrical heating though	Amine tethered materials best for this application due to low regeneration energy	2011
TEPCO (31)	Yokosuka Thermal Power Station	Japan	Ishibashi	Not disclosed	1000 Nm ³ /h	Coal fired power plant slip stream	2000 hours; PTSA; CO ₂ purity 99%, 90% recovery; power 560kWh/t CO ₂	CaX zeolite used, 3 stages: dehumidification stage, PTSA stage, PSA stage	Process performance extremely sensitive to CO ₂ level in the feed; alumina needed to remove SO _x	1996

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APPENDIX B:

Table 1: CO₂ Storage Projects

Project Name	Project Owner	Location	Project Size	Storage Reservoir	Current Status	Year of First Injection	CO ₂ Source	Total Injection (Tonnes)	Injection Rate	Injection Depth
BSCSP Basalt	Montana State	Pasco, Walla Walla County, Washington, USA	<100,000t	Basalt	Planned	2013	food grade	907	To be determined	2700-2900ft
Callide Oxyfuel Project	CS Energy	Gladstone, Queensland, Australia	<100,000t	SA or DOG	Planned	Not yet known	Callide A Oxyfuel Plant	60000	Approx 10,000 tpa	To be determined
Carbfix	Reykjavik Energy	Reykjavik, Iceland	<100,000t	Basalt	Operational	2012	Magmatic	2000 (through July 2012)	2200 tpa	400-800m
CarbonNet	VIC Gov department of Primary Industries	Gippsland Basin, Victoria, Australia	<100,000t	SA	Planned	2020	Coal Fired PP	To be determined	To be determined	To be determined
CO2CRC Otway (Stage I)	CO2CRC	Victoria	<100,000t	DOG	Injection Complete	2007	Geologic	65000	150 tpd	2000m

Project Name	Project Owner	Location	Project Size	Storage Reservoir	Current Status	Year of First Injection	CO ₂ Source	Total Injection (Tonnes)	Injection Rate	Injection Depth
CO2CRC Otway Project (Stage 2A,B)	CO2CRC	Victoria, Australia	<100,000t	SA	Injection Complete	2010	Geologic	150	600 tonnes (150 CO ₂ & 450 formation water) injected over 5 days ⁴	1400m
Frio, Texas	LBNL/Utexas	Houston, TX, USA	<100,000t	SA	Injection complete	2004	Purchased (Praxair)	1600	160 tpd	1500m
K12B (CO ₂ Injection at K12B)	GDF/CATO	150km NW Amsterdam, Offshore Netherlands	<100,000t	DOG	Operational	2004	Gas processing	70000	45 tpd	3800m
Ketzin	German Research Centre for Geosciences (GFZ)	Berlin, Germany	<100,000t	SA	Injection Complete	2008	Food Grade (Linde AG)	53000	45 tpd	650m
Masdar/ADCO Pilot project	Masdar, ADCO	Abu Dhabi, United Arab Emirates	<100,000t	EOR	Injection Complete	2009	Commercial	22000	60 tpd	2895m
MGSC loudon Field EOR Phase II	MGSC	Fayette County, Illinois, USA	<100,000t	EOR	Injection Complete	2007	Commercial	39	5-10 tpd	457m

Project Name	Project Owner	Location	Project Size	Storage Reservoir	Current Status	Year of First Injection	CO ₂ Source	Total Injection (Tonnes)	Injection Rate	Injection Depth
MGSC Mumford Hills EOR Phase II	MGSC	Indiana, USA	<100,000t	EOR	Injection Complete	2009	Commercial	6260	20-35 tpd	585m
MGSC Sugar Creek EOR Phase II	MGSC	Kentucky, USA	<100,000t	EOR	Injection Complete	2009	Commercial	6623	18-27 tpd	600m
MRCSP Appalachian Basin (Burger) Phase II	MRCSP	Shadyside, Ohio, USA	<100,000t	SA	Injection Complete	2008	Commercial Source	Less than 50 tonnes	8-49 tpd	6500ft
MRCSP Cincinnati Arch (East Bend) Phase II	MRCSP	Rabbit Hash, KY, USA	<100,000t	SA	Injection Complete	2009	Commercial Source	1000	Varied. Max reached 1200 tpd	3200ft
MRCSP Michigan Basin Phase II	MRCSP	Otsego, MI, USA	<100,000t	SA	Injection Complete	2008	Gas Processing	60000 (10,000 and 50,000)	400-600 tpd	3200ft
Mountaineer	American Electric Power service corporation	New haven, WV	<100,000t	SA	Injection Complete	2009	Coal Fired PP	37403.3	50-100 tpd	2469m

Project Name	Project Owner	Location	Project Size	Storage Reservoir	Current Status	Year of First Injection	CO ₂ Source	Total Injection (Tonnes)	Injection Rate	Injection Depth
Nagaoka Pilot CO ₂ Storage Project	RITE	Nagaoka, Japan	<100,000t	SA	Injection Complete	2003	Food Grade	10400	20-40 tpd	1100m
PCOR Williston Basin -Phase 11 (N E Mcgregor Field)	PCOR	Williams County, North Dakota, USA	<100,000t	EOR (carbonates)	Injection Complete	2009	Commercial	400	313 tpd	2450m
PennWest Energy EOR Project	Pennwest	Alberta, Canada	<100,000t	EOR	Injection Complete	2005	Gas Processing	56749	50 tpd	1650m
SECARB Stacked Storage Project Cranfield Phase II	SECARB	Natchez, MS, USA	<100,000t	DOG	Injection Complete	2008	Geologic	50000	2750 tpd	10300ft
SECARB-Mississippi Saline Reservoir Test Phase II	SECARB	Escatawpa, Jackson County, Mississippi, USA	<100,000t	SA	Injection Complete	2008	Geologic	3020	100 tpd	2895m
South West Hub (Collie South West Hub) (pilot)	WA Department of Mines and Petroleum	South of Perth, Western Australia	<100,000t	SA	Planned	2015	Industrial source from Collie area	To be determined initially small scale	Not yet known	2000-3000m

Project Name	Project Owner	Location	Project Size	Storage Reservoir	Current Status	Year of First Injection	CO ₂ Source	Total Injection (Tonnes)	Injection Rate	Injection Depth
South-central Kansas CO ₂ Project - Wellington Field	Kansas Geological Survey	Sumner County, Kansas, USA	<100,000t	SA	Operational	2011	Abenogoa Bioenergy Plant	70000	To be determined	>5000 ft
Surat Basin CCS Project (Previously Wandoan) (Pilot)	Xstrata	Approx 300km NW of Brisbane Queensland, Australia	<100,000t	SA	Planned	Not yet known	Not yet identified	To be determined	To be determined	To be determined
Tomakomai CCS Demonstration Project	Japan CCS Co. Ltd.	Tomakomai, Hokkaido, Japan	<100,000t	SA	Planned	2015	Gas Processing	To be determined	To be determined	2400-3000m, and 1100-1200m
Total Lacq	Total	Pau, France	<100,000t	DOG	Operational	2010	Oxy boiler	43000	92 tpd	4500m
West Pearl Queen	Sandia Nat Labs	Hobbs, NM, USA	<100,000t	DOG	Injection Complete	2002	Commercial	2090 (over 2 mths)	70 tpd	1372m
Western Kentucky	KGS	Hancock County, KY, USA	<100,000t	SA	Injection Complete	2009	Commercial food grade	626		1115m & 1535m

Project Name	Project Owner	Location	Project Size	Storage Reservoir	Current Status	Year of First Injection	CO ₂ Source	Total Injection (Tonnes)	Injection Rate	Injection Depth
Aquistore project	SASKPOWER	Southeastern Saskatchewan, Canada	>100000t	SA	Planned	2013	(Boundary dam) Coal PP		2000tpd	
Allison Unit	US DoE	San Juan County, NM, USA	>100000t	ECBM	Injection Complete	1995	Commercial	300000	100000-150000 t/yr	2865m
MGSC Decatur	MGSC (DOE/NETL)	Decatur, IL, USA	>100000t	SA	Operational	2011	Ethanol	999000	900 tpd	2100m
PCOR Zama	PCOR/EERC	Zama City, Alberta, Canada	>100000t	SA	Operational	2006	Acid Gas Injection	281160	55 tpd	5000ft
SECARB Anthropogenic - Citronelle	SECARB	Citronelle, AL, USA	>100000t	SA	Operational	Planned:2012	Plant Barry Coal PP	300000	100000-150000 t/yr	2865m